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Consortium for Electric Reliability Technology Solutions

Grid of the Future White Paper on

Interconnection and Controls for Reliable, Large Scale Integration of Distributed Energy Resources

Prepared for the
Transmission Reliability Program
Office of Power Technologies
Assistant Secretary for Energy Efficiency and Renewable Energy
U.S. Department of Energy

Principal Authors

Vikram Budhraja, Carlos Martinez, Jim Dyer, and Mohan Kundragunta
Edison Technology Solutions

CERTS Grid of Future Project Team

Joseph Eto and Chris Marnay, Lawrence Berkeley National Laboratory
Jim Vancoevering, Oak Ridge National Laboratory
John Hauer and Jeff Dagle, Pacific Northwest National Laboratory
Robert Thomas, Robert Lasseter, George Gross, and Kevin Tomsovic,
Power Systems Engineering Research Center
Marjorie Tatro and Patricia Cordeiro, Sandia National Laboratories

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Preface

In 1999, the Department of Energy (DOE) tasked the Consortium for Electric Reliability Technology Solutions (CERTS) to prepare a series of white papers on federal RD&D needs to maintain or enhance the reliability of the U.S. electric power system under the emerging competitive electricity market structure.[1] In so doing, the white papers build upon earlier DOE-sponsored technical reviews that had been prepared prior to the Federal Energy Regulatory Commission (FERC) orders 888 and 889.[2]

The six white papers represent the final step prior to the preparation of a multi-year research plan for DOE's Transmission Reliability program. The preparation of the white papers has benefited from substantial electricity industry review and input, culminating with a DOE/CERTS workshop in the fall of 1999 where drafts of the white papers were presented by the CERTS authors, and discussed with industry stakeholders.[3] Taken together, the white papers are intended to lay a broad foundation for an inclusive program of federal RD&D that extends – appropriately so -- beyond the scope of the Transmission Reliability program.

With these completed white papers, DOE working in close conjunction with industry stakeholders will begin preparation a multi-year research plan for the Transmission Reliability program that is both supportive of and consistent with the needs of this critical industry in transition.

Philip Overholt
Program Manager
Transmission Reliability Program
Office of Power Technologies
Assistant Secretary for Energy Efficiency and Renewable Energy
U.S. Department of Energy

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[1] The CERTS DOE research performers are Edison Technology Solutions (ETS), Lawrence Berkeley National Laboratory (LBNL), Oak Ridge National Laboratory (ORNL), Pacific Northwest National Laboratory (PNNL), Power Systems Engineering Research Center (PSERC) and Sandia National Laboratories (SNL). PSERC is an National Science Foundation Industry/University Collaborative Research Center that currently includes Cornell University, University of California at Berkeley, University of Illinois at Urbana-Champaign, University of Wisconsin-Madison, and Washington State University.

[2] See, for example, "Workshop on Real-Time Control and Operation of Electric Power Systems," edited by D. Rizy, W. Myers, L. Eilts, and C. Clemans. CONF-9111173. Oak Ridge National Laboratory. July, 1992.

[3] "Workshop on Electric Transmission Reliability," prepared by Sentech, Inc. U.S. Department of Energy. December, 1999.

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List of Acronyms

CERTS	Consortium for Electrical Reliability Technology Solutions
CHP	Combined Heat and Power
DER	Distributed Energy Resources
DOE	U. S. Department of Energy
ESCO	Energy Services Company
EMS	Energy Management System
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
LAN	Local Area Network
MW	Megawatt
MVA	Mega Volt-ampere
NERC	North American Electric Reliability Council
RD&D	Research Development and Demonstration
RRC	Regional Reliability Council
RTO	Regional Transmission Organization
SCADA	Supervisory Control and Data Acquisition
T&D	Transmission and Distribution
WAN	Wide Area Network
Var	Volt-ampere Reactive

Executive Summary

Distributed Energy Resources (DERs) are active devices that supply energy (or load reductions). Yet, in contrast to traditional generation sources, DERs are installed within the electricity distribution (rather than on the electricity transmission) system. In fact, DERs can also be thought of as *dispersed* energy resources; consider, for example, emergency generators owned by individual customers. DERs include a wide variety of generation sources, such as fuel cells, micro-turbines, photovoltaics, and hybrid power plants, as well as more traditional sources, such as diesel engines and steam turbines. However, DERs also include electricity storage technologies such as batteries, flywheels, ultra capacitors and superconducting magnetic energy storage. Finally, end-use load controls that manage demand are also considered DERs. No specific size range has been defined for DERs, but most distribution systems would have difficulty accommodating distributed generating resources larger than 10 MW/MVA at any single location; many systems may have even lower limits.

DERs are in transition from the laboratory to the marketplace. Some foresee a time in the not too distant future when DERs will account for a substantial portion of new installed capacity. This paper summarizes the technical requirements for large-scale integration of DERs into the existing distribution infrastructure for purposes of maintaining or enhancing electricity system reliability. Research to facilitate this transition is needed in the areas of control systems (including sensors and instruments to gather intelligence for real-time power management), and dispatch or coordination among distributed generation resources and utility distribution systems. Research is also needed to improve modeling techniques for characterizing DER technologies and their impacts on the distribution (and, ultimately, the transmission) system.

We use a four-step methodology to identify the interconnection and control issues associated with large-scale integration of DERs into the distribution system. First, we describe five market development scenarios that represent paths the industry could take toward greatly increased reliance on DERs. Second, we identify likely customer and utility needs or applications for DERs within the market development scenarios and the performance requirements for DERs that are implied by these applications. Third, we list current technical barriers that prevent DERs from meeting these requirements. Finally, we present research, development, and demonstration (RD&D) priorities that will lead to reduction or removal of these barriers, and we make a number of recommendations for the most effective areas of research to pursue. The paper concludes with a discussion of relative roles of public and private support for the research we describe, and a series of recommendations.

The five most likely scenarios for the evolution of DER markets are:

1. Back-up generators in an expanded role relative to the current system;
2. Local micro-grids;
3. Interconnected local micro-grids;

4. Utility grids with DER integrated to meet Transmission and Distribution (T & D) needs; and
5. Local micro-grids integrated with utility T&D grids.

The local micro-grid is an important concept in the DER market vision. A micro-grid is a cluster of DER technologies operated as a single unit, independent of or interconnected with the utility T&D grid. Micro-grids will likely operate initially as "islands" (that is, independent of the utility T&D grid) because current utility interconnection practices create significant barriers.[4] T&D grids and other micro-grids in the future. Economic and reliability benefits will ultimately encourage interconnection.

Today, a number of technical barriers inhibit increased market penetration of DERs. These include:
1. High cost and uncertain performance of DER technologies;
2. Lack of uniform standards for power quality and lack of information on DER power quality characteristics;
3. Lack of tools to control DERs for peak-shaving applications;
4. Lack of tools to plan for and operate DERs to defer transmission and distribution upgrades;
5. Lack of information regarding control of significant numbers of DER technologies;
6. Lack of standards and protocols to permit DERs to participate in competitive energy markets;
7. Lack of information on demand-side management as a DER; and
8. Lack of knowledge and institutional arrangements necessary to coordinate utility and DER operations.

The areas of research needed to overcome these barriers and facilitate the greatest penetration of DERs include:
1. Inexpensive, standardized power electronics converters and controls;
2. Islanded (i.e., isolated from the grid) and integrated protection and control schemes;
3. Islanded and integrated real-time MW and voltage regulation for DERs;
4. Islanded and integrated real-time dispatch and control;
5. High-quality power for both islanded and integrated operations;
6. Wide area real-time data communication protocols and infrastructures;
7. Integration of demand-side resources in electricity markets;
8. Independent identification of DER operational requirements; and
9. Field testing of all the above technologies and processes.

We believe a special focus for research is needed in the areas of control systems (including sensors and instruments to gather intelligence for real-time power management), and dispatch or coordination among distributed generation resources and utility distribution systems.

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[4] There are important underlying non-technical reasons for this situation, such as the incentives to utilities created by current ratemaking practices to discourage loss of load through customer-owned DERs. These issues are beyond the scope of this paper). In the future, however, we expect that micro-grids will have the capability to be interconnected with (as well as disconnect from.

Research should also include improved modeling techniques to characterize DER technologies and their impacts on the distribution (and, ultimately, the transmission) system.

Taken together, the RD&D tasks we identify will lead to technologies that will:
1. Allow customers and utilities to maximize the energy cost benefits from the installed DERs;
2. Facilitate development and implementation of national standards;
3. Meet customer's needs for reliable energy and power quality;
4. Meet electric system needs for energy, ancillary services, and local voltage support; and
5. Provide options for utilities to defer transmission and distribution expenditures and to improve power quality and grid reliability.

Figure EX.1. DER R&D Priorities.

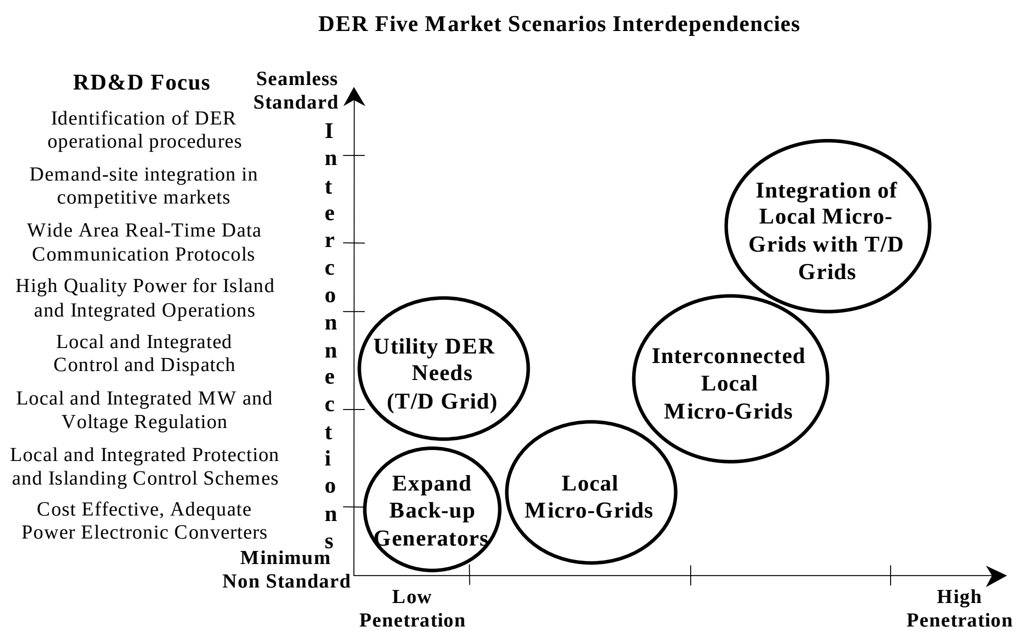

Figure EX.1. summarizes the five key emerging market scenarios that will lead to increased DER market penetration and identifies the key R&D interconnection elements required to support the development of these markets. We believe there is a need for a coordinated national focus on DER interconnection and operations issues and on the effects of DERs on system-wide reliability, as described above. A federal program of research is needed to ensure that the diverse interests of the many stakeholders in the emerging DER market are served in ways cannot be pursued effectively by stakeholders acting individually because of the mixed incentives they face, the great risks involved, or the fundamental nature of the work that is required. In these instances, a federal program is needed to ensure that the greater public interest in reliability-enhancing integration of DER is served adequately.

1. Introduction

Distributed Energy Resources (DERs) are active devices that supply energy (or load reductions). Yet, in contrast to traditional generation sources, DERs are installed within the electricity distribution (rather than on the electricity transmission) system. In fact, DERs can also be thought of as *dispersed* energy resources; consider, for example, emergency generators owned by individual customers. DERs include a wide variety of generation sources, such as fuel cells, micro-turbines, photovoltaics, and hybrid power plants, as well as more traditional sources, such as diesel engines and steam turbines. However, DERs also include electricity storage technologies such as batteries, flywheels, ultra capacitors and superconducting magnetic energy storage. Finally, end-use load controls that manage demand are also considered DERs. No specific size range has been defined for DERs, but most distribution systems would have difficulty accommodating distributed generating resources larger than 10 MW/MVA at any single location; many systems may have even lower limits.

DERs are in transition from the laboratory to the marketplace. Several trends in the global economy -- the move from centralized to distributed technologies, from economies of scale to mass production economies, and from centralized to distributed controls -- are driving the move toward greater reliance on DERs. In addition, a number of changes specifically in the energy industry are contributing to greater penetration of DERs. These include the move from custom to standard interconnections, the restructring of the utility industry, an increase in customer demand for reliable and high-quality power, the widespread availability of inexpensive natural gas, falling prices and improving efficiencies for new small-scale generating resources, and market offerings for innovative bundles of energy and non-energy product and services; all point to an increased reliance on distributed energy resources in the future. By some estimates, DER represents 5 percent of current nation's installed capacity. Studies indicate that DERs could contribute as much as 15 to 20 percent of energy capacity needs by 2010.[1]

This paper examines the likely characteristics of such a future and summarizes the technical requirements for supporting large-scale integration of DERs into the existing electricity distribution infrastructure. We use a four-step methodology. First, we describe five market development scenarios that represent paths the industry could take toward greatly increased reliance on DERs. Second, we identify likely customer and utility needs or applications for DERs within the market development scenarios and the performance requirements for DERs that are implied by these applications. Third, we list current technical barriers that prevent DERs from meeting these requirements. Finally, we present research, development, and demonstration (RD&D) priorities that will lead to reduction or removal of these barriers, and we make a number of recommendations for the most effective areas of research to pursue. The paper concludes with a discussion of relative roles of public and private support for the research we describe, and a series of recommendations on how to proceed.

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[1]Distributed Resources Strategic Review." 1998. Electric Power Research Institute (EPRI) report TR-110245, April.

2. Background

The market penetration of DER technologies is slowly increasing as consumers use them to reduce energy costs, improve power quality, increase reliability, and lower energy cost volatility. From an energy service provider's perspective, packaging a DER with direct access to the electricity grid can offer consumers the benefits of improvements in power quality and reliability, mitigation of ancillary service costs, and a means to reduce peak energy demand. Substantial progress has been in made in developing commercial generation and storage for DERs, but tools are lacking to assess realistically the effects of DERs on system reliability and to identify economic and system benefits for different stakeholders. In particular, we believe deployment of DER technologies will likely be limited unless there is a comprehensive national effort to define the RD&D needed to facilitate large-scale penetration.

The list below summarizes the focus of past RD&D and current issues for DERs:

- Development of specific distributed generation and storage technology devices -- typically as an alternative to utility investments in generation -- rather than the integration, interconnection, control, and operational requirements of DERs.
- The assumption has been that grid owners, current Independent System Operators (ISOs), and future Regional Transmission Organizations (RTOs) should influence, define, and enforce DER interface requirements. This mindset comes out of a system that has relied on large central station power plants rather than a vision in which customer micro-grids or local grids reliably and efficiently serve end users, yet may also be interconnected with utility grids.
- Performance of distributed generation has only been evaluated for base-load operation; i.e., DER generating units have not been evaluated for their usefulness in meeting schedules or responding to price signals.
- Current DERs have not been outfitted for real-time control responses and interconnection control systems that would allow them to supply and efficiently participate in ancillary services markets.
- No uniform DER interconnection standards exist, with the exception of those for photovoltaics (PVs); development efforts are in progress.
- DER deployment strategies have not always taken advantage of demand-side loads as a valuable integrated resource.
- Effective and easily available data communications, appropriate metering infrastructures, and dispatch protocols for DER end-use customers are still lacking. There are no standard real-time data interfaces to connect and dispatch DERs in response to electricity market signals such as price, transmission availability, and other market parameters.

A primary goal of this white paper is to identify the RD&D needs and field testing strategies that address the issues and gaps identified above. The objective is to outline needed developments to facilitate safe, reliable, large-scale interconnection, control, and operation of DERs as part of the electricity distribution system. In doing this, we hope to contribute to a national RD&D agenda for DERs. However, we recognize that a comprehensive agenda should also address deployment costs, regulatory and policy issues, and the specific requirements that DERs must meet in order to interconnect with the power distribution system. Detailed treatment of these additional issues is beyond the scope of this white paper.

3. DER Market Development Scenarios

The technical requirements for large-scale, integration of DERs into the existing distribution system infrastructure will depend on the evolution of the markets that will rely on DERs. Currently, there are two primary markets: back-up generation -- a customer-driven market-- and utility distribution system enhancement -- a utility-driven market. We expect that these markets will lead to three additional future markets: isolated, local micro-grids; interconnected, local micro-grids; and interconnected, local micro-grids and utility distribution systems. Demand-side management -- i.e., customer programs to control energy demand -- is important in all of the markets listed below and is discussed separately at the end of this section.

3.1 Back-Up Generation

DERs are already used extensively to meet specialized customer needs. Back-up/emergency generators, for example, which provide electricity when the electric utility grid cannot, are owned almost exclusively by customers. Uninterruptible Power Supplies (UPSs) -- essentially batteries with a charge/discharge control system-- are also used, especially for computer-related, "ride-through" applications. As improved distributed resources enter the market, their operating hours will likely increase; for example, inexpensive, efficient fuel cells could be operated as baseload facilities.

3.2 Distribution System Enhancement

Utilities are currently exploring use of DERs in applications that are integrated within the distribution and transmission system. DERs of various sizes may be installed at utility locations throughout the grid to meet the following needs:

- Feeder Relief
- Transformer Bank Relief
- Reactive Support for the T&D Grid
- Remote Load Servicing
- Power Quality Improvement
- Peak Shaving
- Load Growth and Ancillary Services
- Loss Reduction
- Transmission and Distribution Expansion Deferral
- Grid Asset Utilization Improvement

3.3 Local Micro-Grids

With the right combination of economic conditions, customers will leave the grid entirely and meet their on-site needs for energy, power quality, power back up, and co-generation through micro-grids. A micro-grid is a cluster of small generators; each generator typically has, in addition to storage, a capacity of less than 500 kW. The micro-grid operates as a single unit independent of or interconnected with the utility T&D grid.

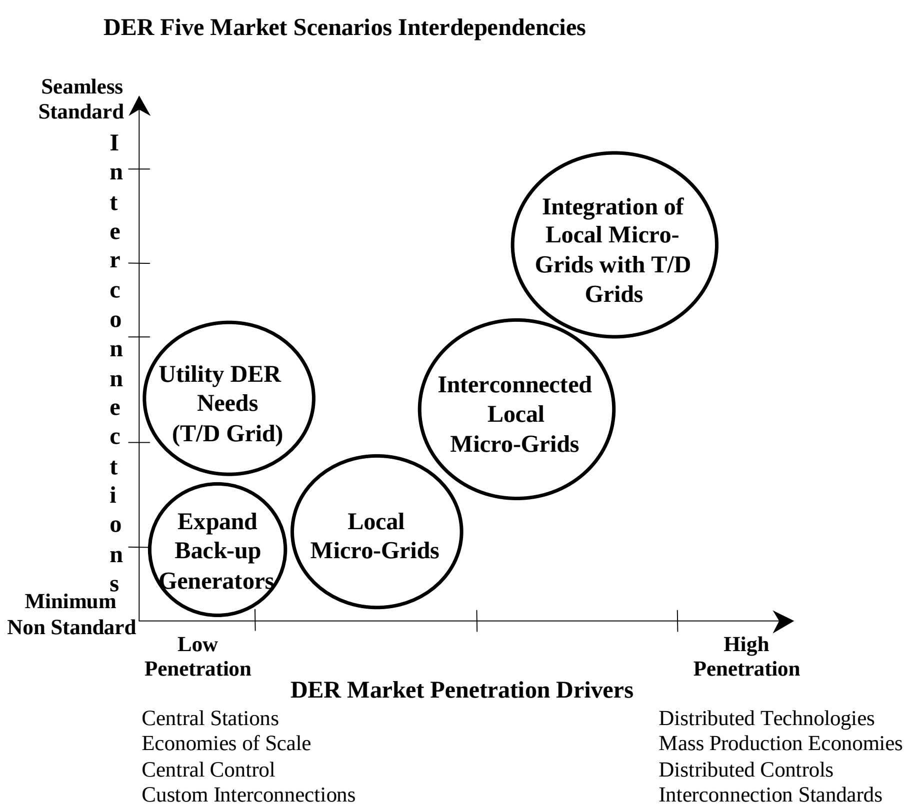
3.4 Interconnected Local Micro-Grids

One market segment will consist of customer micro-grids that are interconnected with other micro-grids to satisfy energy, reliability, quality, and efficiency needs that are enhanced by sharing arrangements among groups of customers who will take advantage of a common infrastructure. Micro-grids will likely be interconnected according to their own safety and reliability guidelines but without specific, standard interconnections with utility grids.

3.5 Interconnected Local Micro-Grids and Utility Distribution Systems

Another market segment will consist of micro- and utility grids interconnected based on mutually agreed upon, standardized national guidelines. This interconnection will allow customer micro-grids to participate in competitive energy and ancillary services markets. Micro- and utility grids will back up one other while meeting the energy, reliability, and power quality needs of each group of micro-grid power customers. See Figure 1.

Figure 1. DER Market Scenario



3.6 Demand-Side Resources

For more than a decade, many electricity customers have created internal demand-side management activities to control their electricity consumption and costs. Customer management of loads in this regard should be treated in manner consistent with treatment of distributed generation as another example of a distributed energy resource. Specifically, demand-side management can allow customers to:

1. Make adjustments when internal or external energy resources become unavailable;
2. Reduce demand during hours when energy costs are highest;
3. Offer control of their loads in a competitive ancillary service market;
4. Manage internal electrical facility outages; and
5. Improve power supply reliability.

Similarly, utilities can benefit from demand-side management, which will offer:

1. Enhanced ability to manage T&D congestion;
2. Ability to support or respond to system needs during or immediately after disturbances;
3. Reduction of expenditures for grid enhancements;
4. Increased utilization of T&D assets; and
5. Improved reliability of service to customers.

4. Customer and Utility DER Applications

In each of the market development scenarios identified above, DERs will be adopted based on their ability to meet customer or utility needs. These needs will define the applications for DERs, which, in turn, points to the RD&D needed to facilitate the integration of DERs into the power system.

4.1 Customer-Driven DER Applications

4.1.1 Stand-by power, reliability firming -- Any DER that provides readily dispatchable, reliable back-up power during outages of more than a few minutes is an "emergency" or stand-by generator. These generators may or may not be interconnected with the utility; most often they are not.

4.1.2 Premium power -- Premium power DERs can improve power quality and/or allow customers to ride out power outages of a few minutes or less.

4.1.3 Peak shaving -- Peak-shaving DER options allow utility customers to generate all or part of their power needs on-site during periods of high electric demand (for either the facility or the power grid). Customers use peak shaving strategies to avoid excessive electric demand charges and/or or time-of-use energy charges.

4.1.4 Low-cost energy -- In some cases, customers can produce significant amounts of electric energy at a cost that is lower than the price of purchasing equivalent electric energy from the utility. In these situations, customers use DERs to reduce electric energy costs. Demand charge reductions may also accrue if DERs produce electricity during peak demand periods. DERs used for low-cost energy typically operate for 4,000 to 8,000 hours per year. In most cases, DERs used for low-cost energy also yield thermal energy, as described next for "combined heat and power" applications.

4.1.5 Combined heat and power -- Many DER generating technologies can produce both electricity and heat -- known as combined heat and power (CHP) or co-generation. Generators used for CHP are usually operated for most or almost all hours during the year.

4.2 Utility-Driven DER Applications

4.2.1 Augmentation of distribution systems/relief for feeders and capacitor banks -- In the near term, electric utilities will use an increasing amount of distributed generation to augment their power distribution systems. Most DERs used for this application will produce modest amounts of energy, adding to the utility's power distribution system during periods of peak demand when DERs have a lower overall cost than alternative strategies.

For example, small DER "modules" may be added to augment the capacity of a nearly overloaded substation or delay the need for a feeder upgrade. DERs may also be installed to delay the need for expensive substation reinforcement. Utilities may use DERs for more permanent distribution capacity, if the life-cycle cost of DERs is lower than the cost of substation and feeder upgrades, which can be $500/kW, or more.

The benefits for applications that augment the distribution system come in the form of delayed wires investments (especially rewarding in a system of performance-based rate-making), firming up less reliable feeders, and for improved voltage support. The owner of DER units used for grid support, would, in theory, also be able to dispatch the unit to supply high peak central station loads, which would add to the unit's value.

4.2.2 Central dispatch of DER -- Significant benefits can accrue to a utility that has emergency access to reserve power, through, for example, activating customer-owned standby generators. As severe system peaks become more commonplace in the U.S., the ability to quickly and easily call up a fleet of 100-MW standby generators can be very valuable.

4.2.3 Service power quality and reliability -- Utilities can also use DERs to maintain power quality and/or reliability of electric service within specific parts of the power distribution system. For example, if voltage is below acceptable levels at certain times of the day and for only a few days per year on a specific distribution wire, then a utility-owned UPS or generator may be used to improve the voltage.

Similarly if the reliability of an area is poor, a distributed generator could be placed on the feeder to pick up at least the most valuable loads if service is interrupted. If a feeder has had high outage rates, say 10 hours per year, and customers value their reliability at $5.00 per kWh of lost service, the value of serving that lost load with distributed resources would be $50/kW-year, or an equivalent capital cost of about $500/kW, using utility financing.

4.2.4 Power quality and reliability firming -- Utilities will use DERs to improve power quality and/or reliability in targeted parts of the power distribution system and/or to meet the power quality and reliability needs of specific high-value customers. Distributed resources can be used to prop up sagging voltage profiles in relatively weak distribution systems or eliminate the need for bringing in a second feed to a customer with special reliability requirements. Customers with sensitive loads may begin to group, and either filter power or add distributed generation and storage to firm up the reliability to those loads.

4.2.5 Energy services -- Many utilities do or will include DERs in their suites of "energy services." DERs may be incremental in nature, used to address specific customer needs such as power quality that is superior to normal (e.g., a customer may have "high value-added" computer operations and be willing to pay for superior service to those operations). A stand-by generator located on the utility side of the meter could be used to provide high-reliability service to specific customers.

DERs may also be offered by utilities as part of an energy "strategy" -- utility bill consolidations, customer productivity enhancement partnerships, CHP installations, etc.

5. Current Technical Barriers to DERs

Currently, there are a variety of technical barriers to integration of DERs with the power grid. After listing the most well-known of these, we conclude this section with an extended discussion of barriers related to the operational requirements of DER. These barriers highlight the structural and institutional issues that are raised by the shift from reliance on large central station generators as sources of power today to greater reliance on distributed energy resources in the future.

5.1 Technical Barriers to DERs

Protective devices used in the traditional electricity distribution system are normally very simple in nature. A typical distribution feeder may only have straight overload and ground protection at the source bus, as well as fuses on feeder taps and directional overload where lines are operated looped at remote stations. These simple relay or protective applications are likely to be insufficient as DER technology is deployed in large pockets on the distribution system. In order to assess the impact of large numbers of distributed resources on the dynamics of a regional electric grid as well as on local service conditions during a disturbance, it will be necessary to develop methods that treat the distribution system as bi-directional and integrated with the transmission network in a consistent fashion.

Of particular importance is work on power electronics converters and controls whose current cost along with their unproven operational performance and maintenance requirements and the lack of field demonstration sites for them have caused customers and utilities to be cautious in implementing DER technology.

Furthermore, no adequate data are available on DERs to permit simulation studies of their dynamic behavior and their impact on customer power quality and system reliability.
New methods are needed to assess the effects of large numbers of distributed technologies (e.g., storage) on local area and system reliability. In order to assess the impact of large numbers of distributed resources on the dynamics of the regional electric grids and on local service conditions during a system disturbance, methods are needed that treat the distribution system bi-directionally and as integrated with the transmission network in a consistent fashion. (Conventional transmission planning models, by contrast, treat the entire distribution system as individual loads at substation buses; distribution system planning models treat the transmission network as a voltage source at the each substation low-voltage bus.)

Currently, no dynamic models are available that allow simulation studies to identify the automatic watt and voltage response characteristics and control and regulation requirements for DER technology. The reliability impact of micro-grids operating on local distribution networks will be difficult to quantify without adequate data.

DERs will be deployed by both utilities and customers in the expectation that these resources have load-following capability, which will be utilized to provide peak shaving or to unload electrical facilities. Currently few or no data are available that can support or discount any manufacturer's claim that a technology has this capability. Poor load-following performance by a DER could negatively affect system reliability.

Currently, many utilities have limited or no real-time data from their own local distribution substations, and there is little or no communication infrastructure to collect this or other information pertaining to operations on the customer side of the meter. Extensive real-time data communications in the form of Wide Area Networks (WAN), protocol standards and other support infrastructure may be required to allow management and control of some distributed technologies as well as the local distribution grid and the transmission grid.

Outside of load management and time-of-use pricing, the electricity industry has paid little attention to the impact of customer loads on reliability; similarly, little attention has been paid to capabilities for managing customer loads to solve short-term reliability needs.

In summary, the primary technical barriers to increased reliance on DERs include:

1. Need for protective devices that are adequate for a system in which power sources are widely distributed; the protective devices used to the traditional electric distribution system are simple in nature and are unlikely to be extremely inadequate for a system in which DER technology is deployed in large pockets.
2. The current high cost of power electronics to control micro-generators as well the unproven operational performance and maintenance requirements of these electronics and a lack of field demonstration sites for them; as a result, both customers and utilities have been wary of implementing DER technology.
3. Lack of data for analyzing how DERs respond to rapid, real-time system dynamics, which, in turn, would allow evaluation of the effect of DERs on power quality.
4. A need for new methods to assess the effects of large numbers of distributed technologies on local area and system reliability.
5. Lack of data to quantify the impact on system reliability of micro-grids operating on local distribution networks.
6. Lack of data to evaluate manufacturer claims that DER technologies have load-following capabilities.
7. Lack of data for reliable control and efficient dispatch of DERs.
8. Lack of information on the effects of managing customer demand to solve short-term reliability needs.

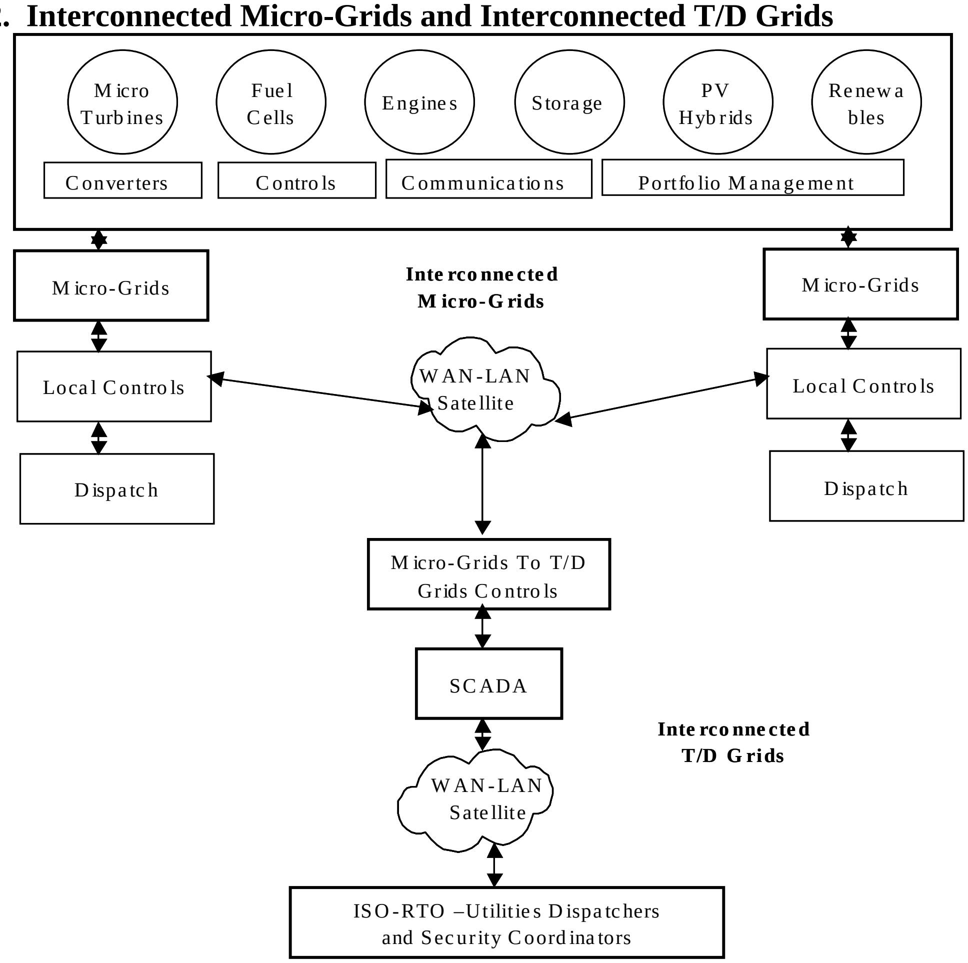
5.2 DER Operational Requirement

In the remainder of this section, we focus on DER operational requirements because they highlight the complex structural and institutional issues that are raised by greater reliance on distributed energy resources in the future. In a summary, it is easier to ensure reliable electricity service when one entity has total ownership or control of all facilities involved; accordingly, distributed energy resources, by their dispersed nature, pose significant new challenges for reliability. Operating procedures will be needed to address the reliability needs of both the owners of DERs and the local utilities through whom DERs will be interconnected with the power grid. Utility and non-utility DER operations will have to be closely coordinated to ensure that reliability standards are maintained.

If a DER is part of an isolated micro-grid, the owners and operators of the micro-grid as well as its participants will have to establish reliability standards appropriate to their needs, and, if they wish to be interconnected with the utility, to the utility's needs. Once reliability standards are established, the micro-grid infrastructure must be designed to meet them. Operational requirements and procedures will then be needed to effectively manage the reliability of the micro-grid.

Figure 2 shows an integrated view of technically feasible configurations for DER generation, customer micro-grids and utility T/D grids. As the integrated diagram shows, micro-grids can be configured in an islanding (or electrically isolated) mode, intraconnected with other micro-grids, or interconnected with T/D grids. As discussed in the next section, there are cross cutting technologies required for all feasible configurations such as improved power electronics, and control data communications, and other technologies that are unique for each configuration such as local and global dispatch systems.

Figure 2. Interconnected Micro-Grids and Interconnected T/D Grids



5.2.1 DER Operational Issues. It is not our intent to identify all operating issues that utility and non-utility entities might encounter when planning to connect a DER to the utility grid or to an isolated micro-grid. We list below the key types of concerns that may arise and that will require utility and non-utility entities to coordinate operations. These include the need for:

1. Short-term planning process for energy, capacity, ancillary service, and maintenance;
2. Real-time management for energy, capacity, ancillary service, and maintenance;
3. Delineation of jurisdictional authority of electrical facilities;
4. Protocols for reporting of events;
5. Control of reactive power to manage voltage;
6. Authority to request a deviation from normal operation;
7. Defined operating requirements for normal and unplanned events;
8. Agreements regarding operation during loss of metering or control capabilities;
9. Agreements regarding operation during a system black start;
10. Agreements regarding operation during a system energy or capacity deficiency;
11. Definition of safe work practices with electrical equipment;
12. Establishment of data and voice communications for operations.

5.2.2 Preplanning and Procedures to Address DER Operational Issues. In order to address these issues, adequate preplanning and operating procedures will be required.

Pre-planning includes:

1. Identifying as many likely operating events and emergency scenarios as possible;
2. Analyzing the potential impact of these events on operations;
3. Defining operational requirements to mitigate negative impacts;
4. Writing appropriate operating procedures to manage events; and
5. Training of staff in these procedures.

Operational procedures should clearly and concisely:

1. Identify personnel to whom each procedure applies;
2. Define the operating events/emergencies covered and their potential impact(s);
3. Describe the desired outcome or results of the procedure;
4. Identify jurisdictional authority and areas of overlapping authority;
5. Define expected operation during an emergency; and
6. Identify the appropriate staff to be contacted and the proper protocol.

5.2.3 Parties Responsible for Defining DER Operational Requirements. Several key groups of stakeholders will be responsible for defining these operational requirements:

National Electric Reliability Council (NERC)/Regional Reliability Council (RRC) – The standards and criteria produced by NERC and the RRCs are intended for control areas and pertain primarily to the bulk power transmission system.

Utilities – Utilities are the organizations likely to be best able, because of their experience, to determine operational requirements and procedures. However, customers/DERs could perceive utilities as imposing unnecessary requirements.

Customers – Customers might not have sufficient expertise to determine the necessary requirements and would have economic motivation to select only the least expensive requirements.

Regulatory authorities – Regulatory agencies may or may not have the experience or resources to define operating requirements.

6. Who Should Do What? Public and Private Support for DER Research

In this section, we consider the relative roles that public and private support for DER research should play in addressing the technical barriers identified in the previous section.

6.1 Near-Term Research, Development and Demonstration

Utilities will use distributed technologies in the near term as capacity resources, mostly to augment the power generation system. These resources will be used rarely if at all to produce significant amounts of energy or to reduce the need for high-capacity-factor central generation resources. Distributed resources will also be used to defer or eliminate the need for expensive upgrades to the power distribution system, thus improving transmission and distribution asset utilization. Utilities will use DER to improve the quality and reliability of power in specific areas and as part of packages of “energy services.”

Customers will use distributed resources in the near term to improve the quality of power to sensitive equipment, to firm up poor reliability, to reduce their demand charges, and to take advantage of “waste” heat associated with on-site power generation, thus increasing cost effectiveness. Partnerships with utilities and Energy Service Companies (ESCOs) may lead customers to activate their standby generators for system peaking needs.

The private sector is well positioned in the near term to develop distributed resource technologies, setting costs and performance based on market forces and customer input. The private sector can best choose among the diverse opportunities for near-term DER technologies, more effectively picking winning technologies and leading customer applications and market timing than the public sector can. Small, innovative companies may be discouraged from entering distributed resources markets, however, unless DER interconnection barriers are reduced for all market participants.

6.2 Long-Term Research, Development and Demonstration

Long-term interconnection RD&D, development, and field testing should focus on technologies that will help remove the interconnection barriers identified for each of the DER markets. During the next decade, as distributed resource technologies improve, higher capacity factors will be likely along with deeper penetration on feeders and more dependence on embedded resources. Successful interconnection technologies must be able to ride through severe power disruptions safely, reliably, and effectively.

To support the long-term vision of reliable, large-scale penetration of multiple and diverse distributed resource technologies, a comprehensive public RD&D program will be needed. This program should include high-risk, high-payback elements for interconnection, control, and operational techniques as well as advanced distributed generation and storage technologies.

Public support is appropriate to help overcome barriers to DERs because:

- Many aspects of DER interconnection technology are cross cutting in nature; therefore, no single private company has an incentive to develop needed technologies.
- Interconnection research may be too expensive for a single private company to undertake.
- Some of the technology objectives in this emerging field are still ill-defined, so the broad perspective of multiple stakeholders, brought together in a public forum, is necessary.
- There may be high-risk, cutting-edge opportunities for long-term research and development. This type of work is most appropriate for publicly funded research organizations.

The DER technology revolution is already under way and unlikely to be stopped. Investing in research that will help shape this revolution will produce large rewards in the form of economic vitality for utilities, consumers, and technology developers. The risk of not undertaking research to understand and influence the new market for DERs is that unfavorable policies may be enacted, which will be difficult and costly to reverse.

7. Public Interest RD&D to Remove Technology Barriers and Facilitate Reliable, Large-Scale Integration of DERs

The priorities for public interest RD&D offered in this section are based on the following considerations:

1. Public support is appropriate for RD&D that advances national interests and that will otherwise be inadequately supported by the private market.
2. Currently, the entities with the greatest potential interest in an expanded role for DERs are unlikely to pursue the necessary RD&D: customer and equipment manufacturers lack the information necessary for pursuing this research, and utilities face uncertain or negative incentives for doing so.
3. Current RD&D focuses primarily on individual DER technologies, not on issues of system integration and interconnection.

Based on these conditions, we propose a federal program for RD&D on DER system integration and interconnection that emphasizes:

- Providing local and integrated DER real-time controls.
- Establishing DER inter- and intra- connections and integration requirements.
- Creating demonstration field-test beds.

The following interconnection and control RD&D are critical to the widespread interconnection and integration of DERs:

Power Electronics -- A cost-effective converter is needed, using the latest power electronic devices, to withstand voltage spikes and high current:

1. The new converter should have bi-directional capability so that generation and storage can be integrated with customer load and the utility grid.
2. Testing should ascertain that the converter does not add harmonics or negative sequence quantities to the utility grid.
3. Converter and control hardware/software should be proven to meet the power quality needs of customers during system disturbances.
4. The peak-shaving capability of DER should be demonstrated at customer sites as customer load demand increases; utility supply should be kept constant during peak conditions.
5. Regulation capabilities of DERs should be demonstrated; utility supplies should be kept constant while customer load changes during a 24-hour period.

Data Acquisition -- Uniform standards are needed for real-time acquisition of massive numbers of customer data points. A process is needed to obtain industry consensus regarding the type of control data, the frequency and format for data collection, and the length of time during which data need to be collected for various DERs. The data necessary for static and dynamic application of DER for various applications (e.g., power quality, ancillary services, regulation, dispatch) must be identified.

Relay Protection and Islanding Schemes -- Uniform industry-wide standards must be adopted for relay protection and islanding schemes for large DERs that are integrated with the utility grid. Relay protection requirements must be identified for various DERs at various voltage levels on the customer and utility sides during steady-state and emergency conditions. These systems must be demonstrated to show that they can meet the protection and islanding requirements of various types of DERs under various conditions.

Control Data Communications -- As shown in Figure 2, real-time control data communications will be required at two levels: from DER devices to local DER controllers, and from local DER controllers to utility substations and subtransmission or even transmission Supervisory Control and Data Acquisition (SCADA). An open-standard two-way data communication protocol is needed to send and receive DER control data to utility substations and SCADAs and vice versa. Software must be created to control the DER remotely and in real time from the utility's SCADA, in order to improve the reliability of the system during disturbances.

Regulation Control -- Load Regulation (MW): To reduce the cost of ancillary services, a customer's demand and the energy output of a DER must be closely matched. Therefore, DER output must be regulated, and, where storage devices are utilized, output must be integrated with storage.

Voltage Regulation (VAR) -- A voltage regulation design is needed that does not interfere with the utility's voltage regulation process. This design must meet regulation at various voltage levels (480V, 4.16 kV, 12 kV, and 33 kV).

Dispatch Software -- Software is needed to dispatch and redispatch DERs during steady-state and emergency conditions to meet the energy, ancillary, and reliability requirements of the power grid. This software should be demonstrated in pilot projects at a customer sites and at the utility; the software must accommodate ancillary service, power quality, and reliability needs.

Technical Standards -- Size and performance specifications must be developed to facilitate low-cost mass manufacturing of DERs.

Field Test Beds -- Islanded micro-grids, intraconnected micro-grids, and interconnected micro- and T&D grids must be tested and validated. This testing will provide the opportunity to develop commercial-grade products for DER deployment.

Safety -- Installations at customer and utility locations must demonstrate that DERs are safe for customers, the general public, and utilities.

Operational Requirements and Procedures--Operational procedures must be independently identified for the DER technologies that operate interconnected to the utility grid or as part of isolated micro-grids. Research must determine whether the requirements change when the same resource is connected to different operating voltages.

Demand-Side Participation in Energy Markets.[1] The following issues associated with inclusion of demand-side resources in DERs require special attention:

1. Collection of data on short-time interval load characteristics;
2. Development of modeling requirements that will permit simulation of demand-side performance;
3. Demonstration of control of demand-side resources;
4. Identification of communication, infrastructure, and integration requirements; and
5. Quantification of the long-term benefits of DERs for grid reliability.

Table 1 identifies, for each the five DER market driven scenarios and most likely DER applications for them, the three main categories of DER interconnection and control RD&D; 1) local and integrated control technologies, 2) interconnection and system technologies, and 3) field demonstration test beds. For each of these categories, the table identifies the RD&D that is needed to facilitate reliable, large-scale integration of DER.

[1] See also the CERTS white paper: "Review of the Structure of Bulk Power Markets," by B. Kirby and J. Kueck.

Table 1 - DER Market Scenarios Framework for Identification of RD&D for Interconnection and Controls

DER Market Driven Scenarios	DER Applications	*RD&D Needs for Local and Integrated Controls Technologies*	*RD&D Needs for Interconnection and System Technologies*	*RD&D Needs for Field Demonstration Test Beds*	DER Policies and Regulatory Issues
Integration of Micro-Grids with T/D Grids	• **Joint access to markets** • **Mutual power back-up** • **Improve local & system power quality and reliability**	• **Automatic islanding and resynchronizing** • **Adaptively sized and configured** • **Integrated dispatch** • **Integrated load management** • **Improve power quality**	• **Mutual back-up functions** • **Interconnection standards** • **Provide micro-grid owners access to energy and ancillary markets**	• **Dynamic control** • **Definition and deployment of test beds for micro-grids to T/D grids interconnection**	• **Standard, seamless Interconnections** • **Tariff for backup power**
Interconnected Micro-Grids	• **Distributed power supply** • **Shared reliability and energy** • **Increased efficiencies** • **Shared resources** • **Cogeneration**	• **Cluster controls and dispatch** • **Mini SCADAs & EMSs** • **Real-time control Wide Area power network**	• **Voltage control** • **Reliability issues** • **Safety issues** • **Integrated metering** • **Interconnection flow control** • **Resource allocation** • **Identify operational requirements**	• **Definition, deployment of micro-grids Test Beds** • **Software and hardware for customer micro-grids Energy Management**	• **Same as local micrp-grid Scenario** • **Proper metering** • **One stop for permits**
Local Micro-Grids	• **Local power quality** • **Local reliability** • **Back up power** • **Peak shaving** • **Cogeneration** • **Energy needs** • **Emissions reduction**	• **Integrated, low cost converters & controllers** • **Load following** • **Frequency control** • **Cost and performance of power electronic** • **Relays protection**	• **Islanding operation** • **Micro-grid reliability** • **Control data communications** • **Local dispatch** • **Identify operational procedures** • **Voltage control**	• **Dynamic control simulations** • **Definition, deployment of intra and inter connected micro-grids test beds**	• **Siting issues** • **Environmental issues**

Table 1 - DER Market Scenarios Framework for Identification of RD&D for Interconnection and Controls, continued.

DER Market Driven Scenarios	DER Applications	*RD&D Needs for Local and Integrated Controls Technologies*	*RD&D Needs for Interconnection and System Technologies*	*RD&D Needs for Field Demonstration Test Beds*	DER Policies and Regulatory Issues
Utilities DER Needs (T/D Grid)	• **T/D deferral** • **Reactive support** • **Remote loads** • **Power quality** • **Ancillary services** • **Reliability utilization** • **Improved grid asset utilization**	• **Lower power electronics costs** • **Wide area control data networks** • **Integrated control and dispatch** • **Adapt relay schemes** • **Voltage regulation**	• **Integrated distribution planning models to include power supplies** • **Identify operational/ maintenance issues**	• **Demonstrate a 10 MW DER for grid support for one or several of the utility uses**	• **Incentives for utilities for DER rate base** • **Regional market Studies** • **Credit for T/D deferral** • **Credit for Ancillary Services**
Expanded Role for Back-up Generators	• **Expand role of back-up generators** • **Energy Services**	• **Load following** • **Frequency control**	• **Islanding operation** • **Control data communications**	• **Dynamic control simulations**	• **Siting issues** • **Environmental issues**

8. Conclusion and Recommendations

The North American power grid will require significant additional generating capacity during the next decade. The presence of powerful drivers for a DER market should motivate T& D utilities and customers to strongly consider relying on DERs to meet some of this need. DERs will operate both in isolated micro-grids and interconnected with the utility grid. The owners and operators of DER facilities will have to meet local and industry reliability requirements. The challenge for both the local utility and customer will be to manage both planned and unplanned operations that could have a negative reliability impact on power supply reliability for any subset of consumers. Utilities and customers will have to closely coordinate their electrical operations to ensure the established reliability standards are maintained.

How and how fast different stakeholders will get the most benefits from the integration of this new technology will depend on finding the appropriate solutions for the still existing real time control, interconnection and institutional issues facing this technology and identified in this paper.

The RD&D priorities identified and described in the paper will facilitate and allow for a timely, safe and reliable integration of DER technologies as either cluster of independent micro-grids or as integrated resources within utilities power systems. We summarize these priorities in the following recommendations for a coordinated program of public interest research:

Recommendation 1: The Department of Energy should take a leadership role in funding RD&D to ensure or enhance power grid reliability for a scenario that assumes DER technology will provide at least 20 percent of the nation's energy capacity by 2010.

Recommendation 2: Appropriate DER demonstration field test bed(s) should be established so that power electronics manufacturers, consumers, and utilities can obtain measured performance data for DERs, interface equipment, and grids.

Recommendation 3: Field test bed(s) should be created with adequate real- time metering capability to provide the T&D grid and micro-grid planners and operators with the information necessary to identify dynamic characteristics, models, and corresponding data requirements for DERs.

Recommendation 4: A team of modeling experts should be formed to identify the needs and requirements for future T&D grid and micro-grid planning and for operational models reflecting an integration of DERs with the transmission and distribution systems.

Recommendation 5: A DER demonstration test bed should be created for protective engineering experts to evaluate advanced and new protective schemes for DERs and define minimum requirements for DER protection technologies.

Recommendation 6: A demonstration test bed should be established to provide engineers with sufficient real-time MW, VAR, and voltage data from local grids and DERs. These data should be used to evaluate the impact of DERs on system reliability. Various DER control schemes can be tested to identify minimum control and performance standards for mitigating negative impacts on electricity system reliability.

Recommendation 7: A test bed should be created to evaluate the load-following capabilities of DER technologies.

Recommendation 8: Test bed(s) should be established for defining the minimum real-time data communications WAN, protocols, and infrastructure requirements to insure reliable system operation in areas where significant numbers of DERs are likely to be deployed.

Recommendation 9: Test bed(s) should be established to study demand-side technologies and practices. This research should focus on developing new methods and technologies to understand the characteristics of different types of loads under various system conditions. With improved understanding of loads, the industry can develop effective strategies, infrastructure requirements, and support systems to respond to grid disturbances, enhancing overall system reliability and benefiting customers.

Recommendation 10: A team of independent industry experts should be assembled to facilitate definition and development of DER operational requirements. Practical application of these requirements should, to the extent possible, be evaluated at DER demonstration test beds.