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System Impacts from Interconnection of Distributed Resources: Current Status and Identification of Needs for Further Development

T.S. Basso

Technical Report
NREL/TP-550-44727
January 2009

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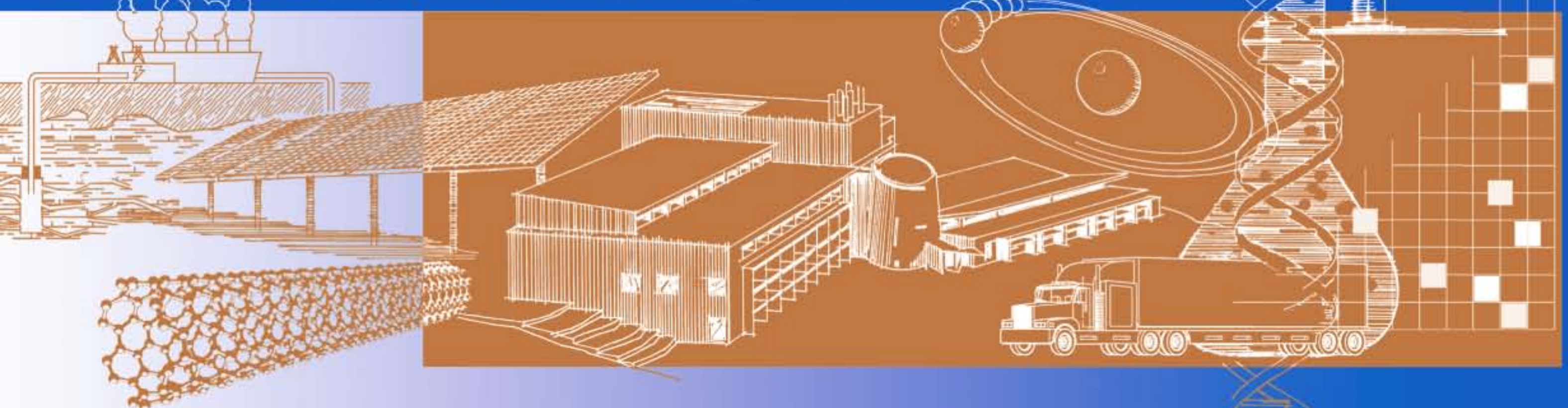

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List of Acronyms

AC	alternating current
DC	direct current
DER	Distributed Energy Resources
DEW	distributed engineering workstation
DG	distributed generation
DR	distributed resource
EEI	Edison Electric Institute
EMTP	electromagnetic transients program
EPS	electric power system
IRP	integrated resource planning
ISO	independent system operator
NEC	national electrical code
NRTL	nationally recognized testing laboratory
PCC	point of common coupling
PSC	public service commission
PV	photovoltaic
R&D	research and development
RPS	renewable portfolio standards
RTO	regional transmission operator
SCADA	supervisory control and data acquisition
T&D	transmission and distribution

Executive Summary

Distributed resource (DR) interconnection can contribute to conditions that might go beyond what originally was planned for, designed, and built into the electric grid. A system impact study identifies the electric power system (EPS) impacts that can result if a proposed DR is interconnected without modifications to the area or local EPS. The impact study focuses on potential adverse effects to the operation, safety, and reliability of the area EPS. The decision whether to conduct an engineering system impact review generally lacks a clear, broadly accepted, and strong engineering foundation. Those involved in grid interconnection of DR tend to formulate rules of thumb for impact studies and for establishing their individual preferential resolutions. There are no universally accepted approaches and tools specific to the whole of assessing DR interconnection impacts and resolutions.

With the advent of IEEE Standard 1547, modern interconnection equipment has made significant strides by having universal, transparent requirements for interconnection. During grid modernization, however, few changes have been made with the explicit intent to take advantage of accommodating DR to provide benefits to both the DR owner and the grid owner or operator. During these changing times, the grid also is becoming increasingly diverse, and some believe that its existing, site-specific electrical qualities and parameters are less well-known overall. This lack of accommodating DR is not simply a technology issue—equipment is available, but the technology needs to be interoperable with other advanced equipment and also with the legacy equipment that makes up the grid, and with grid operations. Further, improved grid operations (e.g., distribution automation) needs to be taken into account. Making the modern grid more robust should include accommodating DR to improve electricity availability for customers, improve grid reliability, and provide additional benefits to both grid operators and their customers. Concurrent with the U.S. Department of Energy research and development (R&D) for grid modernization and with the Energy Independence and Security Act of 2007's "smart grid interoperability framework," better approaches, methods, and tools are needed to aid in the consideration of DR interconnected to the grid, for system impact studies, and for resolution that concomitantly promotes and aligns with interoperability and robustness of the U.S. electricity transmission and distribution (T&D) infrastructure.

This report documents and evaluates system impacts from the interconnection of distributed resources to T&D systems, including a focus on renewable DR technologies. The report also identifies system impact-resolution approaches and actions, including extensions of existing approaches. Lastly, the report documents the current challenges and examines what is needed to gain a clearer understanding of what to pursue to better avoid or address system impact issues.

Following are the three major conclusions of this report, together with the respective recommendation of needs (italicized text) which primarily are related to the specific conclusion but which also crosscut all three.

1. The grid was not planned, designed, built, and operated with distributed resources and modern grid aspects in mind (e.g., distribution automation, semi-autonomous operations, DR, load management, smart grid). Need: *Qualification of the grid*.

2. Today's interconnection systems are based on traditional grid design and equipment, and on traditional grid operations (e.g., reactive to abnormalities) where the old, traditional grid interconnection systems were designed to address DR independently from the grid design and operations. Need: *Qualification of modern interconnection systems* (e.g., smart grid concepts beyond IEEE 1547-2003 base standard to allow grid support).
3. The grid, interconnection systems, and DR technologies lack full electrical and integration information analysis tools (characteristics, parameters, models, tools for analysis and integration). Need: *Modeling and simulation improvements* (toward total integrated electrical system analyses).

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1 Background and Framework

1.1. Introduction

Distributed resource (DR) interconnection can result in electric grid operating conditions that normally would not occur without the DR installed—these resulting conditions are called DR system impacts. Examples include protection issues, voltage regulation, coordination, power quality, grounding impacts, and service restoration. This report examines DR system impacts and effects, including:

- Identifying critical impact areas on transmission and distribution (T&D) systems based on interconnection requirements and operational needs, with a special focus on renewable distributed resources
- Identifying best practices studies, modeling, simulation, and mitigation techniques related to resolution of system impact issues
- Identifying current challenges and needs for further development to improve DR interconnection penetration by better addressing system impact issues.

Subsequent sections present background information on the electric power system (e.g., grid), interconnection systems, and DR.

1.2. The Electric Power System

The electric power system (EPS) consists of the area EPS and the local EPS. The area EPS consists of generation, transmission, subtransmission, and distribution systems. Most electricity is generated by central station plants at voltages up to 30 kV (but usually less), and generator step-up transformers at the plant substation raise the voltage to greater levels to power the transmission system. Transmission facilities generally are greater than 34 kV or 69 kV, and subtransmission systems typically range from 34.5 kV to 69 kV. Distribution systems are in the 15 kV range and include distribution substations; the primary voltage circuits supplied by these substations; distribution transformers; secondary circuits, including services to customer premises; and circuit-protection, voltage-regulation, and control devices.

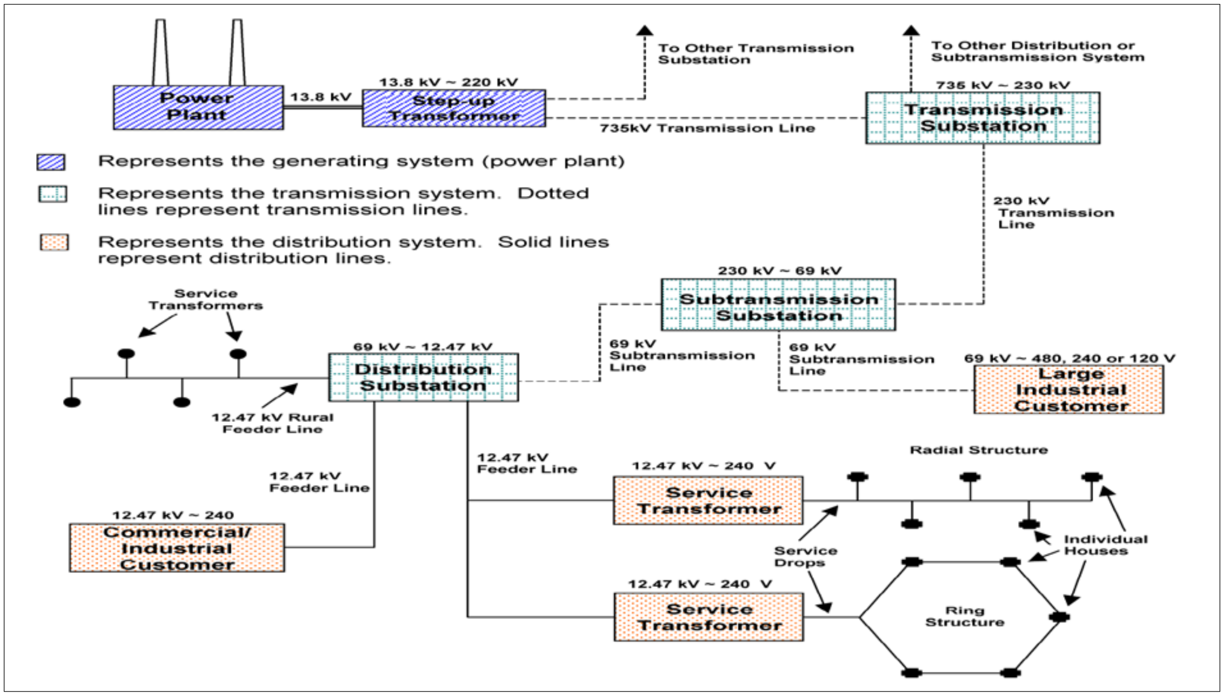

Figure 1. Representation of United States transmission and distribution infrastructure system

The area EPS is mandated to satisfy a number of requirements, including service, reliability, security, quality, and cost-effectiveness. The area EPS also must meet numerous technical performance requirements parameters such as voltage, frequency, power quality, and fault duty. There is no universally binding requirement to make the EPS more accommodating for DR interconnection. The local EPS consists of distribution and facility equipment on the customer's side of the point of common coupling.

1.2.1. The Area Electric Power System and Distributed Resource

Nearly all area electric power systems initially were not—and still are not—planned, designed, or built for interconnection of DR or "embedded" power flow. Most of the smaller DR systems (less than 10 MW to 20 MW) are interconnected to area EPS distribution systems. An example distribution system topology is shown in Figure 2. Interconnection of some DR at some points in the system can be done with virtually no system impacts. Interconnection of other distributed resources can cause minor to major system impacts, depending on the type of DR, the area EPS configuration, and the location of the DR interconnection. If there is a potential for system impacts, then reasoned mitigation can eliminate the adverse impact. In some cases, however, the equipment (e.g., for DR, interconnection, and modifications to the area EPS) is too costly, and the DR project is canceled.

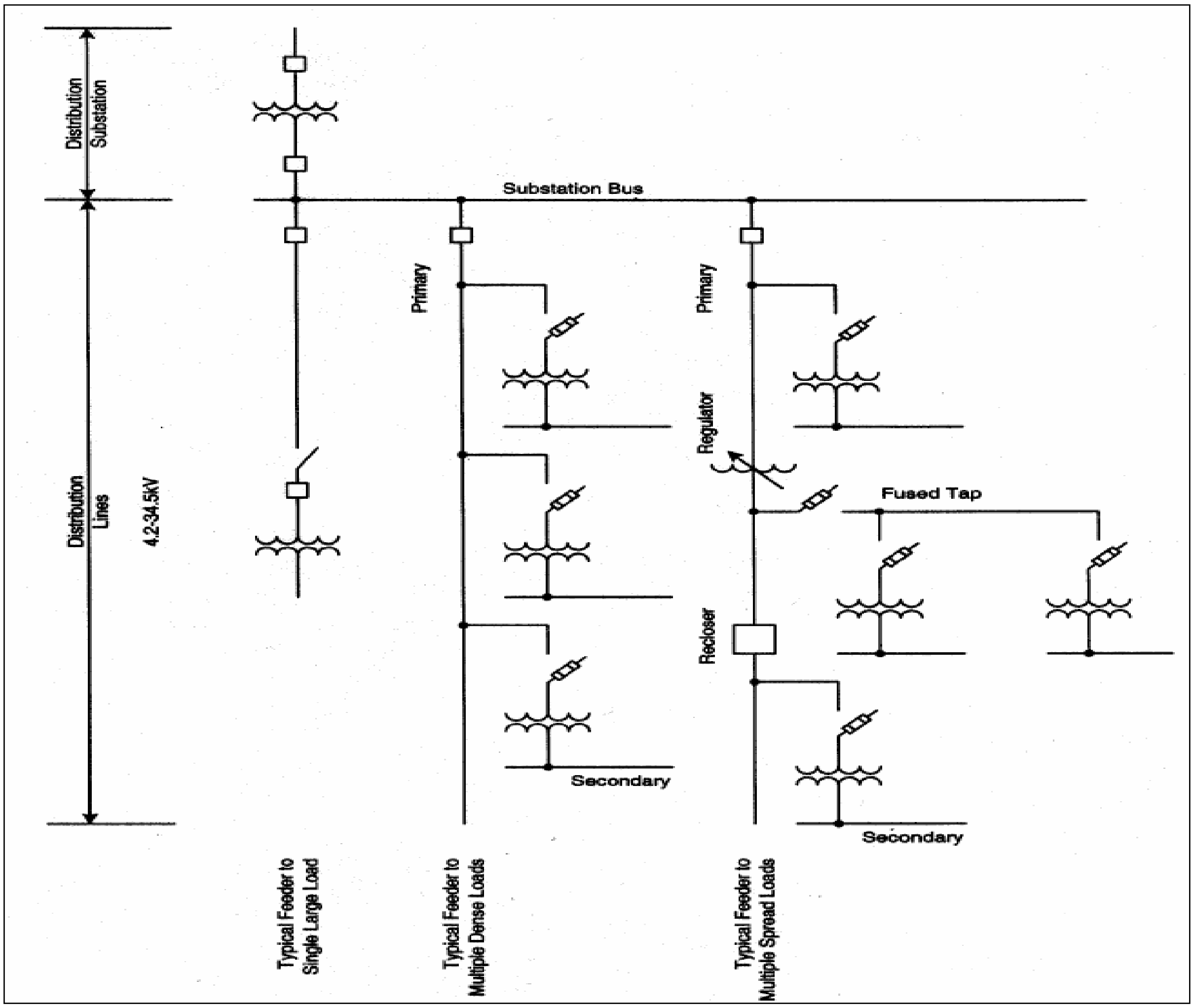

Figure 2. Example distribution system

1.2.2. Planning and Design of the Area Electric Power System

Area electric power systems are planned and designed to safely and reliably deliver electric power to customers (loads or demands). Transmission system area EPS planning is regulated primarily at the federal level. Transmission systems are owned by both vertically integrated utilities and independent entities. Transmission planning normally is performed by the utility, regional independent system operator (ISO), or regional transmission operator (RTO) following a regional transmission expansion plan. Among other requirements, this plan ensures that there is adequate capacity to deliver power from the generating stations to the distribution systems serving customer load. Distribution system area EPS planning typically is performed by the local utility throughout the United States and for independently owned utilities; they predominantly are regulated by the state public service commission (PSC). Distribution systems are upgraded as needed (e.g., based on consideration of demand from new and existing customers), for equipment replacement, and to meet new requirements for issues such as improved reliability.

Transmission systems are designed to transmit electricity as efficiently as is feasible, and take into account economic factors, safety, reliability, and redundancy. Transmission systems include power lines, cables, circuit breakers, switches, transformers, and substations.

Most distribution circuits in the United States are radial circuits or open-loop circuits that are operated as radial circuits. Most distribution circuits are at the 15 kV class voltage level and have three-phase main feeders between 3 and 15 miles. Single- and three-phase laterals branch from the main feeder. Most primary distribution circuits are four-wire, multi-grounded neutral with the neutral grounded (typically at each transformer, switching device, or at each pole).

Transformer connections play a key role in DR interconnection. Many different types of transformer connection types are used in the United States, and the type of winding configuration and connection can affect how the DR impacts the area EPS. Different configurations have different advantages and disadvantages, depending on the type of DR and distribution system.

Only a few state PSCs have started to consider how DR should be addressed in integrated resource planning (IRP) and other planning processes. Integrated resource planning is a public planning process and framework in which the costs and benefits of both demand- and supply-side resources are considered to develop a least-cost mix of resource options. In many states, IRP considers environmental impacts and identifies energy efficiency and renewable energy options. IRP has become a formal process prescribed by law in some states, and in other states utilities are required to perform some type of least-cost planning.

1.2.3. Operation of the Area Electric Power Systems

Area EPS operation requires *proactive* planning to anticipate problems and to take appropriate action to avoid future problems and meet customer needs. It also requires *reactive* activities to correct unplanned operating conditions as they develop.

Safety is the primary concern in the operation of the area EPS system. Typically, day-to-day operation of the area EPS is controlled by a dispatching or operating authority which monitors conditions on the area EPS and initiates appropriate actions to maintain proper operation and address abnormal conditions.

The area EPS often includes automatic devices to control voltage, maintain circuit power factor, and sense and isolate faulted line sections and equipment. Supervisory control and data acquisition (SCADA) can be used to facilitate remote monitoring and control of equipment.

1.2.4. Area Electric Power System Modifications

New facilities and system improvements are added to the area EPS as needed. New customers require the installation of new area EPS distribution system facilities. System improvement plans are developed and implemented to maintain adequate capacity and quality of service. Improvements vary from adding new voltage regulators to a new substation and reconductoring of line sections.

1.2.5. Impacts of Renewable Portfolio Standards on Area EPS Planning

Renewable portfolio standards (RPS) are state-level policies that require a minimum amount (usually in the 10% to 20% range) of the electricity supply provided by each supply company to be generated from renewable energy. States typically have different definitions for what is considered “renewable,” but most include wind, solar, and biomass. These technologies require plants that are smaller than central station plants, and many consider them to be distributed resources. One challenge is that some of these technologies must be located in a specific region in order to maximize their output (e.g., wind turbines need consistent wind; solar troughs need ample sun). In some cases the area EPS does not have sufficient capacity, or the location is not an ideal place to add generation to the area EPS. Because of this, RPS requirements may have significant effects on area EPS planning and operation.

1.2.6. Grid Modernization and the Smart Grid

Considerable effort is being made to develop a strategy to modernize the U.S. grid and turn it into a "smart grid." A smart grid has the following characteristics:

- Allows active participation by consumers in demand response (including distributed generation)
- Operates resiliently against both physical and cyber attacks
- Maintains high power quality
- Accommodates all generation and storage options
- Enables new applications (including distributed generation and load participation), self-healing, and efficient operation
- Incorporates interactive power and evolving information technology.

One of the more significant aspects of the modern grid as currently envisioned is that it seamlessly integrates many types of load, generation, and storage systems with simplified interconnection processes (i.e., analogous to or achieving "plug-and-play" interoperability).

1.2.7. The Local Electric Power System

The local EPS consists of all of the electrical distribution equipment on the customer side of the point of common coupling. National electrical code (NEC) requirements govern local EPS design and operation. Most local electric power systems are simple radial designs with one service from the area EPS. A large industrial or mission-critical local EPS typically can involve more complex designs and multiple services from the area EPS.

The loads in a facility are the primary design consideration. Also, significant differences exist among different facility types. A residential service can have a 120/240-V, 100-A (or more) service from the area EPS, a panel board with a main circuit breaker, and multiple branch circuit breakers. A small commercial customer might have a 240/120-V or 208Y/120-V, three-phase service. A large commercial customer or small manufacturing customer could have a 480Y/277-V, three-phase service with a main switchboard or panel board that has feeder circuit breakers that extend to additional panel boards and transformers in other locations. Campus-type facilities such as colleges, military installations, large hospitals, and large industrial customers could take service at the area EPS distribution or transmission voltage and extend the medium-voltage or high-voltage system throughout the campus.

1.3. Distributed Resources

Distributed resources—also known as distributed energy, distributed energy resources, or distributed generation—refer to small-scale power generation or storage located close to where the electricity is used. Distributed resources can use various renewable and non-renewable energy sources or fuels, and various technologies are used to produce electricity such as photovoltaic (PV) arrays, wind turbines, hydro-powered turbines, fuel cells, microturbines, conventional diesel and natural gas reciprocating engines, Stirling engines, and gas-fired turbines.

The behavior of a DR as it interacts with an area EPS largely is influenced by the type of power conversion device it uses; three main categories are available: (1) synchronous machines; (2) induction machines; and (3) inverter-based machines. The synchronous- and induction-based interconnection systems and power conversion devices driven by DR technologies include internal combustion engines and combustion, steam, wind, and water or hydro turbines. The inverters use DC sources such as batteries or fuel cells, or an AC-generating source and a converter such as high-speed or variable-speed microturbines or wind turbines. The different types of DR combined with power conversion devices impact the electric power system differently, because each responds differently to changes due to the different mechanical and electrical inertias and the time constants of the regulators by which they are controlled.

1.3.1. Prime Movers

1.3.1.1. Rotating

Rotating prime movers turn rotating generators directly through a shaft or indirectly through a reduction gearbox. These include technologies such as combustion turbines; microturbines; reciprocating engines; wind, water, and steam turbines; and energy storage technologies such as flywheels.

1.3.1.2. Non-Rotating

Non-rotating prime movers produce DC power. Non-rotating prime mover technologies include fuel cells, photovoltaic (PV), and energy storage technologies such as batteries and supercapacitors.

1.3.2. Fuel Energy Source and Intermittence

Some renewable DR technologies—such as wind and PV—operate intermittently. In the case of high grid penetration such intermittent operation impacts the electric power system. If these energy sources are being relied upon and suddenly decrease power output, the area EPS operator quickly must switch to conventional energy sources. Other solutions include spatial diversity of the renewable resources, flexible conventional generation, limited curtailment for extreme events, and better load management.

1.3.3. Dispatchable and Non-Dispatchable Distributed Resources

A simple way to categorize DR systems is as being either dispatchable or non-dispatchable. Dispatchable DR is readily available and can be called upon to operate for a predetermined amount of time. Examples include engines and turbines with a reliable source of fuel. Non-dispatchable systems cannot be relied upon indisputably to operate when required. Examples include PV and wind.

1.3.4. Power Conversion Devices

Power conversion devices take one form of power (e.g., rotating shaft, DC power) and change it to another form of energy (e.g., AC power). Power conversion devices can be grouped into three main categories: synchronous, induction, and inverter based.

1.3.4.1. Synchronous Machines
Synchronous machines are driven at a speed determined by the number of poles of the machine and the frequency required by the area EPS. A governor varies the torque from the prime mover to control the real power. Reactive power is controlled by the level of excitation of its field. Synchronous machines have more complex control systems compared to induction machines, in terms of controlling the field excitation and synchronizing with the EPS. Additionally, synchronous generators require special protective equipment to isolate from the EPS under fault conditions. Advantages of synchronous machines include the ability to provide power during EPS outages and control of the power factor.

1.3.4.2. Induction Machines
Induction machine power conversion is driven at a speed slightly greater than the corresponding synchronous speed; if its speed drops below the synchronous speed it will absorb power from the EPS. The governor of the prime mover controls the real power it produces. Conventional induction machines absorb reactive power and cannot control voltage or power factor.

1.3.4.3. Inverter-Based Machines (Power Electronics)
Inverter-based machines (also known as static power converters) convert DC electricity into AC electricity and can offer additional electronic power conversion. They convert DC or non-synchronous AC electricity from a prime mover energy source into a synchronous AC system of voltages that can be interconnected with the area EPS system smoothly and easily. A number of different types of electronic inverters are available, and the system impacts vary by inverter type.

1.3.5. Energy Storage Systems
The two main parameters that define energy storage systems are 1) capacity in terms of maximum power, and 2) capacity in terms of the amount energy that can be delivered during the discharge cycle. An energy storage system can be used in combination with renewable DR to reduce some of the renewable technology-specific system impacts.

1.4. Interconnection
Interconnection involves technical requirements and specifications as well as business or process aspects. The business and process aspects often modify, constrain, or limit the number of possibilities that otherwise normally would be able to satisfy the purely technical requirements and specifications. This report focuses on the technical aspects, however some business or process aspects—such as the use of technical screens—are mentioned because of their technical significance.

1.4.1. IEEE 1547 Series of Standards
IEEE 1547, “Standard for Interconnecting Distributed Resources with Electric Power Systems” establishes requirements and criteria for interconnection relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection. The standard’s technical specifications and requirements are focused on the point of common coupling (PCC). The standard does not address system impacts, and it states that some additional technical requirements and tests could be necessary for some limited situations. There might be technical specifications and requirements beyond IEEE 1547 that are necessary to minimize system impacts. Being “1547 compliant” does not mean that a DR system of any size can be interconnected at any location in any area EPS without system impacts. IEEE 1547 is not the

whole solution to making DR "plug and play." The IEEE 1547 series of standards is cited in the U.S. Federal Energy Policy Act of 2005, with IEEE 1547 being one document in the IEEE 1547 family of standards.

1.4.2. Interconnection Functions

Functional technical specifications and requirements, such as those stated in IEEE 1547 for interconnection, are statements of what needs to be accomplished and do not prescribe what equipment or operations to use. Some interconnection functions are satisfied by a discrete piece of equipment. In other cases the functions are provided by software or firmware; in still others the proper design and operation of the interconnection system as a whole meets the interconnection functional requirements. Interconnection in IEEE 1547 is defined as "the result of the process of adding a DR unit to an area EPS," and Figure 3 shows an example interconnection system.

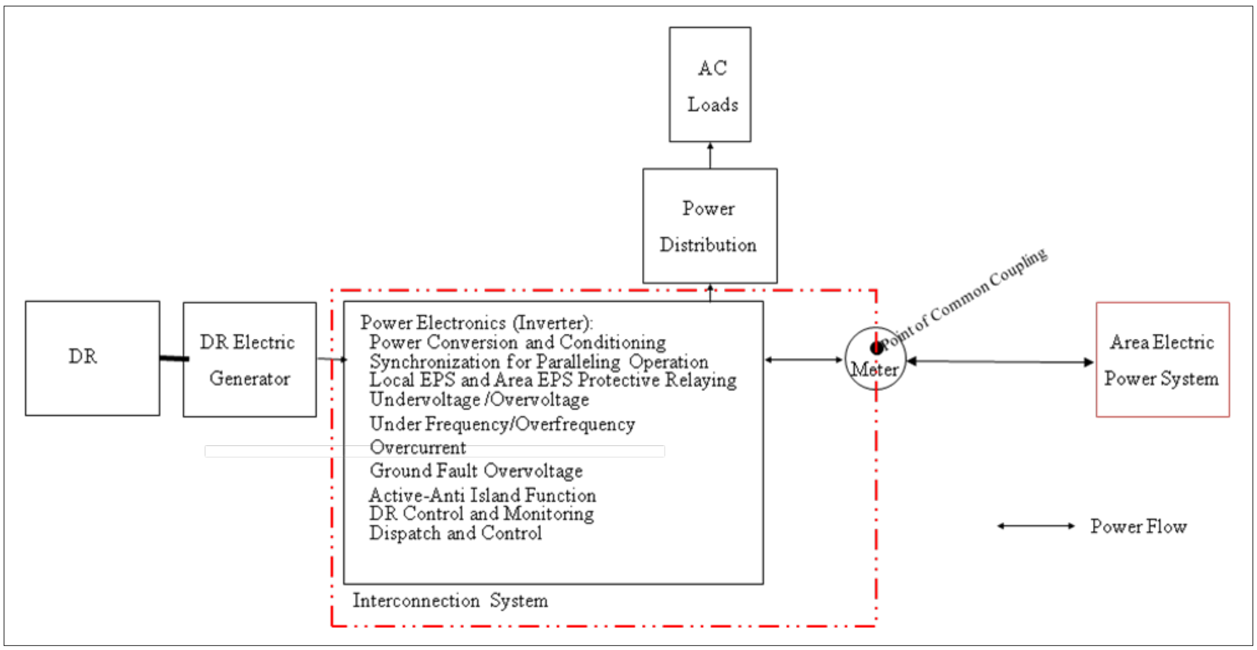

Figure 3. Example interconnection system

Interconnection requires that the DR stay synchronized with the area EPS during normal operation, and the interconnection system must respond appropriately during abnormal conditions. Interconnected DR can be non-exporting—power is generated for onsite use and is not transmitted through the utility distribution system, or be exporting—power is generated and some or all of the DR energy produced is distributed through the utility distribution system.

IEEE 1547 applies whether or not a system is exporting energy. The standard also applies to DR interconnections where paralleling with the area EPS occurs for more than 100 ms. The system impacts described in this document, therefore, refer to that same condition where DR paralleling occurs for more than 100 ms.

PJM Interconnect, Inc., an independent system operator/regional transmission operator, has been interconnecting DR for many years. Historically it has relied on its full-time engineering staff to review each proposed DR interconnection project on a case-by-case basis, starting with a feasibility review and then, as needed, examining system impacts and facilities/construction needs. The incorporation of IEEE 1547 for PJM's technical requirements has helped simplify and streamline its approach to interconnection in general, and to feasibility studies, system impacts, and facilities upgrade studies.

2 System Impacts

A technical barrier to the interconnection of DR is its effect on the area EPS—referred to as system impacts. Numerous factors influence the degree of system impact, including the size of the DR, the type of power -conversion device, the type and configuration of the local EPS facility equipment interfacing with the area EPS, the location of the interconnection on the area EPS, and the configuration and characteristics of both the local EPS and the area EPS. By complying with the requirements of IEEE Standard 1547, system impacts can be minimized at the distribution circuit level.

The decision of whether to conduct an engineering systems impact review generally lacks clear, broadly accepted criteria, and is not always based strictly on strong engineering foundations Individuals involved in interconnection and integration of DR with the area EPS tend to formulate their own rules of thumb, building on discussions with others and based on personal preference and historical approaches. Unfortunately, this sometimes becomes ingrained in regulatory mandates and can hamper open and innovative engineering approaches to interconnection.

The type of interconnected generator and its power conversion have different affects on the type and severity of the system impacts. The area EPS type and specific location of the point of common coupling also affects the potential impacts. Generally, a DR system that exports to the area EPS has the potential to cause greater system impacts than a non-exporting DR system. Figure 4 shows a generalized functional block diagram of an interconnection system.

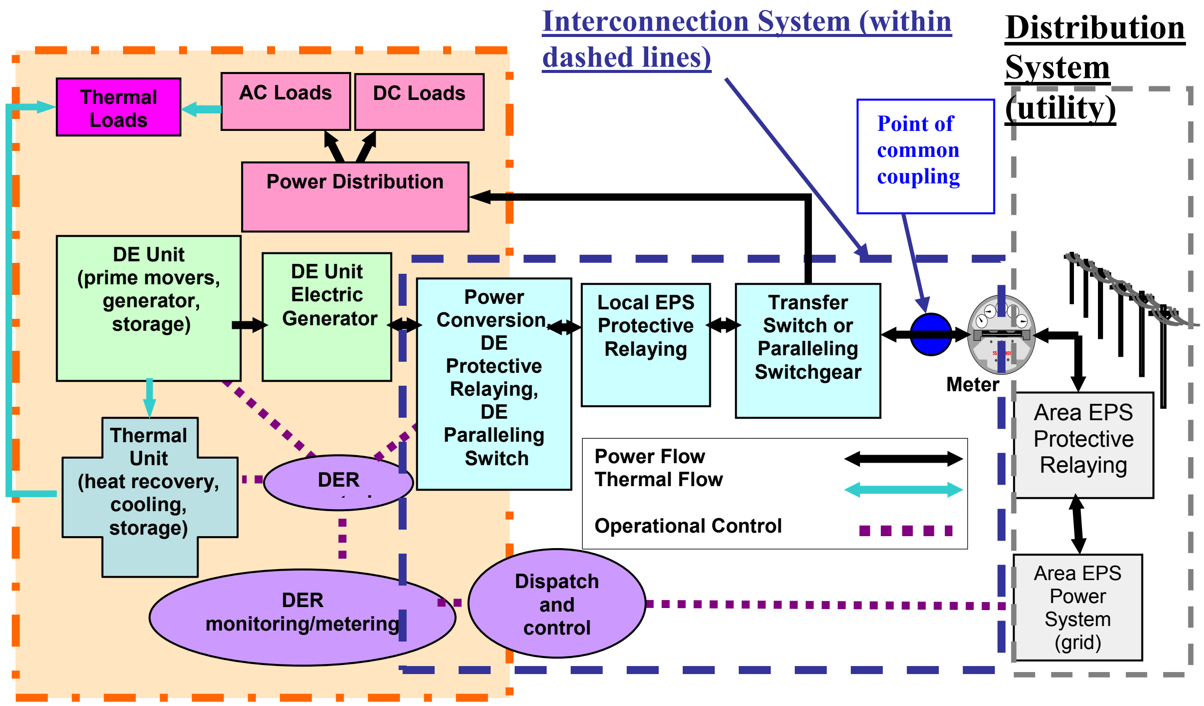

Figure 4. Example interconnection functional block diagram

The area EPS can be affected in numerous ways by the addition of DR. These effects can range from insignificant to severe, depending on the factors noted above. In the extreme, a system impact study might require modifications that are found to be impractical (e.g., due to cost or necessary facilities upgrades). Often, for larger or more complex DR interconnection projects, "system impacts" approach is undertaken as a graded approach to first consider feasibility, then perform detailed system impact studies, then determine what facilities upgrade and construction would be needed, and finally to reach agreement between the area EPS operator and DR owner-integrator to proceed with the project. This report considers this graded approach under the one heading of systems impacts. Generally, the area EPS operator and the DR owner-integrator can work together to reach effective resolution of the specific system impact. Sometimes a resolution to a specific impact proves impractical for the specific DR or its location on the area EPS, however, or the DR owner or area EPS owner could choose not to implement the suggested upgrade.

System impacts can affect both area and local electric power systems, and usually increase with the size of the DR and the size of the DR relative to the capacity of the EPS. System impact studies can be more involved for non-inverter DR interconnections than for inverter-based interconnections. System impact studies might be needed even if DR interconnection equipment meets certification or listing requirements based on IEEE 1547 design and production test requirements. The use of appropriately certified or listed equipment can greatly simplify whether an impact study of a proposed DR installation is needed, because basic understanding regarding the characteristics of the DR is established via the certification compliance.

System impacts can be categorized under the following headings:

- Protection and coordination
- Unintentional (unplanned) islands
- Voltage regulation
- Power quality
- System stability
- Grounding
- Special issues related to DR on secondary distribution network systems (networked systems)
- Special issues related to renewable energy DR.

Some of the impacts studied under the respective headings may be eliminated or minimized by IEEE 1547 compliant equipment, and for some DR interconnections differing levels of impact studies should be undertaken. There exist numerous papers, reports, and tutorials on interconnecting DR to the grid. The Edison Electric Institute (EEI), for example, conducted a review that established the "EEI 29 issues" and many of those issues were considered in the development of IEEE 1547. Many issues relating to specific equipment and grid impacts (some from the EEI review) are categorized under the headings provided below. The general description of system impact topics follows.

2.1. Protection and Coordination

The circuit protection of EPSs in both local EPS and area EPS is critical to ensure safety and reliability. Most radial circuits employ feeder breakers at the distribution substation, line reclosers at circuit points where the substation breakers maximum reach (zone of protection) is located, fuses along the laterals, and fuses at transformer banks. All of these devices are coordinated to enhance reliability and reduce costs. This protection is used to clear temporary and permanent faults.

Distributed resources can impact a variety of levels of short-circuit current. The separated local EPS and DR systems have to provide enough fault current to operate the protective devices (as designed) in the EPS, including circuit breakers, fuses, and fault-protection relays. The addition of DR on a circuit may need to be studied to establish whether changes are needed for coordination or protection equipment.

Automatic circuit reclosers also may be deployed in the feeder circuit to automatically clear faults and quickly restore service on the feeder. Reclosers reenergize the circuit automatically at a predetermined time after a trip resulting from a feeder fault. The response of the DR unit needs to be coordinated with the reclosing strategy and the settings of the recloser isolation operations within the area EPS. Coordination is required to prevent possible damage to area EPS equipment and to equipment connected to the area EPS other than the DR.

Protection and coordination system impacts and some resolutions are described below.

2.1.1. Reclosing

Area EPS reclosing practices restore service following an interruption for a momentary fault. If the area EPS reclosing devices try to reclose before the DR ceases to energize the area EPS, the area EPS, local EPS, and DR equipment may be damaged. There is an IEEE Standard 1547 requirement for the DR to cease to energize the area EPS prior to reclosure by the area EPS, and there also are standard 1547 clearing times requirement settings for different abnormal voltage ranges at the PCC. The area EPS operator might be able (and willing) to modify its reclosing and coordination practices and settings to help accommodate DR interconnection.

2.1.2. Improper Protective Device Coordination

Distributed resource fault-current contributions can impact the coordination of fault-protective devices on the area EPS. IEEE 1547 (clause 4.2.1) addresses the requirement for the distributed resource's detection of faults on the area EPS. IEEE 1547.2 discusses impacts on the area EPS and provides guidance for consideration.

2.1.3. Area Electric Power System Protection Desensitization

Distributed resource fault-current contributions can cause the feeder protection of the area EPS equipment to be desensitized, especially with a large DR.

2.1.4. Nuisance Fuse Blowing

Frequently, the area EPS is designed, built, and planned to use fuses and other protective devices on the distribution system to attempt to clear momentary faults without causing an extended outage. The fault-current contribution from a DR, however, could impact this planned scheme (Figure 5).

2.1.5. Fuse Saving Schemes

Portions of the area EPS can be designed, built, and planned to be protected by fuses and fuse saving schemes, and to be implemented by distribution reclosers and the substation breakers. These schemes result in the recloser tripping very quickly for initial faults—more quickly than fuses can respond. For subsequent tripping for the same fault, the recloser could operate on a much slower time delay. Fault current contributions from DR, however, can cause the fuse to operate much more quickly than it otherwise would, and disrupt the fuse-saving scheme (Figure 5).

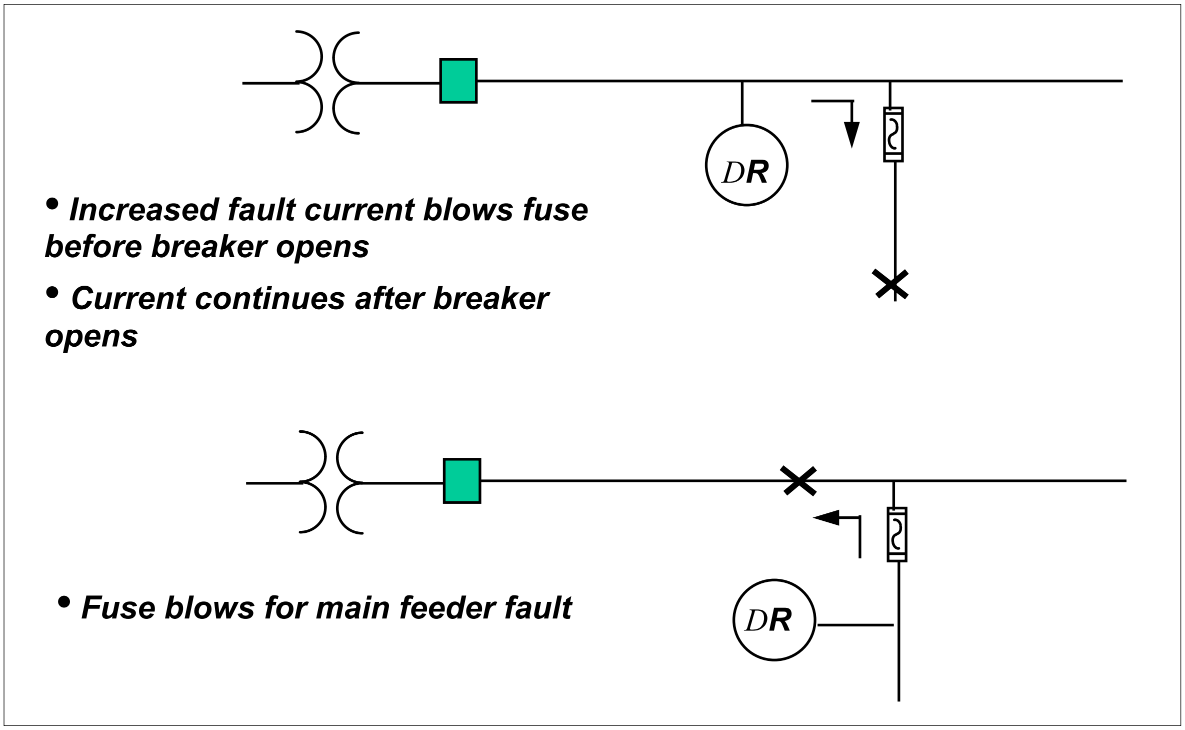

Figure 5. System impacts: fuse operations

2.1.6. Sectionalizers

Sectionalizers are relatively inexpensive devices used to minimize the number of customers affected by a permanent fault. These devices count the number of complete power interruptions in a given period. If a DR does not cease to energize the area EPS as required by IEEE 1547, then a sectionalizer will not sense zero-voltage conditions as expected by area EPS design processes and, therefore, will not "count" as expected. Sectionalizing scheme operation could be disrupted by DR.

2.1.7. Nondirectional Area Electric Power System Relaying

Due to the traditional radial nature of distribution systems, most protective devices on the area EPS are nondirectional in nature and respond to a given value of current without regard to the direction of flow of that current. Because DR produces fault current of various magnitudes for faults on the area EPS, the traditional radial nature of the distribution system is disrupted and nondirectional relays could operate improperly.

2.1.8. Power Relaying

Distributed resources can cause reverse power relays on the area EPS not to operate as planned without the DR accounted for. If, for example, directional power relays are applied on the EPS to automatically reconfigure the EPS, then the addition of the DR could cause these relays to no longer be coordinated properly.

2.1.9. Underfrequency Disturbances

Underfrequency relaying with a wide tolerance band can cause DR to trip while the load remains. From a practical consideration, coordination usually is not applied to generators smaller than 20 MW. A delay in isolation of the DR for momentary islands, however, could cause the malfunction of area EPS underfrequency load-shedding schemes.

2.1.10. Distribution Automation Circuit Reconfiguration
Distribution automation circuit reconfiguration schemes require extensive system protection coordination and should be studied for normal, abnormal, and emergency-state conditions. Remote control switches with intervening manual switches and hybrid three- and five-recloser loop schemes that incorporate DR could require additional DR protection and coordination.

2.1.11. Equipment Short-Circuit Duty
As more DR is added on a circuit, switchgear ratings on existing equipment could be exceeded—both on the area EPS and other local EPSs (which may or may not have DR). This impact can affect the ability of equipment to carry fault current for the brief periods that a fault persists, and affect its ability to interrupt downstream faults. Equipment in nearby customer facilities can be affected, as can area EPS equipment.

2.2. Unintended (Unplanned) Island
An island is an occurrence in which a portion of the area EPS and DR unit(s) electrically separate from the rest of the area EPS, and the DR unit(s) continue to energize the island. IEEE 1547 has an unintentional islanding clause requiring the DR interconnection system to detect the island and cease to energize the area EPS within two seconds of the formation of the island. An unplanned (unintended) island is not desirable as it can lead to safety and power quality problems affecting the area EPS and local loads. During EPS electric maintenance or repair operations by personnel, such as when dealing with downed conductors, an unplanned island powers portions of circuits that otherwise would be de-energized. Utility personnel generally are required to ground and test circuits before working on them. An unplanned or unintended island is a concern for a number of non-personnel-related reasons. Once an island forms, the area EPS operator no longer has control of the frequency or voltage on it. An unplanned island can result in damage to equipment and can delay service restoration.

2.2.1 Propensity to Create an Undetected Island
IEEE 1547 requires that the DR cease to energize an unintended island on the area EPS. In almost all cases in compliance with IEEE 1547, this can be easily accomplished. In rare cases, however, this could be difficult to achieve in practice. For interconnection of a proposed DR with a radial distribution circuit, it generally is agreed as a rule of thumb that an undetected island cannot be sustained if the aggregate generation, including the proposed DR, on the circuit does not exceed 15% of the line section annual peak (maximum) load as most recently measured at the substation. If the line section minimum load is known, then it typically is agreed that 50% of that minimum value instead could be used as the criteria. A line section is that portion of the area EPS connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.

2.2.2. Induction Generator Self-Excitation
Induction generators with capacitors can self-excite under temporary or permanent unintentional islanding conditions.

2.3. Voltage Regulation
The primary objective of voltage regulation is to provide each customer connected to the utility with voltage that conforms to limits generally taken as the American National Standard ANSI C84.1 voltage range A for normal operation. Voltage supplied to each customer at the PCC is an

important measure of service quality. A satisfactory voltage level is required to operate lights, equipment, and appliances properly.

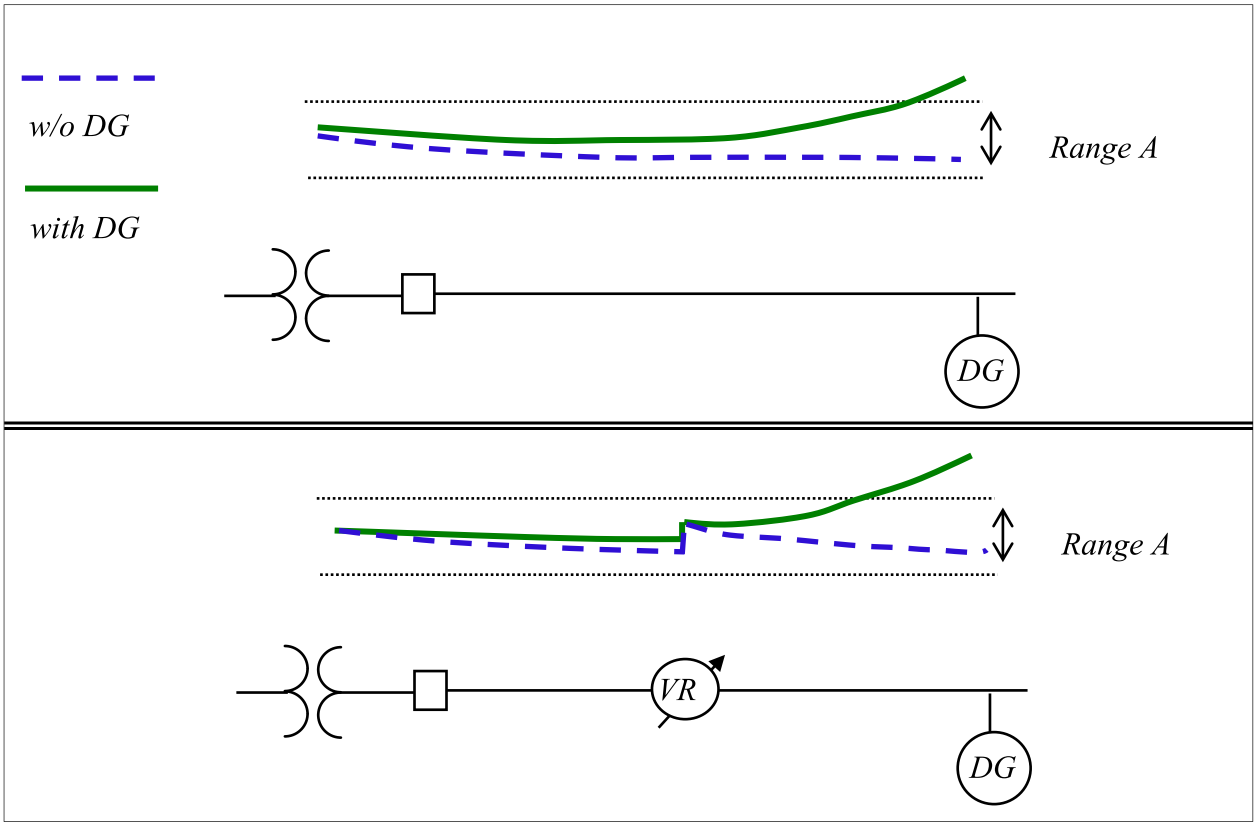

Figure 6. System impacts: voltage regulation

Injecting power from a DR device into the power system offsets load current, thus reducing the voltage drop on the utility (Figure 6). The DR device could inject leading reactive power (capacitive) into the power system or draw lagging reactive power (inductive) from the power system, thus affecting the voltage drop on the utility.

Area electrical power systems use equipment such as load tap changing transformers, switched capacitors, and various types of voltage regulators to keep the voltage within a specified range. All of these devices are designed and controlled to respond to unidirectional flow of power from the substation to the loads. Introduction of DR to a circuit results in reduced loads or, in some cases, “reversed” as bi-directional power flow. In some cases, changes will need to be made to the voltage regulation scheme to accommodate the DR. Various voltage-related issues are described below.

2.3.1. Resonant Overvoltage

Depending on the grounding methods of the DR, the configuration of the area EPS, and the design of area EPS components, the interconnection of DR can result in a resonance between transformers.

2.3.2. Equipment Overvoltage

Depending on the grounding methods of the DR, it could cause steady-state overvoltages on the area EPS for ground-fault conditions that are difficult to detect.

2.3.3. Line-Drop Compensation

Many voltage regulators and load-tap-changing transformers on traditional area electric power systems use line-drop compensators that sense the current flow through the regulating device, and adjust to regulate the voltage based on the calculated voltage drop downstream of the regulating device, based on load current. A DR that is downstream of these voltage-regulating devices can reduce the current observed by the line-drop compensator and cause the voltage at the voltage-regulating device to be adjusted incorrectly. This could cause the regulating devices to constantly adjust the voltage in an attempt to reach the desired target voltage. Sometimes recalibration can correct this situation.

2.3.4. Area Electric Power System Reactive Support

Induction generators, and inverters that provide reactive support, require capacitive reactive support from the area EPS to provide their excitation system requirements. Deficiencies in capacitive reactive support can cause significant undervoltage problems on the area EPS.

2.3.5. Area Electric Power System Voltage Variations Due to Distributed Resources

When large loads are energized or de-energized, voltage variations are possible across the area EPS prior to the response of the voltage-regulating equipment. The area EPS is designed and operated to compensate for this. A DR can cause similar problems during synchronizing and ceasing to energize the PCC, and these issues need to be mitigated similarly to avoid voltage variation impact on other customers on the area EPS. If significant impact occurs, then operation of the DR needs to be adjusted to minimize voltage changes immediately after synchronization or after ceasing to energize the PCC.

2.3.6. Distributed Resource Undervoltage Relay Operations

Close-in faults on other feeders that are fed from the same bus can cause voltage dips on non-faulted feeders. This can cause the DR on those feeders to trip on undervoltage.

2.3.7. Induction Generator Startup Current Inrush

Current inrush on induction machines without rotor flux can cause voltage dips on a feeder. The induction generator initially could cause significant voltage drops if not compensated for.

2.4. Power Quality

It generally is agreed that there is little chance of impacting the power quality of the area EPS if the DR normal rated current, in aggregation with other generation on the distribution circuit, does not contribute more than 10% to 15% of the distribution circuit's maximum fault current at the point on the high-voltage (primary) level nearest the proposed point of change of ownership. This ensures that the fault current from the DR does not desensitize protection equipment on the area EPS, and any voltage disturbances that could occur because of normal or abnormal operation of the DR are not likely to have a significant effect on voltage supplied to other customers. For ranges greater than 10% to 15%, interconnection of DR to an area EPS potentially could significantly impact power quality in the distribution system. These power quality system impacts can be categorized as harmonics, DC injection, and flicker.

2.4.1. Harmonics

Due to the power electronics and digital methods used to form the AC waveform from DC, inverter-based DR technologies produce various harmonics of the power system frequency. If the DR complies with IEEE 1547 (clause 4.3), then harmonics typically are not problematic.

Harmonic currents can cause transformers to overheat which, in turn, overheats neutral conductors. This overheating could cause erroneous tripping of circuit breakers and other equipment malfunctions. The voltage distortion created by nonlinear loads could create voltage distortion beyond the premises' wiring system, through the utility, to another user. Distributed resource interconnection systems should comply with IEEE 1547 for interconnection. With non-linear loads on the grid, however, harmonic distortion onto the grid possibly still could result from the DR grid load interactions. Therefore, the most effective mitigation should be determined (e.g., possibly addressing the non-linear loads).

2.4.2. Direct Current Injection

Direct current injection produces a DC offset in the basic power system waveform. This offset increases the peak voltage of one-half of the power system waveform and decreases the peak voltage in the other half of the waveform. The increased half-cycle voltage has the potential to increase saturation of magnetic components, such as cores of distribution transformers.

2.4.3. Flicker

Flicker is a power quality issue associated with changes in voltage levels. Flicker can cause noticeable changes in light output from incandescent lighting and similarly for fluorescent lighting (but that requires somewhat greater voltage deviations than for incandescent lighting). Voltage level changes causing flicker may also be severe enough to cause equipment to operate improperly.

2.5. System Stability and Thermal Limits

Adding a DR unit to an area EPS most likely will not impact the stability of the distribution system but could impact the stability of the local EPS or the DR unit. Various issues are discussed below.

2.5.1. Distributed Resource Unit Stability

The area EPS can be considered to be an infinite source from the viewpoint of the DR operator. DR generally will not cause instability of the area EPS system.

2.5.2. Feeder Loading Capability

Most customer loads will remain connected to a de-energized area EPS feeder following an interruption of the feeder at the area EPS source. When the area EPS feeder is reenergized, many of the loads demand higher current than their steady-state load current. This usually is referred to as "cold load pickup". If the area EPS assumes a level of DR penetration, and all DR are disconnected during an outage, then the area EPS feeder loading capability could be exceeded by the cold-load pickup when reenergized. This primarily only is an issue with high DR penetration.

2.6. Grounding

Depending on how the DR is constructed within the local EPS, there could be grounding conflicts in the installation that can impact transformer configuration setups. If the point of interconnection for the DR is within a building inside of a local EPS facility comprised of multiple buildings, then it is more likely that this issue will require attention.

2.7. Special Issues Related to Distributed Resource on Distribution Secondary Network Systems

The design of urban secondary networks raises DR integration issues that are more complex than those of radial systems.

The primary technical challenges are the network protectors and network protection schemes that are part of the design of all distribution secondary network systems. Network protectors are used to prevent power from back-feeding from one transformer through another. Network protectors are designed to open quickly when they detect back-feeding. These network protectors detect any power exported by DR usually as back-feeding. Distributed resources, primarily non-inverter based systems, introduce other problems with fault currents in distribution network systems. Specific technical challenges to interconnecting DR to distribution network systems include those listed below.

Network protectors open because of reverse power flow from DR. If a DR unit exceeds the local load and feeds electricity back into the network distribution system, it causes the network protector to open, thus compromising the reliability of the system. Other issues related to networked system impacts are discussed below.

- **Network protectors can be damaged by islanded DR.** When a distributed resource is islanding, the voltage across an open network protector can exceed the rating of the device. The voltage is a result of the island being out of synch with the utility.
- **Network protector cycling.** Under light load conditions, network protectors could repeatedly open and close because of the power supplied by the DR. Continuing this cycling for an extended period reduces the life of the protector and compromises the reliability of the distribution network.
- **Inadvertent opening of network protectors under fault conditions.** Fault current fed from DR can cause network protectors to open for faults occurring on the primary side of a network transformer. This condition has the potential to isolate an entire secondary network and can cause all customers on that network to lose power. Also, DR fault current contribution could exceed the equipment ratings of other distribution system equipment and cause equipment failure.
- **Equipment standards and withstand capability.** Network protectors might not be rated to withstand the voltages and currents that can be produced by DR. Additionally, network protectors are not designed to synchronize/disconnect the DR from the utility system. The protector relays are not designed to reclose a constant frequency utility network to DR, and out-of-phase reclosing could cause the protector to fail.

Potential solutions to such technical issues include acceptance of distributed generation (DG) on spot networks through hardware development, without compromising the current high standard of safety and reliability on secondary distribution networks. The overall technical concept envisioned is to provide directional power sensing by the network protector at the PCC and to also provide control of customer-sited DG by the utility network protector across the PCC. If successful, such work could lead to more DG successfully interconnecting and integrating into spot and potentially area (grid) networks.

2.8. Renewable Distributed Generation and System Impacts

Renewable DG technologies can lead to additional system impacts, for example, because of intermittent operation and other factors. Examples of additional system impacts for renewable systems are identified below.

Wind and Large Solar

- Steady-state and transient stability analysis
- Load/generation coincidence
- Integration with automatic generation control
- Incorporation of renewable resource forecasting
- Examination of current operating practice and new concepts to enable high penetration
  - Frequency responsive (create regulating reserves)
  - Demand-side coordination.

Distributed Solar and Small Wind (issues listed above, plus the following)

- Voltage and VAR regulation
- Additional power quality concerns (harmonics, flicker, DC injection)
- Unintentional islanding
- Protection design and coordination (short-circuit, recloser)
- Equipment grounding
- Load and generation imbalance
- Generation interaction with controllable loads
- Storage and storage controls.

3 Impact Resolution—Existing Approaches and Solutions

A system impact study identifies the potential results of interconnecting a proposed DR to the electric system without modifying the area or local EPS. The study focuses on potential adverse effects on the operation, safety, and reliability of the area EPS and local EPS. System impact studies can take many forms, ranging from a simple comparison of the attributes of the DR and the area EPS, to a detailed, comprehensive analysis that employs a variety of traditional and specialized power system studies.

3.1. Existing Utility Practice for Impact Studies

Existing utility practice regarding system impact from distributed resources varies widely. In many cases, the approach to impact studies is established by broad rules at the state or federal level. The rules most often provide wide latitude to utilities regarding criteria for determining when studies are needed, what to study, what tools or approaches are adequate and not overly burdensome, and what resolutions to the impacts should be implemented. For DR interconnection impacts, each utility tends to have its own company-specific approaches, methods, and engineering requirements and specifications—which sometimes are based loosely on engineering judgment (e.g., multiple derating factors applied and sometimes not documented clearly). Currently, however, nearly all distribution systems were not planned, designed, or built for embedded generation.

In many cases, using “rules of thumb” was the historical approach to evaluating whether a system impact study was needed for DR. An example of one such criteria for allowing an expedited process or simple impact study process follows. For a proposed small generator facility interconnected by a certified inverter-based interconnection system to a line section on a radial distribution circuit, if the aggregated generation on the line section, including the proposed small generator facility, does not exceed 15% of the line section annual peak load, then that DR interconnection system might require little to no additional study.

Rules of thumb sometimes can have multiple deratings factored in the quantitative criteria, or be based on designs related to outdated equipment that no longer is representative of what is installed on the area EPS. Other rules might be based on anecdotal evidence or even on a single failure. Such rules should be reviewed to ensure that they are based on sound engineering principles and are up to date.

Historically, tradition was the impetus for determining utility practice regarding system impacts. More recently, and as deregulation evolves, state-level interconnection rules are becoming major drivers for documenting the considerations for requiring system impact studies. Many states have different review “levels” for DR interconnection—with the level being dependent on factors such as the type and size of the DR, and the type of distribution system. Typically there are four levels, with “screens (rules of thumb criteria)” to determine which level is applicable to a certain DR interconnection. Lower-level reviews allow for interconnection without a fully detailed impact study, although the screens could be considered to be simple impact studies. For example, small (often less than 10 kW) inverter-based distributed resources interconnected to radial systems are at the lower end (level 1) of the criteria values, and larger distributed resources and more complicated interconnections are at the higher levels (levels 2–4). For the higher level reviews (primarily level 4), extensive impact studies typically are required.

3.2. Simple Impact Study

In many ways, the criteria for a simple impact study are very similar to the screens that are used to determine the review levels. A simple impact study actually is just the criteria that allow a DR interconnection to follow the lower-level review process, which does not require a detailed impact study. Simple impact studies examine attributes of the DR and the EPS and determine whether system impacts will occur and whether a detailed systems impact study is required. This usually is done by examining conditions such as those discussed below.

Simple impact studies generally require the use of certified (or listed) DR equipment. Although the definition of what constitutes pre-certified or certified varies from state to state, example requirements are listed below.

- The interconnection equipment has been tested in accordance UL 1741 and IEEE 1547.1, in compliance with the appropriate codes and standards (e.g., IEEE 1547), by a nationally recognized testing laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration (OSHA) to test and certify interconnection equipment pursuant to the relevant (designated) codes and standards.
- The interconnection equipment has been labeled and is publicly listed by a NRTL.
- The interconnection customer verifies that the intended use of the interconnection equipment falls within the use or uses for which the interconnection equipment was labeled and listed by a NRTL.

If the interconnection equipment is an integrated equipment package such as an inverter, then the interconnection customer shows that the generator or other electric source being utilized is compatible with the interconnection equipment and is consistent with the testing and listing specified for this type of interconnection equipment. If the interconnection equipment includes only interface components (e.g., switchgear, multifunction relays, other interface devices), then an interconnection customer must show that the generator or other electric source being utilized is compatible with the interconnection equipment and is consistent with the testing and listing specified for this type of interconnection equipment.

Additionally, simple impact studies normally only apply to DR interconnected to radial systems. In some cases, however, they could apply to very small certified inverter-based DR interconnected to network distribution systems.

3.3. Detailed Impact Studies

A detailed impact study is an engineering exercise that carefully reviews the potential effect of a DR unit on the area EPS. The concerns of this study are similar to those of the simple study, but the size, type, or location of the equipment precludes the possibility of validating the site without detailed study.

Detailed impact studies can include analyses of impact such as power flow, short-circuit conditions, voltage drop and flicker, protection and control coordination, and grounding. These analyses can identify system reliability-criteria violations, equipment overstress, power quality impacts, stability problems, and other issues relevant to the proper operation of the area EPS. The detailed studies (and facilities studies) also can identify feasible mitigation measures for identified problems, provide recommendations for facility modifications, and include estimates of cost and construction time. These studies involve gathering data about the DR and area EPS, running models based on those data, interpreting the results, and proposing mitigation measures for any adverse impacts identified.

All detailed impact studies begin with an evaluation of the specific situation to determine the scope of work necessary to validate the distributed resource installation. It therefore might not be necessary to carry out all of the following steps (each of which is described in more detail below):

- Short-circuit analysis
- Stability analysis
- Power flow analysis
- Power quality study
- Flicker study
- Steady-state performance
- Voltage drop study
- Protection and coordination study
- Grounding review
- Analysis of equipment interrupting ratings.

3.3.1. Short-Circuit Analysis

A short-circuit analysis:

- Determines the effect on system fault currents
- Identifies circuit breaker short-circuit capability limits exceeded as a result of the interconnection
- Evaluates the impact on breaker fault duty
- Determines whether any circuit breaker or other interrupting equipment would have its interrupting capacity exceeded by the addition of the DR
- Identifies the need for equipment replacement based on preceding findings.

3.3.2. Stability Analysis

Stability analysis shows the effects of the new generation on the transient stability of the area EPS and surrounding utility generators. Transient stability is concerned with recovery from faults on the distribution system that are in close proximity to generating facilities. It also evaluates transient events on synchronized machines to demonstrate that they maintain synchronism.

3.3.3. Power Flow Analysis

A power flow analysis examines the steady-state operation of an electric power system. The power flow analysis (sometimes called load flow studies) calculates the voltage drop on feeders, the voltage at each bus, and the power flow in all circuits. The analysis determines whether system voltages remain within specified limits under all contingency conditions, and whether equipment such as transformers and conductors could potentially be overloaded. The power flow analysis often is used to identify the need for additional generation, capacitive or inductive VAR support, or the placement of capacitors and reactors to maintain system voltages within specified limits.

3.3.4. Power Quality Study

A study of power quality impacts includes transients, harmonics, ferroresonance, and temporary overvoltages. The impacts can cause equipment damage or customer disturbances. Typical steps include the following:

- Build the area EPS and DR models in an electromagnetic transients program and harmonic analysis program
- Simulate fault-and-clear operations and evaluate the resulting transients and temporary overvoltages
- Simulate capacitor switching and DR switching operations, along with startup of nearby motors, and evaluate the transients for proper DR operation and impact on nearby customers
- If single-phase fault interruption can occur, simulate this to evaluate the possibility of ferroresonance
- Estimate the harmonics contributed by the DR.
- Evaluate flicker, if necessary.

3.3.5. Steady-State Performance Study

A study of steady-state performance includes voltage control and loading at various points along the feeder. Load and DR generation cycles have to be considered. The impact on capacitor switching and voltage regulator tap operations also should be considered.

3.3.6. Voltage Drop Study

In most cases, the impact of an individual residential-scale (< 10 kW) DR unit on the primary voltage level of the area EPS is negligible. This might not be the case if a number of small units or a single larger unit is installed on the same area EPS. In such cases, the voltage regulation scheme could be reviewed to ensure that the area EPS voltage will be maintained within appropriate limits.

At secondary voltage levels on the area EPS, even a small, individual residential-scale DR device could adversely affect voltage available to other customers. When DR devices are added to a transformer that serves multiple customers, the voltage regulation could be reviewed to ensure that the area EPS voltage will be maintained within appropriate limits. The voltage regulation also could require a review when many individual residential-scale DR devices, a larger DR device, or multiple DR devices are to be located.

Distributed resources can impact voltage regulation in two ways. When power is exported from a DR device into the grid, it offsets load current and thus reduces the voltage drop on the area EPS. If the DR exports reactive power or absorbs reactive power from the power system, then it affects the voltage drop.

3.3.7. Protection and Set Point Coordination Studies

Protection and set point coordination studies analyze loss of coordination, nuisance fuse blowing, loss of sensitivity, bidirectionality, variability of fault current, and overvoltages.

3.3.8. Grounding Reviews

A grounding review ensures that the grounding scheme of the DR interconnection will not cause overvoltages that exceed the rating of the equipment connected to the area EPS and will not disrupt the coordination of the ground-fault protection on the area EPS.

3.3.9. Analysis of Equipment Interrupting Ratings

Electric distribution companies typically replace a circuit breaker when the expected calculated current through the breaker for a fault exceeds 100% of the circuit breaker interrupting rating without recloser de-rating applied, as determined by ANSI/IEEE C37.5, C37-010, and C37.04, breaker rating methods. The addition of distributed resources could cause the calculated current expected through a breaker to exceed its interrupting capability.

3.4. System Modeling

Modeling and simulation software most often is used to conduct system impact studies. Distribution studies typically are conducted by first addressing power flow (i.e., voltage drop) and fault current issues on radial feeders, and then evaluate additional issues as appropriate. Typical power flow applications include conductor sizing, ampacity checks, voltage drop checks against ANSI C84.1 limits, regulator tap settings, line-drop compensator settings, and capacitor bank impacts. Typical fault current applications include equipment rating checks and coordination of relays, reclosers, sectionalizers, and fuses. All of these are important to include in DR impact studies.

System modeling of area EPSs with interconnected DR requires the capability to handle the different types of DR power conversation devices (e.g., inverter, induction, synchronous), a variety of DR interface models (e.g., constant current or constant power), support for user-written models, a robust solution for distribution systems that may have a two-way power or fault flow, and solutions that perform analysis over a load or generation profile curve.

A number of commercial tools are available for impact studies. Traditionally, impact studies evolved for larger industrial and commercial customers. These tended to involve heavy electricity use, or special equipment or considerations. Some of the advanced traditional engineering analysis applications have included reliability estimates, capacitor bank optimization, open tie switch optimization, load allocation, load balancing, and arc flash hazards—many of which are indirectly related to DR.

The distributed engineering workstation (DEW) software package first considered distribution circuits at the onset and has evolved to transmission and an integrated systems approach. The DEW software has been used successfully in a number of analysis projects. Additionally, DEW is a readily available, open software package that enables users to accommodate their own modifications and semi-customization.

3.4.1. Modeling the Area Electric Power System

The area EPS operator should have an electrical model of the distribution feeder and substation source that includes overcurrent protective device settings, capacitor control settings, and tap changer control settings. The area EPS operator also should have load profiles or load duration curves, and nearby harmonic or flicker sources.

3.4.2. Modeling the Distributed Resource Installation

The model of the DR should include impedance data and grounding method; transformer data, type connection, and impedance; generator facility one-line diagram; facility operation description; protection equipment list; and point of interconnection protection equipment. The generator data can be provided in the form of a dynamic or transient stability machine model, if it is appropriate to the DR technology. Vendors sometimes can provide more-detailed models that include schematics and block diagrams. Using this information, the DR installation modeling typically includes the following components.

3.4.2.1. Power Flow

The power flow, or voltage drop, calculates the voltages and currents at all points during a steady-state, non-faulted system condition. A variety of load and generator characteristics versus voltage may be used.

3.4.2.2. Short-Circuit Analysis

The short-circuit analysis is a steady-state solution of the voltages and currents during a fault condition. This is typically a short circuit, but it may also include open conductors. For DR impact studies, it is important that the DR short-circuit contribution be properly represented. Some DR technologies do not behave like classical synchronous generators or induction machines, which most engineering analysis packages can handle.

Base case analysis is sometimes augmented with the sequence network data where faults (usually three-phase and single-line-to-ground) are applied to the point of interconnection with and without the DR. The fault duty at that point is calculated.

The voltages during short-circuit conditions can be used to estimate voltage sag magnitudes experienced by other customers, including any impacts from DR.

3.4.2.3. Transient Stability Programs

Transient stability analysis is a time-based simulation that assess the ability of synchronous machines to remain in synchronism with each other and with the area EPS shortly before, during, and following a contingency. It also analyzes all voltages within the system to ensure they return to an acceptable level within a reasonable post contingency time frame.

3.4.2.4. Post-Transient Analysis

Post-transient analysis considers a short period in time, after the time considered in transient stability evaluation, where tap changing transformers, static VAR devices, phase-shifters, and area interchanges have not had time to adjust. In performing a post-transient analysis, disturbances are applied to the system. A post-transient load flow calculation is then performed.

3.2.4.5. Contingency Analysis

A list of possible contingencies is developed and then a series of load flows is performed, with and without the DR, to determine overloads for each of the contingencies. Once overload conditions have been identified, mitigation measures can be developed.

3.4.2.6. Electromagnetic Transients

This type of program simulates high-frequency transients in the time domain with a full unbalanced system model in phase coordinates. These are commonly referred to as electromagnetic transients programs (EMTPs).

3.2.4.7. Harmonic Load Flow and Frequency Scan

This type of program calculates driving point and transfer impedances versus frequency for the area EPS. It also evaluates the flow of harmonics in the area EPS given specified current injection sources. The applications include harmonic filter design and estimates of harmonic voltage distortion at various points in the area EPS. The solution method is similar to a fault analysis or, less commonly, power flow. The main differences are that the solution is performed at several frequencies and output reports are specialized to harmonics.

3.5. Results of Impact Studies

The analyses showing the system impacts resulting from the addition of the DR to the area EPS are similar to what would need to be done if a new major load were placed on the area EPS, or if an equipment upgrade on the area EPS were to be deployed, such as to increase the reliability of the area EPS. Based on the detailed study characteristics, various mitigation techniques are used for the issues that identified in an impact study. These mitigation techniques primarily involve changing equipment settings, upgrading equipment, changing facilities, or possibly modifying some operations.

3.5.1. Mitigation of System Protection Concerns

Examples of measures to address system protection concerns include:

- Replacing automatic line reclosers with intermediate circuit fuses between the DR and the source substation
- Adding directional protection added to distribution system protective devices
- Adding transfer trip from the substation to the DR
- Modifying the source substation protection schemes to include tripping of the feeder terminal breaker on those circuits that have interconnected generation.

3.5.2. Mitigation of Steady-State Performance Concerns

The steady-state issues identified can include voltage limit violations, equipment overloads, and adverse voltage control interactions. Some possible mitigation methods are:

- Upgrading substation transformers and feeders to eliminate overloads or voltage violations
- Moving the distributed resource closer to the substation source

- Replacing temperature or time-controlled capacitor switching with local voltage control, current control, reactive power control, or centralized capacitor dispatch
- Modifying voltage regulator settings, or providing voltage regulators designed to operate properly with reverse power flow.

3.5.3. Mitigation of Power Quality Concerns

The issues identified can include excessive harmonic or flicker contributions from the DR, or equipment damage from transients. Other concerns include the following:

- Installing filters
- Changing DR interface technology or vendor tuning of the interface controls to reduce levels
- Relocating the DR closer to the substation
- Applying surge arrestors to protect the equipment. (The surge arrester voltage ratings can be increased from normal levels, subject to maintaining adequate protective margins for the insulation. A change in transformer connection type or supplemental grounding transformers might be considered. DR control tuning also could help.)

3.5.4. Mitigation of System Stability Concerns

Concerns identified by the stability study can include loss of synchronism, excessive transient voltage deviation, excessive transient frequency deviation, and underdamped oscillations. A candidate mitigation option is implementation of protective schemes so that faults or devices are cleared or isolated before a system becomes unstable. If a stability concern is identified, then the stability study also should determine the critical clearing times needed to clear faults or isolate devices for the concerns.

3.5.5. Modeling Example of System Impact Studies

The following is an example of results from modeling and simulation studies, and these studies have been validated with actual field measurements at a utility (Figure 7). The DEW software analysis package was used to consider DR impacts on a utility grid circuit as well as the effects of unbalanced loading and voltage regulation. The software was used to determine the voltage profiles of utility distribution circuits under different operating conditions, such as peak load and light load conditions. It was also used to analytically determine the voltage profile of the circuit with and without distributed resources in operation (e.g., synchronous, induction, and inverter-based DER), and with traditional methods for voltage regulation (e.g., substation transformer load tap changers, bus regulation, line regulation, capacitors (shunt and series), and bi-directional regulators). The model also was verified through actual field measurements of the utility-selected circuits (e.g., four-wire Y multi-grounded three-phase circuit).

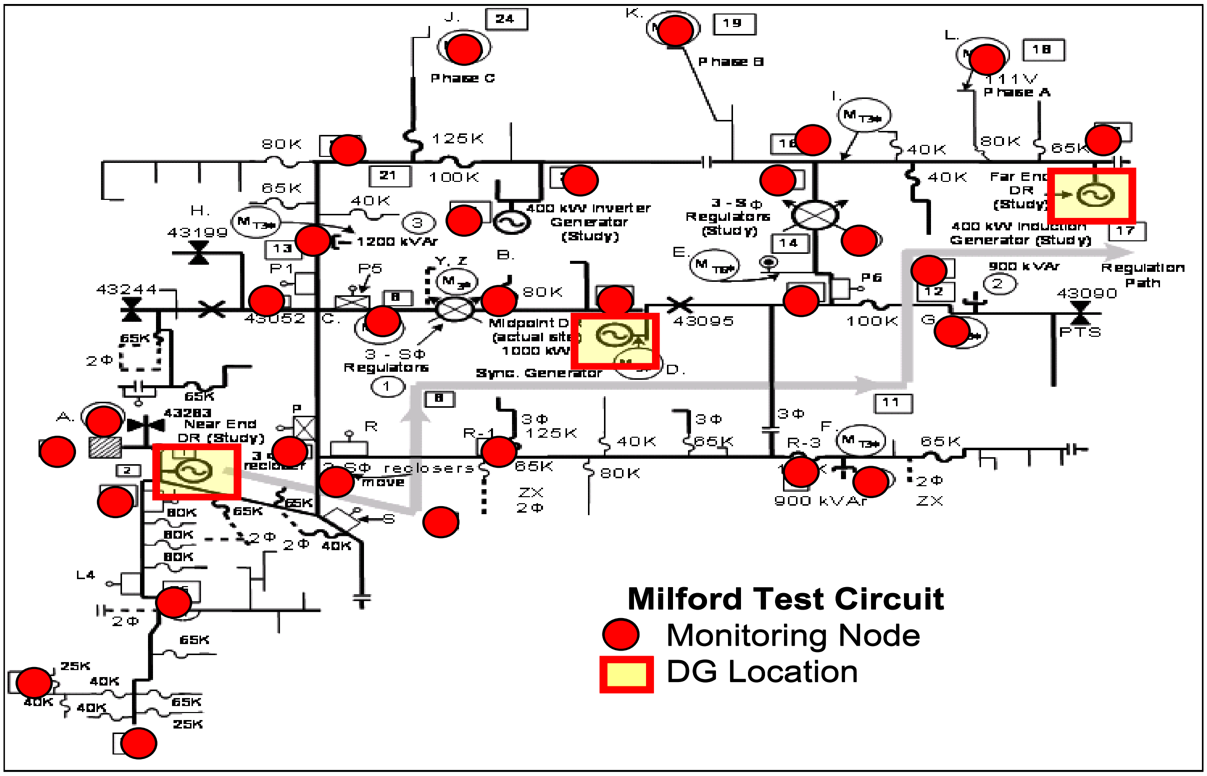

Figure 7. Circuit used for DEW analyses

Further, in another prior study DEW was used to determine the DR system penetration limits imposed by the local grid due to a number of utility coordination issues (e.g., voltage dynamics, voltage stability, system protection). Those two studies have proven successful and illustrate the broad applicability of the DEW software tool for system impact studies.

4 Current Challenges and Future Solutions: Needs for Further Development and Recommendations

System impacts are a somewhat misunderstood concept by some stakeholders in the distributed resource community. Many potential DR owners who want to interconnect with the grid think that if their equipment is IEEE 1547 compliant, then they should be able to interconnect to the area EPS at any location and without causing any system impacts or requiring any studies to be conducted by the area EPS operator. Although this might be true for distributed resources in many locations, there are certain cases in which impact studies are required and changes will need to be made to accommodate the DR. Until fundamental changes are made in the planning, design, and facilities and operations of the grid, detailed system impact studies always will be a priority for utilities for most significant DR projects—especially if the distributed resources are large in size or high penetration. Further, as better understanding of—and tools for—DR interconnection and impacts studies become a more mainstream utility practice, distributed resources could be viewed as another option for use by both the grid owner and customers for improving electric infrastructure performance and reliability.

4.1. Current Challenges and Future Solutions

The traditional model of electric power generation and delivery is based on the construction of large, centrally located power plants and is characterized by a grid design—much of which typically is 40 to 60 years old. Electric power grids consist of two separate infrastructures: (1) the high-voltage transmission system and (2) the lower voltage distribution system. High voltage is used for transmission lines, and minimizes electrical losses. Lower-voltage distribution systems connected to transmission lines reduce the voltage down to 12 kVA to 35 kVA or less for distribution to individual customers or distribution substations. Transformers located along the distribution lines further step down the voltage for customer end use.

Substations contain electrical switchgear and circuit breakers to protect the transformers and the high-voltage transmission system from electrical failures on the distribution lines. Beyond the substation, circuit breakers are located along the distribution lines to locally isolate electrical problems (such as short circuits caused by downed power lines).

A significant challenge to DR interconnection is that the electric grid is not designed to accommodate active generation and storage at the distribution level. This is particularly true for two-way distribution where, for example, a local residence- or business-sited DR could send power back into the distribution system or contribute to fault effects on the distribution system. A grid that was designed 40 to 60 years ago was designed for one-way power flow, and based on traditional protection studies will require additional steps to effectively interconnect DR; to assure, for example, system protection metering and basic design compatibilities such as grounding.

In certain cases existing grids need to be evaluated through system impact studies to determine whether they should (and can) be modified to accommodate an interconnected DR unit. Distributed resources can obviate or reduce the need to build new high-voltage transmission equipment and lower-voltage distribution lines. Another benefit is that overall efficiency improves by limiting line losses, which are the power losses that occur when electricity travels over transmission and distribution lines for long distances and through transmission and distribution equipment.

The distributed resource designs that reduce or eliminate problems with the existing utility distribution system now are being further developed. However, additional analysis, research, development, demonstration, and deployment are needed. Better engineering justification based on analyses is required to establish methods and procedures that have verified applicability for system impacts, understanding, and mitigation for accommodating increasing use of distributed resources The advanced utility distribution system of the future (the smart grid) should be largely capable of extracting the full benefits offered by DR for both the DR owner and for other customers of the distribution system. There are increasing challenges to DR interconnection systems, however, that will require proactive participation in supporting the modern grid—going beyond the traditional IEEE 1547 interconnection system grid interaction approach, which is based on the historical grid designed without DR originally embedded within it.

To fully address the DR system impact concerns and to get the greatest value to the electric infrastructure from the DR, the electrical transmission and distribution system needs to evolve in several important ways. Particularly important is utilizing emerging digital technologies that are more reliable, flexible, and maintainable at lower costs than other electro-mechanical counterparts. The overall approach truly needs to be a complete systems approach, especially addressing systems integration to fully understand and alleviate the root causes of systems impacts of embedded DR (Figure 8). In addition to systems integration, evolution of interconnection and interfaces, technical standards, and advanced technologies round out the systems approach.

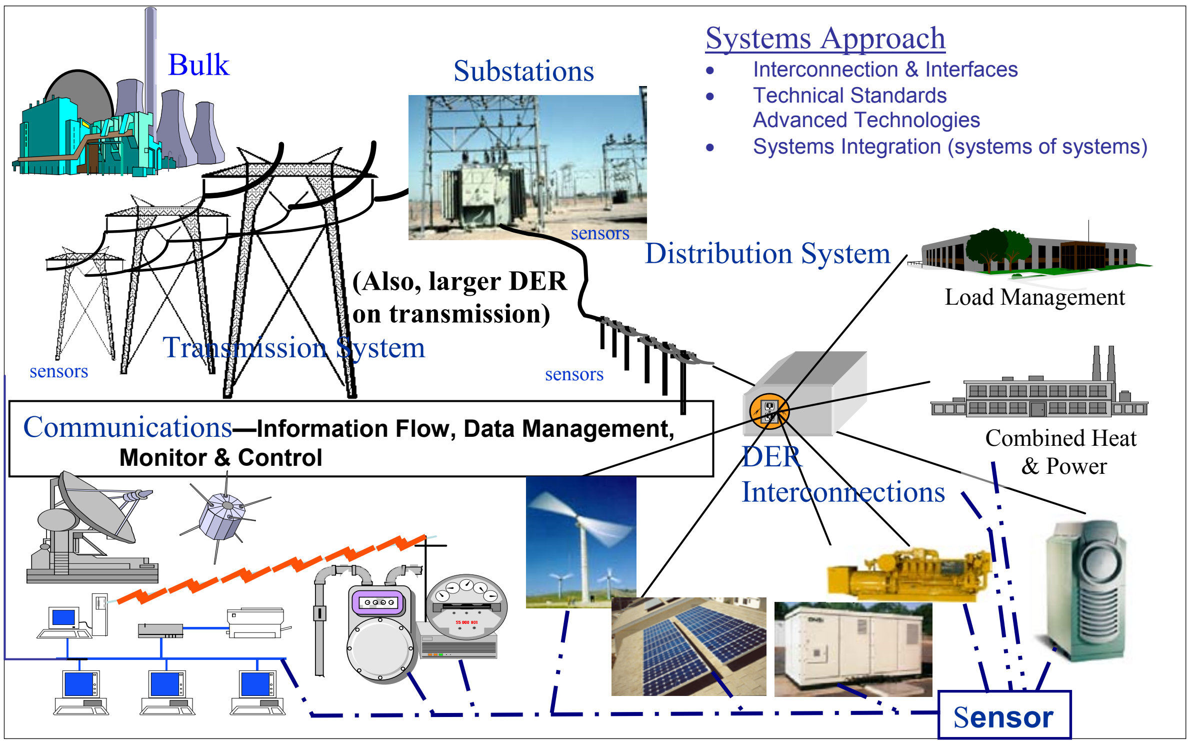

Figure 8. Example evolutionary electric power system infrastructure

4.2. Needs for Further Development

The need for further development of impact studies capabilities and features is centered around the lack of: (1) universally accepted approaches to systems impacts (e.g., sophisticated, quantitatively based rules); (2) wholly integrated systems analyses to account for modern grid and modern distributed resources; and (3) qualification of both the modern grid and modern interconnection systems. Satisfying these needs will enable faster and more effective development, planning, building, operating, and maintaining of a modern grid that includes both two-way power flow and two-way communications among grid and DR equipment.

At the core, modern transmission and distribution systems embracing DR, interoperability, and the smart grid need to be configured (or reconfigured) and operated to provide local control authority for:

- Actions that must be undertaken quickly (e.g., local voltage regulation)
- Aggregation and balancing of generation and load

- Maintaining the distribution voltage and frequency within limits specified by a central control authority
- Dispatching reliability services (e.g., spinning reserve, black start) in response to commands from a central control authority.

Future distribution systems need to have the following key capabilities:

- Enhanced technology features
- Modeling, simulation, and real-time comparative analyses and operations
- A layered control system that satisfies the needs of the customers and loads, the local distribution system, and the transmission grid
- A well-defined hierarchy of priorities in the control logic
- A protection system that will accommodate routine two-way power flow with localized generation/storage
- Ability to rapidly change configuration, island, re-align, and start and stop generation.

The modern electrical distribution system and substations will handle two-way electrical flows as well as both centralized and dispersed communications, permitting all interconnected DR to be dispatched, monitored, and controlled either autonomously or semi-autonomously in an intelligent manner. The distribution system will rely on upgraded substations that could incorporate communications with improved capabilities for monitoring and reporting, GPS, electric equipment diagnosis, real-time video capture and transmission, audio-signature analysis, and substation security supervision. Advances in low cost communications networks, sensors and controls, energy storage, and power electronics will enable the connection of great numbers of DR to the grid in a fully functional manner which, in turn, will result in greater reliability, increased efficiency, and improved power quality.

Hierarchical control systems and distributed, intelligent agents will overlay local decision making with a systems hierarchy that is composed of supervisors having increasing levels of sophistication. This framework allows decision making to be pushed down to the lowest level and results in a number of operational benefits, including increased speed of communication and control, and the availability of much more detailed information to the central control authority when necessary.

Low cost sensors and fast local communication systems with embedded intelligence will allow DR systems to seamlessly integrate with the electrical distribution system and to operate cooperatively and autonomously. The modernized and highly automated distribution system will support: remote monitoring of device performance; dynamic and optimized aggregation; and the detection of system faults, instabilities, and congestion problems.

Modern distribution system technologies will become an integral part of control and switching devices throughout the distribution system. The distribution system of the future might include a DC bus and high-frequency AC networks, and possess self-healing capability. This last characteristic is especially important in dense distribution systems where a fault can take hours of trial and error to locate and repair. For example, a non-U.S. utility developed a system operation to automatically detect and isolate a fault on a feeder. Once the faulted section is isolated, the automated supervisory system closes the appropriate switch and restores power to the feeder (typically within 20 seconds of the fault).

Tomorrow's mainstream distribution system will be smart, flexible, and more reliable than those of today. Instead of the struggle to interconnect today's DR technology with today's electric distribution system, through future developments the interconnection of advanced DR with the smart grid will be nearly seamless. Much of this development will occur methodically as a matter of fact as utilities deploy increasingly smart components when maintaining, replacing, or upgrading distribution systems. Utilities will do this because operations and maintenance costs are lessened when better technologies are used. In other words, tomorrow's distribution system will slowly evolve as new technologies inevitably are deployed. However, targeted research, development, and applications efforts today can speed this process along by mitigating barriers and improving the underlying technologies and experience.

4.3. Recommendations and Conclusions

The following recommendations for system impact studies improvements and for impact mitigation are provided for consideration and implementation.

- Qualification of the grid (e.g., system impact studies will be simpler or eliminated if grid "classes" are established based on agreed upon electrical characteristics and operations of the grid).
- Qualification of new interconnection systems and smart grid interconnection concepts beyond IEEE 1547-2003 (e.g., voltage ride through, voltage regulation, and advanced monitoring and controls)
- Modeling and simulation improvements.

For effectively addressing the above recommendations, systems-based approaches should be undertaken based upon the principles inherent in, and the development of, interoperability protocols, standards, and frameworks covering such things as advanced technologies, data/information, and improved schemes and operations.

Such interoperability protocols and standards will further align policy, business, and technology approaches in a manner that would enable all electric resources, including demand-side resources, to contribute to an efficient, reliable electricity network. For example, approaches should pursue codes, standards, and related infrastructure framework needs for impacts; modeling and simulation; system protection and coordination; interoperability; voltage regulation; grid planning; operations; and the smart grid.

Minimizing system impacts not only requires evolutionary changes to interconnection systems in terms of enhancements to power conversion devices, but also requires the significant changes noted above for a truly integrated, total systems approach to area EPS planning, design, architecture advances, and smart grid operations. When these changes are common practice, the area EPS then will be qualified not only for distributed resources but for greater ease and effectiveness of addressing future infrastructure advancements. If certified DR were connected to a qualified area EPS, then the need for system impact studies would be greatly simplified or even eliminated.

A number of advanced technologies or new features, proven operating practices, analytical tools, and standards need to be developed or proven in deployment to address system impacts from the interconnection of DR with electric power systems, including the following:

- New grid-protection schemes (e.g., fault detection, non-islanding, planned islanding, two-way power flow, embedded DR contributions)
- Real-time monitoring equipment for incipient fault detection and self-repair
- Interfaces that control power flow, voltage, and frequency
- Smart substation designs that allow real-time control of DR microgrids and other DR units interconnected to the substation's distribution feeders
- Modifications to the electrical distribution system that increase its reliability, lower its maintenance costs, and ensure secure operations in the face of crippling natural disasters or terrorist activities
- Distribution automation and DR interoperability
- Improved distribution system VAR support, without necessarily adding new generating capacity
- System-control models that incorporate automatic local contingency response
- Advances in low cost communication and control networks and advanced supervisory control and data acquisition that enable aggregations of DR to be an integrated operation with the scalability to meet individual user, facility, and utility requirements
- Modular, standardized interconnection devices that allow DR to be readily and inexpensively interconnected with the electrical distribution system
- Digital programmable relays, improved sensors and controls, and expert systems that enable real-time dispatch and monitoring of DR units
- Better screening methods to identify DR applications and grid sites that do not require detailed impact studies
- More complete and universally accepted knowledge of DR and grid electrical and integration characteristics
- Total integrated modeling and simulation approaches and tools encompassing grid and DR (e.g., for planning, design, operations, and contingency).

5 Conclusion

In sum, the three major conclusions of this report follow along with the respective recommendation of needs (italicized text) primarily related to the specific conclusion but crosscutting all three conclusions.

1. The grid was not planned, designed, built, and operated with distributed resources and modern grid aspects in mind (e.g., distribution automation, semi-autonomous operations, DR, load management, smart grid). Need: *Qualification of the grid*.

2. Today's interconnection systems are based on traditional grid design and equipment, and on traditional grid operations (e.g., reactive to abnormalities) where the old, traditional grid interconnection systems were designed to address DR independently from the grid design and operations. Need: *Qualification of modern interconnection systems* (e.g., smart grid concepts beyond IEEE 1547-2003 base standard to allow grid support).
3. The grid, interconnection systems, and DR technologies lack full electrical and integration information analysis tools (characteristics, parameters, models, tools for analysis and integration). Need: *Modeling and simulation improvements* (toward total integrated electrical system analyses).

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This report documents and evaluates system impacts from the interconnection of distributed resources to transmission and distribution systems, including a focus on renewable distributed resource technologies. The report also identifies system impact-resolution approaches and actions, including extensions of existing approaches. Lastly, the report documents the current challenges and examines what is needed to gain a clearer understanding of what to pursue to better avoid or address system impact issues.

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