Distribution System Design for Strategic Use of Distributed Generation

1010671

Distribution System Design for Strategic Use of Distributed Generation

1010671

Technical Update, December 2005

EPRI Project Managers
F. Goodman
L. Ard

ELECTRIC POWER RESEARCH INSTITUTE
3420 Hillview Avenue, Palo Alto, California 94304-1395 ▪ PO Box 10412, Palo Alto, California 94303-0813 ▪ USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com

ORGANIZATION(S) THAT PREPARED THIS DOCUMENT

EnerNex Corporation

This is an EPRI Technical Update report. A Technical Update report is intended as an informal report of continuing research, a meeting, or a topical study. It is not a final EPRI technical report.

NOTE

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

CITATIONS

This report was prepared by

EnerNex Corporation
144-E Market Place Blvd.
Knoxville, TN 37922-2337

Principal Investigators
T. E. McDermott
N. Samaan

This report describes research sponsored by the Electric Power Research Institute (EPRI).

This publication is a corporate document that should be cited in the literature in the following manner:

Distribution System Design for Strategic Use of Distributed Generation. EPRI, Palo Alto, CA: 2005. 1010671.

ABSTRACT

This project was undertaken to identify distribution system design characteristics that limit widespread distributed generation (DG) penetration in utility distribution systems and to suggest new system design paths that increase strategic use of DG by distribution system operators. This work in 2005 was the first phase (requirements definition) of a multi-year project in the EPRI Advanced Distribution Automation (ADA) program plan. The multi-year project calls for design, implementation, and testing of a specific advanced distribution system concept for strategic use of DG in subsequent years. For the shorter term, this report outlines impact studies and integration techniques that should work for low-penetration scenarios. For the intermediate term, utilities can gain significant power quality and distributed resource benefits through relatively inexpensive changes to their protection systems. Feeder-level and substation-level controls can also evolve toward the full mini-grid and micro-grid concepts. EPRI can facilitate this evolution by making sure that IEC Standards 61850, 61968, and 61970 all support the necessary DER impact studies and adaptive control/protection schemes. EPRI should also support one or more system development projects, integrating DG as a part of the larger emerging picture in Advanced Distribution Automation (ADA). Candidate projects would include medium DG penetration on a radial feeder, high penetration on a primary mini-grid, and high penetration on a secondary micro-grid. All of these activities, along with development of new software to support DG engineering, should be coordinated with other ADA efforts. In parallel, EPRI should support and extend its earlier DG-specific work, by creating a database of DG case studies and application guidelines.

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1

INTRODUCTION

The project's main objective was to identify the aspects of distribution system design that limit growth of distributed resources (DER) to high penetration levels. The primary deliverables are:

- Guidelines to help utilities evolve their distribution systems
- Requirements for follow-up EPRI research and development work

In this report, DER refers to both distributed generation (DG) and distributed storage (DS). A low penetration level of DER means that simple screening tools and standardized interconnection techniques will suffice. A medium penetration level of DER means that a more detailed impact study is necessary. The end state considered in this report is that of a high penetration level, at which islanding and micro-grids become feasible.

In the past, DR has often served as the abbreviation for Distributed Resources, but this can be confused with Demand Response, which is another concept closely associated with distribution systems and distribution automation. This report uses the acronym DER, except when referring to certain older EPRI projects and reports by name.

In most places, the report also uses the abbreviation DG instead of DER, especially when discussing specific electrical behaviors. This follows common industry practice. It is also technically sound, because the DS technologies of DER pose the most "interesting" problems when they act like DG, supplying power to the distribution system. At other times, from an electrical point of view, they are simply another load.

The next three sections of this report discuss the obstacles to DER applications on the distribution system, and the overall re-design path to remove these barriers. Section 5 recommends follow-up EPRI research projects to address these needs. Appendix A presents the near-term utility evolution guidelines, and appendix B includes an up-to-date bibliography.

Relationship of DER to ADA

The application of DER seems closely related to Advanced Distribution Automation (ADA), even though the concepts are not strictly identical. EPRI's high-level driving factors for ADA include [1]:

- The value of reliability and power quality

- Improved operations and asset management
- Reduced losses
- Overall system energy management, reliability, and security.

DER applications could improve energy management, reliability, power quality, and minimize losses in some situations. But in general, other ADA technologies provide a simpler and more direct method of achieving these utility goals. The driving factors for DER applications are often to help customers and public policy makers achieve their goals, which may complicate matters for the utility. However, there are important technical synergies between ADA and DER, because both require enhanced communication infrastructure on the distribution system, and more widespread adoption of intelligent electronic devices (IED) on the distribution system. Given the expense of both improvements, any technical synergy between ADA and DER could speed up the adoption of both. In particular, it could be easier for a utility to implement DER than a customer or third-party investor.

Distribution automation has earlier been justified for these reasons:

- Load management
- Improve reliability indices
- Improve voltage regulation
- Distributed generation (DG) control and dispatch
- Electric vehicle (EV) charging

The first three factors have been around for 25+ years, with several implementations, and the issues are well understood. These first three factors also cover most broad justifications for distribution automation, such as "better asset utilization". Adoption has been relatively slow in the U.S. compared to other countries, and what could make the adoption go faster? Would the availability of better technology be enough?

The last two factors, DG and EV, are newer than the first three factors. More importantly, they represent forces external to the utility industry. They represent new business drivers for distribution automation.

For EV, the main concern has been the ability to handle harmonics, but most studies predict that 20-40% EV penetration could be supported on existing feeders. There is some concern about the time profile of EV chargers, if they produce overloads in the early off-peak hours by drawing higher currents at the beginning of their (coincident) charging periods. This would be a good application of load management.

DG could become a very important business driver for distribution automation and for ADA. There are strong incentives for economic dispatch, and for making the distribution system operate as a network instead of with radial feeders. Improved reliability indices will also become more important on feeders with DG. This might be what has been missing for the past 25+ years, in terms of driving the widespread adoption of distribution automation.

If the distribution system is ready for high penetration levels of DG, it will also be ready for ADA. The converse also holds true; a system ready for ADA is ready for DG. Follow up to this project could, therefore, focus on the design or demonstration of an advanced distribution (AD) feeder. This AD feeder would be more like a transmission or sub-transmission system, which:

- Includes many desired features to support DG and ADA
- Is already well understood and accepted by utilities

These two factors may compensate for the increased cost.

Previous EPRI Work

EPRI has published two guidebooks for integration of DG in distribution systems [2, 3]. These cover fundamental topics of transformer interconnection, overcurrent protective device coordination, voltage regulation, ferroresonance, harmonics, transient overvoltages, reliability, and islanding. These have been partially superseded by the approval and publication of an IEEE standard covering technical requirements for DG interconnection [4], but the EPRI guidebooks should be kept up to date. In December, 2001, EPRI published a software screening tool for DG integration, which has recently been updated [5].

There has been another previous software development effort by EPRI [6], providing a tool that calculates the potential benefits of DG in deferring T&D investments. This tool, EDC, features a comprehensive electrical simulation over the entire load and generation profile, to produce estimates of the un-served energy. A tool like this, updated for practical use, could help utilities get the most economic benefit from DG (or DS) installed on their feeders.

EPRI has also commissioned simulation case studies of three feeders with hypothetical DG applications [7, 8]. One feeder was urban, one suburban, and the third rural. These three feeders were selected because the utilities were willing to provide data and cooperation to the study team. These case studies took a comprehensive look at modeling, fault current levels, overcurrent protection, voltage and frequency control, harmonics, and transient voltages. Some penetration limits were identified based on these three cases, and it was suggested that further case studies should be performed to refine the penetration limits, develop guidelines for utilities, and develop simplified analytical methods. Two of the feeders are 25-kV class, which is less common than 15-kV class, and that illustrates one problem with relying on case studies to develop guidelines. However, these three case studies are valuable examples of how to conduct a DG impact study, and they should be maintained, updated, or extended by EPRI.

EPRI has pursued other projects relevant to this one. In particular, the various Advanced Distribution Automation (ADA) and IntelliGrid initiatives could enable high penetration levels of DG. The EPRI Utility Communications Architecture (UCA) project, which has since migrated into IEC 61850, will be another critical enabler for high penetration levels of DG. Finally, the EPRI Common Information Model (CIM), which has since migrated into IEC 61970 and 61968, will facilitate the new engineering analyses required for high penetration levels of DG. EPRI should build on all of these efforts, and the others discussed above, to focus its research on DG penetration.

References

1. *Technical and System Requirements for Advanced Distribution Automation*, EPRI, Palo Alto, CA, June 2004. 1010915.

2. *Engineering Handbook for Dispersed Energy Systems on Utility Distribution Systems,* EPRI, Palo Alto, CA: 1995. TR-105589.

3. *Engineering Guide for Integration of Distributed Generation and Storage into Power Distribution Systems,* EPRI, Palo Alto, CA: 2000. 1000419.

4. *IEEE Std. 1547TM, Standard for Interconnecting Distributed Resources with Electric Power Systems*, IEEE, Piscataway, NJ, 2003.

5. *DR Integration Assistant – Version 4.0,* EPRI, Palo Alto, CA: February 2005. 1008428.

6. *EDC – Engineering Design and Costing Model – Version 1.0b*, EPRI, Palo Alto, CA: 1997. AP-109733 and SW-44843-CD.

7. *Integration of Distributed Resources in Electric Utility Distribution Systems: Distribution System Behavior Analysis for Suburban Feeder*, EPRI, Palo Alto, CA: 1998. TR-111490.

8. *Integration of Distributed Resources in Electric Utility Distribution Systems: Distribution System Behavior Analysis for Urban and Rural Feeders,* EPRI, Palo Alto, CA: 1999. TR-112737.

2
DER-LIMITING FEATURES OF DISTRIBUTION SYSTEMS

With the recent advances in distributed generation (DG) technology and reduction in DG unit costs, DG is expected to play an important role as a vital Intelligent Electronic Device (IED) in the future distribution system. DG has many strategic values in improving the reliability and the economics of the distribution system. Yet, there are many barriers that can prevent proper operation of distribution systems with heavy DG penetration. Some of these barriers are design characteristics of current distribution systems and others are operation and maintenance characteristics, regulations and lack of adequate tools for distribution engineers. This section describes the limitations of existing distribution systems to be ready for safe DG penetration and other factors that prevent achieving the optimal usage of DG as a strategic IED in future distribution networks.

Limitations of Distribution System Protection

In the conventional radial distribution systems, the power flow direction is always known. Power flows from the substation to the main feeder and then through laterals to various loads. Protection is designed on this basis. Installation of DG units on main feeders and laterals will result in power flowing in both directions. In this case conventional reclosers may not work properly, as they are designed to reclose the circuit only if the substation side is energized and the other side is not energized. Having DG units installed could result in both recloser sides being energized. Although the currently approved IEEE 1547 standard suggests that this not be allowed, a future document in the series (P1547.4) will address intentional islanding.

Short circuit levels throughout the distribution network will increase. The substation and all installed DG units on the network will contribute to short circuit current. DG units based on synchronous or induction generators without inverters can contribute up to 10 times their rated current for the first few cycles after fault. Consider a temporary fault on a lateral; DG will contribute to the short circuit current, causing the lateral fuse to blow before the fuse saver (upstream recloser or circuit breaker) opens the circuit. There will be a need to recalculate short circuit levels, and possibly replace current breakers and fuses with new devices that have higher interruption capacity.

When a fault occurs on the primary of a substation transformer, DG units will supply short circuit current to the fault. If the transformer is mainly protected with a high-voltage fuse instead of a differential relay scheme, then it may not have been designed for short-circuit current coming from the "load" side. It will be necessary to make sure the secondary breaker trips in this situation.

Radial protection coordination techniques, which presume downstream devices clear a fault before upstream devices, may not function properly with DG units in the distribution network. Downstream DG units reduce the reach of overcurrent relays, by contributing to the short circuit current. This decreases fault current seen by the overcurrent relay. As a result, it will take longer to operate, and it may not even detect some high impedance faults.

Suppose a permanent fault occurs on the main feeder shown in Figure 2-1. Short circuit current will flow from both the substation, and DG units on the other side of the fault. Both feeder circuit breaker CB_1 and DG circuit breaker CB_2 will open. There will be no strategic value in having the DG unit as a backup power source with intentional islanding, unless the protection is modified. Protection can be changed by adding another circuit breaker CB_3 on the main feeder before the DG unit, as shown in Figure 2-2, so that the DG unit will still be able to supply downstream loads. Such intentional islanding must be planned carefully; otherwise, it represents a hazard to the distribution system. There must be enough DG capacity to supply these loads, or else DG units will be overloaded. The DG units cannot supply downstream loads, if their circuit breakers trip on overload. DG units in intentional islands should also have a robust control system to maintain voltage and frequency within standard limits.

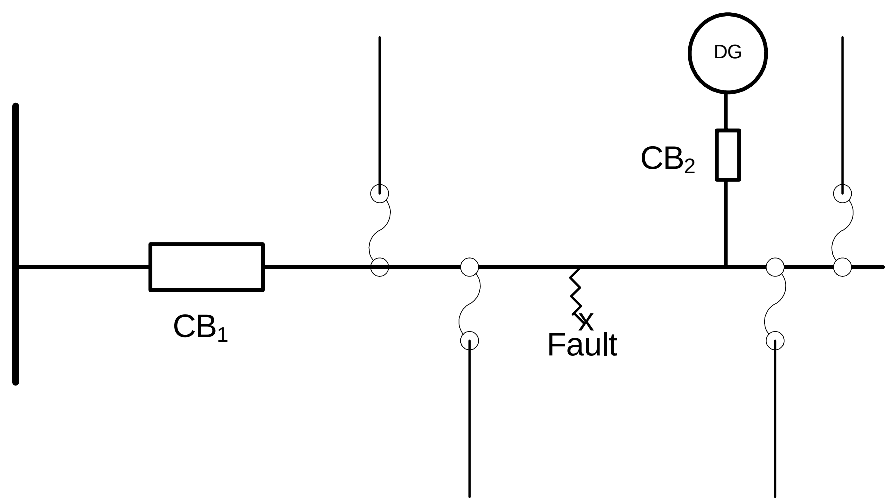

Figure 2-1
Permanent Fault that will Interrupt Power to all Loads

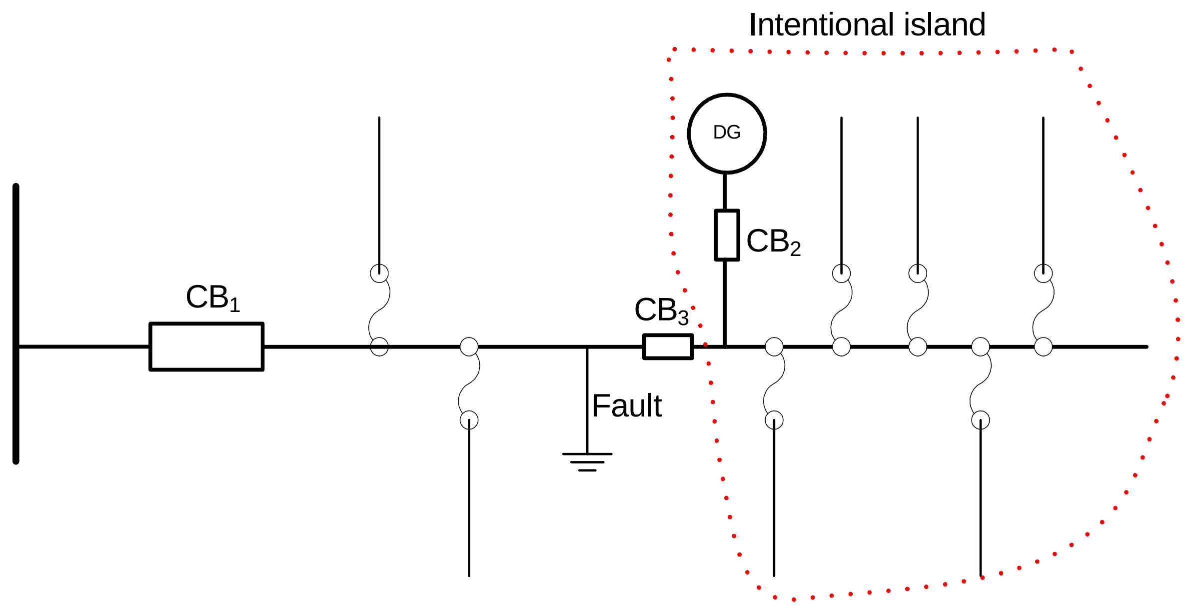

Figure 2-2
A Circuit Breaker Installed Just Upstream of the DG Unit Allows the DG to Supply Downstream Loads

Consider the circuit shown in Figure 2-3. During a fault at point X, the DG unit supplies fault current, even though it's located on a parallel, non-faulted feeder. This can produce a trip of the DG unit, or its feeder. Protection devices should be correctly coordinated so that CB_2 opens before CB_3 and CB_1.

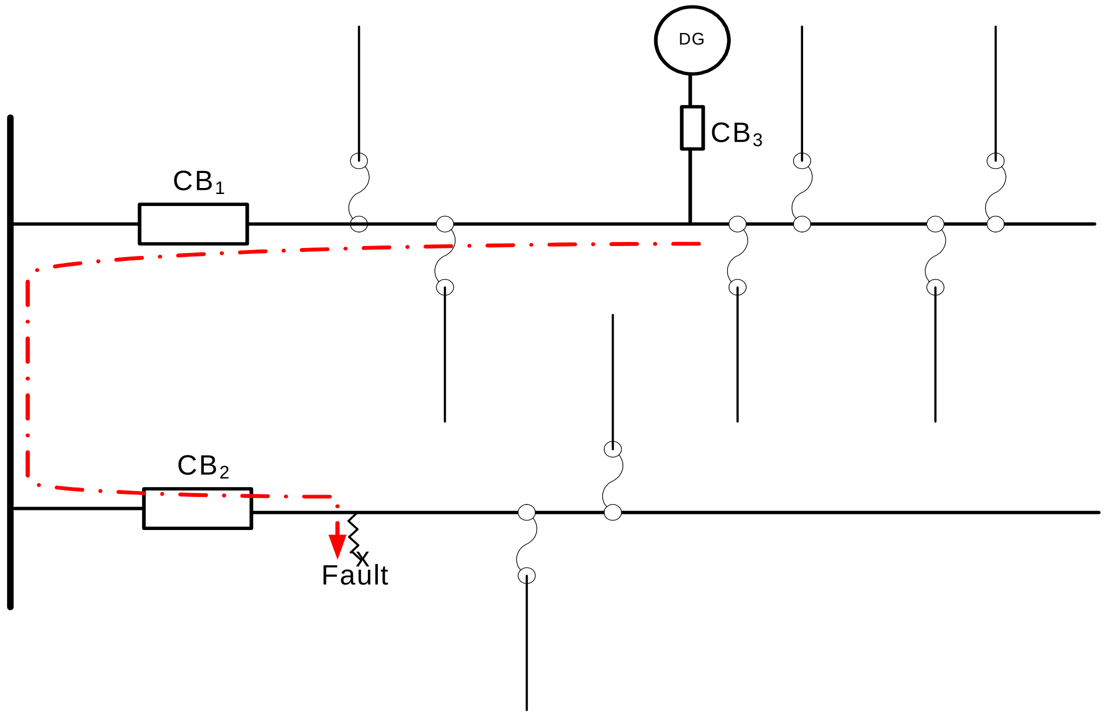

Figure 2-3
Improper Protection Coordination Can Result in Tripping of Unfaulted Feeders

Interaction between Voltage Regulators and DG

Voltage regulator controls are based on the conventional radial system. With the installation of DG units, the control of these devices should be modified to account for bi-directional power flow. Interaction between existing voltage regulators and newly installed DG units raises many problems to consider [1, 2, 3, 4, 5].

1. A directional voltage regulator may decrease the voltage level on its primary when a downstream DG unit causes reverse power flow, from secondary to primary, through the regulator. This may produce undervoltage at loads downstream of the DG, because the voltage drops to those loads are no longer compensated. Therefore, unidirectional voltage regulators should be replaced with bi-directional voltage regulators that can regulate voltage in either direction.

2. DG units installed just downstream from a voltage regulator may cause the line drop compensator control to take incorrect actions. The controller sees a load current less than the actual value flowing from DG to load, causing it to not fully compensate for that voltage drop. Again, this will subject the downstream loads to undervoltage.

3. DG units connected directly to the distribution transformers can subject customers connected to the secondary of the same distribution transformer to an overvoltage. This may occur when an upstream voltage regulator controls the transformer primary voltage to a level at or above the ANSI upper limit on service voltage. Without DG, the transformer voltage drop

would result in a secondary voltage within limits, but with DG, the secondary voltage may be too high.

4. If DG output power changes frequently, which is the case with wind turbines, there will be voltage flicker and voltage drop through the section of the feeder upstream from the DG unit. This could result in hunting for upstream regulator controls, causing even more voltage flicker.

5. To avoid some of these problems, the IEEE 1547™ standard states that the DG shall not actively regulate the voltage at the Point of Common Coupling (PCC.)

Interaction between Capacitor Banks and DG

During islanding conditions, it is possible for series resonance to develop when the capacitance of capacitor banks almost equals the subtransient inductance of the DG generators. This would subject feeder equipment and customer loads to overvoltage [6].

During islanding conditions, ferroresonance can occur as a result of the interaction between the non-linear magnetizing reactance of the DG step-up transformers or other magnetic devices, and the system capacitance. As a result, lightning arresters and other equipment may see sustained overvoltages up to 3 perunit, and may be damaged [6].

Both capacitor banks and DG units provide voltage support. Installation of a new DG unit can interact with exciting capacitor bank controls, subjecting feeder equipment and customer loads to overvoltage. There may be a need to switch off a capacitor bank while certain DG units are online, and switch on the capacitor bank when the DG unit is offline. This requires coordination between capacitor banks and DG controllers.

Limited Functionality of Current Distribution Systems SCADA

With the expected installation of many DG units at any point on the distribution system, there is a need to monitor real power, reactive power and voltage profile at almost every section of the distribution system. The IEEE 1547™ standard states that real power output, reactive power output, and voltage at the point of DG interconnection must be monitored for aggregated capacity of DG > 250 kVA. This will force utilities to install more IED devices that can communicate with each other. Utilities will need to move toward the implementation of an ADA system. A big barrier for this implementation is the lack of communication infrastructure on many main feeders and laterals. Not all utilities have adequate financial resources to heavily invest in this direction. There will be a need to adopt open-systems communication architecture standards for all of the IEDs in the distribution system, including DG. The IEC 61850 series of standards is now becoming the most promising such architecture. However, the standards are yet to be completed, and their wide spread adoption is even further away.

Limitations of Commercially Available Distribution Systems Analysis Software

There is no available commercial software package capable of fully simulating various types of DG to help distribution engineers perform 3-phase load flow, short circuit, protection coordination and harmonics analysis studies, for distribution systems with various types of DG units installed in main feeders and laterals. Limitations include:

1. Many available tools provide a mechanism for modeling DG only in the form of negative loads, or a PQV model for an induction or synchronous generator [7].

2. There is an absence of DG models specifically for inverter-based devices, such as micro-turbines and fuel cells, to represent their performance during various operational modes and disturbances [7].

3. No specific device parameter information is easily available for DG devices, beyond the voltage rating, power output and interconnection requirements.

4. Current analysis tools were not designed for studies of multiple DG locations in a distribution system, and would not facilitate introducing DG systems of various sizes.

5. Recently, a very few vendors have claimed that they have improved their programs to consider various types of DG units.

6. Accuracy and reliability of new programs must be tested before utilities completely rely on their analysis.

7. There will also be a financial burden for utilities to upgrade their programs. This burden largely occurs in the areas of training, data conversion, and work flow integration.

Regulatory and Business Environment

There are many non-technical factors that can play a role in preventing DG from achieving its strategic contribution in improving the reliability, power quality, and economical power sources. Some of these factors involve regulations that govern DG penetration while ignoring many of the engineering issues. Overcoming business obstacles also plays a role in the success or failure of new DG projects. These obstacles include:

1. Governmental regulations favor non-utility DG owners, assuming that small DG interconnections are supposed to be easy and ignoring utility's technical concerns.

2. Investors and DG manufacturers are pushing regulators to act quickly, rather than giving enough time for utilities to upgrade their systems and make them safer for DG penetration.

3. Current utility practices for distribution system operation, control and maintenance cannot be applied any more without taking into consideration the existence of DG units. Utilities will

need to train their crews and engineers to face many scenarios and technical issues that they have not encountered before DG penetration.

4. DG unit output is controlled by the owner or designated operator, which may cause problems for the utility. They might not be able to dispatch DG unit power, nor perform accurate day-ahead load forecasts to figure out the amount of power they need to purchase from the bulk power system. Also, there is uncertainty associated with power that can be generated from wind turbines and photovoltaic units due to the intermittent availability of the resource.

5. Maintenance for DG units varies, depending on the unit type. Units with moving parts will need more maintenance. Some DG owners will not have their own dedicated maintenance crew, as the utility does, and this may increase repair times.

6. There is a need to secure fuel supplies in advance for some types of DG units, such as diesel generators and micro turbines.

7. Insurance companies could be hesitant to insure DG units, due to their lack of operation and utility interaction history.

8. There will be a need for a new entity to take responsibility for providing operational services to DG owners, such as maintenance, repairs and fuel supply. This entity can be independent, or a new division in the utility.

9. Some utilities have long term contracts to buy certain amounts of power from bulk power system producers. New DG units on their system could result in their paying DG owners for power they have already agreed to purchase.

10. Fuel availability and delivery may be less secure than for central station generators.

11. The high investment cost of many DG technologies will also pose a significant barrier.

12. Noise, pollution, electromagnetic interference, and visual impacts are all more complicated to manage when there are many DG sites and technologies, instead of a few central generating stations.

In cases where the utility owns the DG, many of these non-technical barriers would be mitigated or eliminated. But this does not cover all DG applications, because many of them will be installed by utility customers to achieve their own goals.

Limitation of Distribution Network to Support Intentional Islanding

One important strategic value for DG is that it represents a backup power source for vital loads. This requires that DG units be capable of supplying critical loads during blackouts and rotating load shedding. To achieve this, there will be a need to redesign the distribution system so that each substation would be configured to work as a micro-grid, supplying vital loads in case of bulk power outage or required load shedding.

One potential problem is the resynchronization of DG units in an island with the remaining network. Suppose a part of the load is entirely supplied by DG units, isolated by a circuit breaker from the remaining network due to a fault or load shedding. When reconnecting the island with the distribution network, the frequency of heavily loaded DG units can be substantially less than 60 Hz. This makes it extremely difficult to synchronize these units with the network. Even when the frequencies match, the DG could be out of phase with the utility system. Current practice is to momentarily open the DG circuit breaker, then close the feeder circuit breaker, and finally resynchronize the DG units with the network after a delay. This can be difficult to implement, and if DG units are connected without proper synchronization, they could be damaged. There is also a possibility that island loads can experience a momentary interruption.

During islanding, voltage, frequency and quality of power delivered to the island loads may not be within acceptable limits. Islanding can also delay power restoration. In such cases, islanding should be prevented by tripping all DG units during network disturbances. The IEEE 1547 standard presented solutions for preventing unintentional islanding; it requires DG units to have relay protection what will trip the unit when the distribution network’s voltage and frequency are not within certain limits. DG units should not be reconnected until the utility voltage is within ANSI range B limits, and the frequency is between 59.3 and 60.5Hz for at least 5 minutes. The SCC21 working group is preparing a follow-up document in the 1547 series of standards (P1547.4) that will address intentional islanding [8].

DG Response during Network Disturbances

There is no well-established information about the response of DG units to system disturbances. There are three types of DG power converters: synchronous generators, induction generators, and inverters. It is not yet clear, with heavy penetration of DG units, how they will respond to the simultaneous starting of big induction motors, arc furnaces, voltage sags, lightning strokes, capacitor bank switching, and other events. There is a possibility that DG protection of many units can trip during these events. Consequently, in distribution networks that depend 25% or more on DG units for supplying load, this can result in a sudden overload at the substation. If this causes a feeder or transformer breaker to trip, some customers will be without power. There are also some transmission stability problems that can arise as a result of simultaneously tripping a large capacity of DG units.

Thermal Rating Limitations of Distribution System Equipments

Ratings of feeders, laterals (overhead lines or cables) and distribution transformers could limit heavy penetration of DG. The conductors often decrease in size and capacity further away from the substation, because the normal power flow decreases with distance from the substation in radial distribution systems. This limits the size of DG units that can be installed at downstream locations, at least without lateral and main feeder reinforcement.

Ratings of distribution transformers will generally allow only small single phase DG units to be connected to their secondary windings. Mid and large size DG units would be connected directly to main feeders, through step-up transformers that raise DG unit output voltage to the distribution primary voltage.

Limitation of Installing DG units on Secondary Spot Networks

DG has been difficult to apply on secondary spot networks, although at least one test application has been successful [9]. The reverse power relays on the network protectors are very sensitive, and it's possible to insert some time delays and change the settings, but this may only work for low DG penetration levels. Furthermore, it was necessary in this example to automatically trip the DG when the network load level became too low. The inherent design concept of a secondary spot network precludes DG from sending power to other load points, i.e., to other secondary networks.

Therefore, it would be preferable to put all urban DG on the primary, rather than the secondary network. This is better than modifying the secondary network design, because the secondary network works extremely well for providing reliable urban service, and a utility would not wish to compromise that. On the other hand, the utility may have to accommodate at least some DG owned by secondary network customers. If this reaches a significant level, the utility might consider a dedicated secondary network for the DG only, along with a means of secondary transfer when the DG is needed for backup power.

Power Quality Problems

With several DG units installed on the network, frequent start and stop operations, or variations in output power, may subject customers on the network to voltage flicker. This is a particular concern with wind turbine generators.

Many types of DG use inverters to deliver AC power within the required frequency and voltage levels. Depending on the power electronics technology used in the inverter, harmonics in the current supplied by the inverter will vary. Current supplied by synchronous generators can also contribute a significant level of 3rd harmonic. With more DG units installed, higher levels of harmonics in the distribution network must be expected. And in distribution systems where harmonic levels are already high, DG units can be a sink for these harmonics, causing harm to DG units through increased winding thermal losses.

A number of single phase DG units could lead to an unbalanced three phase distribution system, with higher levels of neutral return currents. These currents may exceed the neutral conductor's ampacity, and also lead to stray voltage or other ground potential problems. Harmonics produced by single phase DG units are often higher than those produced by three phase units [3].

DG Grounding and Transformer Connection Issues

Most DG units are connected to the primary of the distribution network through step up transformers. Improper grounding for the DG unit, and/or using the incorrect interface transformer configuration, can result in serious problems:

1. During single phase to neutral fault, after the substation circuit breaker opens and if the DG unit circuit breaker does not open, the voltage of the neutral will be equal to the voltage of the faulted phase. Consequently, single phase loads and devices such as lightning arresters connected between one of the other two phases and the neutral will be subjected to line-to line voltage rather than line-to-neutral voltage [6]. This overvoltage can damage customer loads and utility equipment. To overcome this problem, the DG unit should be effectively grounded. This can be achieved by having a grounded-wye winding through a reactor on the secondary, i.e., the high voltage side of the DG step up transformer. The primary of the transformer could be connected as delta or grounded wye only if the generator is effectively grounded [1]. These connections still have their own drawbacks.

2. The existence of DG will increase backfeed current and voltage during a line-to-ground fault where one phase opens. This problem can be solved by having a ground overvoltage trip relay installed on the DG generator.

References

1. T. A. Short, "Electrical Power Distribution System Handbook," CRC Press, Boca Raton, FL, 2004.

2. Philip P. Barker and Robert W. de Mello, “Determining the Impact of Distributed Generation on Power Systems: Part 1 - Radial Distribution Systems,” Proc. of IEEE/PES Summer Meeting, July 2000, vol. 3, pp. 1645-1656.

3. Roger C. Dugan, Thomas E. McDermott, D. T. Rizy, and Stephen J. Steffel, “Interconnecting Single-Phase Backup Generation to the Utility Distribution System”, Proc. of IEEE/PES T&D Conference and Exposition, vol. 1, 28 Oct – 2 Nov 2001, pp. 486-491.

4. Roger C. Dugan and Thomas E. McDermott, “Distributed Generation,” IEEE Industry Applications Magazine, vol. 8, no. 2, MAR/APR 2002 , pp. 19-25.

5. The California Distributed Energy Resources Guide, http://www.energy.ca.gov/distgen/

6. Philip P. Barker, “Overvoltage Considerations in Applying Distributed Resources on Power Systems,” Proc. of IEEE/PES Summer Meeting, July 2002, vol. 1, pp. 109-114, Chicago, USA.

7. D. T. Rizy and R. H. Staunton, “Evaluation of Distribution Analysis Software for DER Applications,” ORNL/TM-2001/215, Oak Ridge National Laboratory, Oak Ridge, TN, September 2002 http://www.ornl.gov/~webworks/cppr/y2001/rpt/112228.pdf.

8. *IEEE P1547.4 Draft Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems*, for status information see http://grouper.ieee.org/groups/scc21/1547/1547_index.html.

9. M. Baier, W. E. Feero and D. R. Smith, "Connection of a Distributed Resource to 2-Transformer Spot Network," Proc. of IEEE/PES Transmission and Distribution Conference, Sept. 2003, Dallas, USA, vol. 2, pp. 520-526

3

DISTRIBUTION SYSTEM RE-DESIGN PATH

This section describes the long-term evolution of new distribution system designs that can accommodate high penetration levels of DG. The objective of this task is to identify staged system redesign actions to be taken by the utility to insure safe penetration of DG into their networks and to fully take advantage of DG units as one type of IED in a coordinated future distribution system. One of the key factors to determine the success of this transition into the advanced distribution system is to develop a multi-layered hierarchy for protection, control, monitoring and analysis based on intelligent solutions and communications.

Power System Architecture

One of the key requirements in the development of any power system of the future is the improved reliability and efficiency of operation. This can be achieved based on several different approaches, including building new transmission lines and power stations. These are very difficult to implement due to the fact that they require significant investments, take time and face much resistance from environmental and other groups.

Advancements in communications and protection and control technology can lead to significant improvement in the efficiency of operation and the reliability of the power system. This approach is further supported by the availability of distributed generators at all levels of the electric power system.

By understanding the system control hierarchy, it will be possible to bring about immediate improvements in the operation of the system. New concepts for monitoring and control, which work in different levels of the existing system hierarchy, are much easier to implement than a wholesale upgrade.

The conventional electric power system hierarchy includes the following levels (from the top down):

1. Bulk power system - typically 230 kV and above with non-radial transmission lines and substations, including interconnections with neighboring systems

2. Transmission power systems – typically 230 kV and below (down to 69 kV) with non-radial transmission lines and substations

3. Sub-transmission – typically 69 kV down to 35 kV, with either radial or non-radial lines and substations

4. Distribution – typically 15 kV and below with radial distribution circuits, although some North American utilities use 25 kV and 35 kV class distribution voltages

The voltage levels above are just the typical ranges, but should not be considered as the determining criteria to classify a system as transmission or bulk.

Electric power generating stations in the typical utility have been connected to the transmission or bulk system. At the same time, some smaller generating stations might be connected to the sub-transmission system.

The control of the power system during abnormal conditions has been typically based on a limited number of underfrequency and undervoltage protection schemes, as well as special protection or remedial action schemes. Some of the characteristics of these solutions are:

1. In many cases they operate when it is already too late to execute any optimal control.

2. They work after the uncontrolled separation of the system and the formation of islands of different sizes and levels of load – generation balance.

The changing utility environment requires the development and implementation of new solutions that will allow the optimization of the protection and control of the electric power system under normal or abnormal system conditions.

The increasing number of distributed energy resources and their connection to the distribution system leads to a significant change in the characteristics of the distribution system. This requires new methods for the protection and control of the electric power system hierarchy's distribution level.

One key principle is to define the system's control hierarchy so that it supports controlled separation into relatively balanced sub-systems at each level. This will reduce, or even eliminate the effects of wide area system disturbances on most of the customers. Taking another look at the power system hierarchy, several components of the power system hierarchy are defined, from the point of view of power system control.

Bulk and Transmission Systems

They are the backbone of the system. They have been the main subject of development for protection, monitoring, control and energy management for many years.

Transmission System Islands

These typically form as a result of the tripping of multiple bulk or transmission lines that isolate a sub-part of system from the rest. Since this is an uncontrolled action, it is rare that even an approximate load – generation balance is achieved at the time of islanding. After the operation of underfrequency load shedding schemes it might be possible to achieve a post-disturbance balance. If at the moment of separation the generation is more than the load, generator controls based on overfrequency elements will balance the load and generation. However, this means that valuable generation will be lost, that may be used in other areas of the power system outside of the island.

The Sub-Grid

The Sub-Grid is a new concept that can be defined as a controlled transmission island. Based on continuous monitoring of the load and generation in different areas of the system, in case of an emergency the power system can be split into Sub-Grids with a relative balance between the load and generation.

As can be seen from Figure 3-1, under normal conditions all Sub-Grids operate in parallel as part of the power system. They need to be continuously monitored in order for the system control to determine the state of each Sub-Grid balance. Each Sub-Grid contains one or more Mini-Grids (mGrid in Figure 3-1). Each Mini-Grid contains one or more Micro-Grids (μGrid in Figure 3-1). To summarize the grid hierarchy:

1. Sub-Grid is a controlled island at the bulk transmission level.

2. Mini-Grid is a controlled island at the substation level.

3. Micro-Grid is a controlled island at the feeder or customer load level.

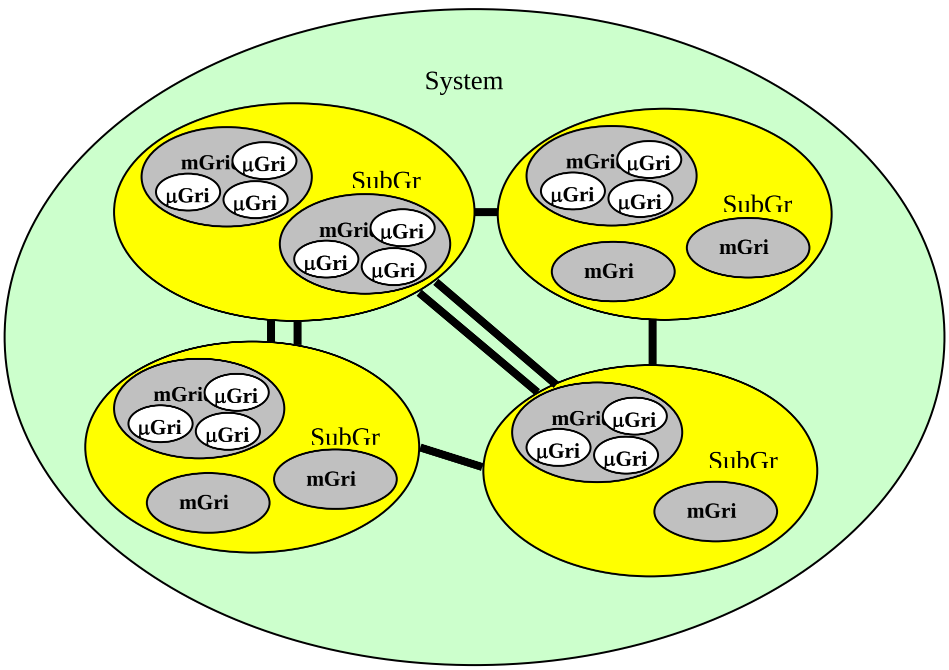

Figure 3-1
Power System Hierarchy, Sub-Grid = Transmission Island, Mini-Grid = Substation Island, Micro-Grid = Feeder or Load Island

The Sub-Grid balance can be determined based on different sources of information:

1. System configuration
2. Generation
3. Loads
4. Power flow between the Sub-Grids

Based on this real-time data the control system can make a decision during an emergency to split, which means putting one or more Sub-Grids into an island mode.

Since Sub-Grids are at the transmission level, this report does not cover details of their control strategy. The Sub-Grid Control system is discussed only in relation to the control strategy of the Mini-Grids and Micro-Grids (μGrid).

A Sub-Grid will typically include one or more utility or non-utility owned power stations. It will also include one or more Mini Virtual Power Station (mVPS). A Mini Virtual Power Station in this case is defined as the total power produced by all distributed energy resources in a Mini-Grid.

Since each substation connected to the Sub-Grid transmission system will be considered as a Mini-Grid in case it has some form of distributed energy resources, the control system of the Sub-Grid will know the level of balance of each Mini-Grid based on the power flow through the power transformers.

The Mini-Grid

Normally the distribution system of a substation is supplied through one or more power transformers and does not have any other active source. This has changed with the introduction and increasing number of distributed generators. It might be possible to balance the combined output of all the distributed generators with at least the critical loads connected to the distribution system.

This allows us to define the distribution system of a substation as a Mini-Grid. It can be isolated from the rest of the power system when all power transformers are taken out of service due to fault, abnormal system condition or intentionally in order to reduce the effect of a wide area disturbance on the distribution system.

Monitoring and controlling the balance in the Mini-Grid will be one of the main tasks of the Mini-Grid Control System (mGCS). A Mini-Grid will typically include one or more distributed generators or wind parks connected directly to the distribution feeders, with a goal to sell energy to different users in the Mini-Grid. It will also include one or more Micro Virtual Power Station (μVPS). A Micro Virtual Power Station in this case is defined as the total power produced by all distributed energy resources in a Micro-Grid.

A customer facility connected to the Mini-Grid distribution system will be considered as a Micro-Grid in case it has some form of distributed energy resources. The control system of the Mini-Grid will know the level of balance of each Micro-Grid based on the power flow through the distribution transformers at the interconnection point.

The Micro-Grid

Micro-Grids include one or more distributed energy resources of different types and, depending on their output, may support the full load of the facility, or a subset of critical loads in case of separation from the Mini-Grid. If the total output of the μVPS is more than the load at any moment in time, the Micro-Grid will export power to the Mini-Grid.

System Control Concept

All of the above described hierarchical components of the power system have one thing in common – they allow the separation of a balanced area at each level of the power system. This is possible due to the fact that electric power systems in the industrialized world are going through a period of change - from being mainly a generation-dominated system, characterized by thoughts of system security and reserves, to being a consumer-oriented, economically and ecologically-optimized energy supply system with the following features:

1. All available energy resources are included in the decentralized energy supply concept.

2. Improved economic utilization of renewable energy in the energy mix in conjunction with storage, controllable loads for different consumer requirements and combined heat and power cycles.

3. Online balancing of actual energy availability with actual load demand.

4. Optimization of inter-regional energy transfer.

Application of these new systems combining new and emerging energy technology with advanced communications and information technology:

1. Energy management of generation, storage, and consumption.

2. Supply management through contracts, metering, and billing.

3. System management based on information, organization, marketing, and services.

The crucial aspects of this change will be economics and overall commercial success.

With the integrated systems that have been described above and that include sophisticated communications and distributed intelligence, it will be possible in the future to optimize the overall energy supply as a closed control loop.

This process can be implemented from the bottom upwards instead of, as in the old ways, from the top downwards.

This represents a complete reversal of the present structure of the power system based on large power plants connected to the transmission system. It allows a significant proportion of decentralized units, at least 30 to 40%, to be seamlessly integrated into the networks of today's distribution systems. Such decentralization may open more opportunities for renewable-energy generation.

Solving the problems introduced by distributed generation on the protection and control systems is one of the first and most critical steps to be made in this direction. And this is the task of the Mini-Grid Control System.

Mini-Grid Control System

By definition the Mini-Grid is a single distribution substation with its distribution system and all loads, distributed generators and Micro-Grids connected to it. Figure 3-2 shows an example of a Mini-Grid connected to the transmission system (or Sub-Grid through two transformers).

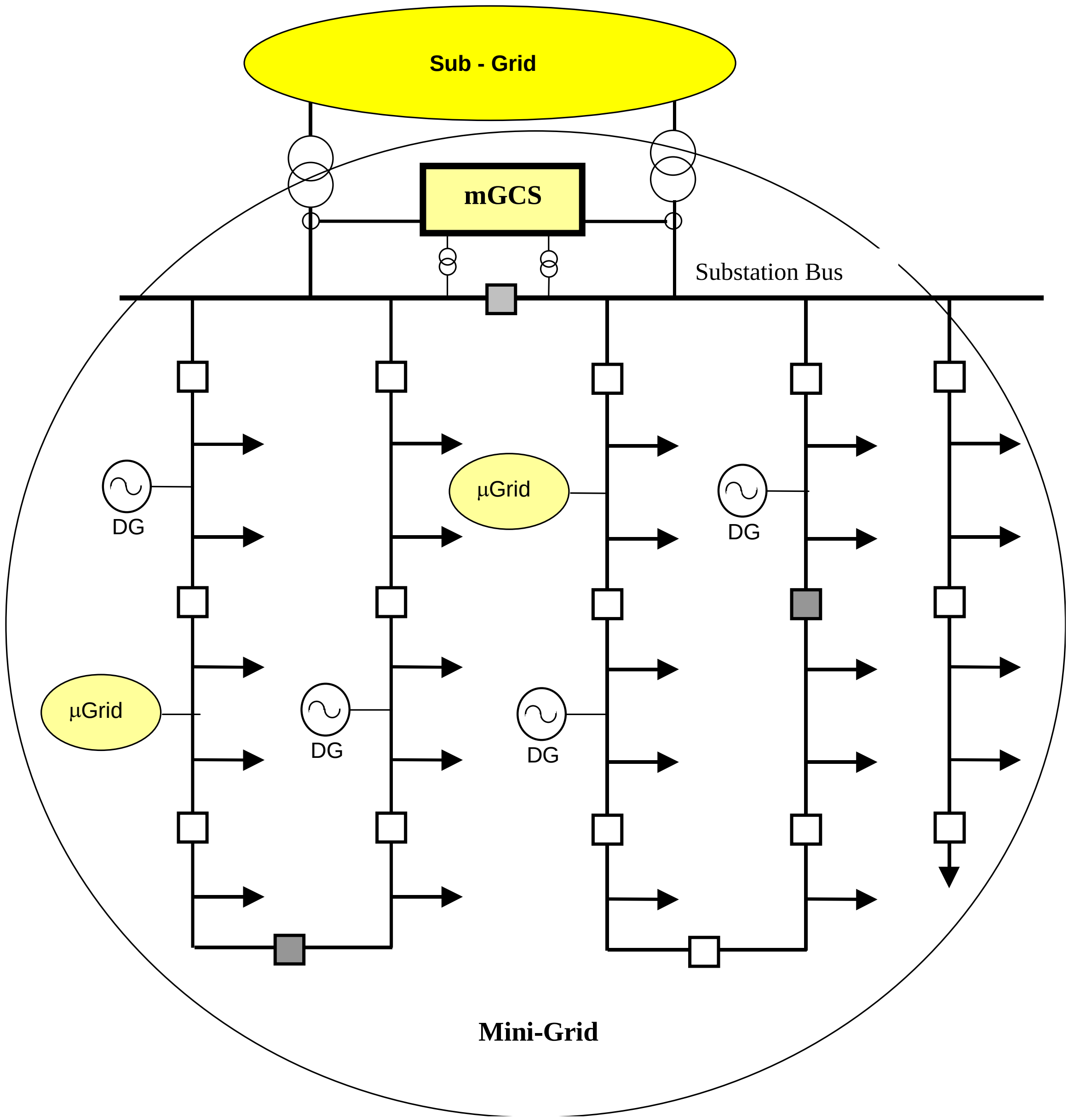

Figure 3-2
Mini-Grid Example

The Mini-Grid in Figure 3-2 may be considered as having two sources – the two power transformers connected to the transmission system. Each of the transformers may be capable of carrying half of the total maximum load of the Mini-Grid.

Each of the transformers is connected to one of the distribution buses. Under normal operating conditions the tie-breaker between the two distribution buses is in an open state.

There are 5 distribution feeders in the example Mini-Grid. Two pairs of distribution feeders have a loop configuration with one of the breakers in the loop in open state in order to maintain the traditional radial configuration of the distribution system. Which of the breakers in each loop will be opened is decided by the Mini-Grid Control System based on the selected control strategy. The example system also includes four distributed generators (some of them can actually be wind farms) and two Micro-Grids.

The main goals of the Mini-Grid Control System (situated between the Sub-Grid and the Micro-Grids as shown in Figure 3-3) are:

1. To monitor the state of the Mini-Grid and maintain the most efficient mode of operation of the Mini-Grid

2. To receive and execute commands from the Sub-Grid Control System

3. To provide information on the status of the Mini-Grid to the Sub-Grid Control System

4. To support adaptive protection of the different components of the system

5. To receive information on the status of the Micro-Grid

6. To make decisions and send commands to the Micro-Grid Control System

7. To make decisions and send commands to switching devices, distributed energy resources and loads

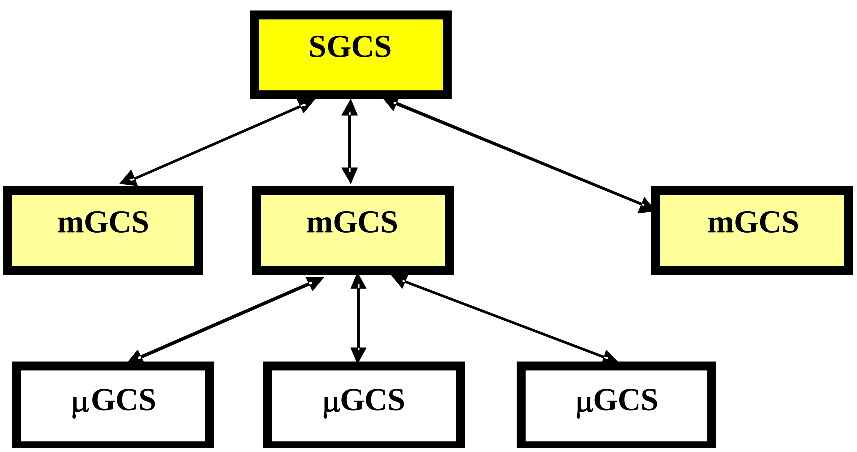

Figure 3-3
Mini-Grid Control System Communications Hierarchy

The following sections describe in detail each of the individual tasks and address some of the issues related to the communications and equipment requirements that will allow the implementation of the Mini-Grid control concept.

It should be noted that this concept can be realized with existing technology and improved further by emerging technologies, such as low-cost non-conventional sensors and advanced wireless communications.

Mini-Grid Monitoring

The monitoring of the state of the Mini-Grid is one of the most important tasks of the Mini-Grid Control System. As discussed earlier it is required in order to achieve the most efficient operation during normal and abnormal system conditions, as well as to provide information to the Sub-Grid Control System.

Information on the status of different components of the Mini-Grid is also essential to the implementation of adaptive protection that will allow the optimization of the performance of the protection system during short circuit or series faults on the distribution network. Real-time data allows continuous evaluation of the balance between the output of all available distributed energy resources and the loads in the Mini-Grid. The overall state of the Mini-Grid is clearly visible through monitoring of the power flow through the two power transformers providing connection of the Mini-Grid to the transmission system.

As can be seen from Figure 3-4, the Mini-Grid Control System located at the substation directly monitors the currents through the transformers and the voltages on the two sections of the distribution bus. Based on these measurements the mGCS can calculate the power flow through each of the transformers and based on the total of the two determine the overall state of the Mini-Grid.

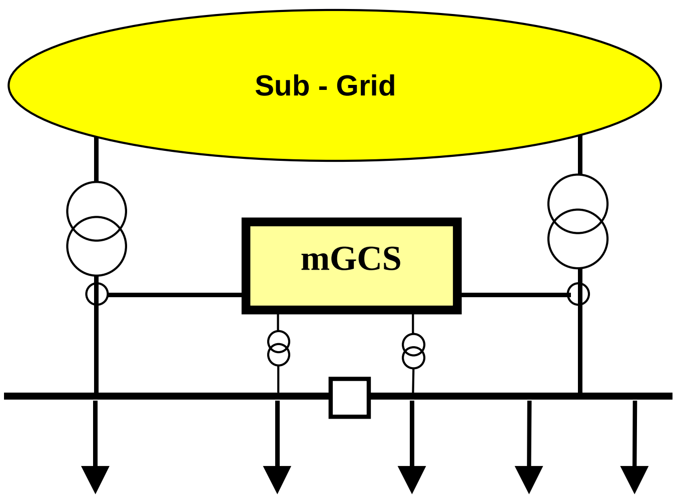

Figure 3-4
Mini-Grid Monitoring

It is recommended that the system also monitor the voltage on the high side of the transformers. This may be used to locally detect power system disturbances that require local action by the Mini-Grid Control System. It also may be required as a local supervision for control signals received from the Sub-Grid Control System. Such local control may prevent undesired operation due to error introduced in a control message from the upper layers of the power system control hierarchy.

The system also needs to monitor the power flow through each of the distribution breakers. This will typically be achieved by polling the protection IEDs on each of the distribution feeders.

The Mini-Grid Control System also needs to know at all times the state of all switching devices located along the distribution circuit. Any change of state of these switching devices – breakers or reclosers – needs to be reported by the local IED to the mGCS.

Last, but not least, the Mini-Grid Control System needs to receive information on the state of the Distributed Generator and Micro-Grids. The data received from the Micro-Grid Control Systems, the distributed generators and the local measurements will allow the Mini-Grid Control System to determine the total load of the Mini-Grid and make decisions for the optimization of the system operation.

It is important to establish methods for grouping of controllable loads by their levels of sensitivity. Monitoring of these loads will allow the Mini-Grid Control System to take optimized actions in case of wide area system disturbances or other abnormal conditions that may require the separation of the Mini-Grid from the transmission system under balanced load-generation conditions.

The communications required for the monitoring of the system are point-to-point and can be achieved using a variety of wired, wireless, or fiber optic methods.

Interface with the Sub-Grid Control System

The interface with the Sub-Grid Control System is very important because it allows the Mini-Grid Control System to make decisions for action within its controlled area in case of disturbances that can not be properly detected based on local measurements.

At the same time the information from the Mini-Grid Control System is essential to the optimal operation of the Sub-Grid or the overall power system. In this case the Mini-Grid Control System is a server to the Sub-Grid Control System.

Based on the load-generation balance in the Mini-Grid, the Sub-Grid Control System may make a decision to:

1. Stay in parallel with the Mini-Grid if it is exporting power into the transmission system

2. Disconnect the Mini-Grid from the transmission system if there is some generation in the Mini-Grid that can support sensitive loads

3. Stay in parallel and perform load-shedding within the Mini-Grid if there is no sufficient generation within the Mini-Grid that can support sensitive loads

The communications with the Sub-Grid Control System are also important in the cases when there is a common circuit between two distribution substations, for example a critical load that requires primary and backup supply from two independent sources. Such example is shown in

Figure 3-5. The configuration of both Mini-Grids may change as a result of opening or closing of switching devices along the common distribution circuit.

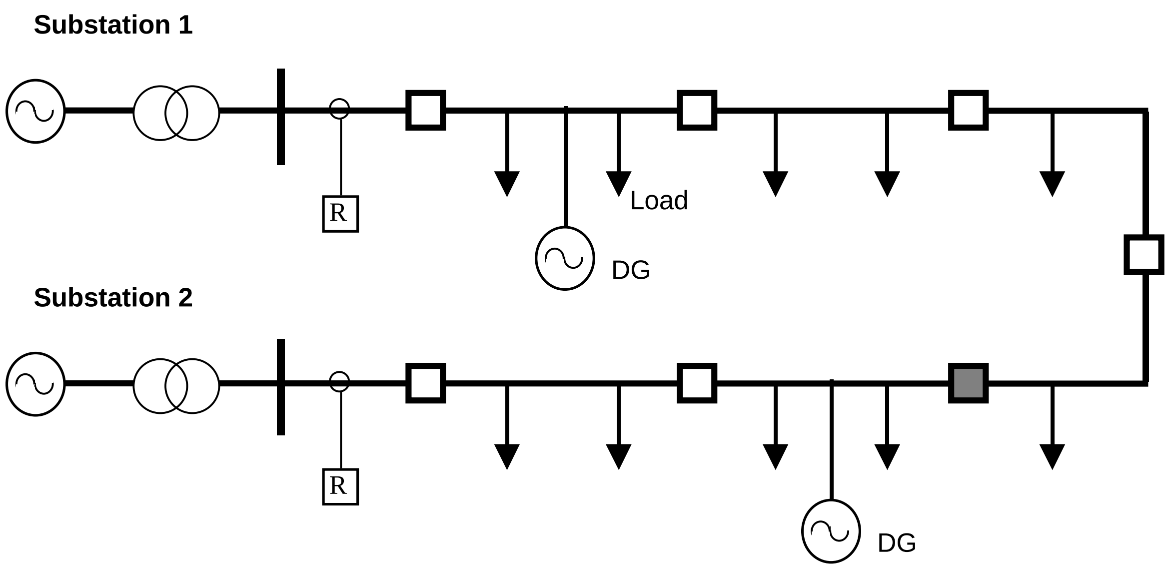

Figure 3-5
Distribution System with Two Overlapping Mini-Grids

Figure 3-6 shows, in heavy arrows, the changing communications requirements if there is a common circuit between Substation 1 (Mini-Grid 1) and Substation 2 (Mini-Grid 2). This will require new direct communication links between the two control systems MGCS1 and MGCS2. Figure 3-7 shows a common link between Mini-Grids, implemented by closing a bus tie breaker.

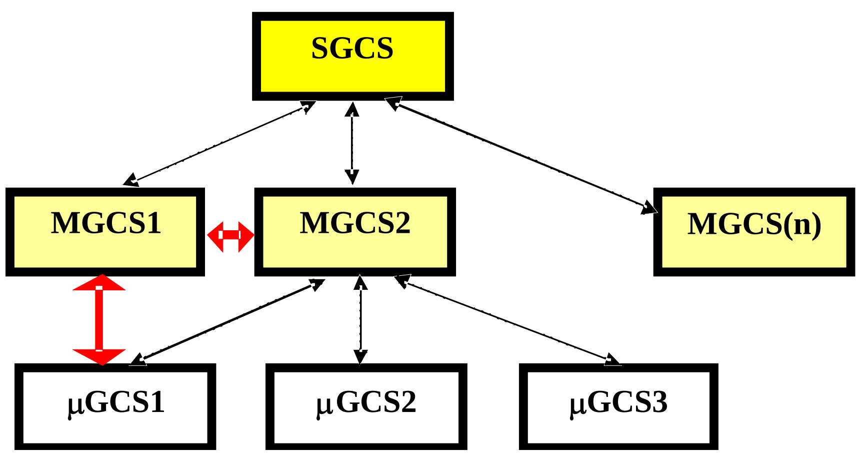

Figure 3-6
Inter Mini-Grid Control Center Communications

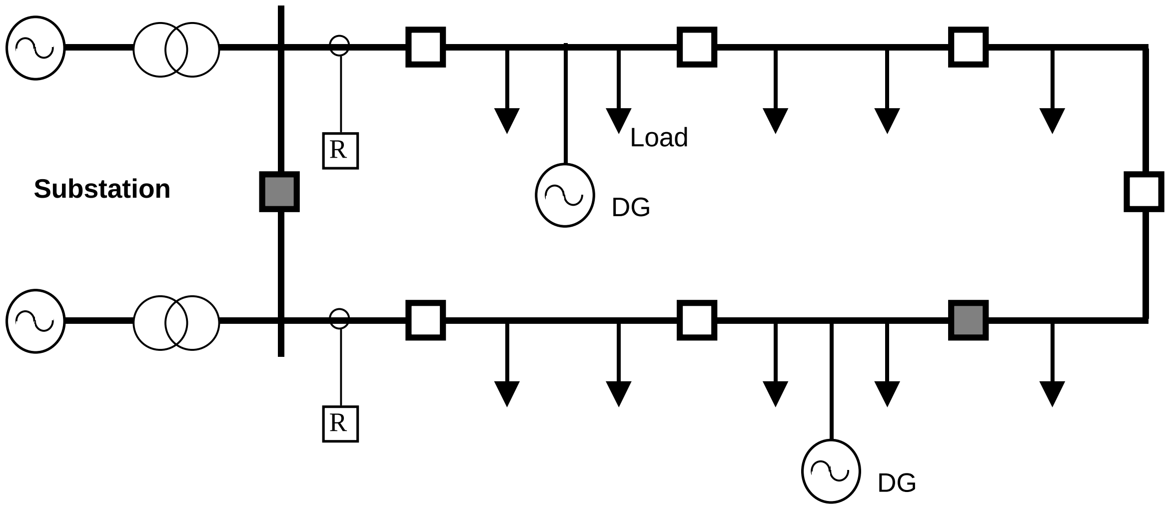

Figure 3-7
Topology of a Loop Distribution Circuit with Distributed Generation

Also, if Micro-Grid 1 can be connected to either of the Mini-Grids depending on the state of the switching devices, it will need to have a communications link with both Mini-Grid Control Systems.

Another alternative is to keep the communications as shown in Figure 3-3 and exchange the information between the two Mini-Grid Control Systems through the Sub-Grid Control Systems. This is clearly a less expensive solution, but the drawback is deterioration in performance which at the end might not be acceptable.

The communications required for the interface between the Sub-Grid Control System and the Mini-Grid Control System is usually point-to-point and can be achieved using different communications methods described previously. However, in some cases it might be necessary to implement multicasting or broadcasting from the Sub-Grid Control System.

Mini-Grid Control

As stated earlier, one of the main goals of the Mini-Grid Control System is the efficient operation of the Mini-Grid under normal and abnormal system conditions.

Voltage Control

Voltage control is one of the functions that is significantly affected by the availability of distributed generators connected at different locations on a radial distribution circuit.

Figure 3-8 shows the voltage profile of a typical distribution feeder – radial, without any generators, capacitor banks, or line regulators. The voltage gradually drops along the circuit and has its lowest level at the end of the line. In order to maintain the line end voltage at an acceptable level, the system needs to control the voltage level at the substation bus taking into consideration the length of the circuit and the loads along it.

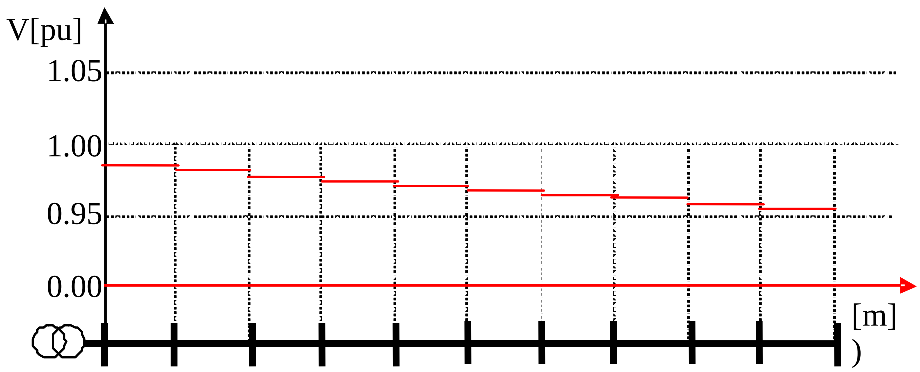

Figure 3-8
Voltage Profile of Distribution Feeder

Figure 3-9 shows a simplified voltage profile of the same distribution circuit, but with distributed generators. Depending on the size and location of the distributed generators, it is possible to actually have the maximum voltage level across the distribution circuit at its end. This will require a significant change in the voltage regulation methods.

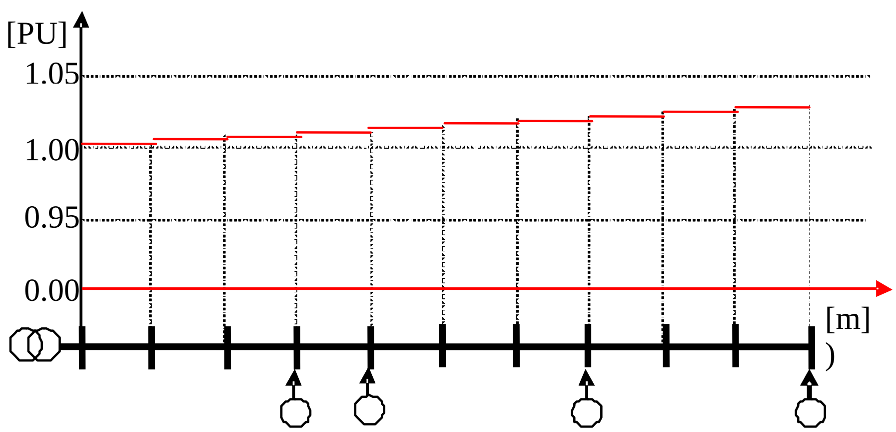

Figure 3-9
Voltage Profile of Distribution Feeder with Distributed Generators

Operation of capacitor banks and line regulators, each under local control, would complicate the voltage profile. However, DG still upsets the profile in that case. For example, a line regulator with line drop compensation would see less load current than normal, if a downstream DG supplies some of the load. The regulator may not raise the tap enough, resulting in low voltage for downstream customers. This would be the case if the DG is not controlled to regulate its voltage, as specified in the current version of IEEE 1547. But knowing the state of the distributed generators and the loads along the line, a Mini-Grid Control System can implement Optimal Voltage Control.

Transformer Loss Minimization

The operation of the power transformers connecting the Mini-Grid with the transmission system can be optimized by continuously monitoring their loading, and switching the transformers in order to achieve transformer loss minimization.

Real transformers have two types of losses:

1. Open circuit or iron losses

2. Short circuit or copper losses.

The open circuit losses are independent of the power through the transformer and can be reduced by improved design, for example raising the cross section of limb or using new ferromagnetic materials. They are also called no-load losses and are caused by the magnetizing current needed to energize the core of the transformer. They do not vary according to the loading on the transformer. They are constant and occur 24 hours a day, 365 days a year, regardless of the load.

Normally the open circuit losses are of the order of 0.2 to 0.5 % of the nominal power; whereas the short circuit losses are 0.7 to 2.1% of the nominal power. Because it is unusual to always operate transformers at full load it is some times more important to decrease the open circuit losses than short circuit losses.

Transformers should always be loaded optimally to get better utilization of the transformers. Proper load management of the transformers by the Mini-Grid Control System will lead to substantial savings. This will determine the proper transformer load management in order to achieve better transformer performance.

Based on each transformer’s MVA and its characteristics, as well as the level of the power flow, the Mini-Grid Control System takes one of the following actions:

1. One of the transformers can be switched off on holidays or during periods of low load level.

2. When in service, both transformers should be always loaded to optimum level.

Distribution Feeder Losses Minimization

Another task of the Mini-Grid Control System is the minimization of the distribution feeder losses. This is based on the Mini-Grid system loss analysis and can be achieved using one of many available or emerging methods.

The optimization task is further complicated by the distributed generators and requires the Mini-Grid Control System to have information on:

1. The different loads

2. Status of all distributed energy resources

3. Topology of the distribution loop

Based on the above information and as an output from the optimization procedure, the Mini-Grid Control System will make a decision to change the topology of the loop in order to reduce the losses.

Support for Adaptive Protection

As discussed earlier in this section, the distributed generators connected to the distribution feeders introduce problems for the operation of the protection system. Use of communications based protection systems eliminates many of these problems. However, such solutions require communications links between the substation and the distributed generators interconnection points. The problem becomes more difficult with the increase of the number of distributed generators connected to the same feeder. This will require significant investment in communications equipment.

Adaptive Protection is not a perfect, but more or less no-cost solution. The Mini-Grid Control System continuously receives information on the state of the distributed generators, as well as the network topology (based on the status of the switching devices on the network).

Based on this information it may change the active setting group of the distribution feeder protection relays in order to provide better performance considering:

1. The infeed from the distributed generators
2. Their location
3. The length of the distribution feeder

Load – Generation Balancing

One of the key characteristics of the Mini-Grid is that it can operate in two modes:

1. In parallel with the transmission system
2. Isolated from the transmission system

The transition between the two modes is another task of the Mini-Grid Control System. It is extremely critical, especially when disconnecting from the Sub-Grid during a wide area disturbance or due to any other event – for example, fault in a single transformer that is in service at the time of the fault.

One of the most important factors to be considered in this analysis is the dynamic behavior of the different types of distributed energy resources during a wide area disturbance or after islanding following a wide area disturbance. Different types of distributed energy may shut down during a disturbance, thus further deteriorating the system condition. Due to this fact, many countries (see

Figures 3-10 and 3-11) are taking measures to ensure that distributed generators can ride through the voltage sag during a short circuit fault condition.

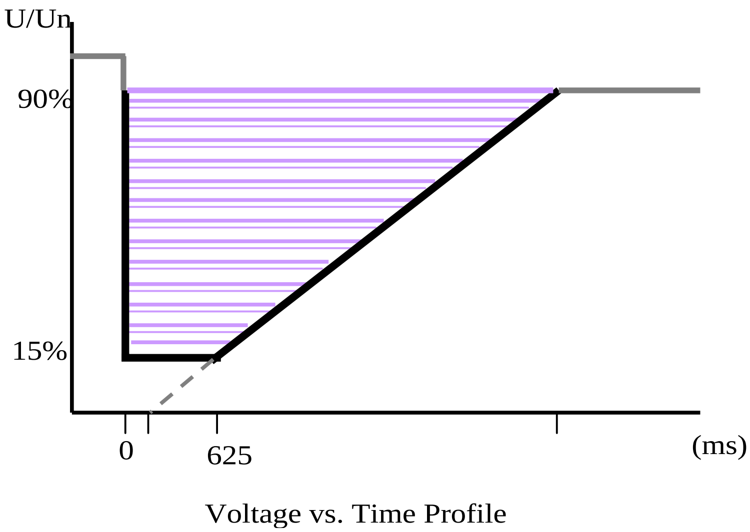

Figure 3-10
Wind Generator Ride-Through Capability for the Irish Power System

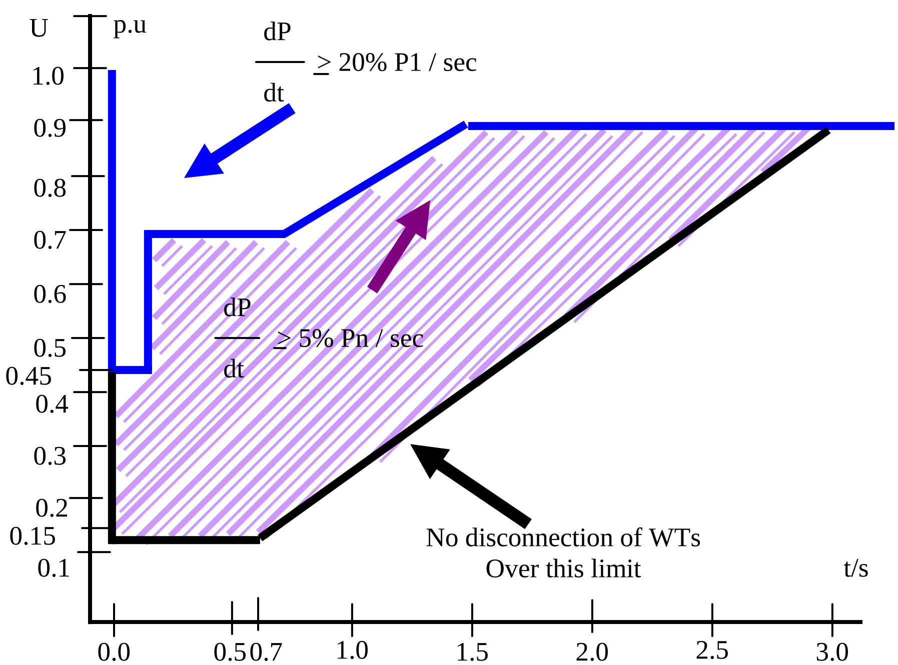

Figure 3-11
Wind Generator Ride-Through Capability for the German Power System

Since the behavior of the different distributed energy resources is not well known when there is significant initial unbalance between the load and generation in the island, the Mini-Grid Control

System needs to continuously monitor the load and generation. Based on this data it shall determine in advance what action needs to be taken, preferably before the collapse of the system or the disconnection from the transmission system.

The ideal solution is to reduce the load within the Mini-Grid to the level of the total available power from the different energy resources, i.e. to have zero power flow through the power transformers connected to the transmission system. At this point the transformer breakers can be tripped, thus establishing a balanced isolated Mini-Grid.

Optimal Load Shedding

As described earlier, the Mini-Grid Control System may need to implement load-shedding in two main cases:

1. Due to a command from the Sub-Grid Control System or a system-level remedial action scheme

2. To balance the load with the Mini-Grid

The system can implement a new approach to load-shedding, very different from the conventional – tripping of the distribution feeder breaker.

Some of the requirements listed in the section on Mini-Grid Monitoring are directly related to the concept of Optimal Load-shedding. Knowing the unbalance between load and generation is used to determine at any moment the load that needs to be shed to balance the load with the generation. Knowing the groups of loads that are available and the amount of load in each of them allows the control system to optimize the load-shedding process based on different criteria:

1. Shedding an amount of load equal to the required, regardless of the sensitivity of the loads

2. Shedding an amount of load sufficiently close to the required, but shedding predominantly loads with less sensitivity.

A preferred method will be to start the load shedding process by directly tripping groups of hot water heaters, area heaters, air conditioners in residential areas. This will require the use of different communications methods – broadcasting or multicasting, instead of the conventionally used point-to-point communications.

The Mini-Grid Control System can directly monitor the results of the load shedding based on the power flow through the transformers. As soon as it gets down to zero, the load-shedding process can be stopped.

It will be beneficial for this optimal load-shedding process if the Mini-Grid Control System knows at least approximately the level of the residential loads before it runs the optimization procedure. One possibility is to use the data from an Automatic Meter Reading System (AMR).

Figure 3-12 shows an example of such solution. In this example, the AMR center is actually one of the Mini-Grid Control System functions.

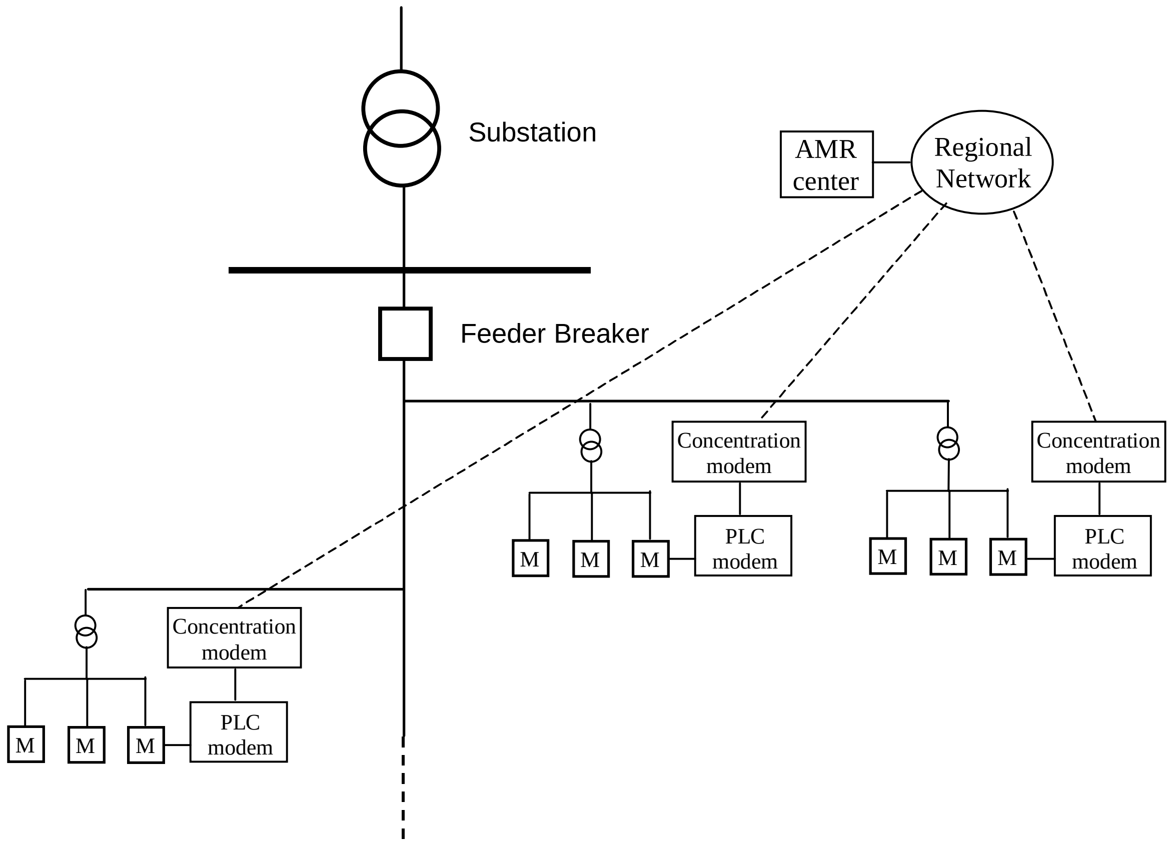

Figure 3-12
Use of AMR Data for Optimal Load Shedding

Once a decision for load-shedding has been made and the groups of loads to be shed are determined, the Mini-Grid Control Center needs to execute the load shedding. As mentioned earlier, the most efficient method to achieve that is through multicasting or broadcasting.

Figure 3-13 shows one potential solution. It is based on the use of a combination of broadcast satellite systems and multicast protocols. This allows the simultaneous transmission of the load shedding signal to a group of selected loads. The communications architecture is based on an Interactive Data Broadcast System (IDBS).

This possible solution takes advantage of the new asymmetrical communications methods being implemented. These asymmetrical, unbalanced networks use separate networks for inbound traffic (forward link) and outbound traffic over the return link, providing a viable alternative for end-user access.

In this load-shedding application the Mini-Grid Control System will be connected using TCP to the broadband uplink station (BUS). The load-shedding command then is broadcasted by the satellite and received by the individual loads to be shed. Full advantage of this approach can be taken in case of implementation of intelligent customer energy management systems.

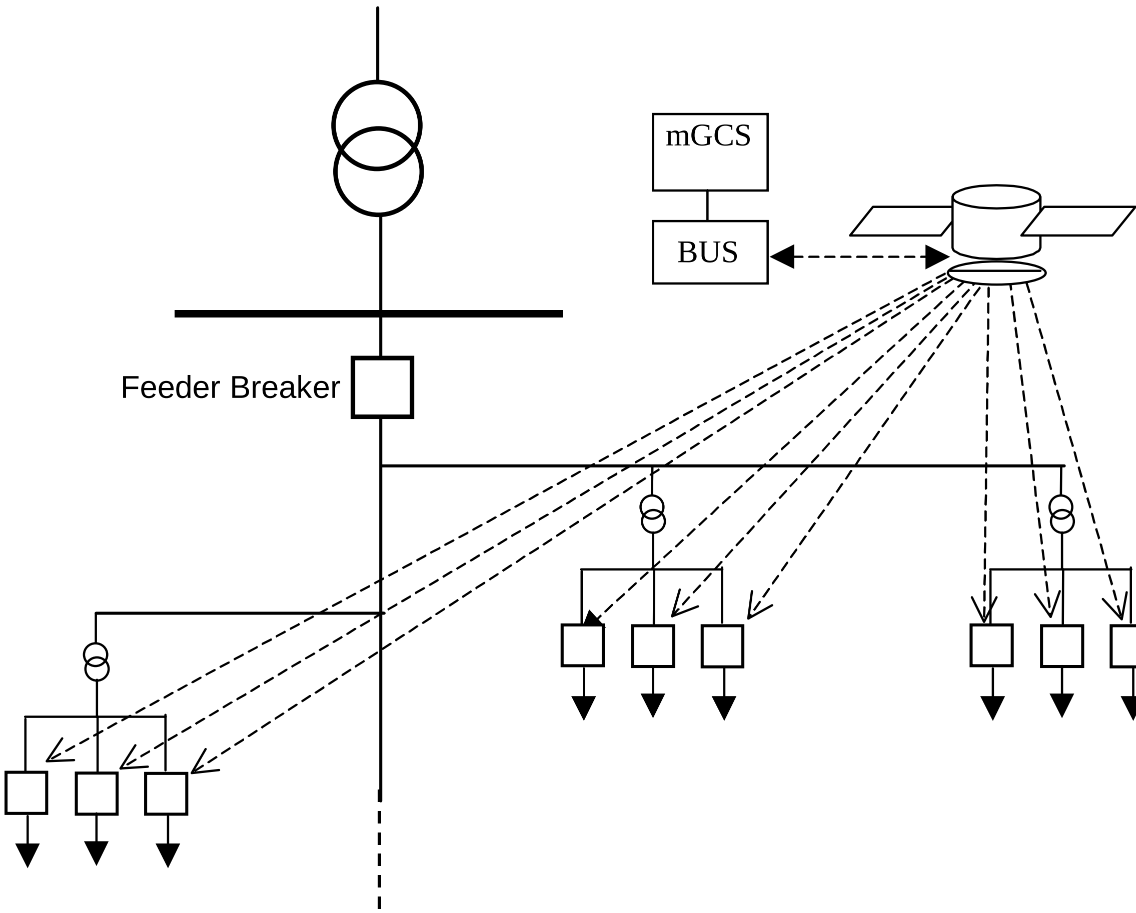

Figure 3-13
Satellite Broadcast-Based Load Shedding

System Re-design Components

This section discusses some of the necessary components to ADA and DER, and how the distribution system design can evolve to support them.

Substation Intelligent Control Schema

The redesign path begins with an intelligent and comprehensive control schema, capable of economically dispatching and controlling output power of DG/DS units installed in the distribution network. This control schema will be installed at each substation (Mini-Grid) so that it could operate as a local island, or linked to a larger system. This will require real time monitoring of real and reactive power and voltage profiles of DG units and key locations on main feeders. This would be an integral part of an ADA system. This control should act automatically, with monitoring and supervision from a local control center (Sub-Grid) that monitors several substations in a certain area.

The controller must access a comprehensive database containing the following information:

1. Operating limitations of installed DG units such as maximum output power, rate of output power change, fuel availability, maximum time of operation for DS units, unit start up time, and unit operating cost.
2. Thermal ratings of feeders, laterals and distribution transformers.
3. Ratings and settings for circuit breakers, reclosers and fuses.
4. Parameters of capacitor banks, voltage regulators and arresters.

The control mechanism must perform the following actions:

1. Perform unit commitment and economic dispatch to decide the amount of power needed from each DG unit, while possibly giving priority to renewable energy DG units.
2. Perform real time load flow to share load between DG units and utility bulk power.
3. Communicate with IEDs installed in the network to monitor real power, reactive power and voltage profiles throughout the network. Predict potential abnormal operating conditions and take preventive actions.
4. Take corrective actions in case of system faults, such as isolating faulted parts, reconfiguring feeders to restore power to loads, and minimizing the number of customers subject to power interruption. It should be also intelligently guess fault locations to help repair crews quickly fix the problems.
5. Decide the optimal times for DS units to be charged and discharged.
6. Ensure system security by preventing overloading of feeders, laterals and distribution transformers. Monitor and record system harmonics and voltage sags for analysis by distribution engineers.
7. Adaptively switch capacitor banks and adjust voltage regulator settings.

Design of Main Feeders as Micro-Grids

DG can play a vital role in improving distribution system reliability, but only if the distribution system is able to take full advantage of DG penetration. The concept introduced here is to redesign main feeders so that each of them can supply its critical loads without the need of power from the substation. Currently, critical loads such as hospitals and some industrial plants, which cannot withstand power interruption for even a few seconds, have their own backup distributed generation units. These units are usually used for a few hours each year. The failure rate of these units can be high, especially with poor maintenance. Owners of these units could make a profit by operating these units on a regular basis to sell power to the utility. During a utility system outage, these backup units owned by various customers could support the total critical load demand. This will improve reliability in several ways.

First, if a certain customer's DG unit fails during a utility power outage, this customer can still get power from other customers' DG units. Second, the DG unit size that each customer needs to install could be less if the demand is shared between several units. To prevent overloading of DG units, only vital loads, totaling less than the available power from the aggregated DG units, should be supplied.

To achieve that, each customer needs to divide their loads into two separate circuits, one serving critical loads and the other serving the remaining loads. During substation power outages, the main feeder with the operating DG units will work as an island supplying only critical load circuits. When power is restored from the utility, DG units should be disconnected and then the system resynchronized with the utility. One advantage of having many micro-grids is to decrease load demand from bulk power system, and to decrease the need for substation reinforcement by adding new power transformers. Another advantage is that these micro-grids can help system operators restore power after widespread outages, by decreasing cold load demand. There would also be less need for long-term rotating load shedding.

Consider the simple radial system shown in Figure 3-14. Switches S1 and S2 have communication channels with the main feeder circuit breaker. During periods when the main feeder has no incoming power from the bulk transmission system, due to a blackout or required load shedding, a control signal will be sent to the main feeder circuit breaker C_1 to open. At this time, the circuit breaker will send signals to switches S_1 to be opened so that all non-critical loads will be shed. Installed DG units on this main feeder will be capable of supplying vital loads supporting each other. After restoring substation power, the DG unit circuit breakers should be opened by a control signal from C_1, which is momentarily closed and then sends signals to the S_1 switches to be closed. The next step is to resynchronize the DG units with the utility power and reconnect them to the utility. This simple design shows how each main feeder can act as a micro-grid. Many other more sophisticated designs can be achieved, depending on the nature of the given distribution network.

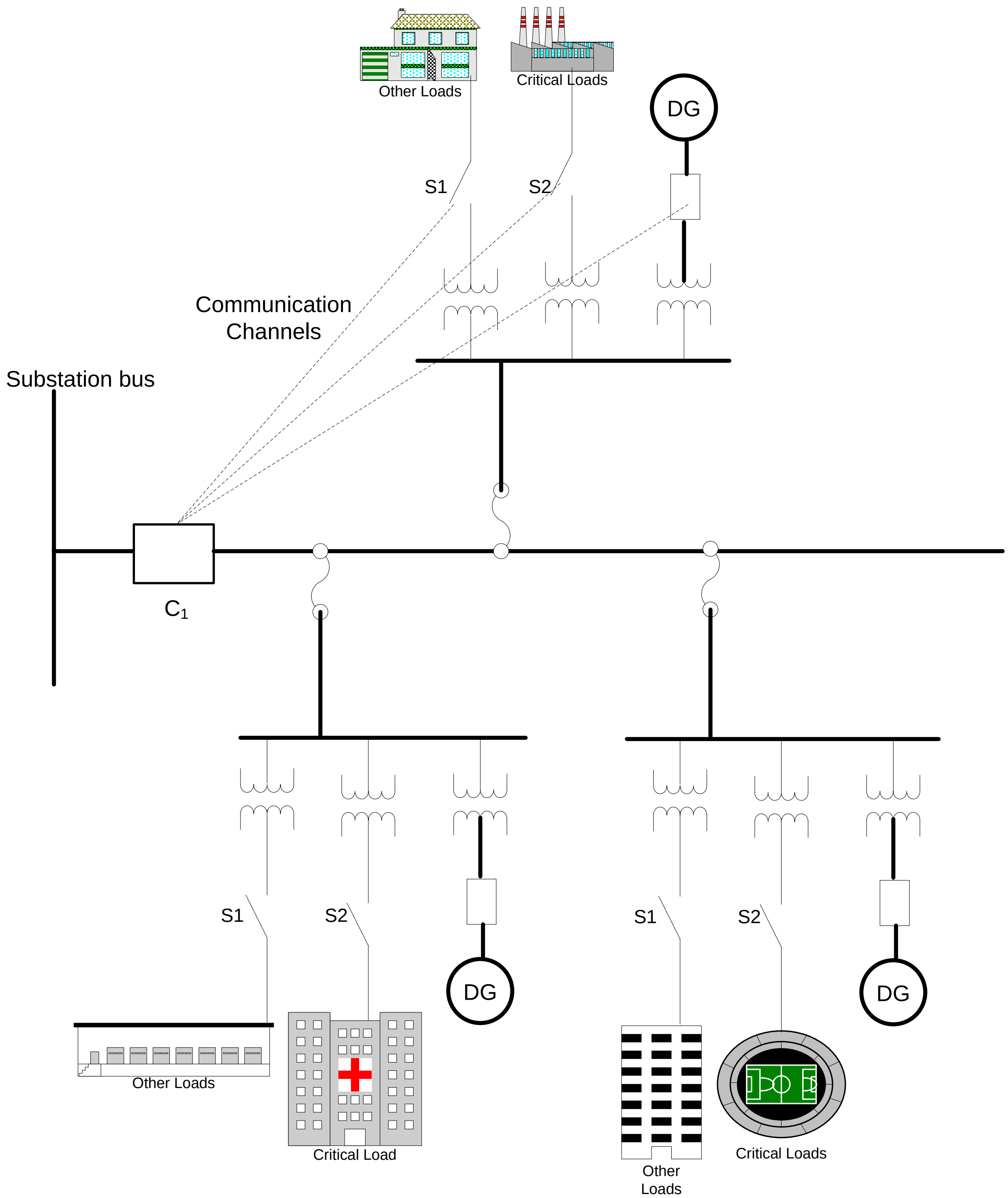

Figure 3-14
Main Feeder as a Micro-Grid

Multi-Objective Optimal Placement and Sizing for DG

During the period from fault occurrence to fault clearance, many load points will be subject to voltage sag. Voltage sag severity at a certain load point will depend on the fault type, fault impedance and fault distance from the load point. Many loads now are very sensitive to voltage sags. Customers expect high power quality from utilities, and voltage sags for only a few cycles can result in computers losing unsaved data, and even failure of hard disks. Most customers consider their lost data as a major event. With current distribution system configurations, utilities can not do much to prevent voltage sags. DG represents a strategic IED that could mitigate voltage sags if optimally placed.

DG can also play a strategic role as a new IED to prevent sustained interruptions, decrease power losses, improve voltage profiles and eliminate the need to upgrade substations. The location and size of the installed DG are primary factors that will determine how much improvement DG can achieve on a certain distribution network. To take full advantage of DG, especially for large units, a multi-objective optimization model for DG placement and sizing is necessary. The objectives of this model might include two or more of the following:

1. Maximize the reduction of voltage sags,
2. Minimize power interruptions,
3. Minimize power losses,
4. Minimize short circuit current levels, and
5. Minimize the cost of installing and operating new DG units.

The constraints would include all of the following:

1. Satisfy the AC load flow equations as function of DG unit location and size.
2. Stay within thermal capacity constraints of feeders, laterals and distribution transformers.
3. Select from available DG unit sizes.
4. Maintain service voltages within ANSI limits.

Using clustering techniques, the yearly load curve can be represented as a fixed number of levels with a probability of occurrence for each point. The optimization problem will be solved for each load level, and the solution that has the best objective value weighted over the load levels should be chosen.

Transmission-style Relaying Adapted to Distribution Systems

As mentioned previously, installation of DG units and evolution of the conventional radial distribution system to a meshed system will result in converting distribution systems for each substation into a small scale bulk transmission network, where power can flow in any direction. To achieve proper protection coordination, the application of bulk transmission protection techniques to the new distribution system configuration becomes a necessity. Protection devices such as directional relays and differential pilot relays will isolate a faulted part in the meshed network. These intelligent protection devices must be capable of communicating between each other to minimize the number of customers subject to power interruption.

These new distribution system protection devices are similar in operating concept to bulk transmission protection devices. Manufacturers will need to redesign equipment to make it more suitable for distribution systems. A critical point here is that protection failures in distribution systems can cause defects in customers' equipment, and could even cause fires very near to customer locations. On the transmission system, those rare events like transformer fires would have been confined to a utility-owned substation.

Interaction of DG with other IEDs in Future Distribution Systems

New IEDs, such as multi-functional solid-state switchgear, smart capacitor banks and intelligent universal transformers will play a vital role in future distribution systems. These new IEDS can facilitate heavier penetration of DG into distribution networks and also help increase the strategic role of DG in future distribution networks. The main issue for the success of the new IEDs is to develop open systems communication standards, for manufacturers of all DG, DS, and all other IEDs to support.

Traditional mechanical based protection devices should be replaced gradually by intelligent microprocessor based relays. Intelligent reclosers and sectionalizers that communicate with each other, supervised by the central substation controller, will allow fault isolation with a minimum number of customers subjected to power outage. Fault locations can be identified more precisely by monitoring the fault data from various IEDs.

Distribution networks will be reconfigured automatically with intelligent sectionalizers. This could include power restoration from available DG units during times of isolation from substation power.

A powerful communication infrastructure will allow customers to monitor in real time the current kWh price, and set responsive patterns for their energy consumption. Depending on that, the substation controller could automatically adjust the settings for their air conditioner, water heater, pool pump, and similar adjustable loads.

Volt/VAR Management Scheme

The intelligent control of voltage profile and reactive power flow will be vital in future distribution systems. This schema can be built by a combination of control of DG/DS, capacitor banks, and static VAR compensators (SVC). The objective of such management is to maintain voltage levels throughout the primary feeders within a required window, and to minimize real power losses. DG units based on synchronous generators will be controlled to absorb or produce reactive power and produce an optimal amount of real power (PQ control), or to fix the feeder voltage at its point of connection at a certain voltage level (PV) control. The use of electronic components such as SVC and DSTATCOM in distribution systems will also help in improving the voltage profile.

Taking Full Advantage of DS

Advancements in DS techniques will play an important role in the design of future distribution systems. DS devices such as batteries, super conducting magnetic (SCM) and flywheels have the advantage that they are dispatchable, depending on the current "charge" state. It is possible to predict how much power DS can supply and for how long. One possible arrangement is to control DS in real time from the substation, where a controller monitors the amount of energy stored in various DS units, along with generation reserves from bulk power system and locally available DG units. The DS controller will take the decision of drawing power from DG units and the bulk system to charge DS during light load conditions. Power stored in DS can be used later during peak demand. In this way, variations in the amount of power taken from DG units and the bulk power system can be moderated for economic and reliable operation.

DG in Urban Spot Secondary Networks

The most convenient location for installing DG units in a spot secondary network would be on the source side of the network protectors. This avoids the problem of the network protectors all tripping under reverse power flow at light load. Unfortunately, for public policy reasons customers must be allowed to connect their DG to the secondary network. To accomplish this, it will become necessary to operate the secondary network as a micro-grid upon reaching relatively low penetration levels. One option would be to adaptively change the reverse power trip settings on the network protectors, depending on how much DG is on-line at a particular moment.

Limiting the Contribution of DG to Short Circuit Current

Fault current limiting devices have been used to avoid or defer widespread switchgear upgrades on transmission systems, as the system short-circuit strength grows through the addition of bulk generation. With increased DG penetration, or with use of looped primary feeders, the same effect may occur on the distribution system. Where this is a problem, power electronic interfaces may be controlled to limit the DG short-circuit contribution to approximately twice the load current.

At higher penetration levels, it is likely that wholesale protective device upgrades will be needed on the feeder anyway. The typical application for a fault current limiter is when just one, or a few, such devices can defer the upgrade of many switchgear devices. This is not likely to be the case on a distribution feeder with high penetration of DG. There is also some concern expressed that on a micro-grid served only by DG, fault currents may even be too low for reliable detection. Therefore, it does not appear that separate fault current limiters are a critical need for the strategic use of DG.

4

DG OWNERSHIP IMPACT ON SYSTEM DESIGN

It is expected that DG units will be owned by both utilities and non-utility entities. This mixed ownership of DG units will raise many difficulties. Ownership would be a barrier to achieve the maximum strategic benefits from DG. Currently, many investors are watching the situation closely and are performing cost/benefit studies to figure out the risks associated with investing in the DG market. It is obvious that mixed ownership will not allow as much flexibility for utilities to achieve the optimal design for DG penetration. Utilities may be pressured to modify the distribution system, so that installation of a DG unit at any point in the network would be safe and will not deteriorate the network reliability. This section discusses issues that may arise as a result of this anticipated mixed ownership.

It's very important to note that none of these identified ownership impacts are technical in nature. Instead, they might be characterized as economic, business, or even "political". For the engineer, these impacts may present constraints on technical solutions or increase the utility's costs, but they (obviously) don't affect the physics of DG applications. Because the ownership impacts are non-technical, it could be easier for utilities to implement DG, than it is for other parties.

Conflicts in Investment Objective

The objective of DG investment is different for utilities than for private parties. Utilities may want to install DG units to achieve many strategic objectives for their distribution network, such as improving reliability, using renewable energy sources, providing emergency power, preventing voltage sags and improving voltage profiles. Meanwhile, the objective of a private party's investment in DG would be to maximize profit. This could mean they wish to sell as much power as possible to the utility, while taking advantage of all state and federal tax credits. That is especially true of technologies like wind. Other DG units, installed primarily for emergency power supply, could be more flexible in its dispatch. Some of these backup DG units will have a ceiling on the hours per year that they run. In this way, ownership objectives can result in different operating patterns for DG units.

Location and Size Choice for New DG

Who will have the right to choose the location of DG units and their sizes? There are three different scenarios:

1. In the first scenario, utilities would allow the DG unit owners to choose any location where the utility owns land. In this case the utility will specify a maximum size for the DG units

depending on the lateral and main feeder thermal capacities. But what if the DG investor wants to install bigger units to achieve more profit? One suggested solution is that the owner in this case must pay for the utility to reinforce their network to support the desired unit size.

2. In the second scenario, utilities will perform planning studies and, depending on the future load demand, will specify potential locations and sizes for installing DG units. After that they will advertise for the best bid from DG investors. This works in a manner like franchise chains.

3. In the third scenario, utilities may site their own DG units based on planning and impact studies. This applies to utility-owned units, but may also apply if the utility is able to recruit or influence third-party installers.

Day Ahead Planning Issues

In the deregulated market, each utility needs to submit to the corresponding independent system operator or regional transmission operator (ISO/RTO) the amount of power they need to purchase for the next day. In a network with heavy privately-owned DG penetration, utilities will have a harder time predicting how much power they need. It is no longer the simple task of forecasting next day load, but also to forecast which DG units will be online at what time and for how long. The utility also needs to forecast the availability and reliability of the DG units. To facilitate this task, DG owners should submit a day or week-ahead schedule of when their units will be available and how much power they want to supply.

Control of DG Output Power

Who will have control over the amount of energy produced daily from each DG unit? If the utility has control over all DG units installed on its territory, day-ahead unit commitment studies can be performed to decide which units will be online and which ones offline during each hour. This only works if the utility has dispatch authority over a DG unit. The utility may also need to shut down some DG units to avoid overvoltages. If there are several choices for which units to shut down and which to run, how is the decision made fair to all DG owners? At certain times of the day, it may be more economical for utilities to take power from their own DG units or from the bulk power system, than to take power from non-utility DG units. These decisions or competitions may not seem fair to non-utility owners, unless an independent market system is established at the distribution level.

Nature of Relationship between Private DG Owners and Utility

The type of the relationship between utilities and non-utility DG owners should also be carefully evaluated. There are many potential scenarios such as:

1. Competitive relation: DG owners will choose strategic locations for their DG units to offer lower-price energy to utility customers. Customers will have the opportunity to contract

either with the utility or DG owners. In this case, all DG owners should have a fair opportunity to access the utility distribution network.

2. Cooperative relationship: Utilities will buy power from DG owners. This kind of relation will be governed under contract between the DG owners and utility, which specifies when and how much power will be supplied from the DG units. In this case, there must be procedures to make sure that all DG owners are treated equally.

3. Independent relationship: It is possible with the price drop in DG units that a group of investors building a new residential, commercial, or industrial area may construct their own micro-grid, having their own DG units supplying power to all loads independent from the utility. They may contract with the utility to provide their micro-grid with a certain amount of backup power.

Distribution Network Ownership

Ownership of the future distribution network may also change. One possibility is to have a separate independent entity (a smaller version of the ISO) that owns the distribution network but does not own any DG units. This entity will include all utility maintenance and operation staff, and its objective is to decide how much power will be taken from each DG unit and from the bulk power system to provide the best price for customers. This entity could be profit or non-profit, taking fees from DG owners and customers to maintain system operation.

Disputes between Utility and Non-Utility DG Owner

Disputes can rise between DG owners and utilities, and standard procedures should be established to fairly solve these disputes. One example for a dispute is when damage occurs to a DG unit or one of its components. What are the causes for that damage? There are two different answers:

1. It is the utility’s responsibility; because of poor design or operation, its distribution system is not suitable for DG.

2. It is the DG owner’s responsibility, again because of poor design or operation of the DG, controller, interface, and/or protection.

Suppose the utility asked the owner of a DG unit to be online continuously for a long time period at its full load, but the unit was not designed for such continuous operation. Who will take responsibility if a failure occurs? Insurance companies might ask the DG owner to pay higher premiums or even refuse to insure the unit.

Regulation and Operation Issues

An important concern with implementing an ADA system is whether the utility can specify more extensive monitoring, communication, and control capabilities than the bare minimums discussed in IEEE 1547 standards or FERC guidelines, when somebody else owns the DG.

Utilities need to do a lot of investment to migrate toward an ADA system. This will facilitate installation of new DG units, but the question becomes - who will pay for these investments, DG owners or other stakeholders? The logical answer is that both must share these costs. A possible scenario is that DG owners will pay a certain monthly fee for some of the utility infrastructure improvements, depending on the DG unit size.

To what extent will utilities have access to daily operating data of privately owned DG units? DG owners may not be willing to share all kinds of data with utilities for several reasons. Utilities must guarantee the security of DG operating data, and that it will not be available to other parties without the approval of DG owners. On the other hand, DG owners will need access to a subset of utility system data, sufficient for the planning, installation, and operation of their DG units.

FERC has recognized the importance of DG and has established policies and forms of contract that can be made between the utility and DG owners as presented in order 104 FERC 61,104 (July 24, 2003). Contracts between the utility and DG owners should include standard procedures for metering of real power supplied by DG units and any tariff that the utility will pay. Also, reactive power should be measured. It may not be fair for utilities or DG owners to have a fixed tariff for long term contracts. There should be another independent entity that watches the power market closely and sets a fair daily kWh price.

Utilities should establish clear procedures that govern the steps that an investor needs to take to in connecting DG units to the distribution system.

Another potential problem is a customer’s right to refuse the connection of DG units on their distribution transformer secondary. There should be an independent entity to inform them about the advantage and disadvantage of having DG units installed on their lateral or distribution transformer. What path can they take to express their refusal? Who will be responsible for any failure or damage to their household devices caused by the DG? The utility and the DG owners may have to arbitrate those questions. Neighbors will also worry about environmental impacts of some DG types, such as noise and exhaust gases. Such concerns may appear before the state regulatory, legislative, or even judicial bodies.

If investor-owned DG projects fail to achieve certain levels of profit, that will discourage new investment activity in DG, leaving the utility as the only entity that may want to invest in DG. That means utilities need to provide an adequate environment to encourage investments in DG, without sacrificing the security of the distribution system.

Different Design Scenarios for DG Penetration Based on Ownership

In this section, some scenarios for locating DG units based on ownership are explained to illustrate what role ownership can play in shaping the future of DG.

DG Units can be Owned only by Utility

If the utility is the sole player in the DG market in its territory, it will have full control of the type, size and location of the DG units to be installed. In this case, the utility will have an attractive short term solution to overcome many of the interconnection problems mentioned in section 2, namely, to install DG units of relatively large size right in the distribution substation. This would maintain radial power flow on the feeders. Utilities need to be careful in choosing the type of DG units. Comprehensive studies should be done, taking into consideration how long the DG units will run daily, their utilization factor (MW used/unit capacity), fuel availability, production cost per kW, how frequently maintenance is needed, and the availability of crews performing maintenance. This solution has several advantages:

1. Power will still be flowing in one direction from substation to loads. As a result, there will be no need to change protection coordination or maintenance procedures, or to worry about the safety of utility crews working out on the line.

2. T&D investment deferrals, i.e., eliminating the need for investing in costly central station power plants and bulk power transmission lines. This reduces the utility's operating cost.

There are some problems associated with this solution, such as:

1. Voltage profiles will not improve on the main feeders and laterals.

2. Power losses will increase on the feeder.

3. There may not be enough space in the substation to install DG units.

4. There may not be enough capacity in the existing feeders to transfer extra power. In this case, new feeders must be built, conductors must be replaced, and/or loads must be redistributed.

5. Protection schemes of substation transformers may need modification to account for short circuit current that DG will contribute for faults on the sub-transmission or transmission system.

There are many design alternatives for this solution. All DG units could be connected to one common bus as shown in Figure 4-1, or some DG units could be connected on the line side of certain feeder breakers.

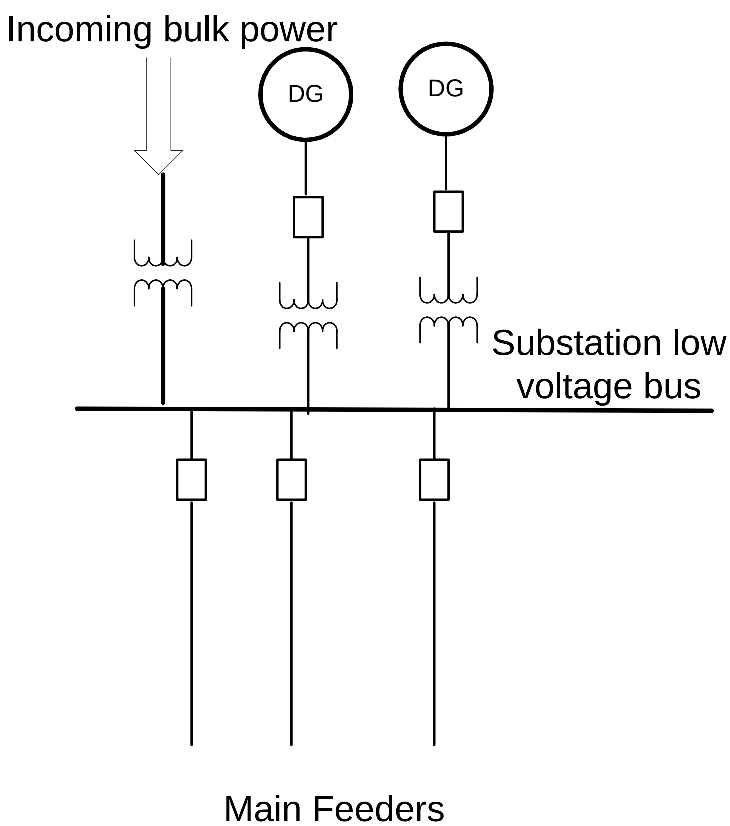

Figure 4-1
Connecting DG to Substation Low Voltage Bus

Mixed DG Ownership with Utility Control over the Units

Until more advanced technologies for protection, simulation and communication are commercially available, it may not be feasible to have mid to large sized DG units installed at "any and all points" in the distribution system. One possible solution is for the utility to perform comprehensive studies and specify optimal locations for DG units. Based on these studies, utilities can build small scale substations as "DG Ready Substations." These new substations are owned by the utility and will act as common points for connecting large and mid size DG units. DG owners will then choose one of these locations to connect their units. Each DG unit will have its own meters to measure real and reactive power. Hence, it is possible for different DG owners to use the same DG substation. Both utility and non-utility DG units can be installed simultaneously in these substations. Each substation could be designed for certain types of DG, i.e., "Fuel Cells Ready Substation", "Micro Turbine Ready Substation", etc. Maintenance, operation, and control over these units would be the utility's responsibility. The utility will pay DG owners monthly, depending on the amount of power taken from each unit. This solution allows many DG units to be connected to the same point in the network, and makes it easier for the utility engineer to perform load flow and short circuit studies.

DG is Owned by Non-Utility Entities

In systems where nearly all DG units are owned by non-utility entities, investors will have wide latitude in choosing DG unit locations. Existing customers wishing to install DG will have to be accommodated. The utility might be able to influence new investors in locating DG units, but the burden would still exist for the utility to accommodate these DG units in some form. Utilities will need to do a lot of work and reengineer the distribution network to facilitate such random penetration of DG units. More advanced and sophisticated control, protection, SCADA, and communication techniques will be required in such distribution systems.

5
RECOMMENDED FOLLOW-UP EPRI PROJECTS

This section recommends projects that EPRI should complete over the next four years. The main recommendation is to conduct at least one demonstration project of Distributed Energy Resources (DER) with Advanced Distribution Automation (ADA). Example projects include a smart radial feeder, a primary mini-grid, and a secondary micro-grid.

A secondary recommendation is to develop engineering support for DER applications. These include new simulation tools, and an IEC object model that links the simulator with devices in the field. These needs are shared with ADA in general. Previous EPRI work specific to DER should also be updated.

Long term, there are two possible avenues for utilities to integrate large quantities of DER on their systems:

1. **The smart radial feeder**. Every device is configurable from the central office, and a good model exists so that performance can be analyzed as each new DG is added. It might be necessary to change the device settings every few months, as DG units are added, or as system conditions change. DG units will not regulate voltage and will not form intentional islands. However, they may reach a level at which simple screening tools and approximate formulas no longer suffice. This approach sticks with a radial system, and gets the most out of it.

2. **The distribution primary or secondary grid**. Feeders will operate as a substation-level mini-grid with multiple sources. The overcurrent protection will be similar to that for a subtransmission system. Voltage regulation will become simpler, with less need for capacitors and line regulators. Instead, the substation transformer load tap changer (LTC) and DG will regulate the voltage. On the secondary network, the network protectors will need adaptive settings based on the DG running status and load levels. This approach would be more practical for selected areas with high-value loads and/or high levels of available DG.

Many of the needs discussed in this section are important, yet do not completely fit within the funding plan of the EPRI follow-up base project P124.001, “Distribution Design to Integrate New Intelligent Electronic Devices”. EPRI should explore funding these through other means.

Demonstration Projects

EPRI could fund a design competition on the blue-team/gold-team format, similar to how the military services sometimes develop new systems. The design teams must have a participating utility, and must fully embrace Advanced Distribution Automation (ADA). In addition, equipment supporting IEC 61850 is preferred. One reason is to demonstrate and test the promise of Substation Configuration Language, as discussed later. More importantly, by minimizing proprietary features or local customizations, the demonstration would have broader use to other utilities. However, since the IEC standards are still evolving, older architectures like DNP3 are also acceptable.

Design entries should be reviewed by EPRI, and a committee of sponsor (but not competing host) utilities, possibly with assistance from a third party consultant. Only the winning design should receive EPRI base funding, but other designs may still be implemented with entirely supplemental (cost share) funding.

Each design team would be pre-qualified by EPRI, with partial funding of up to $60K to complete their candidate design. That won't be enough to complete the design; instead, the teams will have to want to participate and take advantage of the opportunity for partial funding plus market exposure. EPRI serves as a catalyst, but doesn't supply all of the driving force for implementation. When the technology matures, $60K should be a reasonable and acceptable engineering cost for system-level designs of this type. As an alternative, EPRI could award $120K during 2006 for a single design, but this level still probably constitutes only partial funding of the design.

The basis of selection for design funding should be team qualifications, corporate commitment of the participants, feasibility of the conceptual design, and how well the conceptual design would meet the goals of the demonstration project. A proposal for design funding must include:

1. A host utility on the team
2. A commitment from specific utility customers to interconnect DG, to the necessary level, as part of the demonstration project.
3. A brief design concept, consisting of a drawing and 2-3 pages of text explanation.

The funded and submitted design entries must include a final report that shows:

1. Distribution system one-line diagrams, showing before and after configurations.
2. Diagrams of the protection and metering systems.
3. Short-circuit and overcurrent protection studies. Device settings for all overcurrent protective devices must be included.
4. Projected reliability indices before and after the demonstration project. Projected power quality indices (e.g., $SARFI_{70}$) may also be provided.
5. Plan for voltage control. Settings and control strategies for all switched capacitor banks, line regulators, DG units, and tap-changing transformers must be provided.
6. Plan for frequency control, accounting for unintentional islanding, resynchronization, cold load pickup, and intentional islanding (if that is part of the demonstration).

7. Verification that harmonic distortion and flicker levels will be within acceptable limits.

8. Specifications of all Intelligent Electronic Devices (IEDs) to be installed or upgraded. Off-the-shelf IEDs are preferred.

9. Dispatch plan for each DG installation.

10. Interconnection agreements, drawings, and specifications for each DG installation.

11. Test plan for verifying all DG interconnections.

12. Diagram showing communication devices and channels, including a specification of all hardware to be purchased.

13. Cost estimate and schedule for implementation and testing.

14. Estimated purchase cost of all hardware components in a mature marketplace.

15. A statement of goals and constraints from the host utility's perspective; i.e., how does the host utility judge success of the demonstration project?

The hardware cost of a digital relay might only range from $1K to $10K, but the actual cost of deployment could be several times higher. Much of this extra cost represents the initial engineering work to develop settings, and another large portion represents the effort of manually configuring and testing the device. The typical installed cost of a line recloser might be around $25K, with a relative handful of such devices on the feeder. Therefore, the IED hardware cost of these demonstration projects should be reasonable, provided the engineering and maintenance costs can be managed.

Upon selection, the host utility would be responsible for implementing, testing, and documenting the demonstration. EPRI will provide some base level funding, and could also provide access to such EPRI software tools as the Distribution System Simulator (DSS), the DEWorkstation, the ETMSP, or Distributed Resource Integration Assistant (DRIA).

Whether selected or not, each design team should retain full ownership rights in the design that they submit. EPRI is only providing partial funding, and the goal of these demonstrations is not to develop brand-new intellectual property, in the form of new hardware or truly innovative system concepts. Instead, the goal is to encourage the use and testing of system design ideas that have already been conceived, resulting in more confidence in the marketplace and the beginning of "best practices". The best outcome would be that all submitted designs proceed to implementation, and they all have some degree of success.

The following sub-sections describe examples. Bidders should propose a pilot project similar to one of these, or an alternative that they develop and justify. The project feasibility begins with interest from a host utility and sufficient DG owners. Utility-owned DG projects are also of interest. Also if there is enough interest, in the form of supplemental funding, EPRI could undertake more than one such project.

Example: Medium-Penetration DG on a Radial Feeder

This first project demonstrates a smart radial feeder with medium penetration level of DG, to focus on upgrades of existing radial protection and voltage regulation. The DG penetration level should be approximately 20% of the feeder's peak load in order to meet the demonstration goals.

Figure 5-1 shows a primary radial feeder with a moderate amount of DG capacity installed at different points. There is too much DG for simple screening tools to be used with confidence, but not enough for intentional islanding to practically serve the whole feeder. Therefore, line voltage regulators and switched capacitor banks would still be used to control voltage profiles along the feeder.

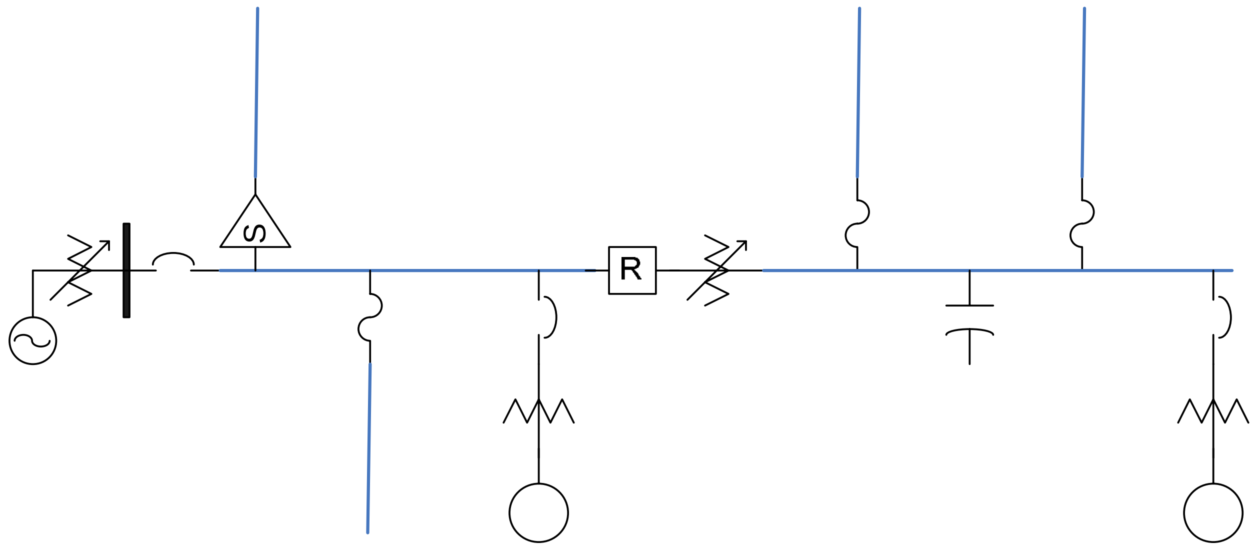

Figure 5-1
Smart Radial Feeder for Medium-Penetration DG

The basic radial topology and power equipment won't change, but the controls and settings must be adjusted for the presence of DG. Capacitors and line regulators would be controlled with IEDs, probably linked to the substation and the DG units. Protection is expected to still use time-overcurrent coordination, but existing recloser and breaker controls may require upgrades. The existing fuses probably remain in place, although sectionalizers close to the substation might be replaced with an IED-controlled interrupter.

Because the system changes are relatively limited, this demonstration is probably the least expensive and least risky. It's possible that many of the IEDs will remain under local autonomous control, but it's probably necessary to link at least a few of them in a communications system. The submitted design entry must contain all of the basic elements discussed earlier.

Example: High-Penetration DG on a Substation Mini-Grid

This project demonstrates a primary network with a high penetration level of DG, to focus on intentional islanding, mini-grid control, and protection schemes that are new to distribution systems. The DG penetration level should be around 30% to 50% of the feeder's peak load, in order to demonstrate intentional islands.

Figure 5-2 shows a primary network with two feeders and two substations in a mini-grid. In contrast to open-loop feeder designs, all of the switches are normally closed. In contrast to Figure 5-1, there are no line regulators or shunt capacitors shown on the feeders. Instead, voltage regulation will be provided by tap-changing transformers in the substations, and the DG units, which are more numerous and possibly larger than in Figure 5-1. It should be possible to operate the mini-grid, or at least a portion of it, with one substation or both substations out of service. (Note: in the actual demonstration, capacitor banks may still be used for economic reasons, as they are on some transmission systems. But with the presence of significant reactive capacity in the form of DG, capacitor banks probably become less necessary.)

In practice, most existing substations are serving more than just one or two primary feeders, so that the mini-grid could actually be more extensive than indicated in Figure 5-2. If the primary distribution were designed from scratch as a network, there might be more substations of smaller size. The demonstration project should consider this impact and some ameliorating measures. For example, it may be necessary to split existing substation buses, or to construct new "DG Substations" to serve a similar role.

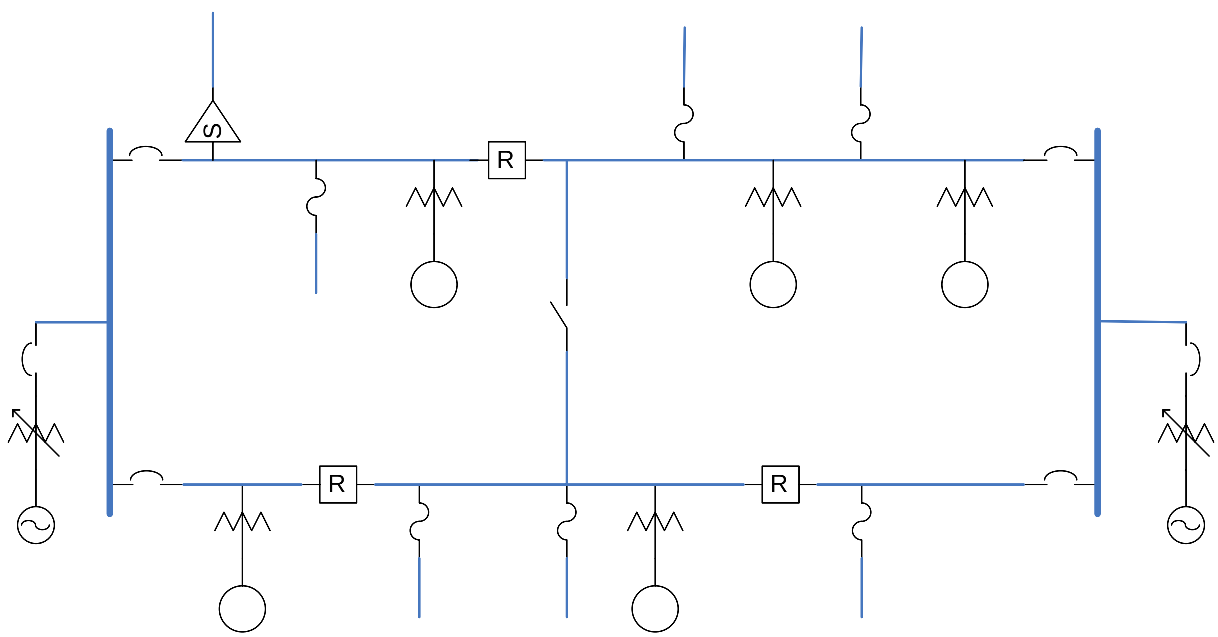

Figure 5-2
Primary Mini-Grid for High-Penetration DG

On the three-phase trunk, line differential or bus differential protection schemes might be used. A ring bus design could also be employed. Almost certainly, all protective devices will be linked through a communication system. The protective device settings would follow principles already established for transmission and sub-transmission systems, although they must account for the presence of a large number of taps. Many of the existing single-phase laterals could still be protected with fuses.

Some automatic switches, without fault interrupting capability, could be added to the network as shown in the middle of Figure 5-2. These would improve system reliability, and facilitate automatic system restoration. These may also be used to implement critical load re-configuration during intentional islanding, where part of the mini-grid load is served only by DG.

The submitted design entry must contain all of the basic elements discussed earlier. In addition, the design should demonstrate and test some level of intentional islanding. On a real system with real customers, it may not be easy to schedule a complete islanding test, and the design entry should specifically address this point.

Example: Medium-Penetration DG on a Secondary Network Micro-Grid

This project demonstrates a secondary network with medium penetration level of DG, to focus on micro-grid control and adaptive network protectors (NWP). The DG penetration level should be at least 20% of the load, to force the use of adaptive NWP settings.

Figure 5-3 shows a secondary spot network with three primary feeder sources, each with a separate transformer and network protector. The two primary bus tie breakers are normally open. A moderate number of relatively small DG units have been shown connected to the secondary network. A variation on this scheme, the secondary network or the secondary street network, would have more primary feeder connections dispersed throughout the secondary grid.

The main interest for a demonstration project would actually be the spot network, as shown in Figure 5-3. This provides an opportunity to focus on issues with NWPs and their controls, and it localizes the communication and control problems. However, a secondary street network might also be considered, especially if it provides the opportunity to demonstrate a micro-grid with a diversity of critical load types and customers.

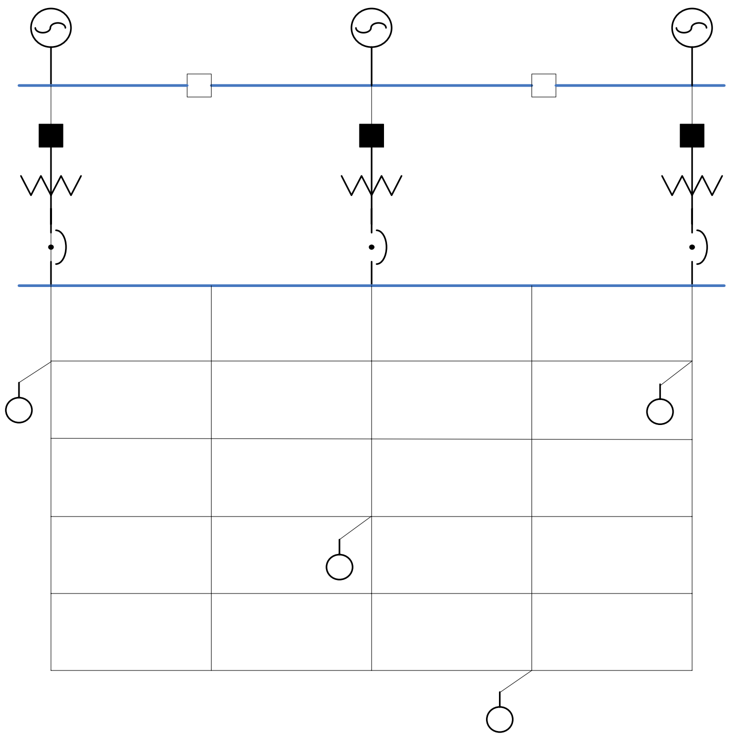

Figure 5-3
Secondary Spot Network Micro-Grid for Medium-Penetration DG

Each NWP needs an adaptive setting scheme that varies depending on the DG dispatch and load level. Previous applications required switching off the DG when the load level drops low enough to allow the possibility of reverse power flow through the NWP. The design should focus on minimizing such restrictions, although it may not be possible to fully eliminate them, nor may it be possible for the DG to serve loads outside of its own micro-grid.

Previous applications also required time delays in the NWP opening at low levels of reverse power flow, thereby allowing the DG some time to trip first. Another concern is that many existing NWPs were not designed to close between two systems with phase angle separation, as might occur if DG units are supporting an island. The design should address and test these concerns. The submitted design entry must also contain all of the basic elements discussed earlier.

Engineering Analysis of DER Applications

A DG integration approach that relies on screening tools and case studies will begin to fail at higher penetration levels. It will be necessary to do a technical analysis of each new application. For example, the following issues would have to be re-visited with each new addition of DG to the distribution system:

1. Neutral impedance sizing in the interconnection transformers, to manage ground fault currents.

2. Line regulator and switched capacitor bank controls, to manage the voltage profiles.

3. Overcurrent protective device settings, to ensure they still coordinate.

4. Flicker and harmonic limits, to ensure they are still acceptable.

This is only a partial list. Some of these require special studies at present, with custom data conversion and model development, using tools outside the normal work scope of distribution planning and protection. Presently, the most efficient consultants can do these studies in about three weeks.

To get around these barriers, three things must occur:

1. Study tools must be seamlessly integrated into the corporate database. Adoption of the IEC Distribution Common Information Model (DCIM), to be defined in IEC 61968 and 61970, can help to address this.

2. Study tools need the correct feature set for DG integration studies; this probably requires new software development.

3. It must be possible to efficiently change device settings in the field. Use of the Substation Configuration Language (SCL) feature of IEC 61850 can help to address this, by enabling device re-configurations remotely, quickly, and with less chance of error.

If there are equipment upgrades required, longer time periods and more cost would be associated with DG installation. But in many situations, the incremental addition of one DG unit into a distribution system with IEDs won’t require such capacity upgrades. It may be possible to interface the DG with only device setting changes on the utility’s part. The DG owner (which could be the utility) still has to purchase the DG, purchase the interface equipment, and design the DG protection.

Harmonize IEC Object Models for Engineering Analysis

In an ideal world, the utility engineer could perform the technical analysis for new DG installations according to the following work flow:

1. All of the relevant model data is extracted from corporate databases, with no special conversion efforts by the engineer. This process should take less than one day.

2. The just-extracted simulation model is updated with actual device settings, control settings, and electrical measurements from the field. This process should take place within the same day as the model extraction in step 1.

3. The software tools provide answers in the form the engineer needs to assess and update the system design parameters. There should not be any manual collation and post-processing required in a spreadsheet, for example. The sequence of simulation tasks and design rule checks should be mostly automated.

4. The engineer should be able to immediately deploy any parameter changes to devices in the field. Excluding a review and approval by other parties, the actual deployment should take less than one day.

It should be possible to complete the entire process of analysis and setting changes within 40 hours of engineering labor. Of course, there will often be additional calendar time for information exchange, review, and approval by other interested parties – these would be DG owners, other departments in the utility, etc.

In contrast with this ideal, the three previous DG integration case studies EPRI has done [2, 3] required the use of three different simulation programs (Aspen's DistriView, DCG's EMTP, and EPRI's ETMSP), along with custom-built formulas and spreadsheets. The study scope includes power flow, short circuit analysis, device coordination, dynamics, harmonics, flicker, and transient voltages. That kind of process requires extensive data conversion between different formats, and a high level of modeling expertise on the utility distribution engineering staff. The same situation would prevail today. Considering the current state of databases and software tools, it would still take an expert consultant at least one month to perform a DG integration study. Even if the average utility could reach the same level of efficiency, this would still not be an acceptable turnaround time, nor an acceptable engineering cost, when DG reaches high penetration levels.

The Common Information Model (CIM), which EPRI initiated, but which has since migrated to IEC 61970, would be a good platform to address item number 1 of the ideal study work flow. The CIM is being extended to distribution systems under IEC 61968, and this extension is sometimes called DCIM. If the utility distribution system assets are stored in a database following the DCIM object model, then it could be very efficient to extract a model for engineering analysis, to any level of required detail.

The Utility Communications Architecture (UCA) object model defined for substation automation, in IEC 61850, could facilitate the DG study model update with actual setting parameters and measurements in step 2 of the ideal work flow. The two object models, UCA and CIM, must be compatible, or else the simple update process won't work.

Step 3 is addressed in a later section. As mentioned, no single software tool meets all DG integration study requirements, leading to extra work by the engineer.

In step 4, the Substation Configuration Language (SCL) in IEC 61850 would facilitate the update of device setting parameters, based on results of the engineering analysis. Again, it would be necessary for the study tool to write SCL-compatible outputs, or alternatively, to save outputs in a database from which SCL is generated, using a separate tool. See Figure 5-4. If neither option is available, then the engineer would have to manually transcribe the study results into device settings, and then have those settings implemented by personnel in the field. Typically, this manual process would take several days.

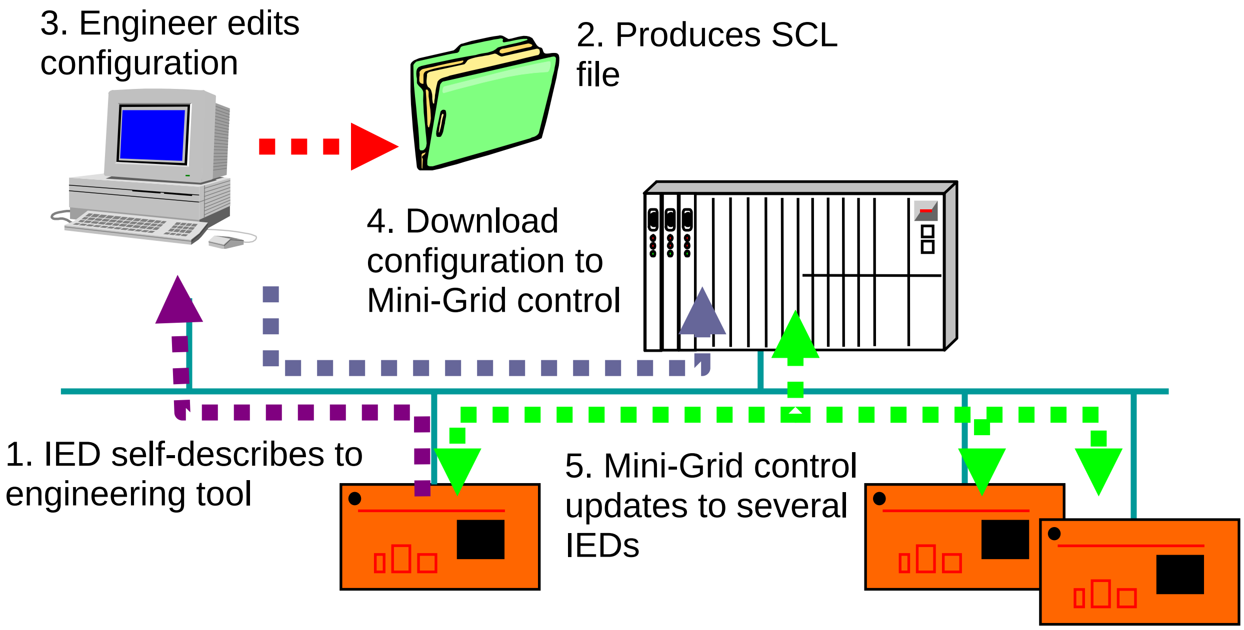

Figure 5-4
IEC Substation Configuration Language Automates Relay Setting Changes

One might hope that DCIM (61968) and UCA (61850) are naturally compatible, but it's necessary to make sure of this before trying to implement the recommended demonstration projects. Unfortunately, it's often the case that engineering analysis concerns are the last to be addressed, especially at the distribution level.

For example, a data importer has been implemented from Multispeak version 1.x to the Utility Wind Interest Group (UWIG) distributed wind feeder simulator. Multispeak is a data standardization effort, similar in many ways to DCIM, but funded through the National Rural Electric Cooperative Association (NRECA), having about 1000 member cooperatives. The UWIG feeder simulator analyzes voltage control and overcurrent protection on a radial feeder with one connected wind turbine generator. Two issues have been discovered while implementing this data interface:

1. The actual protective device settings are not available in the Multispeak XML file.

2. Much of the electrical equipment data is not in the XML file, either. Instead, there is an *eaAnalysis* field containing (in essence) a part number, which in turn refers to a database row in a specific third-party engineering analysis tool.

These omissions might be addressed in future versions of Multispeak, but for now, they prevent a seamless transfer of information from the Multispeak XML file to any other engineering analysis tool. The protective device settings are currently under review for a general implementation. However, note that the *eaAnalysis* field serves as a foreign key, and a different engineering analysis tool vendor would have to either use exactly the same part-numbering system in order to use it, or provide a special mapping file for part number translations.

Regarding the IEC 61850 efforts, searching the report *UCA Object Models for Distributed Energy Resources* for the term “impedance” yields no hits [4]. It is true that IEC 61850 does not address modeling or simulation at all. Instead, it covers measurement data, status, control, and settings. For simulation and analysis, one must turn to the DCIM in IEC 61968 and 61970. There has been some effort to make sure the DCIM supports modeling of simple distribution feeders [5]. But for DG impact studies, the simulation needs will be more demanding.

EPRI should continue its participation in standards work and advocate that the relevant IEC standards will support efficient and comprehensive DG impact and integration studies. There is another proposed EPRI project for 2006 to harmonize the UCA and CIM standards, under P037.018. Of course, it’s not known whether that project would actually be funded, or what the exact scope would be.

For the needs of the DG demonstration projects suggested in this report, EPRI should do at least the following:

1. Review IEC 61850, 61968, and 61970; suggest any changes needed to eventually support the ideal work flow for DG integration studies.

2. Review the data sets for the three previous case studies EPRI has done for DG integration, and make sure all of those models can be expressed in the DCIM, as defined in IEC 61968 and 61970.

This effort is estimated at $30K annually, as an on-going activity. It could be structured as an essential part of the demonstration project, where the contractor provides input to the IEC standardization process based on project results and needs. Simplified letter reporting could be adopted to reduce project overhead for this activity.

Develop a DER Application Database

EPRI should maintain the value of its previous investments in this area. One way of doing that could be to maintain and update an electronic delivery system of reports and case studies, which has been done successfully in the power quality area. The Distributed Resource Integration Assistant (DRIA) has recently been upgraded to version 4.0 under EPRI’s Program 101, and released in February 2005. The DRIA could form a central part of this DER Application Database.

The interconnection guidelines report should be updated to reflect current IEEE Std. 1547 activity. The existing three EPRI case studies should also be maintained and updated. Member utilities should be able to add their own case studies to the DER Application Database. Case studies have limited value for making engineering design decisions, because DG applications are still relatively new. There isn’t enough experience yet to rely on case studies, because each distribution system has differences. However, case studies still have great value as examples, and they will help member utilities just starting out with DG integration. They will also help more DG-experienced utilities account for all factors of a new DG project.

Elements of the DER Application Database should include:

1. The three previous EPRI case studies on DG integration, with data files in electronic format.
2. New tools that convert XML data from the DCIM (IEC 61968 and 61970), into data required to perform DG integration studies. The target formats would include the software EPRI used to perform three previous case studies, or others selected by EPRI.
3. An updated version of report 1000419, which covered DG integration guidelines, considering the most recent IEEE 1547 activity.
4. Continued updates of the DR Integration Assistant, currently in Version 4.0.
5. Links to and summaries of related projects by other parties.
6. DER integration case studies to be added by subscribers.
7. An electronic version of Appendix A from this report, the system evolution guidelines.
8. Engineering analysis reports, data files, test results, and other documentation any of the demonstration projects recommended in this section.

Some of these activities were originally funded by, or currently under the purview of, EPRI program 101. But the last three items would be results of program 124 efforts. Combining all of these products into the same electronic delivery system would benefit members of both programs, because they are all important for integrating DER on the distribution system. Note that EPRI could provide a common delivery platform, but with specific features enabled that depend on which program(s) the member utility has joined.

This effort could range from $120K to $300K over four years, depending on which specific items are selected for inclusion and which studies are updated. There does not appear to be a significant opportunity for cost sharing in this area.

Develop a DER-Compatible Simulator

To support the ideal engineering work flow through step 3, DER impact studies, it's necessary to first specify and then develop a simulator that addresses all study tasks, and allows continual review and updating of feeder device settings. For efficiency, a study tool should fit seamlessly into the utility's work flow and data bases. The engineer should not have to wrestle with a different data set and a different user interface to conduct each type of study. At present, there is too much custom data preparation and conversion required to conduct dynamic, harmonic and transient simulations, on top of the basic power flow and short circuit simulations.

For usable answers, a study tool should produce direct figure-of-merit outputs, not just the voltages and currents. For capacity planning with distributed generation, these outputs would include Un-served Energy over the entire load profile. Selected reliability indices (e.g., SAIFI, SAIDI, and MAIFI) and power quality indices (e.g., $SARFI_n$) would also be useful in DG applications.

For portable models, a study tool should allow users and vendors to write mixed domain models that relate electrical, mechanical, thermal, and other quantities. Until now, most of the necessary models (e.g., lines, generators, motors, and steam turbines) were built in to the software that utility engineers use. But with the adoption of newer technologies like fuel cells, batteries, flywheels, photovoltaics, wind turbines, custom power electronics, and others, customized and even proprietary models will be needed much more often. The study tool must support a standard modeling language, to ensure long-term support and avoid vendor lock-in. This could be IEEE VHDL-AMS [6, 7]. In other electronic industries, hardware vendors provide SPICE models of their chips, and these are very portable. There is no real counterpart in the utility industry.

Specification

Figure 5-5 shows the concept of a new simulator, with use of IEEE and IEC standard data formats. The simulator will include RMS (large-signal AC) analysis in both positive sequence and unbalanced phase modes, and a transient analysis in the unbalanced phase mode. RMS analysis will iterate to a converged solution. Transient analysis will use a variable time step, converging to user-selectable error criteria at each step. These modes are comparable to those offered by unbalanced load flow and short-circuit programs (large-signal AC), and the EMTP/ATP family (transient).

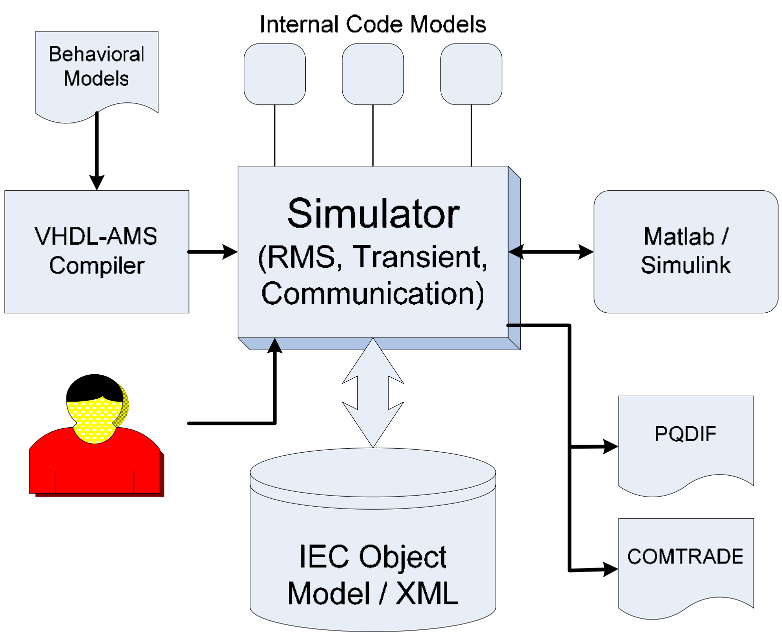

Figure 5-5
Simulation Kernel with Models and Data Based on IEC and IEEE Standards

As a new feature, the simulator must also include communication devices, pathways, environment, and design parameters into the model. With widespread adoption of IEDs and adaptive control schemes on the distribution system, reliability and power quality can easily be affected by communication failure or degradation. Figure 5-6 shows, for a simple example, how control response might be affected by changes in the communications network. The utility must consider this in the overall design, and at present, there are no software tools that combine the power and communication components into the same simulation model.

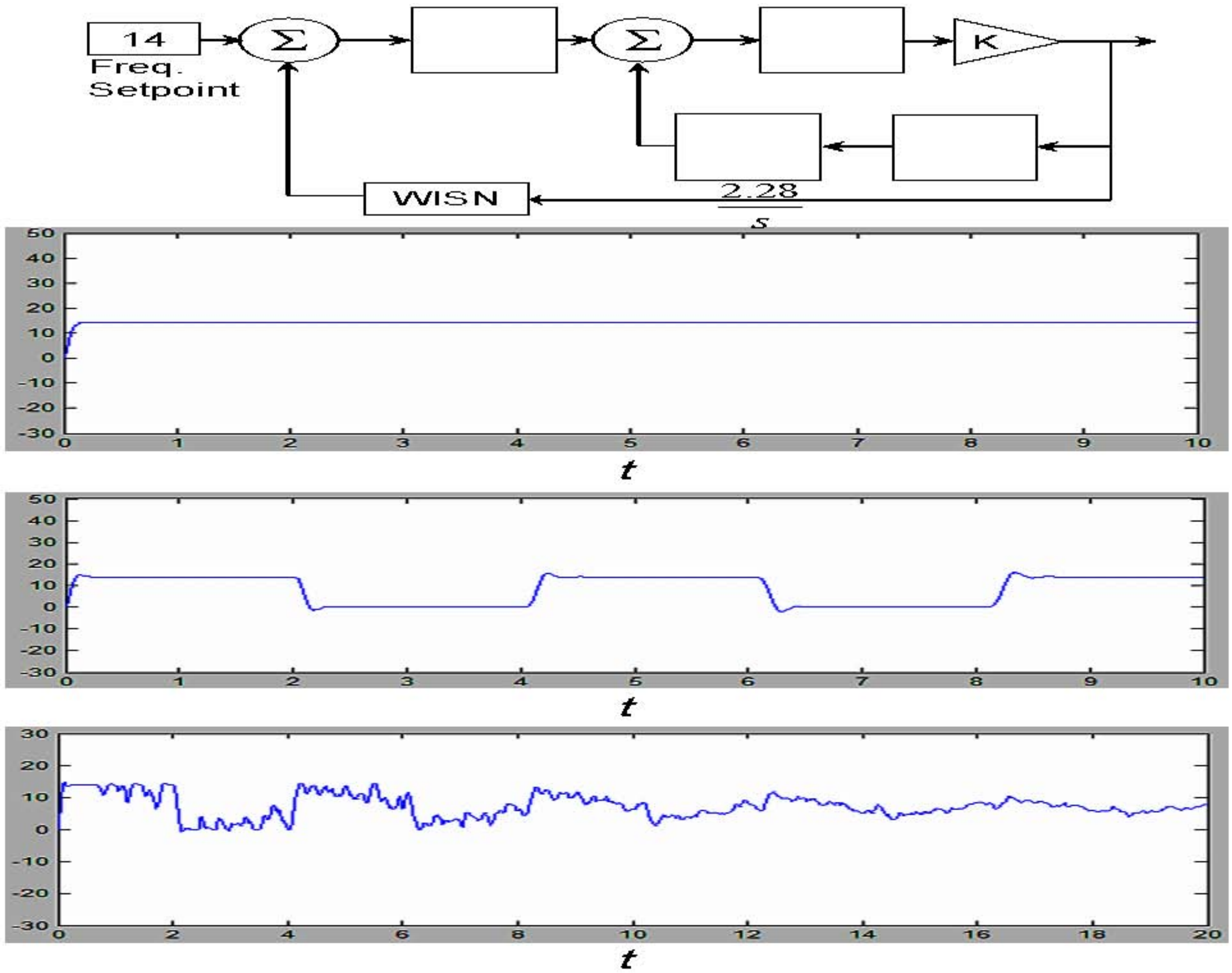

Figure 5-6
Latency Effect in a Wireless Network – None (top), Fixed (middle), and Random (bottom)

The simulator must use open standards to streamline the model preparation and output analysis processes:

1. IEC 61968 and 61970 object models, with elements of IEC 61850, to follow the principle of “standard names for standard things”.

2. IEEE Comtrade (C37.111-1999) and PQDIF (1159.3-2003) output formats, to support the use of standard post-processing and viewing software.

3. IEEE Std. 1076.1, VHDL-AMS modeling language, for customized and portable behavioral models.

4. IEC 61850 Substation Control Language, for deployment of study results to actual hardware.

The core simulator must include basic power system element models:

1. Transmission lines based on physical data, sequence impedances, or phase impedances. The transient model options should include a constant-parameter distributed model with lumped resistance, and a frequency-dependent model in the phase domain.
2. Shunt or series reactors and capacitors.
3. Nonlinear resistances (i.e., surge arresters).
4. Transformers with optional nonlinearity and hysteresis.
5. Loads – constant impedance, constant current, and constant power.
6. Rotating machines based on dq0 transformations.
7. Lumped mechanical elements from the rotational speed physical domain – inertia, torque and speed sources, stiffness, damping.
8. Ideal switches.
9. Idealized tap changer, line regulator, and capacitor switching controls.
10. Protective relays and recloser controls.
11. Instrument transformers (CT and PT).
12. Fuses (current-limiting and expulsion).

Each model will support RMS analysis at the fundamental frequency, with a possible non-linear relationship between fundamental voltage and current. Each model will also support the transient analysis mode.

Issues with Existing Tools

Existing software could meet some of the requirements discussed, but not all of them. A fresh start is better than choosing one of these other tools for a starting point.

Matlab/Simulink

This product has become ubiquitous in college engineering curriculums, and also for control system design in industry. That makes it attractive from a training perspective. Despite availability of the Power System Blockset, Simulink was not designed for conservative systems (i.e., those that satisfy Kirchhoff's Laws). It encounters trouble simulating some electrical circuits. The data format is also proprietary. However, Simulink does provide a co-simulation interface, and this has been incorporated into Figure 5-4. That feature allows a user to include a custom control system, represented in Simulink, directly into the DER simulator's model.

EMTP Family

This category includes ATP and PSCAD. One might observe that "anything" could be simulated in EMTP. Its use is widespread, and some versions are available at no cost. Yet EMTP is not very effective for steady-state analysis of non-linear systems. The competing data formats and licensing terms mean that EMTP is no longer universal or portable, and technically, the software design is dated. A modern simulator should not have fixed time steps and fixed-format input. In contrast, SPICE version 3 had a modular design, with license terms from Cal-Berkeley that encouraged commercialization. Even though it started as buggy university code, several vendors have offered SPICE-based products with extended features. It's now possible to obtain a free SPICE model of almost any chip from almost any hardware vendor. Regrettably, EMTP cannot achieve this status for both technical and business reasons.

Other EPRI Software Products

Much EPRI software has been developed with good technical capability, but it hasn't always been widely adopted, or achieved a long product lifetime, for several reasons:

1. The project funding and skill set didn't support development of a good user interface.
2. EPRI provided no mechanism for long-term support.
3. EPRI did not maintain continuity of development.
4. To reduce cost, some products used convenient and efficient, but non-mainstream, development platforms.
5. Some products were designed to allow third-party algorithms, but not allow third-party models for the built-in algorithms.
6. Some products have been designed for the consultant, academic, or other expert.
7. Most products have their own data format, requiring a customization effort for each installation.

Most of these issues are probably inherent with EPRI's business model and product life cycles.

Open Source Development and Quality Control

To achieve long-term support and industry-standard status, the new simulator development should be conducted as an open source project, but without the full Gnu Public License (GPL) restrictions. The code should be exclusively C/C++, and should run on both Windows and Linux platforms. This general approach improves the code quality and ensures long-term support, by encouraging tests and contributions from the open-source community.

Executable software builds should be posted on a public Web site during the development, for public testing and feedback. This process leads to both progress reporting, and continual testing, with opportunity for early re-design or re-implementation if necessary. Internal test cases should include repeat solutions of the three (urban, suburban, and rural) feeder DG case studies undertaken previously by EPRI.

One might argue that EPRI would “give away” intellectual property by following the open-source model. On the other hand, no EPRI software tool in the T&D arena has achieved a de facto industry standard status over a sustained period of time – and that should be EPRI’s goal in this emerging area. There is a partial exception in the DCG version of EMTP, but that product began with a public-domain code base that was already developed. Noting that EPRI encouraged UCA and CIM to migrate under the IEC umbrella, there is some precedent for EPRI adopting an open-source model of software development.

As the primary funding organization, EPRI would remain the gatekeeper for modifications to the open-source code base. This is less of a burden than having primary funding responsibility for software enhancements and support. Funding for the first one or two versions could be supplemented from utility, government, or other consortium sources. After that, training, application support, and code maintenance could be provided by third parties on a commercial basis for a fee, or through open-source code contributions.

The total development effort for the new simulator could be approximately $600K for the first version, but would expand later. While there is little opportunity for significant cost sharing, it should be possible to obtain co-funding by other organizations. The new simulator would also apply to other EPRI focus areas in distribution systems, so there could be potential cooperative funding between EPRI program areas. Program 124 should participate in such cooperative efforts to make sure that DG-specific needs will be addressed.

Cost and Schedule

For planning purposes, EPRI’s available funding for future project phases is estimated at $1638K, including $894K of base funding, during the years 2006-2009; with the remainder coming from utility and vendor supplemental funding. The 2006 work, which is in the portfolio currently being sold, specifies a design phase for an advanced system concept in 2006, with implementation and testing in subsequent years. Of course, the actual amount of annual funds available, if any, will depend on how well the portfolio activity attracts funding. EPRI could leverage the funds through sponsorship of design competitions and even design prizes.

Figure 5-7 shows a proposed schedule in which a demonstration project would be partially funded. The project begins with a 1-year design phase, followed by a 3-month review period, ending with a 33-month implementation and testing period. EPRI could partially fund two qualified teams in a design competition. At the end of the competition, EPRI could award a contract to one team for implementation and testing. In effect, this constitutes an “EPRI Prize” for advanced distribution design. While EPRI funding probably won't cover the full implementation of any demonstration project, it may be enough to attract serious interest, since the winning team will gain some prestige in the marketplace.

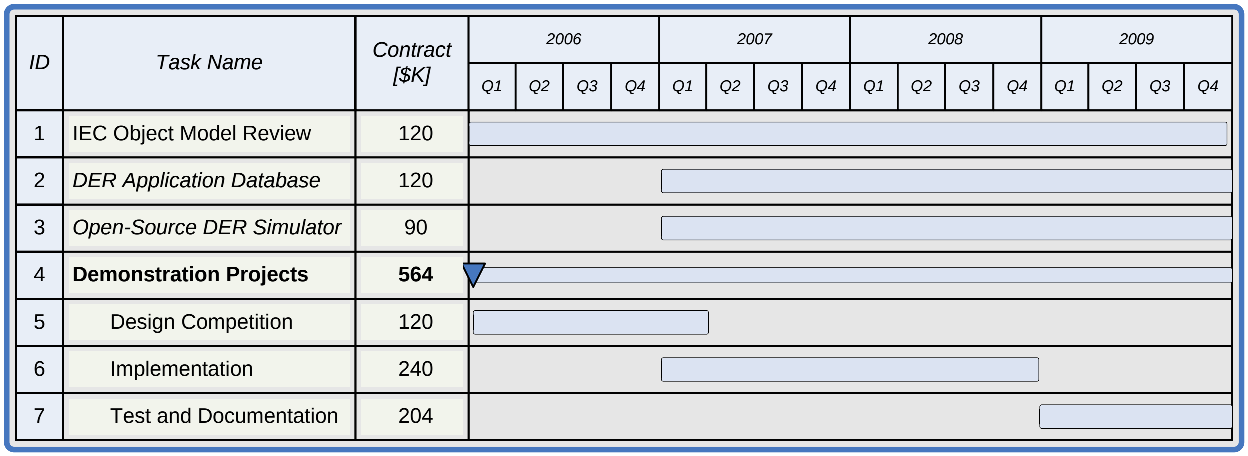

Figure 5-7
Schedule of Priority (Bold-faced) and Second-Tier (Italics) Tasks

The Ansari X Prize, of $10M for the first practical demonstration of civilian space travel, provides an extreme example of the incentives that prizes offer. Burt Rutan and his team won this prize late in 2004, but at a cost of several times the cash value of the prize. The prestige of winning the prize, coupled with the prospect of future earnings and market potential, was apparently enough motivation. World-wide, there were over 20 other teams working on the prize, and some of those "losing" efforts might eventually bear fruit as well.

Another critical task will be to make sure the IEC object model supports the necessary engineering tasks for implementation of any demonstration project. This must be done early in the funding period. EPRI has a special interest in this area because of its early sponsorship of UCA, which migrated to IEC 61850, and of the CIM, which migrated to IEC 61970. As discussed earlier, this activity could be incorporated into the demonstration project.

The other two tasks, *italicized* in Figure 5-7, are also important, but they do not fit within the available funds. EPRI should have a special interest in the DER Application Database, because it preserves the value of earlier investments by EPRI in this area. The new simulator is another opportunity for EPRI to set a de facto standard, because commercial software vendors are not likely to address this area, except in a piecemeal fashion. However, the simulator project is relatively expensive, without apparent cost-sharing opportunities. It's possible that one or both of these projects could be funded through special subscription, through a special interest group, through co-funding with other sources, or through some other mechanism.

Table 5-1 shows a base funding cash flow estimate by major task, and Figure 5-8 presents the same data in a graphical format. This matches the approved base funding level for the years in question.

Table 5-1
Base Funding Cash Flows [$K]

Task	2006	2007	2008	2009	Subtotal
IEC Object Model Review	30	30	30	30	**120**
Design Competition and Review	120	0	0	0	**120**
Pilot Project Implementation	0	120	120	0	**240**
Pilot Project Test and Documentation	0	0	0	204	**204**
DER Applications Database	0	60	30	30	**120**
Distribution Simulator	0	30	30	30	**90**
Subtotal	**150**	**240**	**240**	**264**	**894**

Utility participants, and perhaps the device vendors, will need to contribute supplemental funding in order to implement the demonstration project(s). For the utility, this comes in the form of engineering, equipment purchases, installation, and maintenance. For the vendor, this might come in the form of discounted hardware, or a high level of application engineering support. The cost sharing estimates will vary with complexity of each design to be implemented. Participation depends on specific interest by a host utility. With enough utility and vendor interest, EPRI could even fund more than one demonstration project.

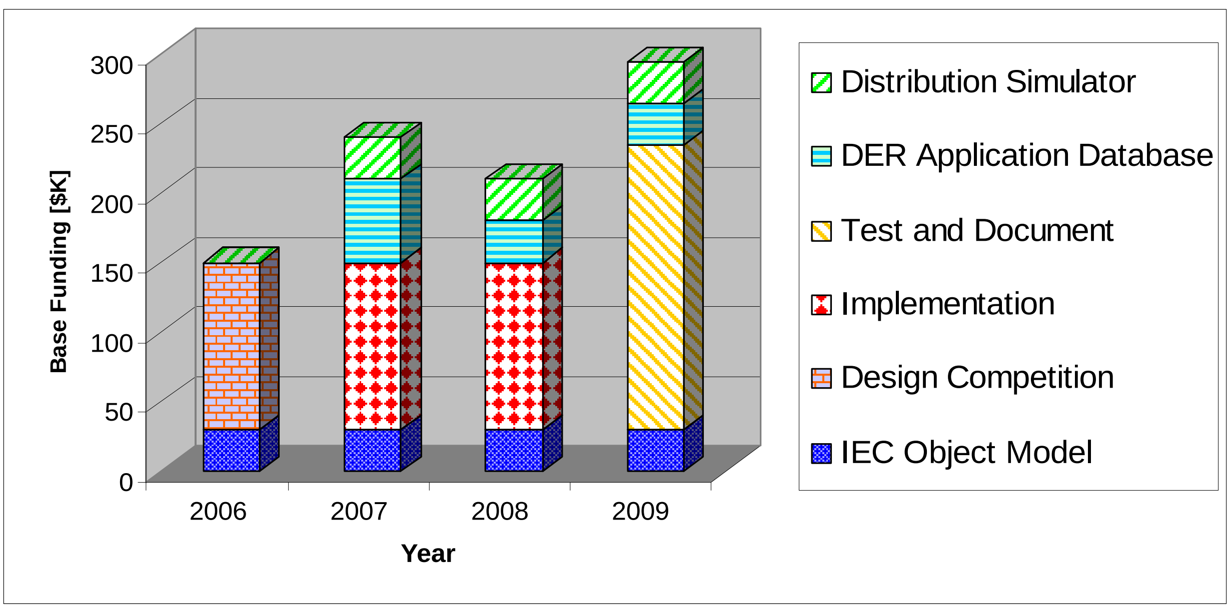

Figure 5-8
Base Funding Cash Flows

References

1. *Technical and System Requirements for Advanced Distribution Automation*, EPRI, Palo Alto, CA, June 2004. 1010915.

2. *Integration of Distributed Resources in Electric Utility Distribution Systems: Distribution System Behavior Analysis for Suburban Feeder*, EPRI, Palo Alto, CA: 1998. TR-111490.

3. *Integration of Distributed Resources in Electric Utility Distribution Systems: Distribution System Behavior Analysis for Urban and Rural Feeders*, EPRI, Palo Alto, CA: 1999. TR-112737.

4. *Utility Communication Architecture (UCA) Object Models for Distributed Energy Resources (UCA-DER)*, Electricity Innovation Institute and EPRI, December, 2003.

5. Xiaofeng Wang, Noel N. Schulz, and Scott Neumann, “CIM Extensions to Electrical Distribution and CIM XML for the IEEE Radial Test Feeders”, *IEEE Transactions on Power Systems*, vol. 18, no. 3, August 2003, pp. 1021-1028.

6. Thomas E. McDermott, Ralf Juchem, and Deepika Devarajan, “Distribution Feeder and Induction Motor Modeling with VHDL-AMS”, IEEE/PES Transmission and Distribution Conference, New Orleans, October 2005.

7. *IEEE Standard VHDL Analog and Mixed-Signal Extensions*, IEEE Standard 1076.1-1999, December 1999.

A
SYSTEM EVOLUTION GUIDELINES

This section describes how to better accommodate DG over the next few years. The first sub-section discusses a general improvement in distribution system overcurrent protection, by reducing the fault clearing times, and increasing the sensitivity and adaptability of the protection scheme. By themselves, these changes will improve power quality on the feeders. The second sub-section goes on to describe how these ideas may be extended for DG on the distribution system. These changes to the protection system require minimal new hardware expense, although they would require some engineering and deployment effort. The third sub-section discusses communication options to support the new protection schemes.

For background information on overcurrent protection, the classic Westinghouse reference *Applied Protective Relaying* has been updated recently [1]. The various distribution equipment vendors also have useful application notes available on their Web sites.

The fourth sub-section describes how the distribution system could evolve into a mini-grid at the substation level. This evolution also requires new communication options. The fifth sub-section describes integration strategies for low penetration levels of DG, primarily involving careful impact studies, and opportunities for cooperation between utilities and DG owners for siting and control purposes.

In general, utilities may follow these guidelines to prepare for DG:

1. Install new or upgraded devices that comply with IEC 61850, whenever possible during normal asset management operations.

2. Upgrade communication infrastructure on the distribution system, as opportunities arise.

3. When IEDs are available to perform overcurrent protection functions, make use of advanced features to improve reliability and power quality.

4. Participate in Advanced Distribution Automation (ADA) or similar pilot projects, as opportunities arise.

5. Encourage local regulatory bodies to adopt the IEEE 1547™ standards, without modification.

6. Make sure that each new DG installation has a complete system impact study.

7. Engage with current and potential DG owners to influence locations, sizes, and technical requirements.

Improved Protection of Distribution Systems

The electric utility industry is going through significant changes related to the reduced tolerance of major customers for deviations from the nominal parameters of electric power. Another major change is the penetration of different types of non-utility generators and distributed energy resources at different levels of the electric power system.

Regardless of the availability of distributed generators, the need for improvement in the quality of the power supply is one of the main requirements for utilities. A significant improvement can be achieved at the distribution system level by proper application of existing protection functions and schemes available in modern microprocessor based protection IEDs, enabled by modern communication systems.

Most of the power quality events that result in failure of different types of equipment involved in a manufacturing or other processes are caused by short circuit faults. There are some emerging technologies being introduced to reduce the effects on sensitive loads by reducing the depth of the voltage sag. However, these are still mostly subject to research and will require significant investments for their wide scale application.

Microprocessor based multifunctional IEDs are now the standard protection, control, monitoring and recording equipment in new or existing (upgraded) substations. They provide increased capability to detect short circuit or other abnormal conditions and reduce the total fault clearing time, thus reducing the effect of the fault on sensitive equipment.

The sensitivity of many industrial facilities to variations in system parameters results in increased requirements for improved quality of power supplied by the utility. A new approach to distribution protection will help avoid costly interruptions of manufacturing or other processes when a short circuit fault occurs in the distribution system.

In order to properly implement an improved protection system, the user first needs to understand the effects of different short circuit faults on the voltage profile across the distribution system. The behavior of typical distribution feeder protection or substation protection systems needs to be analyzed from the perspective of the definitions of voltage related power quality events.

Multifunctional protective IEDs should then be considered. From many successful implementations, it is clear that by using all available advanced distribution protection schemes and programmable logic functions, the user can reduce the effect of short circuit faults on sensitive loads supplied from the distribution substation. A combination of instantaneous, definite time and inverse time-delayed phase, ground and negative sequence elements will produce a significant reduction in the duration of the fault. This will lead to changes in the voltage level and time characteristics of the fault condition and voltage sag, with a reduced probability for the costly interruption of voltage-sensitive processes.

Distribution systems with widespread use of distributed energy resources introduce additional challenges from the point of view of power quality. These include voltage fluctuations and harmonics distortion. Even though they may result in negative effects on sensitive loads, the most common power quality events that affect sensitive customers and may result in shut down of manufacturing process and significant losses are in the group of voltage variations.

The following sections will concentrate on the voltage sags and swells, as well as voltage interruptions. They will present optimizations of the distribution system protection that result in reductions of the severity of these events and their effect on sensitive users.

Effects of Short Circuit Faults

The improvement of power quality during short circuit faults can be achieved in several different ways. Like any other problem that has to be solved, the first step is to understand the nature of the problem and its effect on sensitive users.

The most common short circuit faults in the system – single-phase to ground faults – are characterized by the fact that they introduce a voltage sag in the faulted phase, and at the same time they result in a voltage swell in the two healthy phases. This is clearly seen in Figure A-1 that shows the recorded waveforms of the currents and voltages, as well as the phasor diagram for a single-phase to ground fault.

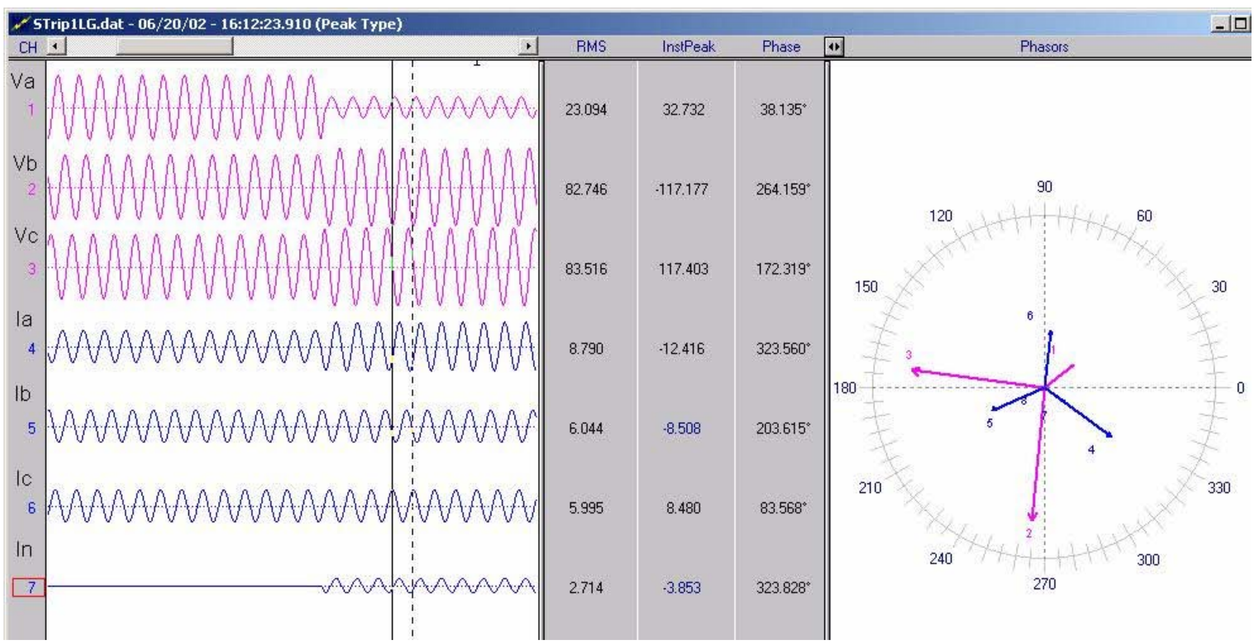

Figure A-1
Voltages and Currents for a Single-Phase-to-Ground Fault on Phase A

The case of two- or three-phase faults is quite different. For three-phase faults, all phases experience the voltage sag. For a two-phase fault, the two faulted phases will have lower voltages, and the healthy phase has no significant change compared to the pre-fault levels. Figure A-2 shows the recorded voltage and current waveforms on a faulted distribution feeder for a two-phase fault.

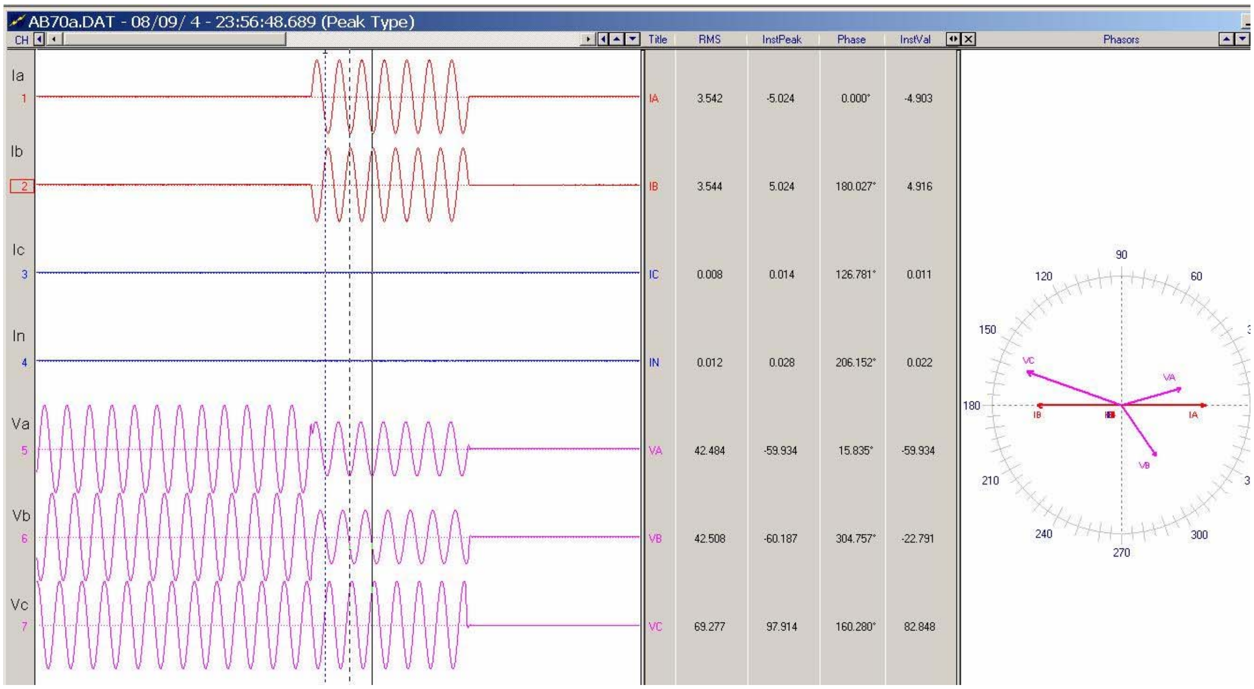

Figure A-2
Current and Voltage Waveforms for a Two-Phase Fault

The effect of the selected reclosing mode must also be considered in the analysis of short circuit faults. From the point of view of power quality events, the effect of a short circuit fault on a transmission line will be quite different compared to a fault on a distribution feeder. Considering a sensitive customer on the distribution feeder, a fault on the transmission system or on an adjacent distribution feeder will result in voltage sag during the fault. As soon as the fault is cleared, the voltage will go back to normal.

This is not the case if the fault is on the distribution feeder where the sensitive load is connected. As soon as the distribution feeder breaker trips to clear the fault, the voltage sag will become a voltage interruption, with duration determined by the setting of the reclosing interval.

Reclosing strategy will also be important, since it will determine how many times a sensitive load will be exposed to voltage sags during one permanent fault event. A common utility practice is to apply three reclosing shots:

1. First shot: Instantaneous (or with a very short time delay)

2. Second shot: Time delay in the range of 30 sec

3. Third shot: Time delay in the range of 120 sec

Figure A-3 shows the waveforms for a two reclosing shot sequence for a single-phase-to-ground fault. As soon as the fault is cleared the voltages returns to normal, at least from the point of view of the voltage transformers connected to the distribution bus. However, there is no current due to the fact that the distribution circuit breaker has opened, i.e. any customer connected to the faulted circuit will experience an interruption during this open interval.

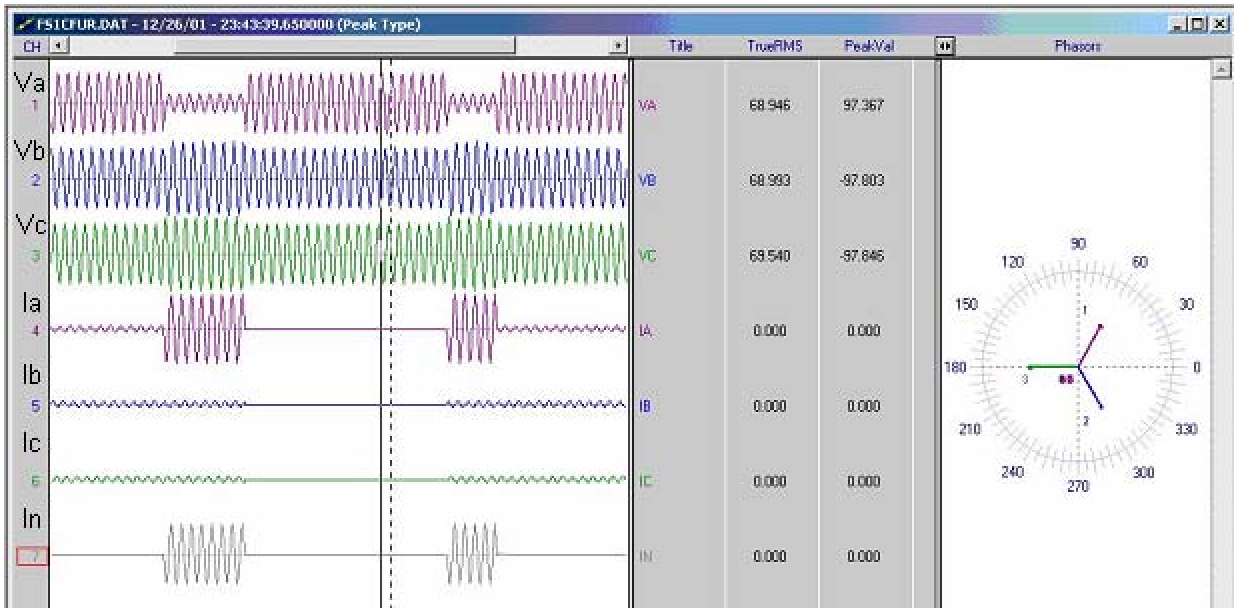

Figure A-3
Successful Two-Shot Reclosing Sequence for a Single-Line-to-Ground Fault

The effects of voltage sags and swells on sensitive equipment have been studied for many years by industry organizations such as the Computer and Business Equipment Manufacturers' Association (CBEMA). These are based on records of both characteristics of the power quality event – the depth of the sag and its duration. The ITI (CBEMA) Curve is published by Technical Committee 3 (TC3) of the Information Technology Industry Council (ITI, formerly known as the Computer & Business Equipment Manufacturers Association). It graphically shows an AC input voltage envelope, which typically can be tolerated with no interruption in function by most Information Technology Equipment (ITE).

Figure A-4 shows the 1996 revised version of the ITI curve. Events to the left and below line A, and to the left and above line B, shall be tolerated by the equipment. The rest of the events will probably result in equipment failure. That shows the importance and benefit of any improvement in the protection scheme that results in a reduction of the fault duration. Such improvements move an event to the left in Figure A-4, into or at least close to the “safe” zone.

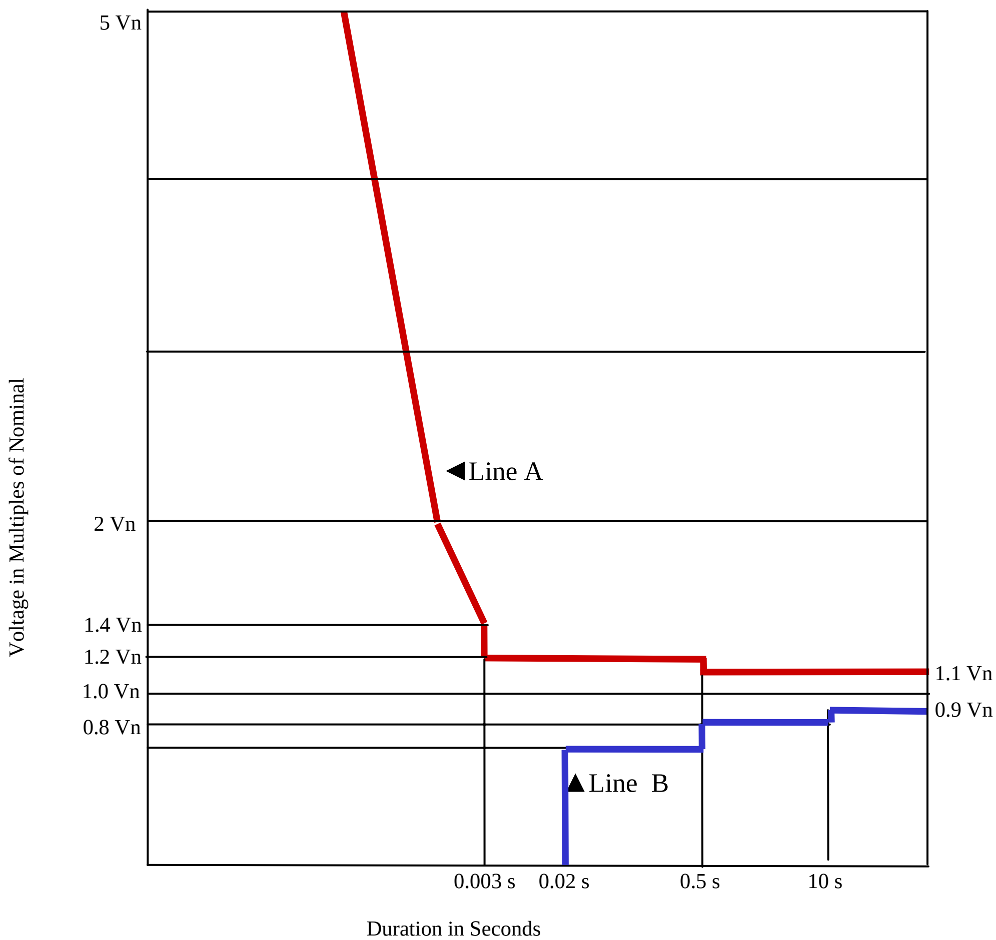

Figure A-4
ITI (CBEMA) Curve

Figure A-5 shows a plot of sag depth vs. duration from actual measurements at a high-volume manufacturing plant. Some of them (shown with the filled dots in Figure A-5) resulted in process shutdown due to failures of variable speed drives and vacuum pumps. These clearly show the sensitivity of power quality impacts to relatively small changes in sag depth or duration. Some sags to the range of 80% to 90% caused shutdowns, while others did not, depending on the duration.

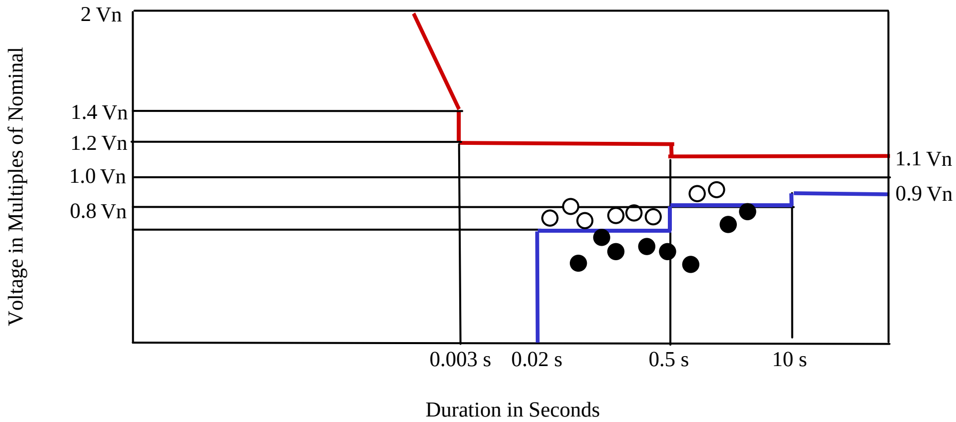

Figure A-5
ITI (CBEMA) Curve from a Manufacturing Plant

There are several factors that determine the voltage level during a short circuit fault on the transmission or distribution system:

1. System configuration
2. Fault location
3. Fault resistance

Figure A-6 shows the effect of the fault resistance (in ohms) on the voltage at the substation, for faults at the end of a sub-transmission line. A variation of the fault resistance from zero to 15 ohms could easily make the difference between a process shutdown occurring or not.

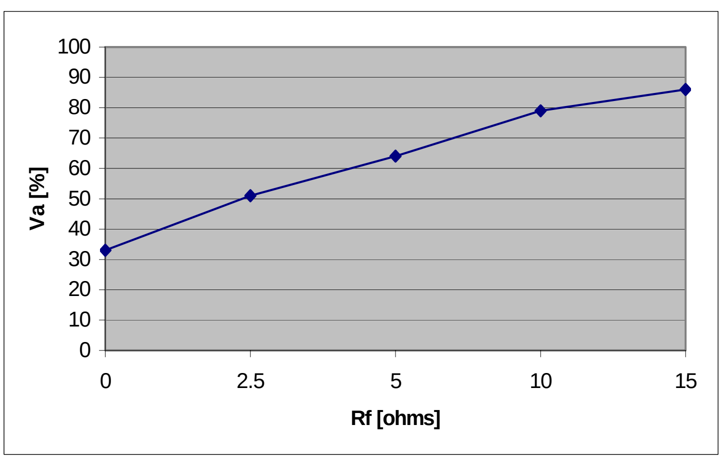

Figure A-6
Effect of Fault Resistance on Voltage Drop

The first characteristic of the voltage sag – the depth – is something that typically cannot be controlled on the distribution system. However, there are some methods being researched and implemented to provide voltage support at the sensitive load site. It is still necessary to study the factors that affect the level of the voltage sags, in order to predict or estimate the effects of different faults on the sensitive equipment.

The second characteristic of the voltage sag – the duration – is the parameter that may be controlled to some extent, by properly applying the advanced features of state-of-the-art multifunctional distribution feeder protection relays. Further, but much more expensive, improvements can be achieved by using circuit breakers with shorter operating times.

Optimizing Distribution Protection

The duration of the voltage sag is a function of the distribution feeder protective relay operating time and the breaker opening time (1).

$$t_{VSag} = f(t_{Prot}, t_{Bkr}) = t_{Prot} + t_{Bkr} \tag{1}$$

where:

t_{VSag} - the duration of the voltage sag

t_{Prot} - the operating time of the feeder protection

t_{Bkr} - the breaker trip time

In an optimization problem, one seeks values of the variables that lead to an optimal value of the objective function. Based on the definition, this optimization problem may be posed as:

"To minimize the duration of voltage sags for different types of faults, fault locations and system configurations."

Since replacement of distribution feeder breakers is very expensive and might be difficult to justify, the circuit breaker trip time will be assumed fixed within a range around the breaker nominal trip time. This assumption is expressed in (2).

$$t_{Bkr} = const \tag{2}$$

The breaker trip time at the distribution level is typically 5 cycles, i.e. 80 msec at 60 Hz or 100 msec at 50 Hz. The optimization problem then simplifies to (3).

$$\min\{t_{VSag}\} = \min\{t_{Prot}\} + t_{Bkr} \tag{3}$$

Protection of Distribution Feeders

Typical distribution feeder protection uses instantaneous and inverse-time phase and ground overcurrent relays, which are set to protect the line for three-phase, phase-to-phase or phase-to-ground faults.

An instantaneous relay operates for close-in faults, and a time overcurrent relay with inverse characteristic provides protection for most faults out on the line. The time overcurrent relay must coordinate with any fuses that protect single-phase laterals or distribution transformers connected to the feeder. The coordination (or time margin) requirements for high current faults result in significant increase in the operating times for faults further down the line. The longest times occur for faults at the remote end. These remote faults produce higher voltage levels (i.e. less severe sags) because of greater impedance between the load and the fault. The sag voltage level for different faults must be coupled with the expected fault duration, based on the overcurrent protection scheme. These results will determine the need for improvements and replacement of existing protection relays with advanced multifunctional protection IEDs.

In order to reduce the number of electromechanical or solid state relays, backup protection for bus faults or breaker failure has been traditionally provided by the transformer protection relays. Considering the fact that they also have to coordinate with the feeder relays, the backup clearing times for bus faults or feeder faults during breaker failure conditions will produce longer duration voltage sags, and will not meet the requirements of sensitive customers.

State-of-the-art multifunctional protection relays have many features that allow significant improvements in the performance of the relays under different short circuit fault conditions. Properly configuring and setting the relays will allow the user to find the optimal solution defined in (3).

The following sections analyze different methods that produce reductions in the distribution feeder protection operating time.

Definite Time vs. Inverse Time Overcurrent

Modern distribution feeder protection relays have multiple phase and ground overcurrent elements, which can be used to reduce the operating time of the relay for different fault conditions. Figure A-7 shows the inverse time characteristic of a phase overcurrent relay; see line 2 without the stepwise indentations. This characteristic coordinates with a downstream fuse, shown with line 1 and its band.

If instead a relay with four phase overcurrent elements is used to protect the distribution feeder, it can be configured with all of them enabled to operate as:

1. one instantaneous
2. two definite time delayed
3. one inverse time overcurrent characteristic

In a conventional distribution system there is a single source of fault current, so all four overcurrent elements should be directional. The heavy line in Figure A-7 shows the two definite time delayed elements and the instantaneous element superimposed on the original inverse-time characteristic. This produces an overall time-overcurrent characteristic with reduced operating times whenever the fault current is greater than 1000 amps, or falls between 150 and 350 amps.

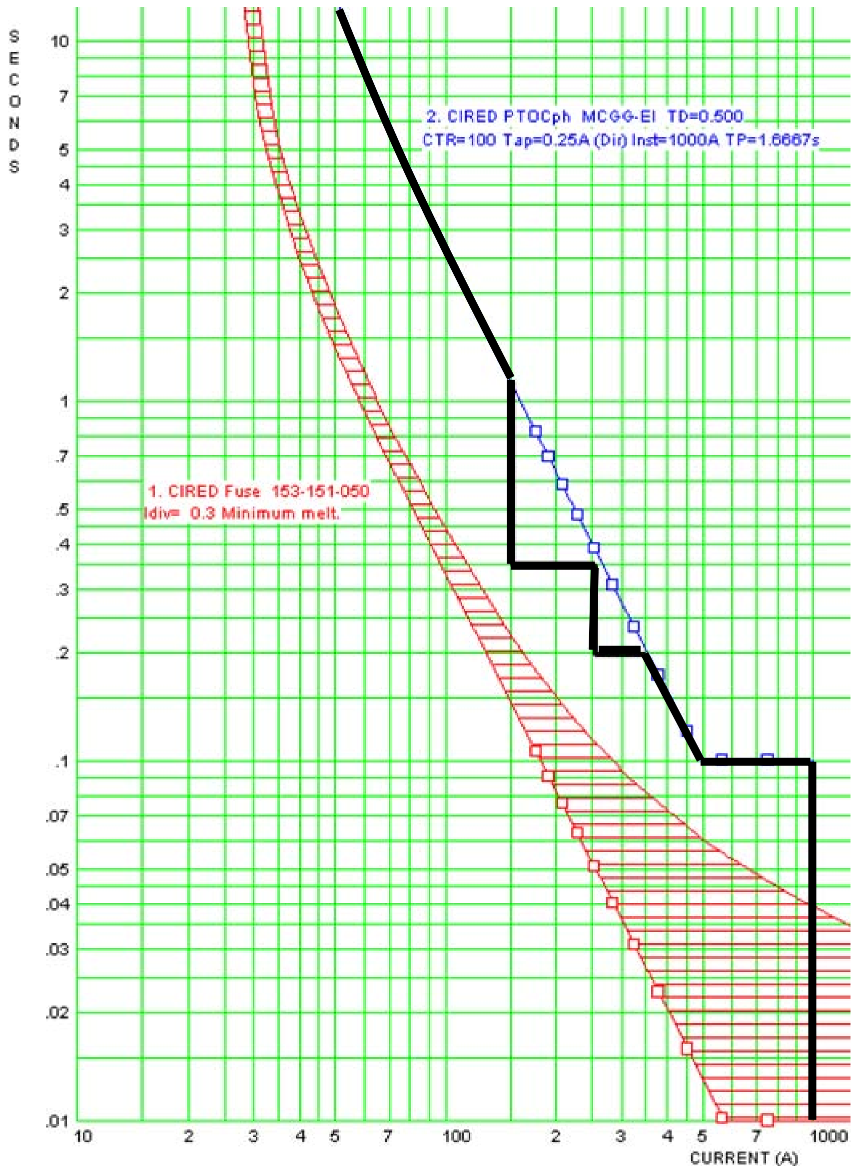

Figure A-7
Inverse vs. Definite Time Overcurrent

Table A-1 shows a comparison of the operating times of the original inverse time characteristic, and as modified with two additional definite time delayed overcurrent elements. The definite time delay settings are 0.2 s and 0.35 s. The last column of Table A-1 gives the difference in the operating times. The advantages are quite significant, especially for the faults closer to the end of the line. Considering the moderate voltage sag level for these faults, the inverse characteristic's longer time delay could produce a process or work interruption. However, when the definite time elements are added to the relay, the voltage sag duration will probably become short enough to fall within the ITI (CBEMA) curve's defined capability in Figure A-5.

Table A-1
Operating Time Comparison, Inverse vs. Definite Time Overcurrent

Fault Location (% Line Distance from Substation)	**TOC time**	**DTOC time**	**Δ time**
40 %	0.24 s	0.20 s	0.04 s
50 %	0.31 s	0.20 s	0.11 s
60 %	0.39 s	0.35 s	0.04 s
70 %	0.48 s	0.35 s	0.13 s
80 %	0.59 s	0.35 s	0.24 s
90 %	0.70 s	0.35 s	0.35 s
100 %	0.82 s	0.35 s	0.47 s

Negative Sequence Overcurrent Protection

When applying traditional phase overcurrent protection, the overcurrent elements must be set higher than the maximum load current and below the minimum feeder end fault current. This limits the sensitivity of the phase relays and also increases the operating times for line end faults. This will be even more important in the case of phase-to-phase faults. Because the phase-to-phase fault currents are generally less than those for three-phase faults, this will lead to further increase in the time required to clear the fault.

Consider an example phase-to-phase fault at 75 % distance down the protected feeder, where the voltage at the relay location is 0.79 V_{nom}, and the phase overcurrent relay with inverse characteristic depicted in Table A-1 and Figure A-7 will operate in 0.71 s. For the same three-phase fault, the voltage seen at the relay becomes 0.71 V_{nom}, with an operating time of 0.53 s.

Modern protection IEDs have multiple sequence based overcurrent elements that can help reduce the fault clearing times. Any unbalanced fault condition will produce negative sequence current of some magnitude. Thus, a negative phase sequence overcurrent element can operate for both phase-to-phase and phase-to-ground faults. If a definite time negative sequence overcurrent element is used, it may be set to clear the example phase-to-phase fault described above in less than 0.3 s. This will reduce the fault duration to within the acceptable region of No Interruption in Function in the ITI(CBEMA) curve.

Negative phase sequence overcurrent elements also provide greater sensitivity to resistive phase-to-phase faults or high resistance phase-to-phase-to-ground faults, where phase overcurrent elements may not operate at all, thus further contributing to the improved protection performance.

Distribution Bus Protection

Until recently, bus fault protection was based on the requirements for stability of the power system. Therefore, bus fault protection at the transmission level is usually provided by high- or low-impedance bus differential relays. At the distribution level, in most cases bus fault protection has been provided through the transformer's backup time delayed overcurrent protection. That is because bus differential protection, especially of the low-impedance variety, requires the installation and maintenance of additional equipment at significant cost.

Accounting for the effects of longer fault clearing times on sensitive industrial equipment would produce a change in philosophy on distribution bus protection. In many cases, such protection is now based on links between the feeder relays and the transformer protection relays in order to provide faster clearing of bus faults. This form of distribution bus protection is possible only when there is a single source, i.e. there is no source at the remote end of any of the distribution feeders. The case of systems with DG requires a different approach that is described later.

Figure A-8 shows a simplified block diagram of distribution bus protection based on links between the distribution feeder protection and the protection IED on the transformer secondary. For either the bus or feeder fault location, the transformer secondary relay will pick up based on the transformer current, $I_{x\text{-}er}$. For the feeder fault location, the relay protecting the faulted feeder will also pick up and issue a trip signal to clear the fault, with a time delay or not, depending on the fault location. At the same time, the feeder relay enables an output that is wired to a transformer relay input. All overcurrent starting signals from the various feeder relays are paralleled to energize an opto-input of the transformer overcurrent protection relay. That signal indicates a feeder fault and will block operation of the bus protection function. In Figure A-8, a fault current detected in I_{Fdr3} blocks the bus protection, but a fault on the bus causes no blocking.

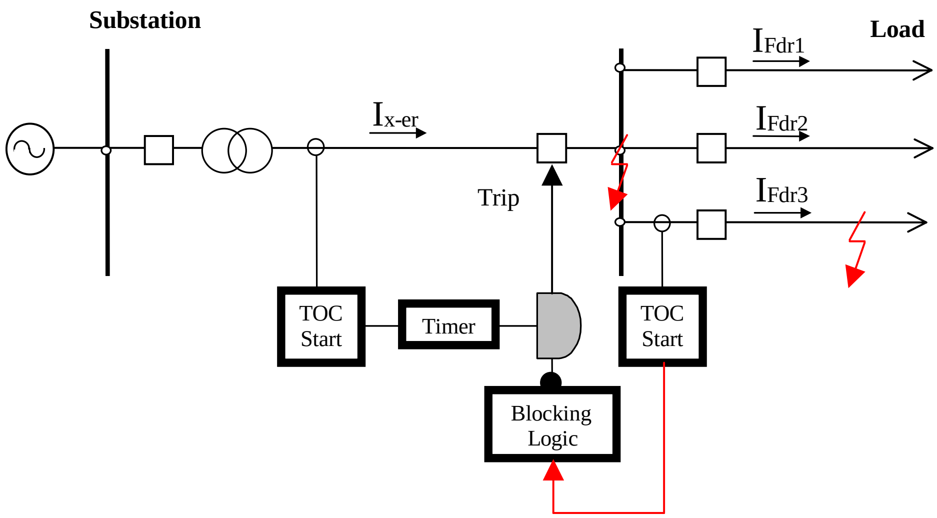

Figure A-8
Simplified Distribution Bus Protection with Bus and Feeder Faults

If the fault is on the bus, no feeder relay will operate, so the relay on the low side of the power transformer receives no blocking signal. This indicates a bus fault to the low side transformer protection relay. The overcurrent elements in a distribution bus protection scheme must be set with a sufficient time delay that allows reception of a blocking signal from any of the feeder relays. At the same time, each feeder relay must communicate the starting of an overcurrent element that is used to block the bus protection element.

The advantage of this type of scheme is fast fault clearing of distribution bus faults, without the need for a distribution bus differential protection relay. Even with a small time delay required to ensure the reception of the blocking signal, the overall fault clearing time still is much faster than typical time-delayed overcurrent elements applied to distribution bus protection. This leads to a significant reduction in the duration of the voltage sag.

Breaker Failure Protection

The need to reduce voltage sag durations in order to limit their effect on electric utility customers leads to changes in the design of distribution feeder protection. Many protection schemes that in the past have only been used at the transmission level are now common at the distribution level. One such scheme is Breaker Failure Protection.

One of the most severe fault conditions in a power system is the failure of the breaker to trip during a fault detected by the protective relays. This results in prolonged exposure of the industrial customers to low voltage and of electrical equipment to large fault current. This often leads to equipment damage and/or complete manufacturing process shut down. This is the reason that Breaker Failure Protection has become a standard feature of distribution feeder protection relays and has gained popularity at the distribution level.

The most common Breaker Failure Protection functions are based on monitoring current in the protected circuit. After a fault is detected and the relay issues a trip signal, it also initiates the Breaker Failure Protection timer. Since at the distribution level the feeder is protected by a single relay, the Breaker Failure Protection function is usually started by a built-in element of this relay. If the breaker trips as expected, the current in all three phases will go to zero, which resets the undercurrent element used to detect the correct breaker operation. If no reset occurs, the timer will eventually trigger operation of the backup circuit breakers.

Tripping of breakers may be required for some conditions other than short circuit faults, for example, when triggered by overvoltage protection. Under these conditions, the monitored current may be less than the level of the undercurrent detector. In this case, the Breaker Failure Protection scheme must instead monitor status of the breaker auxiliary contacts. These contacts are of two different types, designated 52a for a contact normally closed when the breaker is closed, and 52b for a contact normally open when the breaker is closed.

Fuse Saving Scheme

Fuses typically protect the distribution transformers that serve customers from the feeders. The reason is primarily to save money, because fuses are much cheaper than breakers and line reclosers. Short circuit faults in the transformers and on their secondaries do not occur very often, so transformer fuse protection is widely implemented. Fuses also protect many single-phase laterals.

The problem with fuse protection is that it does not allow automatic restoration of the power supply. It also requires that a crew be sent to the location to replace the fuse. This can lead to a significantly long supply interruption. Given that most short circuit faults are temporary in nature, many utilities will make at least one attempt to clear the fault with a circuit breaker and then automatically re-energize the circuit, before the fuse melts and requires replacement.

This is achieved with a Fuse Saving Scheme. A low set instantaneous overcurrent element trips the feeder breaker in the substation immediately after the fault occurs, and hopefully before any fuses begin to melt. There is no need for time coordination of the instantaneous element with downstream fuses. The breaker will automatically reclose after some short time delay, during which the fault might have cleared itself. After the first reclosing operation, the low set instantaneous element is disabled, and both a high set instantaneous and a time-overcurrent element are enabled. The high set instantaneous and time overcurrent elements both coordinate with the downstream protective devices.

The advantage is that in case of a temporary fault the fuse won’t melt, and will not require a replacement. This can be very important, especially in cases where the fuse is at a remote location, and under difficult meteorological conditions, when it will take a long time for the crew to get to the location and replace the fuse.

The disadvantage is that all customers on the feeder experience a short interruption of the load during the first dead-time interval of the breaker’s reclosing sequence. Utilities now track these events in the Momentary Average Interruption Frequency Index (MAIFI). Also, when the fault current is very high, which happens when the fault is close to the substation, the fuse protecting the faulted section or distribution transformer could melt before the breaker trips. This is more likely with a high set instantaneous element, but could also occur with a low set instantaneous element. In that case, the fuse saving is said to have failed, but because the melted fuse only isolates the faulted section, the overall protection system is still properly selective. Because MAIFI has become increasingly important, and because fuse saving doesn't always work, many utilities have disabled instantaneous trips on the distribution system. This decision should be based on the actual feeder load sensitivity to voltage sags or voltage interruptions.

Selective Backup Tripping

Protection of distribution feeders today is commonly provided by a single multifunctional relay. If the relay fails while there is a fault, the protection is typically provided by time-delayed overcurrent elements of the transformer protection that trips the transformer breaker. This has the negative result of:

1. Delayed operation

2. Tripping of the source breaker, leading to a voltage interruption of all other feeders connected to the distribution bus

A significant improvement can be achieved by the selective backup tripping of the distribution feeder breakers from the transformer relay. If the feeder relay fails, it will close an alarm contact wired to an opto input of the low side transformer protection relay, thus indicating that it is out of service.

When a fault is detected by the low side transformer relay and there is no blocking signal from any of the healthy feeder relays, the transformer relay will first send a trip signal to the breaker of the feeder with the failed relay. If the fault is on that feeder, it will be cleared. This will eliminate the need for tripping of the transformer breaker and causing the voltage interruption for all feeders connected to the distribution bus.

Cold Load Pickup

As discussed earlier, distribution feeders are typically protected by phase and ground overcurrent elements. They may have instantaneous, definite time delayed or inverse time characteristics. The low set time delayed elements are used to provide overload protection or protection for line end faults, while the instantaneous elements should provide high-speed fault clearing for close-in faults.

The pickup settings of the low set elements are defined by the loading of the distribution feeder and the levels of the minimum fault currents for faults at the end of the protected feeder. They also have to coordinate with the distribution transformer fuses and downstream reclosers.

When a feeder circuit breaker closes to energize the line, an inrush load condition prevails for a certain time. The current levels may be quite higher than the normal load levels. This may lead to an undesired operation of the low set overcurrent elements following the closing of the breaker.

The magnitude and duration of the inrush depends on the type of loads being fed by the distribution feeder. It is very different between, for example, mostly motor loads and heating loads. These characteristics should be known in order to appropriately set the relay. It may also be affected by the duration of the load interruption before the closing of the breaker. That is why modern multifunctional distribution feeder relays are equipped with Cold Load Pick-up (CLP) protection schemes.

The operating principle of the Cold Load Pick-up logic is based on monitoring the status of the circuit breaker. When the breaker has been opened for a certain time, the logic will detect the line energization by the closing of breaker's 52a auxiliary contact, and typically will block one or more overcurrent protection elements for a user defined period of time.

After the time expires, the overcurrent elements are unblocked and can protect the line in the cases of overload or low current fault conditions. The advantage of this scheme is that the low set overcurrent elements are based not on the maximum inrush load current, but on the magnitude of the maximum load current after the inrush condition is over. One issue to consider when applying this scheme is a switch-onto-fault condition, or when the fault occurs immediately after the closing of the distribution feeder breaker.

An alternative for avoiding the operation of the low set overcurrent elements during distribution feeder energization, instead of blocking the overcurrent element, is to increase the setting for a certain time. This eliminates most of the problems associated with clearing a fault during this time and provides improved sensitivity, because the higher setting of the low set elements is typically still lower than the setting of the high set instantaneous element.

The logic requires breaker status information. The typical breaker status monitoring function in relays is based on a normally open (52a) auxiliary contact of the breaker. Since the auxiliary contacts of the breaker are not always a reliable indication of the status of the breaker, some relays may monitor a normally closed (52b) or both auxiliary contacts. This provides a more reliable breaker status indication.

Sympathetic Tripping Scheme

The Cold-Load Pickup logic of the relays is designed to prevent the undesired operation of the low set overcurrent elements during the inrush condition following the closing of the feeder breaker. After the time expires, the overcurrent elements are unblocked and can protect the line in the cases of overload or low current fault conditions. However, there are certain cases when inrush current can flow through the relay after the feeder has been in service for a while. For example, if a fault occurs on any feeder connected to a distribution bus, it will take some time for the relay protecting the feeder to detect the fault and the breaker to clear it. During that time the distribution system is exposed to low voltage. When the breaker of the faulted feeder trips, the voltage returns to its nominal level and many of the feeders may experience an inrush, especially feeders with predominantly motor loads. This condition may result in the operation of the overcurrent relays on healthy feeders.

To avoid such misoperation, advanced distribution feeder relays are equipped with Sympathetic Trip logic. The principle of operation of this logic is based on the receiving of a blocking signal from a distribution feeder relay that had detected and issued a trip signal for a fault on the feeder it is protecting. When the opto input of the relay on a healthy feeder is energized, it will block one or more overcurrent protection elements for a user defined period of time. This time should be longer than the expected inrush condition time. After the time expires, the overcurrent elements are unblocked and can protect the line in the cases of overload or low current fault conditions. The logic requires a Sympathetic Trip blocking signal from the relay on any of the adjacent faulted feeders.

Protection of Systems with Distributed Generation

The changes in the electric power systems caused by deregulation, energy markets and especially the availability of distributed generators result in changes in the distribution of fault currents and the behavior of protection systems in the distribution system. At the same time they introduce new challenges for the protection systems in order to meet the requirements for:

1. Safety
2. Detection of faults and other abnormal conditions
3. Quality of power supply
4. Restoration of service
5. Costs

All these factors lead to the need to examine the requirements for protection of distribution systems with distributed generation. The requirements for exchange of communications based control signals between the system protection and the protection and control system at the distributed generator interconnection point may justify the installation of communication channels between the two locations.

The availability of a communication channel makes it easier to apply communications based protection and control solutions that will significantly improve the overall performance of the protection system and will reduce the impact of the addition of a distributed generator to the sub-transmission or distribution system.

Implementation of digital line differential protection is possible over different communications media:

1. Direct fiber
2. Multiplexed systems

3. Unconditioned pilot wire

4. Conditioned pilot wire

5. Leased 64 kbit channel

6. SONET rings

Exchange of protection and control signals between relays at different locations on the protected line for breaker failure, direct inter-tripping or other applications are also essential requirements. They must be considered when analyzing the protection applications in systems with distributed generation.

Protection Requirements for Systems with Distributed Generation

Distributed generators of different types are being typically connected to sub-transmission or distribution systems. The definition of such systems varies between utilities and in some cases systems with voltages as high as 138 kV are considered as distribution. The addition of distributed generators has a significant effect on the system.

The levels of short circuit currents, the dynamic behavior of the system following such faults, and the coordination of protective relays are affected and have to be considered in the selection of the protection system. The distribution system protection settings and criteria should take into account in-feed effect, possible power swings and generator out-of-step conditions.

The distribution circuit's configuration will also have an impact on the operation of protection relays during fault conditions. Typical distribution circuits may have one of the following configurations:

1. Three-phase three-wire ungrounded circuit

2. Three-phase three-wire grounded circuit with single ground at the substation

3. Three-phase four-wire grounded circuit with single ground at the substation

4. Three-phase four-wire grounded circuit with multiple grounds (most common in North America)

The transformer configuration at the interconnection point will also effect the operation and requirements for the distribution feeder protection system. Some typical transformer configurations include:

1. Grounded Wye / Delta

2. Delta / Grounded Wye

3. Grounded Wye / Grounded Wye

4. Delta / Delta

Figure A-9 shows a typical distribution feeder, protected by a breaker at the substation. If the fault current levels are low enough, the substation breaker may actually be a recloser. Two line reclosers provide sectionalizing along the main three-phase trunk of the feeder. There are many single-phase laterals from the main branch, protected with expulsion fuses.

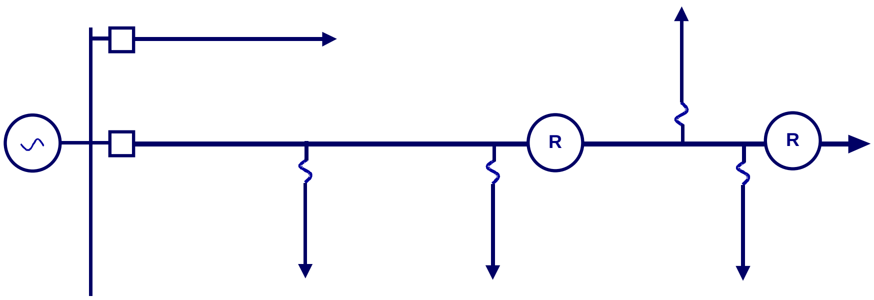

Figure A-9
Typical Distribution Feeder without DG

The increased fault clearing times that are caused by the in-feed effect of a distributed generator may not be acceptable to customers with sensitive loads. The voltage sag is experienced not only by users on the faulted feeder, but also on the adjacent feeders, connected to the same distribution system.

Directional Overcurrent Protection

One of the first feeder design changes that a utility should consider, in response to the connection of DG, would be the use of directional overcurrent protection instead of radial (non-directional) protection.

As can be seen from Figure A-10, when a fault occurs on an adjacent distribution feeder the fault current on the faulted feeder will be the sum of the fault currents from the substation transformer and the current from the distributed generator. The current from the latter will be flowing in the reverse direction through the protection of the distribution feeder. Depending on the size of the distributed generator (or generators) this current may result in undesired tripping of a healthy feeder breaker, thus leading to an interruption of power supply to the customers.

In order to avoid such operation, the overcurrent feeder protection needs to be converted from non-directional to directional. If the distribution feeder is equipped with a multifunctional distribution feeder protection relay that has both current and voltage inputs, the change can be achieved just by switching the required overcurrent elements from non-directional to a forward directional protection mode.

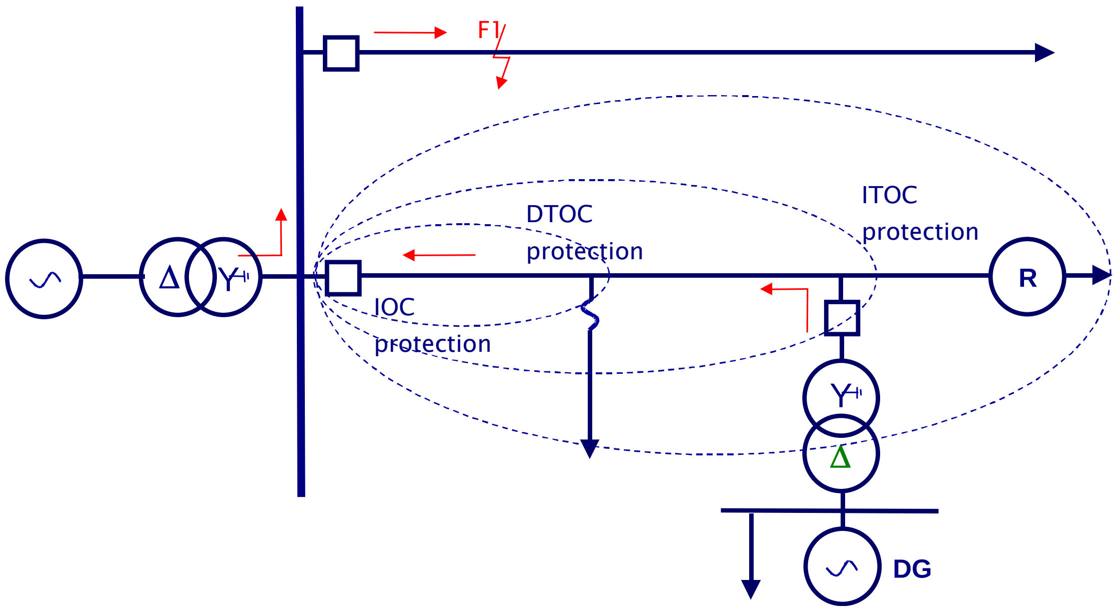

Figure A-10
Fault Current Distribution for Adjacent Feeder Fault with DG

The decision of which elements will need to be directionalized will depend on:

1. The magnitude of the minimum fault current
2. The magnitude of the distributed generator reverse current through the relay
3. The time delay of the different feeder relays
4. The grounding of the interconnection transformer
5. The grounding of the low side of the substation transformer

The last two are of specific interest for the ground overcurrent protection elements. Monitoring the state of the substation transformers and knowing which of them is grounded will help further improve the performance of the distribution system protection. Settings may be adapted when there is a change in the system, and specifically the grounding of the system, as a result of switching.

The first characteristic of the voltage sag – the depth – is a function of the type of fault, fault location and the system configuration. It will also be affected by the state of the distributed generator – if it is in service or not. Single phase-to-ground faults lead to voltage sag in the faulted phase and to voltage swell in the healthy phases. The level of voltage increase is also affected by the grounding of the interface transformer and should be taken into consideration. This is something that a utility cannot control, but needs to study in order to be able to predict or estimate the effects of different faults on the sensitive equipment.

The second characteristic of the voltage sag – duration – is the parameter that can be controlled by properly applying the advanced features of multifunctional protection relays. The distributed generator interconnection protection is subject to many papers, as well as standardization work, such as IEEE 1547™. It is clear that the location of the fault and the infeed from the generator will lead to increase of the fault clearing time and coordination problems.

Protection for Faults on the Feeder with Distributed Generators

Figure A-11 shows the distribution system from Figure A-9 with the addition of a distributed generator. The typical phase, ground and negative sequence overcurrent protection of a distribution feeder is part of the functionality of most microprocessor based relays. The zones of protection of the different overcurrent elements are shown in Figure A-11 as:

IOC – Instantaneous overcurrent protection

DTOC – Definite time-delayed overcurrent protection

ITOC – Inverse time-delayed overcurrent protection

The interconnection transformer is with a grounded wye high-side connection. As a result, there will be infeed for ground faults beyond the interconnection point (F3 in Figure A-11) even when the generator is out of service.

Using some of the advanced features in multifunctional protection relays improves the protection and reduces this time. However, it may still be unacceptable to sensitive loads.

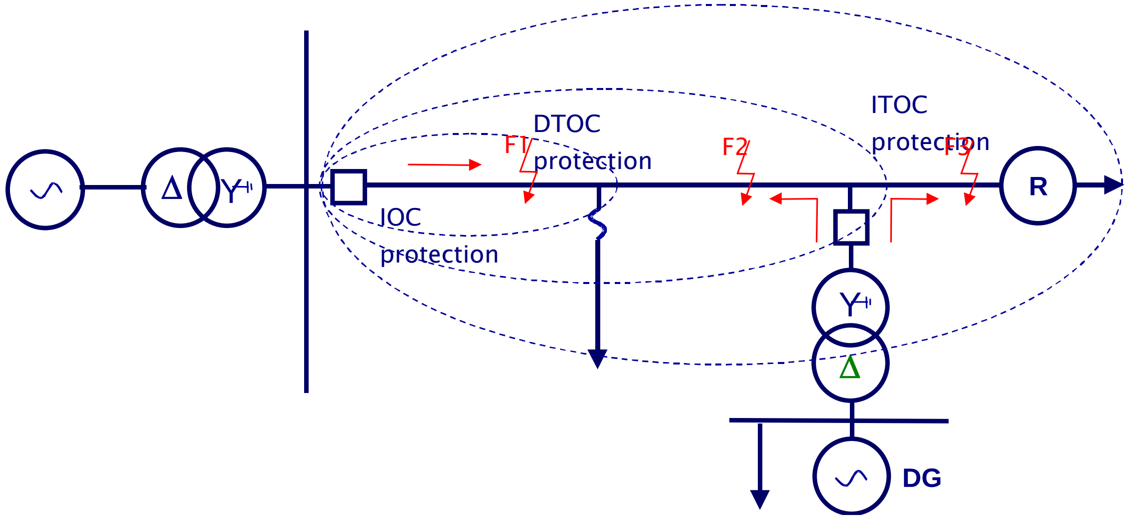

Figure A-11
Distribution System with DG and Zones of Overcurrent Protection

The islanding of part of a distribution system with a non-utility generator is unacceptable in most cases. This condition may not always be detected by the protection of the interconnection. That is why it is a typical requirement to send a Direct Transfer Trip signal from the substation to the generator interconnection breaker in order to ensure that it is disconnected from the system.

The Transfer Trip function requires the availability of communications equipment and channels between the substation and the distributed generator interconnection site. The communications links can be quite expensive if based on direct fiber over longer distances. For shorter distances fiber will be the ideal solution, since it provides high speed and is not affected by ground potential rise or electromagnetic interference.

Other, less expensive communications options such as spread-spectrum radio, pilot wire or whatever other communications media is available should be considered when analyzing the interconnection of the distributed generator to the utility system.

Since a communications link may be available between the substation and the interconnection point it is worthwhile to look into the application of communications based protection. This may improve the protection of the circuit with the distributed generator and reduce the total fault clearing time.

Multifunctional line differential protection relays can be used for circuits with distributed generation. Their application with different communication channels is discussed in the following sections.

Functions in Line Differential Relays and their Application to Circuits with Distributed Generation

Modern line differential relays are designed to meet the requirements of different applications and to communicate with each other over various types of communication links. The primary protection element of the relay is a differential element that is typically a segregated phase current differential protection. This technique involves the calculation of the differential and restrained currents for each phase based on the communicated currents at the substation and the distributed generator site. A communications path between the two is therefore an essential requirement of any such scheme.

The basic operating principle of differential protection is to calculate the difference between the currents entering and leaving a protected zone. The protection operates when this difference exceeds a set threshold.

Differential currents may also be generated during external fault conditions due to CT saturation. This may be the case especially if the current transformers at the distributed generator interconnection point have not been properly selected. To provide stability for through fault conditions and avoid tripping of the distribution breaker due to a fault on the high side or in the interconnection transformer, the relay adopts a restraining technique. This method effectively raises the setting of the relay in proportion to the value of through fault current to prevent relay mal-operation.

Figure A-12 shows operating characteristics of a two slope segregated phase differential element. The differential current is calculated as the vector summation of the currents entering the protected zone. The restrain current is the average of the measured current at each line end. It is found by the scalar sum of the current at each terminal, divided by two.

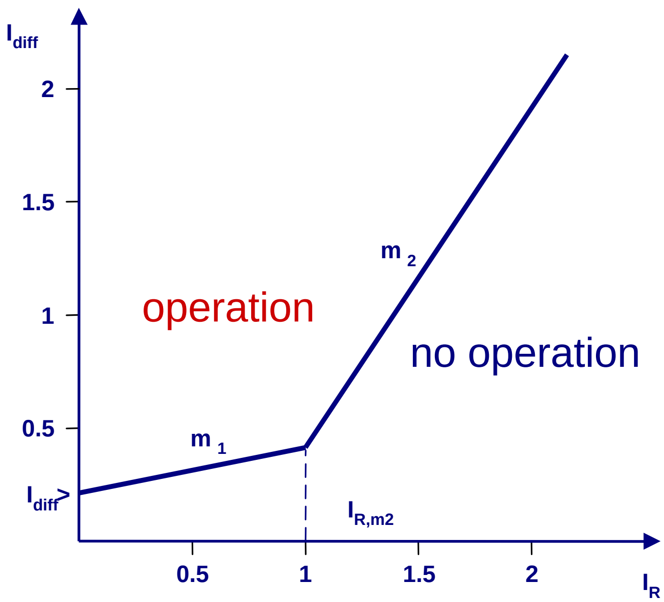

Figure A-12
Differential Characteristic

If the CT ratio at the substation and interconnection is different, CT correction might be required to compensate for the mismatch.

Depending on the location of the distributed generator and other protection equipment on the distribution circuit, in some cases the differential element may be time delayed with a definite time or inverse time characteristic.

When a trip is issued by the differential element, in addition to tripping the local breaker, the relay will send a differential intertrip signal to the relay at the distribution substation. This will ensure fast tripping of the breakers both at the substation and at the interconnection point. The relay receiving the intertrip signal will indicate that it has operated due to a differential element.

Since the operation of the differential element is based on the exchange of messages between the relays at the substation and the distributed generator site, the operating time will be affected by the communications speed. This time will determine the overall duration of voltage sag and swell caused by the fault on the distribution feeder.

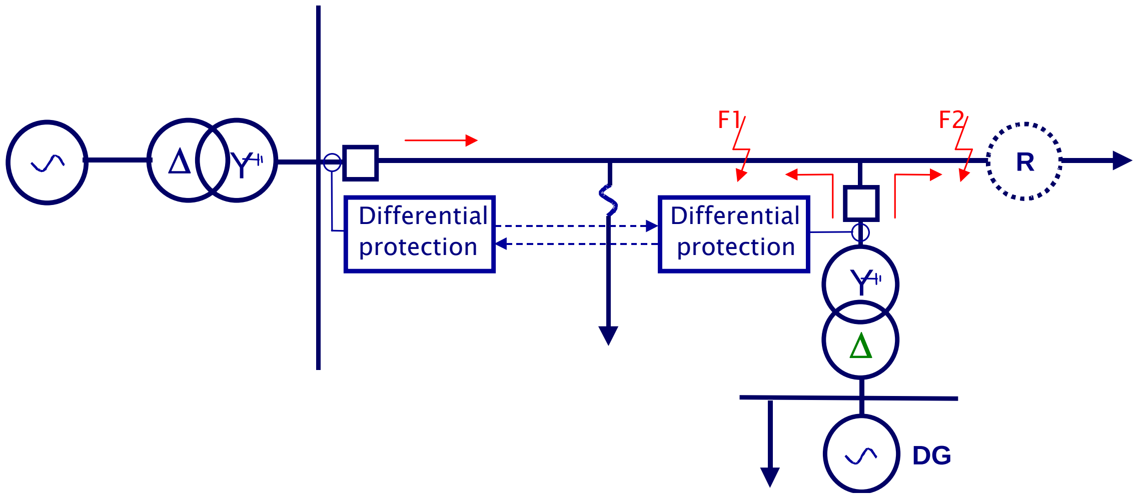

Figure A-13
Differential Protection in Distributed Generation Circuit

Analyzing Figure A-13, it appears that both a fault before the interconnection point (F1) and beyond the interconnection point (F2) will be seen as internal faults to the differential protection. As a result the effect of the infeed that is a problem for the overcurrent protection at the substation is not an issue for the differential protection.

Relay settings for the differential protection must be adjusted to account for load taps, such as the lateral in Figure A-13. Each "large" DG must be included in the differential scheme, and if there are too many DG sources, then a directional comparison scheme on each feeder segment would probably work better. Both of these concepts have been used before on transmission and sub-transmission systems. But note that only DG with a rotating machine interface (synchronous or induction generator) would contribute significant short-circuit currents. Those with power electronic interfaces can usually be controlled such that they provide little or no contribution to short circuit currents.

Overcurrent Protection

Other protection functions required by the application are the overcurrent functions, as described earlier. Phase and ground overcurrent elements are primarily used as the backup form of protection for the complete distribution circuit.

Some line differential relays have up to four overcurrent elements for phase faults and four for ground faults. This allows the protection engineer to set them as one instantaneous, two with a definite time delay and one with inverse time delay. This gives a resulting characteristic that significantly improves the performance of the relay for most of the faults on the protected circuit.

The phase overcurrent elements are less sensitive for line end phase-to-phase faults. This will be further affected by the infeed from the distributed generator. The use of backup negative sequence overcurrent elements makes the protection system more sensitive and will also result in reduction of the fault clearing time for phase-to-phase faults.

Broken Conductor Detection

A serial fault – broken conductor in one or two phases – will lead to unbalance in the protected circuit that may be dangerous for user equipment or the distributed generator. A Broken-Conductor Detection element monitors the ratio of the negative sequence current I2 to positive sequence current I1. This way it is not significantly affected by the load unbalance at peak load time.

Permissive Trip

The communication message that is exchanged between the relays at both ends of the protected circuit contains not only current phasor data, but also some binary signals that can be used in the distributed generation application.

Another possibility is to directly apply communications based protection schemes instead of the line differential protection.

For example, in order to speed up the substation breaker trip in case of interconnection transformer fault and breaker failure, the breaker failure relay at the high side of the transformer will send a Permissive Trip signal to the relay at the substation location.

Upon receipt of this message the relay at the substation end of the circuit will trip the breaker if it has already detected current flowing into the feeder and the current is above a user defined setting. This will reduce the fault clearing time, because otherwise the fault will have to be cleared by the time-delayed backup overcurrent protection.

Direct Transfer Trip

Direct Transfer Trip is another required function in distributed generation applications. It ensures that when the distribution circuit is disconnected from the system because of a breaker trip in the substation, the generator will be isolated from the circuit as well.

An opto input of a protection relay at the interconnection point can be assigned for the Direct Transfer Trip function. This can be a signal internal to the line differential protection of such type of relay. Otherwise, it can be an input that is used in the relay programmable scheme logic to perform this function.

When received at the interconnection point, it will trip the breaker to disconnect the generator from the utility circuit. In this case there is no supervision, which means that the communications should be secure in order to eliminate the possibility for an undesired trip. It is recommended to still apply some local criteria to detect that there is some abnormal condition that requires the tripping of the breaker. Voltage or frequency variations immediately before the receiving of the signal, and power reversal through the interconnection transformer, are some of the criteria that may be used for local supervision of the Direct Trip signal.

Blocked Overcurrent Protection

The overcurrent protection at the substation can be used to provide remote backup for faults in the zone of protection of the transformer interconnection relay. The substation overcurrent relay obviously has to coordinate with the interconnection transformer relay.

If this is the only distributed generator on the distribution circuit, the current seen by the distribution feeder protection relay and the interconnection transformer relay will be the same. In order to meet the requirements for sensitivity, this coordination will be achieved by time delay. As a result, some faults along the protected distribution circuit will be cleared with longer time delays, which, as discussed earlier, may not be acceptable.

The availability of control signals as part of the communications message allows the user to implement certain protection schemes that will speed up the fault clearing, thus reducing the effects of the fault on sensitive customers.

Blocked Overcurrent Protection is one of these schemes. It relies on the distribution feeder time-delayed overcurrent protection function being blocked by the start output signal, from a relay at the interconnection point that detects the presence of fault current above its setting.

Both the feeder and interconnection protection elements can then have the same current and time settings, with coordination provided by the blocking feature. If the breaker failure protection is active, the block on the substation relay will be released if the interconnection circuit breaker fails to trip.

Selective Overcurrent Logic

The blocked overcurrent protection described above uses the start of downstream relays to block operation of upstream relays. In the case of Selective Overcurrent Logic (SOL), the start of an overcurrent element at the interconnection point is used to temporarily increase the time delays of the overcurrent elements of the feeder relay in the substation, instead of blocking them. This provides an alternative approach to achieving a non-cascade type of overcurrent scheme. It may be more familiar to some utilities than the blocked overcurrent arrangement.

Distribution Bus Protection

The distribution bus protection scheme, based on a blocking signal from the start of a feeder overcurrent element to the low side transformer protection relay, will not work in the case of connection of a distributed generator to the distribution circuit. This is due to the fact that when a fault occurs on the distribution bus, there will be current flowing through the distribution feeder relay that may produce a blocking signal, thus preventing the transformer relay from clearing the bus fault.

A modified scheme can be implemented to accelerate the clearing of the bus fault when there is a distributed generator connected to the distribution circuit. It requires the communication of the state of the directional element of the feeder relay. There are two possible schemes, based on reverse and forward fault detection.

When the fault is on the distribution bus, it will be seen as a reverse fault by the distribution feeder relay. This is due to the fact that usually the forward direction detection is for fault current flowing into the protected element – in this case the distribution feeder.

When the relay detects a reverse fault condition it will close an output relay contact wired into an opto input of the low side transformer protection relay. This signal will accelerate the operation of the receiving relay, thus providing a faster fault clearing of the distribution bus fault.

A problem with this scheme is that if the distributed generator is out of service there will be no fault current through the distribution feeder relay, i.e. the reverse element is not going to operate and accelerate the transformer relay tripping.

If instead the distribution feeder relay operates the output to indicate a forward fault, the scheme will be quite similar to the conventional distribution protection scheme described earlier.

Figure A-14 shows a simplified block diagram of the distribution bus protection based on exchange of signals between the distribution feeder protection and the protection IED on the low side of the substation transformer in case of a feeder fault. For a fault on any of the distribution feeders, the relay protecting the faulted feeder will detect a forward fault and with or without time delay (depending on the fault location) will trip its breaker to clear the fault. At the same time it will immediately operate an output that is wired to an input of the transformer relay. This signal will indicate a feeder fault in the forward direction and will block the operation of the bus protection function in the transformer relay.

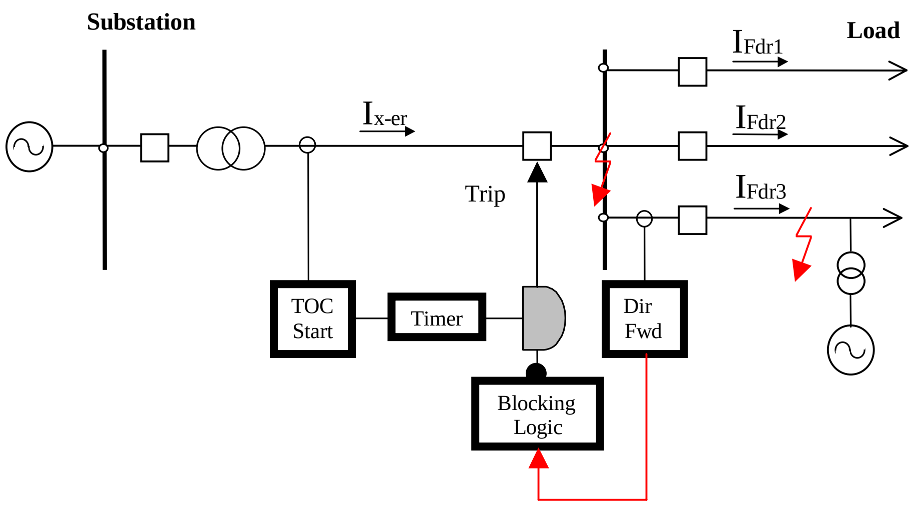

Figure A-14
Distribution Bus Protection with Distributed Generator

If the fault is on the bus, no feeder relay will detect a forward fault, i.e. the relay on the low side of the power transformer will not receive any blocking signal. This will indicate to the low side transformer protection relay that it is a bus fault. The overcurrent elements that are used to implement a distribution bus protection scheme have to be set with a certain time delay that allows the receiving of a signal from any of the feeder relays.

Communication Options and Issues

The communications link between the differential relays at the substation and the interconnection point can be of many different types. The main characteristic is that it is a point-to-point connection between two devices. Most of the applications that require communications discussed in the previous sections involve links between IEDs at a DG site and the substation.

Some of the schemes described also use hard-wired signals, exchanged between two or more relays in the substation. They can be replaced with high-speed peer-to-peer communications.

One of the goals in the use of communications to improve the protection system in distribution systems is to re-use, as much as possible, the existing communications infrastructure. If there is no existing communication link between the distributed generator interconnection point and the substation, an optimal communications solution will need to be selected.

Since the overall operating time of any communications based protection system will be a function of the speed of the communications channel, as well as the communications protocol, these have to be considered when designing the communications between the substation and the distributed generator site. The maximum acceptable fault duration may be used to determine the type of communications link to be used.

Whatever the decision, the selected protection scheme should support all available communication options such as direct fiber optic connections, multiplexers, modems or even direct metallic links. To ensure compatibility with a wide range of communication equipment and media, the relays should work with communication speeds of 9.6 / 19.2 / 56 / 64 Kbps.

Direct Fiber Interface

Fiber is the preferred media because it is not affected by electromagnetic transients and provides high-speed communications. In the case of new transmission lines, fiber is usually available in the static wire. However, that is not the case for existing lines and for most distribution lines, so other communication options should be considered.

The communications interfaces available over fiber are:

1. 850nm multi-mode
2. 1300nm multi-mode
3. 1300nm single-mode

The selection of the type of fiber to be used is based on the protected circuit length. For example, 850nm multi-mode can be used for very short lines – less than 1 mile. For lines in the range of up to about 20 miles, 1300nm multi-mode should be used, while for distances of up to 40 miles, 1300nm single-mode is selected.

Fiber interface from the relay is typically used also when the communications channel is a multiplexer. If the relay and the multiplexer are at different locations in the substation, the distance between the two devices should be covered by fiber.

Multiplexer Interface

The connection between the protection relays and the communications channel can be direct or through some additional equipment. In order to connect the relays at the substation and interconnection site via a pulse code modulation (PCM) multiplexer network or digital communication channel, interface units may be required. The interchangeable protection communications interface allows simple upgrade from fiber optic to multiplexed communications without the need for any software changes.

Some typical communications interfaces are:

1. Interface to multiplexing equipment supporting ITU-T (ITU is the International Telecommunications Union - formerly CCITT) Recommendation G.703 co-directional electrical interface

2. Interface to multiplexing equipment supporting ITU-T Recommendation V.35 electrical interface

3. Interface to multiplexing or ISDN equipment supporting ITU-T Recommendation X.21 electrical interface

The interface module converts the fiber optic signal to the electrical signal required by the multiplexer. The data rate can be 56 Kbit/sec or 64 Kbit/sec as required for the data communications link. Figure A-15 shows the connection between the differential relays through a multiplexer based communications link.

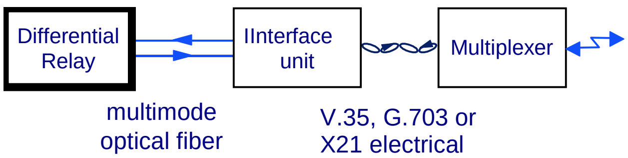

Figure A-15
Differential Relay to Multiplexer Interface

A new IEEE C37.94 standard defines N times 64 kilobit per second Optical Fiber Interfaces between Teleprotection and Multiplexer Equipment. This fiber-optic relay-to-multiplexer interface can be used for an intra-substation, point-to-point fiber-optic connection for synchronous data transport. It specifies the physical connection method, the clock recovery, jitter tolerances, and the equipment failure actions for all communications link failures.

Pilot Isolation

For many years pilot wires have been the typical communications interface between differential relays at the ends of a protected circuit. Interface of digital line differential relays over existing pilot wires is becoming an important requirement in the cases when there is an existing pilot wire, and the user is not ready to install fiber.

The strong magnetic field generated during ground faults in the distribution or sub-transmission system can induce a significant longitudinal voltage between the pilots and ground. To prevent damage to any equipment connected to the pilot circuit, it must be ensured that there is an adequate isolation barrier between the pilot itself and all other electrically isolated circuits. Although it may be difficult to accurately predict the induced pilot voltage during a ground fault, equation (4) approximates the induced voltage for un-screened pilots, and equation (5) for screened pilots.

$$V \approx 0.3 \text{ x } I_F \text{ x } L \tag{4}$$

$$V \approx 0.1 \text{ x } I_F \text{ x } L \tag{5}$$

Where:

I_F = Maximum prospective earth fault current in amperes

L = Length of pilot circuit in miles

In cases where the calculated voltage exceeds a specific level, typically 60% of the relay / modem isolation level, additional isolation must be added. When necessary, 10-kV or 20-kV isolating transformers may be used in conjunction with leased line or MDSL modems. The choice of 10 kV or 20 kV will depend upon the magnitude of the induced voltage.

Unconditioned Pilot Wires

When communicating via a pair of unconditioned pilots for distances greater than 0.75 miles, a leased line or Baseband Modem can be used. Figure A-16 shows a differential scheme with pilot wires and Baseband Modems.

A Baseband Modem is a digital modem that may be used to inter-connect digital equipment over distances of up to 10 miles (6 miles for LAN interconnection) over high speed leased line Internet links, or over a single, un-conditioned twisted copper pair. They overcome distance limitation and noise problems by using special modulation and line equalization techniques, and they allow error-free communication at much higher data rates than conventional analog dial-up modems.

For maximum security and performance, it is strongly recommended that a screened twisted pair of 0.5 mm (or greater) conductors be used.

When choosing between leased line or baseband modems the following aspects should be considered:

1. Leased line modems have a maximum transmission speed of 19.2 Kbps, whereas Baseband modems can transmit at 64 Kbps or even up to 128 Kbps.
2. Baseband modems have longer re-training times, typically between 10 to 60 s. If the connection between the two ends is temporarily lost, the protection communications will be interrupted until the re-training period has elapsed.
3. Since Baseband modems use synchronous communication protocols, there is typically a 20% performance gain over leased line modems that use asynchronous protocols.

Pilot isolation must be considered when connecting modems to unconditioned circuits. As discussed earlier, additional isolation can be provided by the 10-kV or 20-kV isolating transformers.

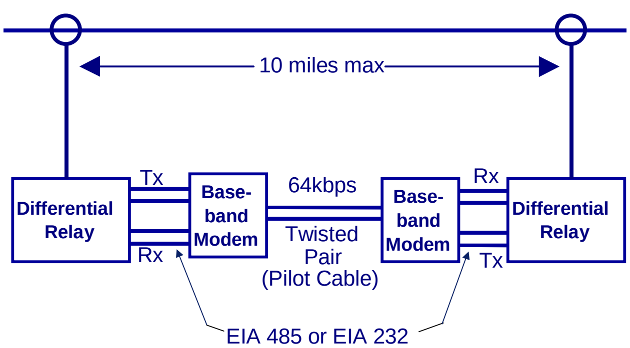

Figure A-16
Differential Relay with Baseband Modem Interface

Conditioned Pilot Wires

When communicating via conditioned pilot wires (i.e. standard dial-up telephone circuits or leased circuits that run through signal equalization equipment) the protection relays should be connected to either leased line or standard dial-up modems at each end of the line. The data rate can be set to either 9.6 or 19.2 kBPS.

Overvoltage and surge protection for conditioned pilot circuits is typically provided by gas discharge tubes (GDT). These are located along the pilot circuit to limit the voltage between pilots and ground during heavy ground faults.

The GDTs limit the high potential by transiently shorting the pilots to both each other and ground. However, this will temporarily interrupt the protection communications, thus preventing the protection from operating when required to do so.

To prevent such interruptions in the protection communications it is recommended that either:

1. The ground fault level is checked to ensure that the resulting pilot voltage is less than the voltage threshold of the GDTs

2. The GDTs be removed and replaced with pilot isolation transformers

Direct 4 Wire EIA(RS)485

Point-to-point connection between two protection relays can also be achieved using the four-wire EIA(RS) 485 interface. It can be used at data rates of 9.6, 19.2, 56 and 64K. Ideally, the interconnecting wires should be two screened twisted pairs.

The direct EIA(RS) 485 connection can cover a distance of up to 4000 feet (1.2 km). It is strongly recommended that surge protection for EIA(RS)485 be used in order to protect the relay communications interface from excessive transverse voltages (i.e. voltage between pilot cores) and static spikes. However, for reliable communications it must be ensured that the longitudinal voltage never exceeds 600 V, as surge protection may corrupt the protection signaling.

If the distance between the substation and the distributed generator site is up to 6 miles, it is necessary to use interfacing devices at each end of the circuit in order to increase the transmission distance of EIA(RS) 485.

SONET

The Synchronous Optical NETwork (SONET) standard for fiber optic networks was developed in the mid-1980s and defines a standard physical network interface that allows multiple technologies and vendor products to inter-operate. In Europe the Synchronous Digital Hierarchy (SDH) refers to essentially the same standard as SONET.

SONET provides a Layer 1 technology (the physical layer in the OSI model) and serves as a carrier of multiple higher-level application protocols, such as the Internet Protocol (IP).

SONET commonly transmits data at speeds between 155 Mbps and 2.5 Gbps. To build these high-bandwidth data streams, SONET multiplexes together channels having bandwidth as low as 64 Kpbs into data frames sent at fixed intervals.

One of SONET's most interesting characteristics is its support for a ring topology. Figure A-17 illustrates the concept of a SONET ring. Normally all data traffic is transmitted over one piece of fiber - the working ring. At the same time a second piece of fiber - the protection ring - remains on standby. If the working ring fails, SONET will automatically detect the failure and transfer control to the protection ring in a very short period of time. That is why SONET is considered to be providing a self-healing network technology.

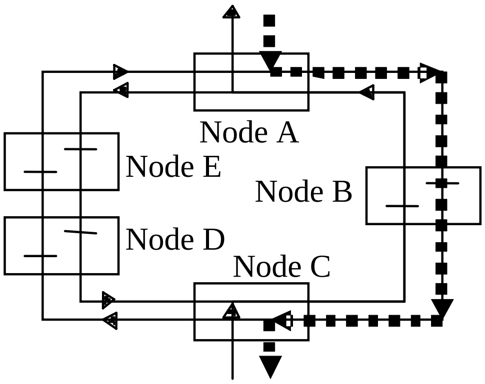

Figure A-17
SONET Ring's Normal Transmission

The usefulness of the rings depends to a great extent on their physical location. If the fiber cables use distinctly different routes to reach the same destination, the ring will provide a much higher reliability, since the likelihood of simultaneous damage on both paths is very small. If the two cables are on the same path, the probability of failure of both the working and the protection path is much higher.

The application of SONET rings for protection uses two sets of cables on the same path to provide simultaneous communications between the two relays in both directions. This is driven mainly by the requirement that the transmission times in both directions are equal.

One of the rings is the working path for the transmitted signal from one of the relays and the protection path for the transmitted signal from the second relay. The opposite is true for the second ring. This approach allows for similar transmission time between the two relays.

The signals enter the ring at a node and are simultaneously transmitted around the ring in both directions. This scheme uses one direction around the ring as the primary signal path, and the other direction around the ring as the secondary or protection path.

If a signal path failure is detected, service is restored through node switching with the local multiplexer. The switching time is a few milliseconds. Figure A-18 shows the transmission in the reverse direction after a failure in the working path. Since most line differential relays do not support different propagation times, typically even in case of failure in a single fiber, both ends will be forced to switch to ensure an equal propagation delay.

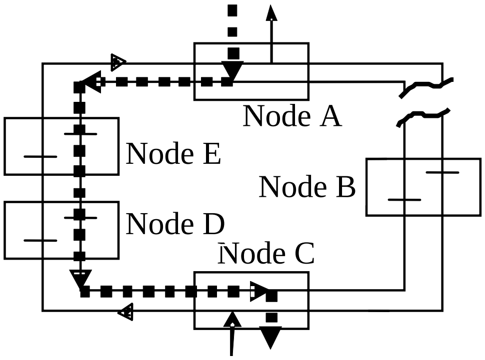

Figure A-18
SONET Ring's Transmission Over the Protection Path

Line differential relays with GPS time synchronization do not have problems with the difference in the propagation delay, so they do not require simultaneous switching of both ends in case of single fiber failure.

Wireless Communications

Spread-spectrum radio communications have been used for many years by the military due to their resistance to jamming and difficulty to intercept. This technology was adopted because it allows multiple users to occupy the same frequency band with a minimum of interference to the other users. The spread-spectrum modulated output signals occupy a much greater bandwidth than the signal's baseband information bandwidth. The spread spectrum technology is used in numerous applications including cordless phones, wireless Ethernet and point-to-point communications.

The Federal Communications Commission (FCC) has reserved several frequency bands for unlicensed applications using spread spectrum technology. This does not guarantee exclusive use of the frequency, as is the case with licensed frequencies. The bands authorized for spread spectrum emissions are; 902-928 MHz, 2400-2483.5 MHz, and 5725-5850 MHz.

Spread spectrum technology uses two basic methodologies to transmit messages:

1. Frequency-hopping spread spectrum (FHSS)

2. Direct sequence spread spectrum. (DSSS)

“Time Hopped” and “Chirp” systems have also been developed, but have not achieved commercial application.

Frequency-Hopping Spread Spectrum Technology

Frequency-hopping spread-spectrum (FHSS) uses a narrowband carrier that changes frequency in a pattern known to both the transmitter and receiver. With proper synchronization it maintains a single logical channel. FHSS appears to be short-duration impulse noise to any other receiver.

Direct-Sequence Spread Spectrum Technology

Direct-sequence spread-spectrum (DSSS) has this name because it employs a high-speed code sequence, along with the basic information being sent. This code (chirping code) is used to recover the original data at the receiving device. A longer chirp increases the probability of recovering the original data. The improved reliability of transmission is achieved by increasing the required bandwidth.

Statistical techniques embedded in the receiving radio are used to recover the original data without the need for retransmission. DSSS appears as low-power wideband noise to other receivers.

Orthogonal Frequency Division Multiplexing (OFDM) Technology

Orthogonal frequency division multiplexing is a spread spectrum technique that distributes the data over a large number of carriers that are spaced apart at precise frequencies. This spacing provides the "orthogonality" and prevents the demodulators from seeing frequencies other than their own.

The benefits of OFDM are:

1. High spectral efficiency

2. Resiliency to RF interference

3. Lower multi-path distortion

OFDM forms a basis of the 802.11a standard, which uses 52 sub carriers, occupying 20 MHz segments of the 5 GHz band, with maximum data rate of 54 MBps.

Migration Strategy toward the Distribution System of the Future

The challenges that distributed energy resources of different types introduce do not allow us to wait until all planned technologies and concepts are available. Utilities and customers need to work together in order to make these new systems work, and at the same time improve the quality of power supplied to the user.

A lot can be achieved based on the advanced functionality of state-of-the-art protective relays and other Intelligent Electronic Devices. Existing and new communication technologies, the development and implementation of substation automation systems and distribution automation systems can significantly improve the operation of the power system and meet many of the requirements of the critical applications in the distribution or demand levels of the system.

Some new concepts have been introduced and discussed in the industry, with pilot projects being used to demonstrate the feasibility of these solutions. These concepts are proposed specifically to cope with distributed energy resources on the demand side of the electric power system – the level that is usually not the subject of any system monitoring and control. Every concept uses a combination of distributed generators (DGs) and distributed energy storage systems (DS). The following sub-sections discuss third-party projects that are similar to and may supplement the EPRI ADA efforts [2].

Power Park

Power Parks can be defined as a collection of multiple IEDs that are joined together by a system having a single electrical point of connection to the utility power system. One of the main goals of power parks is the improvement of the quality of power supply to the customers in the territory of the park. As shown in Figure A-19, advanced power electronics are used to provide power with different characteristics to different users.

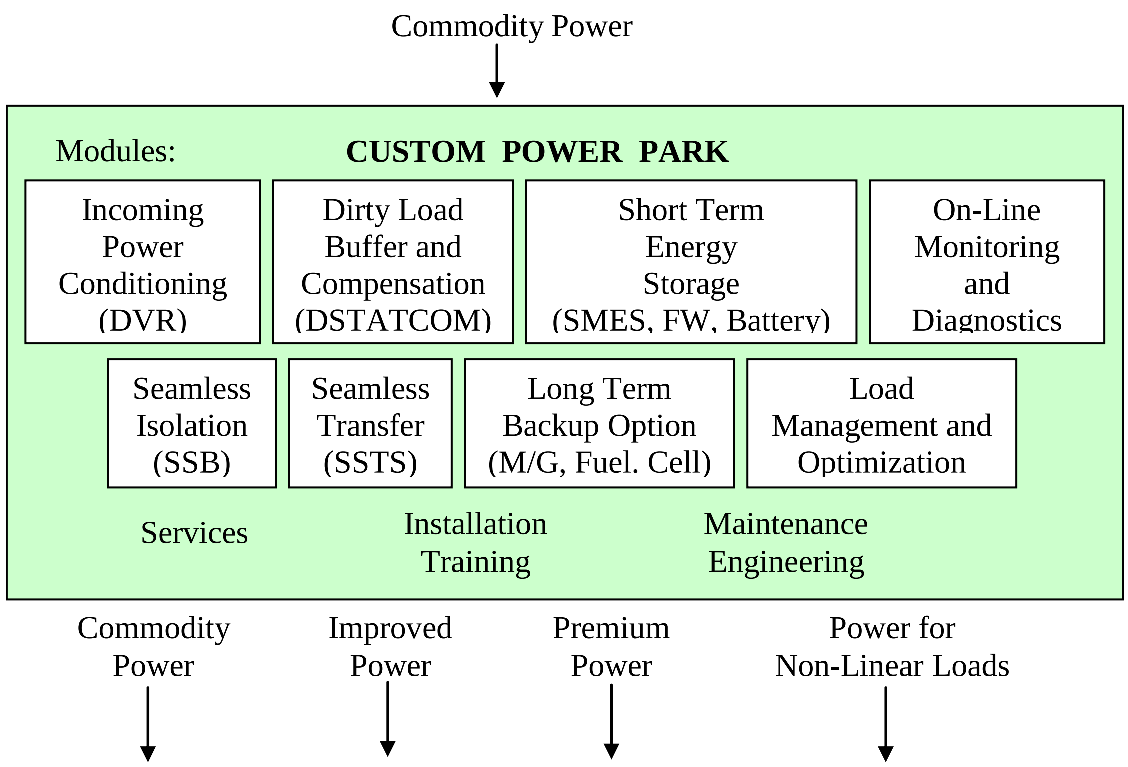

Figure A-19
Custom Power Park Concept

The power parks are mainly related to the "Unbundled Power Quality Services" concept. The idea is to provide different quality levels of electric power, with individual premiums, to customers with different requirements and levels of load sensitivity.

Micro-grid, Virtual Utility, Virtual Power Plant

Micro-grids are one of the most important concepts that will allow the wide spread use of distributed energy resources at the demand level. A micro-grid is defined as a demand-level system that consists of at least one (and preferably more) DG resources on a feeder connectable to a utility system. The key advantage of such a solution is that it may run either in parallel or independently of the distribution system, especially if it has multiple DG units for improved reliability.

Such configurations have existed for some time on university campuses, military bases, and industrial facilities. Now the concept is being expanded and applied in residential developments and commercial areas. This allows balancing between the critical loads and distributed resources in case of separation from the utility. Large hotels and hospitals can also operate as micro-grids.

The Virtual Utility and Virtual Power Plant are concepts similar to the micro-grid, allowing the operation of a demand-level system using methods and tools typically applied at the transmission system level. Both DG and DS are connected to the demand-level power system. The virtual power plant monitors and controls the total capacity of all the DGs of one company or organization (sometimes several organizations), using them just like a large power plant. This allows the use of the multiple distributed energy resources for frequency control, reserved power, etc.

At the same time, the virtual utility monitors and controls all the loads and energy resources for optimal coordinated operation. This is achieved through a central control center and advanced communications. The communication links must be reliable and secure, with many suitable technologies including the Internet.

The advantages of Micro-grids are:

1. High availability

2. Resource optimization

3. Energy mix

4. Economic efficiency

Autonomous Demand Area Power System

The "Autonomous Demand Area Power System", shown in Figure A-20, is a new concept proposed to provide effective utilization of distributed energy resources. It is based on the typical radial distribution system configuration, and is intended to reduce some of the effects that multiple distributed generators have when connected to a radial distribution system.

The system uses a combination of distributed and centralized monitoring and control solutions to provide reliable power supply, by avoiding power congestion or voltage problems. It uses the so-called Loop Power Controllers (LPC) and Supply & Demand Interfaces (SDI). Under normal conditions the operation system controls the LPC at each site, based on the load from each SDI and actual measured values of the distributed energy resources.

Control of the tap changer of the transformer at the distribution substation is targeted towards meeting three conditions:

1. Reduction of loss in the distribution system
2. Improvement of the availability factor
3. Voltage regulation

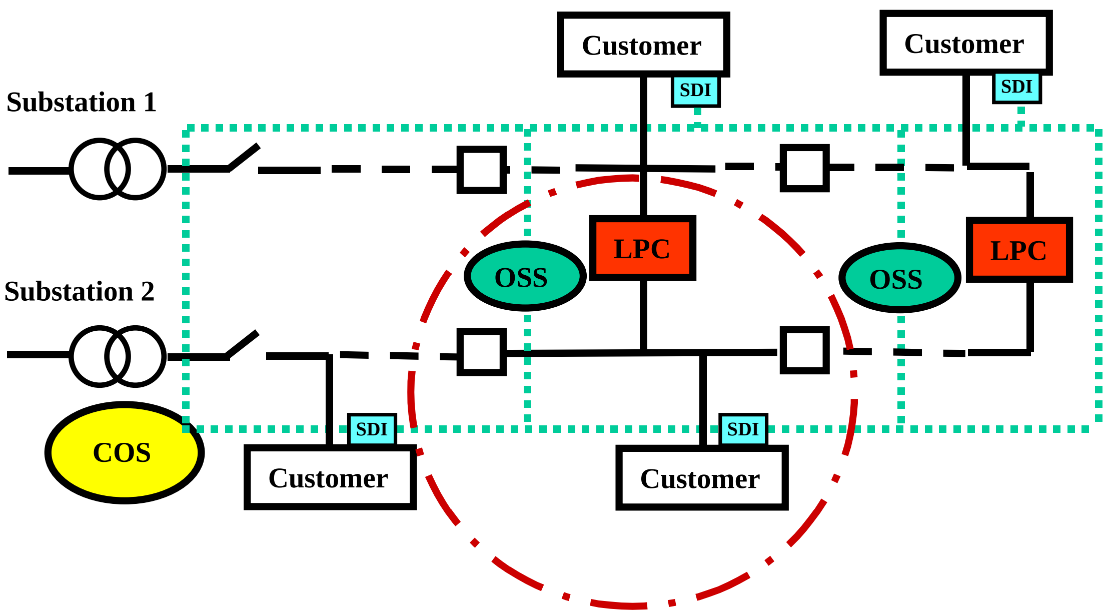

Figure A-20
Autonomous Demand Area Power System

Legend:

LPC – Loop Power Controller

SDI – Supply and Demand Interface

OSS – Operation Subsystem

COS – Central Operation System

The system feeds back information to each supply and demand interface on the electricity demand and supply situation. It controls DGs and loads taking energy saving, reliable power supply, energy prices, etc. into account. Each SDI makes decisions through control information from the Central Operation Control System together with the Operation Subsystem.

When a fault occurs at a section of the distribution system loop, the Operation Subsystem at the faulted section controls the sectionalizing switch, recloser, or circuit breaker, as well as the distributed generators. The goal in this case is for the LPCs to ensure fast fault detection and fault clearing. The central operating system controls the LPCs around a faulted section for fault isolation and redirection of power supply. Efforts to minimize the lost-power sections due to a fault are also included as part of the control strategy.

Intelligent & Integrated Centralized and Decentralized Energy Supply System

This concept was developed under a project with the name EDISon [3]. It is an abbreviation of German words meaning “Intelligent & Integrated Centralized and Decentralized Energy Supply System”. As the name indicates, the goal of this concept is to combine the advantages of the existing centralized distribution control system with the advantages of a decentralized control system, in order to guarantee high availability and high quality of power with low cost.

The implementation of this concept requires four components:

1. Grid analysis tools
2. Distributed energy resources
3. Communication infrastructure
4. Distributed Energy Management Systems

By developing this concept for the future German distribution system, the EDISon project tries to realize a non-radial structure inside the current centralized system.

FRIENDS

FRIENDS is an acronym for Flexible, Reliable and Intelligent Energy System [4]. It is a concept for a new power delivery system to specifically address the requirements for integration of dispersed power generators and energy storage systems, power electronics technologies, communication technologies and intelligent facilities.

This system has some similarities with some of the concepts described earlier and is designed to ensure:

1. High reliability in power supply

2. Flexibility in recognition of the system in normal and faulted states

3. Multiple levels of power quality services, allowing consumers to select the quality of electric power and the supplier

4. Load leveling

5. Energy conservation

6. Enhancement of information services to customers

7. Efficient demand side management

One of the main characteristics of FRIENDS is that it allows the operation of the power system without interrupting the power supply to the customers. This is achieved by flexibly changing the distribution system configurations even after occurrence of a fault.

Installation of Quality Control Centers (QCC) near to the customers allows them to independently select the quality of electrical power they need. Each QCC controls its associated Service Area.

Figure A-21 illustrates the concept of the FRIENDS. Each QCC is allocated near the demand side, corresponding to one section of a distribution line. A QCC can be supplied with electrical power from several substations through several power lines to improve the supply reliability.

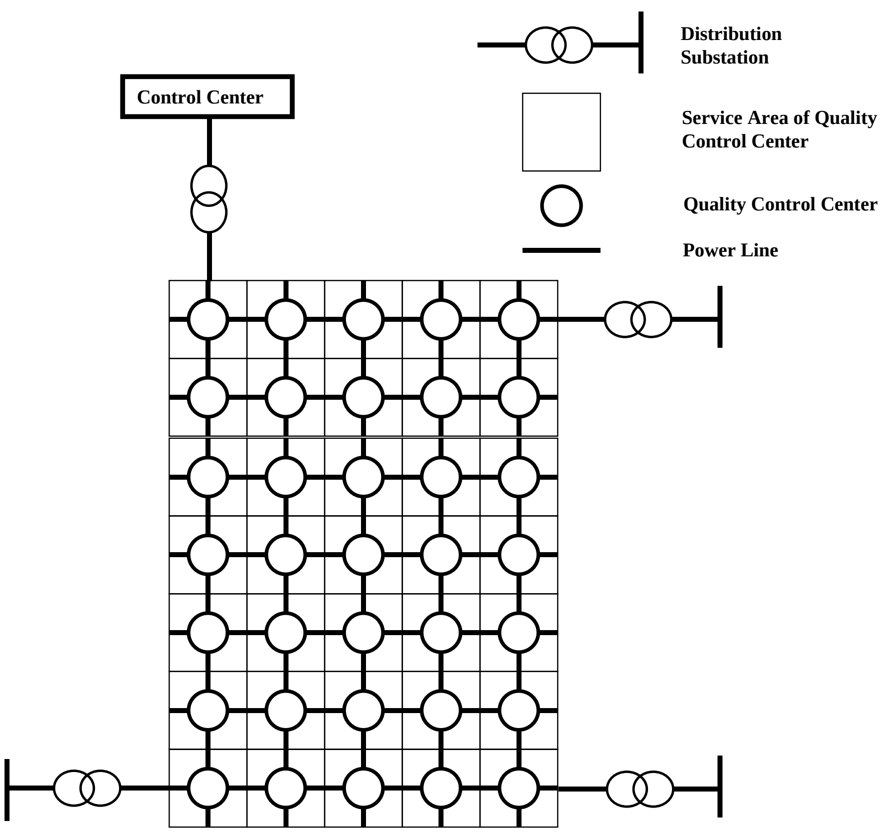

Figure A-21
Flexible, Reliable, and Intelligent Energy System (FRIENDS)

From Figure A-21 it is clear that the network may naturally include loops in it. The system can be operated either as a meshed network or an open loop radial network according to the utility's operating strategy.

The customer may select one of multiple power quality services named "customized power quality services". The concept of these customized or unbundled power quality services is shown in Figure A-22.

The system is designed to operate with multiple distributed energy resources and storage systems at the demand level. Energy conserving measures due to the demand side management (DSM) are also incorporated into this system.

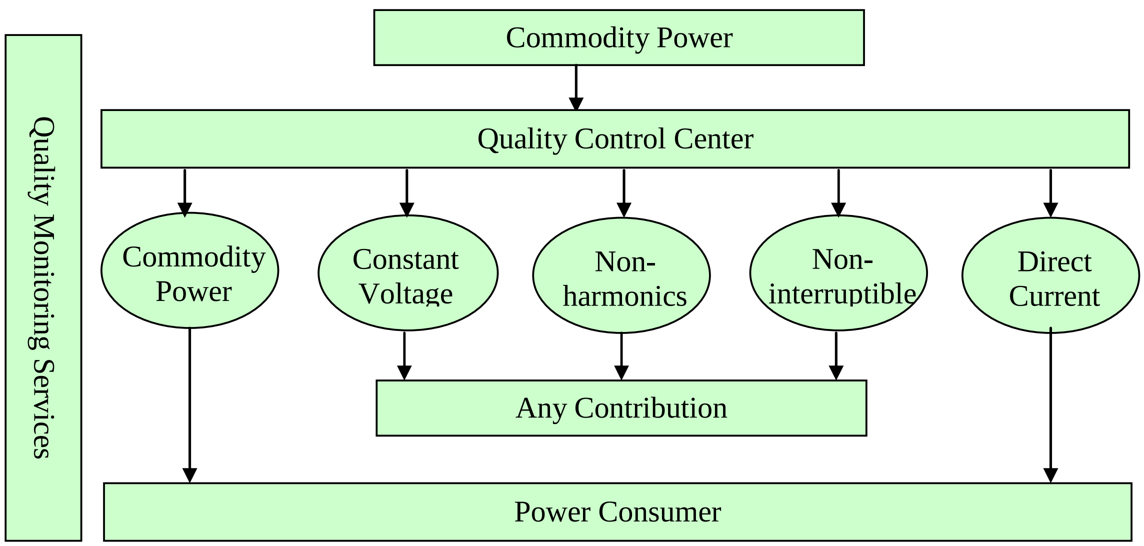

Figure A-22
Customized Power Supply Concept

In FRIENDS, the QCC has roles also as the system's protection center, and an information processing center (data communication center). The QCC controls apparatus, including switches, DG, and DS, and supplies many kinds of information. The operation and control of static switching devices are implemented from a global point of view by co-operating central control computers and small scaled autonomous control computers. As shown in Figure A-23, these may be located at distribution substations, at QCCs, or at individual load points.

A very important characteristic of FRIENDS is its powerful information system based on advanced communication networks connecting suppliers and customers. The communications network can be used not only for power supply information, but also to offer a variety of information services to customers.

In order to realize FRIENDS, the industry needs to make practical use of static switching devices, dispersed generation facilities and energy storage systems. Advanced multifunctional protection IEDs, new distribution network configurations, new communication architecture and technologies, customer information service schemes and various kinds of software to control and operate the system will also be required.

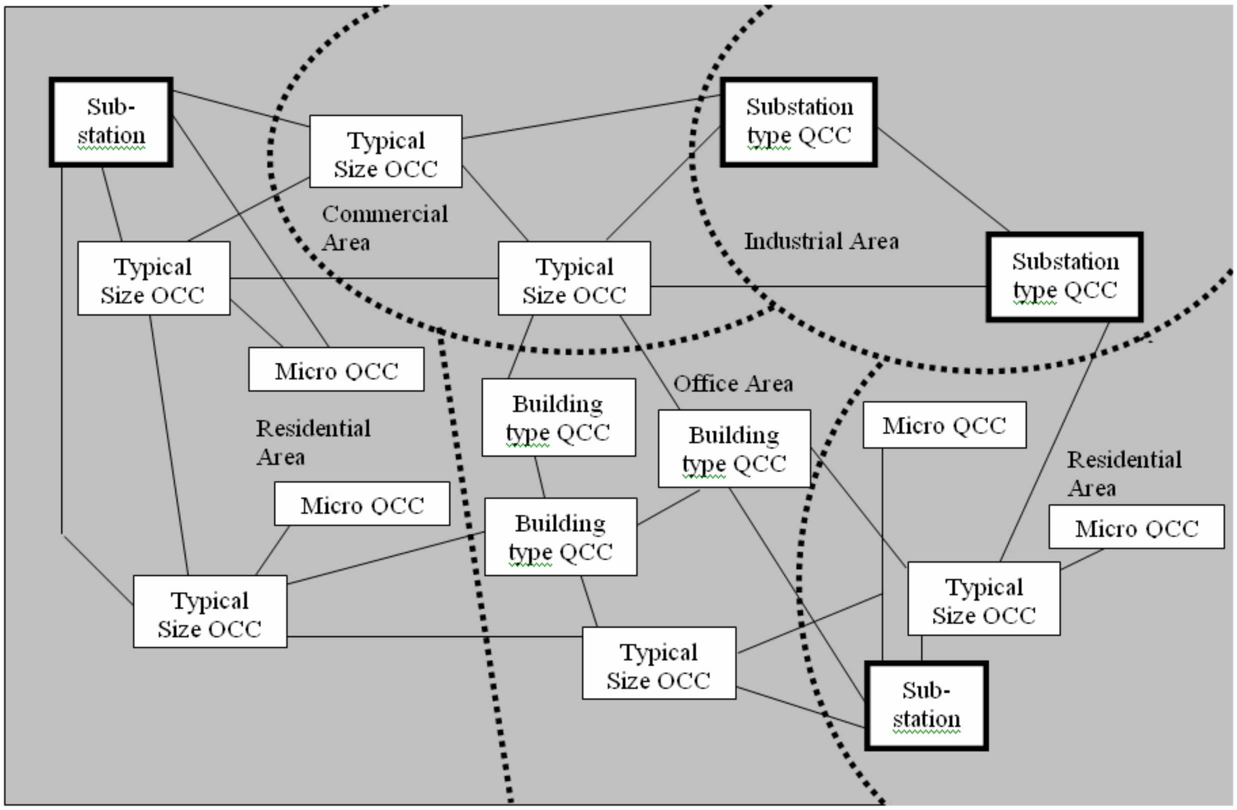

Figure A-23
Quality Control Centers Operating in FRIENDS

Low-Penetration DG Integration Strategies

The objective of this section is to provide utilities with short term solutions to make their system more prepared for installation of DG units using current available resources. Much can be achieved with existing advanced technologies, by using them better and by implementing advanced and adaptive protection and control solutions. This will require modification of existing protection and voltage control systems, rather than wholesale replacement.

Limiting DG Contribution to Short Circuit Current

To avoid changing the protection devices with new ones of higher rating, some preventive actions can be taken:

1. Where DG contribution to short circuit current is a serious concern, it is recommended to use DG units with inverters which will have limited contribution to short circuit current no more than 400% of its rated current. Inverters also have overcurrent protection that will remove the firing pulses when current exceeds some threshold.

2. Choose the DG unit step up transformer with impedance and connection type that limits the contribution of the DG unit to short circuit current. It may be necessary to insert neutral impedances in wye-connected primary windings, to limit the flow of ground fault currents. These extra zero-sequence sources can disturb the coordination of overcurrent protection devices already on the feeder.

3. When a utility has control over DG units installed in their territory, unit commitment can be done for DG units a day ahead. The problem objective is to minimize operating cost at each hour while satisfying system constraints, such as supplying demand and not violating minimum up and down time for the units. Another constraint can be added that short circuit current must be less than a certain value with the DG units online [5].

Load Sharing between DG and Bulk Power

A control mechanism is needed to implement several load sharing polices between utility bulk power and a DG unit's power. The load sharing should take advantage of the existence of DG units in reducing the amount of power needed from the substation, via reduction in feeder load demand. This will also help in reducing feeder power loss, increasing distribution system capacity, and decreasing system generation peak demand. Some of the expected scenarios for utility and DG power sharing are:

1. Utility supplies a fixed base amount of power to each substation for long fixed periods, and DG takes care of any further required power. This scenario will help the bulk power system to have less variation in demand.

2. DG supplies a fixed amount of power all the time, while the utility follows load variations to supply a variable amount of power.

3. Both DG and utility supply variable amounts of power all the time.

DG Impact Studies

It is recommended that utilities perform impact studies before installing mid and large size DG units. Such studies would examine the effect of the new DG unit on the distribution network to insure that it will not affect the system's safe operation.

With the installation of any new DG units, a comprehensive set of short circuit studies must be done to decide which circuit breakers or fuses must be replaced. The overcurrent device coordination must also be checked for the entire feeder.

Comprehensive voltage profile studies should be done to make sure that service voltages are within ANSI voltage standards for all customers after installing the DG unit. These studies will be based on performing load flow analysis, with appropriate modeling of the prospective DG unit to be installed. They should also examine the interaction between the new DG unit and existing voltage regulators and capacitor banks.

A harmonics study should be done before installing the DG unit. This will require accurate modeling of the unit inverter. If the harmonics level will not be acceptable, solutions such as installing filters should be considered. Voltage flicker levels for various customers should also be determined, before and after installing the unit.

Interaction between Utility and DG Owners

Utilities need to develop procedures to make sure that DG owners are complying with applicable laws and regulations, and their contract terms. Just as most political jurisdictions adopt model codes like the BOCA building codes or the Uniform Commercial Code, utilities may hope that most jurisdictions would adopt the IEEE 1547 series of standards. However, there could be local differences. In any case, utilities should penalize violators who compromise a distribution system’s safe and reliable operation. This can range from warnings to canceling the contract. Some states are working in this direction developing their own DG interconnection rules. California has Rule 21 that governs the process, schedule and fees associated with customers interconnecting DG to the utilities’ power systems [6]. The “California Rule 21 Working Group” is working to finalize a modified version of this rule, taking into consideration recommendations from several parties. Disputes are to be resolved by the California Energy Commission, using their customer complaint procedures.

Large DG unit (> 1 MW) owners should be encouraged to cooperate with utilities in choosing the best locations for DG units. Best location in the short term means one that will have the least impact on existing system protection, and where more power capacity is needed.

Utilities could provide several services for investors interested in DG at a reasonable price. Such services can be:

1. cost/benefit studies
2. engineering studies
3. recommended type of DG unit that fits best in the utility system
4. maintenance and operation services for DG units
5. metering and monitoring devices
6. load forecasts and load growth rates
7. advice on compliance with local environmental regulations

Utilities should also educate their customers about distributed generation and how it can benefit them.

Optimum Control for DG to Maximize Investment Return

Utilities and investors should try to get the maximum return from investing in DG. This can be achieved through optimum control mechanisms for DG units. This control system will be responsible for operating the unit and taking the decision to put the unit online or offline. This control will vary depending on the DG unit type. For wind turbine and photovoltaic units, the optimum control is to get as much energy as possible from the DG unit. For other types, operating costs such as fuel and maintenance, and minimum up and down times are important factors for the unit controller. Cogeneration is another strategic value for combustion-based DG units. The unit's exhaust can be used to heat water and warm buildings. A special unit commitment program capable of modeling different DG technologies should be developed to achieve this optimum control strategy. As mentioned before, ownership will be a limiting factor in achieving optimal control for DG units.

There are several control modes for DG, such as maintaining a certain voltage level or supplying fixed amounts of P and Q. If at a certain moment the power generated by DG units is higher than substation loads, power will flow in reverse direction through the substation transformer to the subtransmission network. This may cause numerous problems. To avoid that, output power from DG units could be kept at a fixed percentage of the substation load all the time. In other words, the output of at least large size DG units would follow load variations.

Other Actions to be Taken in the Short Term

Utilities can begin replacing conventional reclosers and line regulators on the main feeder, where power is expected to flow in both directions, with devices having bi-directional controls. A few manufacturers are now offering such new recloser and regulator controls. Any new installations, upgrades, or replacements should have these controls. Retrofits may also be considered; these are replacements before the existing devices have reached the end of their useful lives. Retrofits may be desirable to support DG applications or ADA applications on a feeder.

Utility practices should be modified to recognize the penetration of DG units into the distribution system. New maintenance and operation procedures should be adopted to insure safety for utility workers. These procedures must insure that isolating any section in the distribution system is fully controlled by the utilities, and does not depend by any means on the assumption that a DG owner will take the correct action.

To prevent the occurrence of unintentional islanding, DG units must be installed with voltage and frequency relays to trip the unit when these parameters are out of acceptable limits, as stated in IEEE 1547™ standards. (If the local regulatory commission has not yet adopted IEEE 1547, the utility should encourage them to do so, and to minimize any local differences from IEEE 1547.) When voltage and frequency return to normal values, DG units are automatically resynchronized with the utility after a specified time delay.

Control for large size DG units should be adaptive to choose the optimal control mode, e.g. voltage following or load following. DG units may be switched off when it is necessary to avoid overvoltage.

The most convenient location for installing DG units in a spot secondary network would be ahead of the network protectors, to maintain uni-directional power flow through the network protectors under normal conditions. Even at low penetration levels, some adjustment of the reverse power flow setting may be required. If the secondary network will have a significant penetration level of DG, it may be necessary to implement a Micro-Grid on the network.

References

1. J. Lewis Blackburn, *Protective Relaying: Principles and Applications, 2nd edition*, CRC Press, 1997.

2. *Technical and System Requirements for Advanced Distribution Automation*, EPRI, Palo Alto, CA, June 2004. 1010915.

3. Fraunhofer Institute, *Compendium of Projects on Rural Electrification and Off-Grid Power Supply*, pp. 50-51, http://www.ise.fhg.de/english/publications/brochures_productinfos/gf3/pdf/ise_off-grid_02_print.pdf, 2002.

4. Hokkaido University, *FRIENDS Home Page*, http://svr.huee.hokudai.ac.jp/friends/frame/index.htm.

5. Natthaphob Nimpitiwan, Gerald T. Heydt, John Blevins and A. Barry Cummings, “Potential Economic Impact of Fault Currents Contributed by Distributed Generation,” Proc. of IEEE/PES Summer Meeting, June 2005, pp. 2655-2660.

6. California Energy Commission, Rule 21 Working Group's website http://www.rule21.ca.gov/

B
BIBLIOGRAPHY

This appendix lists publications and web links for more information.

IEEE Publications

Using the IEEE Xplore database, 244 abstracts were downloaded and categorized in this area.

Dispersed Storage

1. **Modeling and analysis of a flywheel energy storage system for voltage sag correction,** Samineni, S.; Johnson, B.K.; Hess, H.L.; Law, J.D.; Electric Machines and Drives Conference, 2003. IEMDC'03. IEEE International, Volume 3, 1-4 June 2003 Page(s):1813 - 1818 vol.3

2. **Transient performance of PV/SMES hybrid dispersed power source,** Tsukagoshi, I.; Takano, I.; Sawada, Y.; Power Engineering Society Summer Meeting, 2001. IEEE, Volume 3, 15-19 July 2001 Page(s):1579 - 1584 vol.3

3. **A voltage control strategy with NAS battery systems considering interconnection of distributed generations,** Ohtaka, T.; Uchida, A.; Iwamoto, S.;, 2004. PowerCon 2004. 2004 International Conference on Power System Technology, Volume 1, 21-24 Nov. 2004 Page(s):226 - 231 Vol.1

4. **A new technique of interfacing DC renewable energy sources with the HV distribution system,** Basu, K.P.; Power Engineering Conference, 2003. PECon 2003. Proceedings. National, 15-16 Dec. 2003 Page(s):233 - 236

5. **Proposal of a local DC distribution network with distributed energy resources,** Brenna, M.; Tironi, E.; Ubezio, G.; 2004. 11th International Conference on Harmonics and Quality of Power, 12-15 Sept. 2004 Page(s):397 - 402

6. **Flywheel energy storage system design for distribution network,** Jiancheng Zhang; Zhiye Chen; Lijun Cai; Yuhua Zhao; Power Engineering Society Winter Meeting, 2000. IEEE, Volume 4, 23-27 Jan. 2000 Page(s):2619 - 2623 vol.4

7. **Supercapacitors as energy buffers: a solution for elevators and for electric busses supply**, Barrade, P.; Rufer, A.; Power Conversion Conference, 2002. PCC Osaka 2002. Proceedings of the, Volume 3, 2-5 April 2002 Page(s):1160 - 1165 vol.3

8. **Ultra-capacitor assisted electric drives for transportation,** Miller, J.M.; Smith, R.; Electric Machines and Drives Conference, 2003. IEMDC'03. IEEE International, Volume 2, 1-4 June 2003 Page(s):670 - 676 vol.2

9. **Energy storage applications for large scale power protection systems,** Roberts, B.P.; Transmission and Distribution Conference and Exposition, 2001 IEEE/PES, Volume 2, 28 Oct.-2 Nov. 2001 Page(s):1157 - 1160 vol.2

10. **Control of power circuit interface of a flywheel-based energy storage system,** da Silva Neto, J.L.; Rolim, L.G.B.; Sotelo, G.G.;, 2003. ISIE '03. 2003 IEEE International Symposium on Industrial Electronics, Volume 2, 9-11 June 2003 Page(s):962 - 967 vol. 2

11. **Impact of energy storage costs on economical performance in a distribution substation,** Chacra, F.A.; Bastard, P.; Fleury, G.; Clavreul, R.;, IEEE Transactions on Power Systems, Volume 20, Issue 2, May 2005 Page(s):684 - 691

12. **Energy storage evolving technologies for protecting larger-scale critical loads,** Roberts, B.P.; Power Engineering Society Summer Meeting, 2000. IEEE, Volume 3, 16-20 July 2000 Page(s):1574 - 1576 vol. 3

13. **Optimal allocation and PQ output ratio of NAS batteries for improving voltage stability in distribution systems,** Ohtaka, T.; Iwamoto, S.; Power Engineering Society Summer Meeting, 2001. IEEE, Volume 3, 15-19 July 2001 Page(s):1369 - 1374 vol.3

14. **Recent GRC aerospace technologies applicable to terrestrial energy systems,** ankam, M.D.; Lyons, V.J.; Hoberecht, M.A.; Tacina, R.R.; Hepp, A.F.; Energy Conversion Engineering Conference and Exhibit, 2000. (IECEC) 35th Intersociety, Volume 2, 24-28 July 2000 Page(s):865 - 875 vol.2

15. **Feasibility study of low-Voltage DC Superconducting distribution system,** Furuse, M.; Fuchino, S.; Higuchi, N.; Ishii, I.; IEEE Transactions on Applied Superconductivity, Volume 15, Issue 2, June 2005 Page(s):1759 - 1762

Distributed Energy Resources

1. **Determining the impact of distributed generation on power systems. I. Radial distribution systems**
Barker, P.P.; De Mello, R.W.; Power Engineering Society Summer Meeting, 2000. IEEE, Volume 3, 16-20 July 2000 Page(s):1645 - 1656 vol. 3

2. **An interaction problem of distributed generators installed in a MicroGrid,** Zoka, Y.; Sasaki, H.; Yorino, N.; Kawahara, K.; Liu, C.C.;, 2004. (DRPT 2004). Proceedings of the 2004 IEEE International Conference on Electric Utility Deregulation, Restructuring and Power Technologies, Volume 2, 5-8 April 2004 Page(s):795 - 799 Vol.2

3. **The impact of dispersed power generation in distribution systems,** Buchholz, B.M.; Boese, C.; Quality and Security of Electric Power Delivery Systems, 2003. CIGRE/PES 2003. CIGRE/IEEE PES International Symposium, 8-10 Oct. 2003 Page(s):198 - 203

4. **Improved distribution system utilization and expansion through distributed generator placement,** Shiqiong Tong; Yiming Mao; Miu, K.; Power Engineering Society General Meeting, 2004. IEEE, 6-10 June 2004 Page(s):941 Vol.1

5. **Challenges in simulation and design of /spl mu/Grids,** Meliopoulos, A.P.S.; Power Engineering Society Winter Meeting, 2002. IEEE, Volume 1, 27-31 Jan. 2002 Page(s):309 - 314 vol.1

6. **Application of probabilistic (N-1) security assessment technique to distribution systems with distributed generation,** Mori, H.; Sakatani, Y.; Transmission and Distribution Conference and Exhibition 2002: Asia Pacific. IEEE/PES, Volume 2, 6-10 Oct. 2002 Page(s):739 - 744 vol.2

7. **Evaluation of interconnection capacity of dispersed storage and generation systems to the power distribution systems from the viewpoint of voltage regulation**, Joon-Ho Choi; Jae-Chul Kim; TENCON 99. Proceedings of the IEEE Region 10 Conference, Volume 2, 15-17 Sept. 1999 Page(s):1438 - 1441 vol.2

8. **A multiphase power flow model for /spl mu/grid analysis,** Meliopoulos, A.P.S.; Cokkinides, G.J.; Lasseter, R.; 2003. Proceedings of the 36th Annual Hawaii International Conference on System Sciences, 6-9 Jan. 2003 Page(s):7

9. **Transient performance and stability analysis of a hybrid grid-connected wind/PV system,** Li Wang; Kuo-Hua Liu; Power Systems Conference and Exposition, 2004. IEEE PES, 10-13 Oct. 2004 Page(s):795 - 801 vol.2

10. **Advanced voltage regulation method at the power distribution systems interconnected with dispersed storage and generation systems**, Joon-Ho Choi; Jae-Chul Kim; Power Engineering Society Summer Meeting, 2000. IEEE, Volume 3, 16-20 July 2000 Page(s):1768 vol. 3

11. **Research, development, and demonstration needs for large-scale, reliability-enhancing, integration of distributed energy resources,** Eto, J.; Budhraja, V.; Martinez, C.; Dyer, J.; Kondragunta, M.; 2000. Proceedings of the 33rd Annual Hawaii International Conference on System Sciences, 4-7 Jan. 2000 Page(s):7 pp.

12. **Multi-agent based control and operation of distribution system with dispersed power sources,** Hiyama, T.; Zuo, D.; Funabashi, T.; Transmission and Distribution Conference and Exhibition 2002: Asia Pacific. IEEE/PES, Volume 3, 6-10 Oct. 2002 Page(s):2129 - 2133 vol.3

13. **Distributed energy sources: needs for analysis and design tools,** Meliopoulos, A.P.S.; Power Engineering Society Summer Meeting, 2001. IEEE, Volume 1, 15-19 July 2001 Page(s):548 - 550 vol.1

14. **Distributed energy sources: needs for analysis and design tools,** Meliopoulos, A.P.S.; Power Engineering Society Summer Meeting, 2001. IEEE, Volume 1, 15-19 July 2001 Page(s):548 - 550 vol.1

15. **Modeling of the integration of distributed generation into the electrical system,** Delfino, B.; Power Engineering Society Summer Meeting, 2002 IEEE, Volume 1, 21-25 July 2002 Page(s):170 - 175 vol.1

16. **Shape of the microgrid,** Marnay, C.; Robio, F.J.; Siddiqui, A.S.; Power Engineering Society Winter Meeting, 2001. IEEE Volume 1, 28 Jan.-1 Feb. 2001 Page(s):150 - 153 vol.1

17. **A multiagent system for microgrids,** Dimeas, A.; Hatziargyriou, N.; Power Engineering Society General Meeting, 2004. IEEE, 6-10 June 2004 Page(s):55 - 58 Vol.1

18. **Optimal load shedding strategy in power systems with distributed generation,** Ding Xu; Girgis, A.A.;
Power Engineering Society Winter Meeting, 2001. IEEE, Volume 2, 28 Jan.-1 Feb. 2001 Page(s):788 - 793 vol.2

19. **Optimal power dispatch of photovoltaic system with random load,** Momoh, J.A.; Wang, Y.; Eddy-Posey, F.; Power Engineering Society General Meeting, 2004. IEEE, 6-10 June 2004 Page(s):1939 - 1945 Vol.2

20. **Mechanical stresses in fixed-speed wind turbines due to network disturbances,** Papathanassiou, S.A.; Papadopoulos, M.P.; IEEE Transactions on Energy Conversion, Volume 16, Issue 4, Dec. 2001 Page(s):361 - 367

21. **Risk based optimization for strategical planning of electrical distribution systems with dispersed generation,** Ippolito, M.G.; Morana, G.; Sanseverino, E.R.; Vuinovich, F.; Power Tech Conference Proceedings, 2003 IEEE Bologna, Volume 1, 23-26 June 2003 Page(s):7 pp. Vol.1

22. **Assimilating wind [wind energy contribution to UK energy needs],** Milborrow, D.; IEE Review, Volume 48, Issue 1, Jan. 2002 Page(s):9 - 13

23. **An enhanced automatic and autonomous excitation control for dispersed generators,** Sishuba, S.; Redfern, M.A.; Power Engineering Society General Meeting, 2003, IEEE, Volume 4, 13-17 July 2003 Page(s):

24. **Voltage regulation coordination of distributed generation system in distribution system,** Kim, T.E.; Kim, J.E.; Power Engineering Society Summer Meeting, 2001. IEEE, Volume 1, 15-19 July 2001 Page(s):480 - 484 vol.1

25. **Composition and operation measures of autonomous demand area power system to cope with large penetration of PV system,** Kobayashi, H.; Okada, N.; Takigawa, K.;, 2003. Proceedings of 3rd World Conference on Photovoltaic Energy Conversion, Volume 3, 12-16 May 2003 Page(s):2159 - 2164 Vol.3

26. **The value of grid-support photovoltaics in reducing distribution system losses,** Hoff, T.; Shugar, D.S.;, IEEE Transactions on Energy Conversion, Volume 10, Issue 3, Sept. 1995 Page(s):569 – 576

27. **IEEE 1547 series of standards: interconnection issues,** Basso, T.S.; DeBlasio, R.;, IEEE Transactions on Power Electronics, Volume 19, Issue 5, Sept. 2004 Page(s):1159 - 1162

28. **Multi-agent based control and operation of distribution system with dispersed power sources,** Hiyama, T.; Zuo, D.; Funabashi, T.; Transmission and Distribution Conference and Exhibition 2002: Asia Pacific. IEEE/PES, Volume 3, 6-10 Oct. 2002 Page(s):2129 - 2133 vol.3

29. **Enabler of introducing distributed generators and its effect to power distribution systems,** Nara, K.; Transmission and Distribution Conference and Exhibition 2002: Asia Pacific. IEEE/PES, Volume 1, 6-10 Oct. 2002 Page(s):584 - 589 vol.1

30. **Distributed generation as voltage support for single wire earth return systems,** Ledwich, G.; Power Engineering Society General Meeting, 2004. IEEE, 6-10 June 2004 Page(s):2176 Vol.2

31. **Reliability evaluation of distribution system connected photovoltaic generation considering weather effects,** Seung-Tea Cha; Dong-Hoon Jeon; In-Su Bae; Il-Ryong Lee; Jin-o-Kim;Probabilistic Methods, 2004 International Conference on Applied to Power Systems, 12-16 Sept. 2004 Page(s):451 – 456

Distribution Systems Design and Planning

1. **Distribution system planning in focus,** Ault, G.W.; Foote, C.E.T.; McDonald, J.R.; Power Engineering Review, IEEE, Volume 22, Issue 1, Jan. 2002 Page(s):60 – 62

2. **Distribution system reconfiguration for loss reduction: a new algorithm based on a set of quantified heuristic rules,** Sarfi, R.J.; Salama, M.M.A.; Chikhani, A.Y.;, 1994. Conference Proceedings. 1994 Canadian Conference on Electrical and Computer Engineering, 25-28 Sept. 1994 Page(s):125 - 130 vol.1

3. **ADSM-an automated distribution system modeling tool for engineering analyses,** Wei, X.-G.; Sumic, Z.; Venkata, S.S.;, IEEE Transactions on Power Systems, Volume 10, Issue 1, Feb. 1995 Page(s):393 - 399

4. **Selecting the best point of connection for shunt active filters in multi-bus power distribution systems,** Moran, L.; Mahomar, J.; Dixon, J.; Industry Applications Conference, 2002. 37th IAS Annual Meeting. Conference Record of the, Volume 3, 13-18 Oct. 2002 Page(s):1703 - 1709 vol.3

5. **An intelligent front end for secondary power distribution system design,** Rao, N.D.; Zhang, Y.;, IEEE Transactions on Power Delivery, Volume 7, Issue 2, April 1992 Page(s):927 - 933

6. **Tools for optimal operation and planning of urban distribution systems,** Carpaneto, E.; Chicco, G.; Mosso, A.; Poggi, A.; Ribaldone, P.; Electricity Distribution, 2001. Part 1: Contributions. CIRED. 16th International Conference and Exhibition on (IEE Conf. Publ No. 482), Volume 5, 18-21 June 2001 Page(s):5 pp. vol.5

7. **Multi-objective feeder reconfiguration by distribution management system,** Roytelman, I.; Melnik, V.; Lee, S.S.H.; Lugtu, R.L.; Power Industry Computer Application Conference, 1995. Conference Proceedings., 1995 IEEE, 7-12 May 1995 Page(s):517 - 522

8. **Substation design and construction in an urban environment,** Shainauskas, F.; Andrews, J.D.; Crockett, E.; Rowe, M.; Miller, K.; Transmission and Distribution Conference and Exposition, 2003 IEEE PES, Volume 2, 7-12 Sept. 2003 Page(s):497 - 503 vol.2

9. **A practical approach to the conductor size selection in planning radial distribution systems,** Zhuding Wang; Haijun Liu; Yu, D.C.; Xiaohui Wang; Hongquan Song;, IEEE Transactions on Power Delivery, Volume 15, Issue 1, Jan. 2000 Page(s):350 - 354

10. **Residential energy resource models for distribution feeder simulation,** Guttromson, R.T.; Chassin, D.P.; Widergren, S.E.; Power Engineering Society General Meeting, 2003, IEEE, Volume 1, 13-17 July 2003 Page(s):

11. **A voltage drop-based approach to include cold load pickup in design of distribution systems,** Gupta, V.; Pahwa, A.; IEEE Transactions on Power Systems, Volume 19, Issue 2, May 2004 Page(s):957 - 963

12. **A systematic approach to the replacement of an aging distribution system,** Rudolph, D.L.; Rural Electric Power Conference, 1997. Papers Presented at the 41st Annual Conference, 20-22 April 1997 Page(s):A4 - 1-8

13. **Rural distribution system design comparison,** Nguyen, H.V.; Burke, J.J.; Benchluch, S.; Power Engineering Society Winter Meeting, 2000. IEEE, Volume 4, 23-27 Jan. 2000 Page(s):2357 - 2362 vol.4

14. **Modelling of electrical power distribution systems by application of experimental design,** Nazarko, J.; Power Engineering Society Winter Meeting, 2000. IEEE, Volume 2, 23-27 Jan. 2000 Page(s):1145 - 1149 vol.2

15. **New dynamic, branch exchange method for optimal distribution system planning,** Peponis, G.J.; Papadopoulos, M.P.; Generation, Transmission and Distribution, IEE Proceedings- Volume 144, Issue 3, May 1997 Page(s):333 - 339

16. **Successful system design and planning using distribution analysis software programs,** De la Fuente, A.; Thomas, S.; Rural Electric Power Conference, 2001, 29 April-1 May 2001 Page(s):C2/1 - C2/7

17. **A fuzzy multiobjective approach for optimal operation of distribution systems using evolutionary algorithms,** Radasanu, D.; Barladeanu, E.; Electricity Distribution, 2001. Part

1: Contributions. CIRED. 16th International Conference and Exhibition on (IEE Conf. Publ No. 482), Volume 5, 18-21 June 2001 Page(s):4 pp. vol.5

18. **An analysis of the five-wire distribution system,** Ward, D.J.; Buch, J.F.; Kulas, T.M.; Ros, W.J.;, IEEE Transactions on Power Delivery, Volume 18, Issue 1, Jan 2003 Page(s):295 - 299

19. **Component-based load modeling including capacitor banks,** Lim, J.Y.; Ji, P.S.; Ozdemir, A.; Singh, C.; Power Engineering Society Summer Meeting, 2001. IEEE, Volume 2, 15-19 July 2001 Page(s):1199 - 1204 vol.2

20. **A new type power delivery system for reliable power supply-FRIENDS and its optimal network design,** Nara, K.; Mishima, Y.; Hasegawa, J.;, 2000. Proceedings. PowerCon 2000. International Conference on Power System Technology, Volume 2, 4-7 Dec. 2000 Page(s):649 - 654 vol.2

21. **The use of Multi-Attribute Trade-Off Analysis in Strategic Planning For an Electric Distribution utility: An Analysis of Abu Dhabi Distribution Company,** Tabors, R.D.; Hornby, R.;, 2005. HICSS '05. Proceedings of the 38th Annual Hawaii International Conference on System Sciences, 03-06 Jan. 2005 Page(s):61b - 61b

22. **Efficiencies in distribution design and operating practices,** Fagen, K.C.; O'Connor, K.; Rural Electric Power Conference, 2005, 8-10 May 2005 Page(s):B3/1 - B3/8

23. **Optimal selection of conductors for distribution feeders,** Mandal, S.; Pahwa, A.; Power Engineering Society Winter Meeting, 2002. IEEE, Volume 2, 27-31 Jan. 2002 Page(s):1323 vol.2

24. **Ecoelectrify: a tool to design electric distribution systems for rural areas in developing countries,** Thirault, D.; Besanger, Y.; Hadjsaid, N.; Almeida, A.; Huard, G.; Power Engineering Society General Meeting, 2003, IEEE, Volume 4, 13-17 July 2003 Page(s)

25. **Design methodology for multiple domain power distribution systems,** Pham, N.; Cases, M.; de Araujo, D.; Matoglu, E.; Electronic Components and Technology, 2004. ECTC '04. Proceedings, Volume 1, 1-4 June 2004 Page(s):542 - 549 Vol.1

26. **Upgrading a large oil refinery electric power system,** 24-Fernandez, L.F.; Industry Applications Conference, 2001. Thirty-Sixth IAS Annual Meeting. Conference Record of the 2001 IEEE, Volume 2, 30 Sept.-4 Oct. 2001 Page(s):1165 - 1172 vol.2

27. **Coordinated comprehensive design of distribution systems at medium and low voltage levels,** Ganjavi, M.R.; Electricity Distribution, 2001. Part 1: Contributions. CIRED. 16th International Conference and Exhibition on (IEE Conf. Publ No. 482), Volume 5, 18-21 June 2001 Page(s):6 pp. vol.5

28. **Optimal selection of conductors for distribution feeders,** Mandal, S.; Pahwa, A.; , IEEE Transactions on Power Systems, Volume 17, Issue 1, Feb. 2002 Page(s): 192 - 197

29. **FPSO: lessons learned,** Brown, R.R.; Industry Applications Magazine, IEEE Volume 10, Issue 2, Mar-Apr 2004 Page(s):18 - 23

30. **Performance regulation of distribution systems using reference networks,** Strbac, G.; Allan, R.N.; Power Engineering Journal [see also Power Engineer], Volume 15, Issue 6, Dec. 2001 Page(s):295 - 303

31. **The first 110 kV /35 kV - 31.5 MVA cast resin transformer,** Yuen, D.C.M.; Choi, V.; Liu Zhi Gao; Jun Han; Industry Applications Conference, 2004. 39th IAS Annual Meeting. Conference Record of the 2004 IEEE, Volume 2, 3-7 Oct. 2004 Page(s):763 - 767 vol.2

32. **600 volt system voltage optimization,** Lawrence, R.; Petroleum and Chemical Industry Technical Conference, 2004. Fifty-First Annual Conference 2004, 13-15 Sept. 2004 Page(s):235 - 240

33. **A value-based probabilistic approach to designing urban distribution systems,** Chowdhury, A.A.; Custer, D.E.;, 2004 International Conference on Probabilistic Methods Applied to Power Systems, 12-16 Sept. 2004 Page(s):939 - 946

34. **Integral planning of primary-secondary distribution systems using mixed integer linear programming,** Paiva, P.C.; Khodr, H.M.; Dominguez-Navarro, J.A.; Yusta, J.M.; Urdaneta, A.J.;, IEEE Transactions on Power Systems, Volume 20, Issue 2, May 2005 Page(s):1134 - 1143

35. **Lets rethink negative reactance transformer paralleling,** Harlow, J.H.; Transmission and Distribution Conference and Exposition, 2003 IEEE PES, Volume 2, 7-12 Sept. 2003 Page(s):434 - 438 vol.2

36. **A distributed measurement architecture for industrial applications,** Bucci, G.; Landi, C, IEEE Transactions on.; Instrumentation and Measurement, Volume 52, Issue 1, Feb. 2003 Page(s):165 - 174

37. **Outage management through AMR systems using an intelligent data filter,** Sridharan, K.; Schulz, N.N.;, IEEE Transactions on Power Delivery, Volume 16, Issue 4, Oct. 2001 Page(s):669 - 675

38. **Residential energy resource models for distribution feeder simulation,** Guttromson, R.T.; Chassin, D.P.; Widergren, S.E.; Power Engineering Society General Meeting, 2003, IEEE, Volume 1, 13-17 July 2003 Page(s):

39. **A distribution system simulator for protection and control,** Baran, M.; Mahajan, N.R.; Kelley, A.W.; Grainger, J.J.; Transmission and Distribution Conference and Exposition, 2001 IEEE/PES, Volume 1, 28 Oct.-2 Nov. 2001 Page(s):307 - 310 vol.1

40. **Study of neutral grounding for 22 kV distribution system,** Oka, K.; Yoshinaga, J.; Koizumi, S.; Uemura, S.; Ariga, Y.; Transmission and Distribution Conference and Exhibition 2002: Asia Pacific. IEEE/PES, Volume 3, 6-10 Oct. 2002 Page(s):2143 - 2148 vol.3

41. **Development of a measurement system for power quantities in electrical energy distribution systems,** Driesen, J.; Deconinck, G.; Van Den Keybus, J.; Bolsens, B.; De Brabandere, K.; Vanthournout, K.; Belmans, R.; Instrumentation and Measurement Technology Conference, 2002. IMTC/2002. Proceedings of the 19th IEEE, Volume 2, 21-23 May 2002 Page(s):1625 - 1630 vol.2

42. **Variable scaling hybrid differential evolution for solving network reconfiguration of distribution systems,** Ji-Pyng Chiou; Chung-Fu Chang; Ching-Tzong Su;, IEEE Transactions on Power Systems, Volume 20, Issue 2, May 2005 Page(s):668 - 674

43. **Determination of critical switches in distribution system,** Chen, C.S.; Cho, M.Y.;, IEEE Transactions on Power Delivery, Volume 7, Issue 3, July 1992 Page(s):1443 - 1449

44. **Divergent evolution and resulting characteristics among the world's distribution systems ,** Carr, J.; McCall, L.V.;IEEE Transactions on Power Delivery, Volume 7, Issue 3, July 1992 Page(s):1601 - 1609

45. **Power electronics for modern medium-voltage distribution systems,** Meyer, C.; De Doncker, R.W.; Power Electronics and Motion Control Conference, 2004. IPEMC 2004. The 4th International, Volume 1, 2004 Page(s):58 - 66 Vol.1

46. **Low-cost VXI-based front-end for distributed measurement applications,** Bucci, G.; Landi, C.; Instrumentation and Measurement Technology Conference, 2000. IMTC 2000. Proceedings of the 17th IEEE, Volume 3, 1-4 May 2000 Page(s):1377 - 1382 vol.3

47. **What future distribution engineers need to learn,** Venkata, S.S.; Pahwa, A.; Brown, R.E.; Christie, R.D.;, IEEE Transactions on Power Systems, Volume 19, Issue 1, Feb. 2004 Page(s):17 - 23

48. **Representing power distribution systems using objects and patterns,** Bouchard, D.E.; Knight, G.S.; Chikhani, A.Y.; 1998. IEEE Canadian Conference on Electrical and Computer Engineering, Volume 2, 24-28 May 1998 Page(s):846 - 849 vol.2

49. **Feeder reconfiguration for distribution system contingencies by object oriented programming,** Chen, C.S.; Lin, C.H.; Wu, C.J.; Kang, M.S.; Power Engineering Society Summer Meeting, 2000. IEEE, Volume 1, 16-20 July 2000 Page(s):431 - 436 vol. 1

50. **Distribution system reconfiguration using graph chain representation,** Delbem, A.C.B.; Bretas, N.G.; De Carvalho, A.; 2000. Proceedings. PowerCon 2000. International Conference on Power System Technology, Volume 1, 4-7 Dec. 2000 Page(s):439 - 443 vol.1

51. **Analysis of influence of load characteristics on distribution system modeling,** Chandrasekaran, A.; Khurshid, A.;1989., Proceedings of the 32nd Midwest Symposium on Circuits and Systems, 14-16 Aug. 1989 Page(s):24 - 27 vol.1

52. **Information integration in computerized distribution system planning,** Yeh, E.-C.; Hahn Tram; Transmission and Distribution Conference, 1996. Proceedings., 1996 IEEE, 15-20 Sept. 1996 Page(s):602 - 607

53. **Optimal energy restoration for general distribution systems by genetic algorithms,** Bretas, N.G.; Delbem, A.C.B.; de Carvalho, A.; Power System Technology, 1998. Proceedings. POWERCON '98. 1998 International Conference on, Volume 1, 18-21Aug.1998 Page(s):43 - 47 vol.1

54. **The fuzzy regression approach to peak load estimation in power distribution systems,** Nazarko, J.; Zalewski, W.; IEEE Transactions on Power Systems, Volume 14, Issue 3, Aug. 1999 Page(s):809 - 814

55. **A systematic approach to the replacement of an aging distribution system,** Rudolph, D.L.; Industry Applications Magazine, IEEE, Volume 4, Issue 3, May-June 1998 Page(s):32 – 36

56. **Explicit loss formula, voltage formula and current flow formula for large-scale unbalanced distribution systems** Chiang, H.-D.; Wang, J.-C.; Miu, K.N.;, IEEE Transactions on Power Systems, Volume 12, Issue 3, Aug. 1997 Page(s):1061 - 1067

57. **Impedance characteristics of decoupling capacitors in multi-power distribution systems,** Popovich, M.; Friedman, E.G.;, 2004. ICECS 2004. Proceedings of the 2004 11th IEEE International Conference on Electronics, Circuits and Systems, 13-15 Dec. 2004 Page(s):160 - 163

Distribution Systems Protection

1. **Reliable protection of low voltage distribution systems with precision breakers,** Cohen, V.; Electricity Distribution, 2001. Part 1: Contributions. CIRED. 16th International Conference and Exhibition on (IEE Conf. Publ No. 482), Volume 3, 18-21 June 2001 Page(s):5 pp. vol.3

2. **Application of AI techniques for fault diagnosis in power distribution system,** Teo, C.Y.; Kwok, W.K.; Lee, C.C.; Intelligent Systems Engineering, 1992., First International Conference on (Conf. Publ. No. 360), 19-21 Aug 1992 Page(s):53 - 58

3. **A new connectionist expert system scheme for distribution system fault diagnosis,** Rao, N.D.; Chen, J.-C.; Chan, W.C.; 1994. Conference Proceedings. 1994 Canadian Conference on Electrical and Computer Engineering, 25-28 Sept. 1994 Page(s):50 - 54 vol.1

4. **An expert system for locating distribution system faults** Yuan-Yih Hsu; Lu, F.-C.; Chien, Y.; Liu, J.P.; Lin, J.T.; Yu, P.H.S.; Kuo, R.R.T.;, IEEE Transactions on Power Delivery, Volume 6, Issue 1, Jan. 1991 Page(s):366 - 372

5. **Artificial neural network and support vector Machine approach for locating faults in radial distribution systems** Thukaram, D.; Khincha, H.P.; Vijaynarasimha, H.P.;, IEEE Transactions on Power Delivery, Volume 20, Issue 2, April 2005 Page(s):710 - 721

6. **A fuzzy expert system for fault diagnosis in electric distribution systems,** Jian-Liang Chen; Rao, N.D.;

1993. Canadian Conference on Electrical and Computer Engineering, 14-17 Sept. 1993 Page(s):1283 - 1286 vol.2

7. Design and evaluation of a current differential protection scheme incorporating a fiber optical current sensor, Li, H.Y.; Crossly, P.A.; Power Engineering Society Summer Meeting, 2000. IEEE, Volume 3, 16-20 July 2000 Page(s):1396 - 1400 vol. 3

8. **Non-communication protection of distribution feeders with tapped-off-loads,** Bo, Z.Q.; Dong, Z.; Liu, J.K.; Shi, S.X.; Caunce, B.R.J.; Montjean, D.;, 2002. Proceedings. PowerCon 2002. International Conference on Power System Technology, Volume 1, 13-17 Oct. 2002 Page(s):285 - 289 vol.1

9. **Improved relay coordination and relay response time by integrating the relay functions,** Kojovic, L.A.; Witte, J.F.; Power Engineering Society Summer Meeting, 2000. IEEE, Volume 2, 16-20 July 2000 Page(s):1202 - 1207 vol. 2

10. **Non-communication protection for radial connected distribution systems,** Chen, F.; Dong, X.Z.; Bo, Z.Q.; Caunce, B.; Richards, S.;, 2004. Eighth IEE International Conference on Developments in Power System Protection, Volume 2, 5-8 April 2004 Page(s):587 - 590 Vol.2

11. **Development of non-communication relays for transmission and distribution systems,** Bo, Z.Q.; Dong, X.Z.; Caunce, B.; Richards, S.;, 2004. Eighth IEE International Conference on Developments in Power System Protection, Volume 1, 5-8 April 2004 Page(s):96 - 99 Vol.1

12. **Controlled switching of circuit breaker and its site measurement in power distribution system,** Liuling Li; Qiu, Y.; 2001. (ISEIM 2001). Proceedings of 2001 International Symposium on Electrical Insulating Materials, 19-22 Nov. 2001 Page(s):777 - 780

13. **Reducing the damaging effects of lightning in an industrial co-generation plant,** Holmquist, J.R.; Jones, R.W.; Industry Applications Conference, 2000. Conference Record of the 2000 IEEE, Volume 5, 8-12 Oct. 2000 Page(s):3483 - 3490 vol.5

14. **An implementation of a hybrid intelligent tool for distribution system fault diagnosis,** Momoh, J.A.; Dias, L.G.; Laird, D.N.; Transmission and Distribution Conference, 1996. Proceedings., 1996 IEEE, 15-20 Sept. 1996 Page(s):123 - 128

15. **Ground-fault protection based on active component of zero-sequence current in resistance neutral grounded distribution systems,** Mu Longhua; Meng Qinghai; TENCON '02. Proceedings. 2002 IEEE Region 10 Conference on Computers, Communications, Control and Power Engineering, Volume 3, 28-31 Oct. 2002 Page(s):1897 - 1900 vol.3

16. **All your eggs in one basket [back-up protection using multifunction relays],** Hazel, T.; Tastet, J.; Quillion, N.; Lusson, B.; Industry Applications Magazine, IEEE, Volume 9, Issue 2, March-April 2003 Page(s):64 - 74

17. **Microprocessor-based relays improve distribution system reliability of a high profile customer,** Hamon, C.; Nicolai, T.J.; Myers, D.A.; Rural Electric Power Conference, 2003, 4-6 May 2003 Page(s):C3-1 - C3-4

Distribution Systems Reliability Analysis

1. **Composite reliability evaluation model for different types of distribution systems ,** Teng-Fa Tsao; Hong-Chan Chang; IEEE Transactions on Power Systems, Volume 18, Issue 2, May 2003 Page(s):924 - 930

2. **Distribution System Reliability Assessment Due to Lightning Storms,** Balijepalli, N.; Venkata, S.S.; Richter, C.W., Jr.; Christie, R.D.; Longo, V.J.;, IEEE Transactions on Power Delivery, Volume 20, Issue 3, July 2005 Page(s):2153 – 2159

3. **Evaluation of reliability indices and outage costs in distribution systems,** Allan, R.N.; Da Silva, M.G.;
IEEE Transactions on Power Systems, Volume 10, Issue 1, Feb. 1995 Page(s):413 - 419

4. **Reliability evaluation of distribution system through the analysis of time-varying failure rate** Jong-Fil Moon; Jae-Chul Kim; Hee-Tae Lee; Chang-Ho Park; Sang-Yun Yun; Sang-Seung Lee; Power Engineering Society General Meeting, 2004. IEEE, 6-10 June 2004 Page(s):668 - 673 Vol.1

5. **Modeling and analysis of distribution reliability indices,** Balijepalli, N.; Venkata, S.S.; Christie, R.D.;
IEEE Transactions on Power Delivery, Volume 19, Issue 4, Oct. 2004 Page(s):1950 - 1955

6. **Effect of environmental factors on failure rate of overhead distribution feeders,** Pahwa, A.; Power Engineering Society General Meeting, 2004. IEEE, 6-10 June 2004 Page(s):691 - 692 Vol.1

7. **New methods and applications for distribution system reliability analysis,** Seitz, T.;, 1995. Proceedings of EMPD '95., 1995 International Conference on Energy Management and Power Delivery, olume 1, 21-23 Nov. 1995 Page(s):166 - 170 vol.1

8. **Reliability aspects in operational structuring of large-scale urban distribution systems,** Strbac, G.; Nahman, J.; 1995., Second International Conference on the Reliability of Transmission and Distribution Equipment, 29-31 Mar 1995 Page(s):151 - 156

9. **Integrating reliability into distribution planning,** Marshall, M.W.; Farmer, D.M.; Rural Electric Power Conference, 2005, 8-10 May 2005 Page(s):B4/1 - B4/6

10. **Developing a reliability improvement strategy for utility distribution systems,** Taylor, T.; Marshall, M.; Neumann, E.; Transmission and Distribution Conference and Exposition, 2001 IEEE/PES, Volume 1, 28 Oct.-2 Nov. 2001 Page(s):444 - 449 vol.1

11. **Current practices and customer value-based distribution system reliability planning,** Chowdhury, A.A.; Koval, D.O.; IEEE Transactions on Industry Applications, Volume 40, Issue 5, Sept.-Oct. 2004 Page(s):1174 – 1182

12. **Customer value-based reliability enhancement models for urban distribution systems,** Melnik, T.C.; Power Engineering Society Summer Meeting, 2002 IEEE, Volume 2, 21-25 July 2002 Page(s):781 vol.2

13. **A failure model for distribution systems,** Ledwich, G.; Power Engineering Society General Meeting, 2004. IEEE 6-10 June 2004 Page(s):1836 - 1840 Vol.2

14. **Assessing the reliability of distribution systems,** Brown, R.E.; Hanson, A.P.; Willis, H.L.; Luedtke, F.A.; Born, M.F.; Computer Applications in Power, IEEE, Volume 14, Issue 1, Jan. 2001 Page(s):44 - 49

15. **Determination of failure rates of underground distribution system components from historical data,** Horton, W.F.; Goldberg, S.; Transmission and Distribution Conference, 1991., Proceedings of the 1991 IEEE Power Engineering Society, 22-27 Sept. 1991 Page(s):718 - 723

Distribution Systems State Estimation

1. **Distribution system state estimation,** Lu, C.N.; Teng, J.H.; Liu, W.-H.E.; Power Systems, IEEE Transactions on, Volume 10, Issue 1, Feb. 1995 Page(s):229 - 240

2. **A highly efficient algorithm in treating current measurements for the branch-current-based distribution state estimation**, Whei-Min Lin; Jen-Hao Teng; Shi-Jaw Chen;, IEEE Transactions on Power Delivery, Volume 16, Issue 3, July 2001 Page(s):433 – 439

3. **A revised branch current-based distribution system state estimation algorithm and meter placement impact,** Haibin Wang; Schulz, N.N.;, IEEE Transactions on Power Systems, Volume 19, Issue 1, Feb. 2004 Page(s):207 - 213

4. **Handling current-magnitude measurement in transmission and distribution system state estimator,** Teng, J.-H.; Generation, Transmission and Distribution, IEE Proceedings-Volume 147, Issue 4, July 2000 Page(s):202 – 206

Distribution Systems Voltage and Transient Stability

1. **Dynamic voltage restoration with minimum energy injection,** Choi, S.S.; Li, B.H.; Vilathgamuwa, D.M.; Power Engineering Society Winter Meeting, 2000. IEEE, Volume 2, 23-27 Jan. 2000 Page(s):1156 vol.2

2. **New concepts of dynamic voltage restoration for three-phase distribution systems,** Ding Hongfa; Gao Jun; Duan Xianzhong; Power Engineering Society Summer Meeting, 2000. IEEE, Volume 3, 16-20 July 2000 Page(s):1427-1432 vol. 3

3. **Optimizing the transient response of voltage source converters used for mitigating voltage collapse problems by** means **of real time digital simulation**, Steurer, M.; Woodruff, S.; Brooks, N.; Giesbrecht, J.; Li, H.; Baldwin, T.; Power Tech Conference Proceedings, 2003 IEEE Bologna, Volume 1, 23-26 June 2003 Page(s):6 pp. Vol.1

4. **Dynamic voltage restoration with minimum energy injection,** Choi, S.S.; Li, B.H.; Vilathgamuwa, D.M.; IEEE Transactions on Power Systems, Volume 15, Issue 1, Feb. 2000 Page(s):51 - 57

5. **Distribution system modelling for voltage stability studies ,** Lind, R.; Karlsson, D.;, IEEE Transactions on Power Systems, Volume 11, Issue 4, Nov. 1996 Page(s):1677 – 1682

6. **On the injection transformer used in the dynamic voltage restorer,** Li, B.H.; Choi, S.S.; Vilathgamuwa, D.M.; 2000. Proceedings. PowerCon 2000. International Conference on Power System Technology, Volume 2, 4-7 Dec. 2000 Page(s):941 - 946 vol.2

7. **Intelligent load shedding to counteract power system instability,** Andersson, D.; Elmersson, P.; Juntti, A.; Gajic, Z.; Karlsson, D.; Fabiano, L.; Transmission and Distribution Conference and Exposition: Latin America, 2004 IEEE/PES, 8-11 Nov. 2004 Page(s):570 - 574

Distribution Systems Control

1. **An expert system for reactive power control of a distribution system. I. System configuration .** Salama, M.M.A.; Chikhani, A.Y.;Transmission and Distribution Conference, 1991., Proceedings of the 1991 IEEE Power Engineering Society, 22-27 Sept. 1991 Page(s):633 - 638

2. **Optimal capacitor placement, replacement and control in large-scale unbalanced distribution systems: system solution algorithms and numerical studies ,** Hsiao-Dong Chiang; Jin-Cheng Wang; Jianzhong Tong; Darling, G.; Transmission and Distribution Conference, 1994., Proceedings of the 1994 IEEE Power Engineering Society, 10-15 April 1994 Page(s):180 - 186

3. **Misapplication of power capacitors in distribution systems with non-linear loads - three case histories,** Simpson, R.H. Pulp and Paper Industry Technical Conference, 2004. Conference Record of the 2004 Annual, 27 June-1 July 2004 Page(s):156 - 166

4. **Reactive power flow control and compensation in the industrial distribution systems,** Das, J.C.; Industrial and Commercial Power Systems Technical Conference, 1993. Conference Record, Papers Presented at the 1993 Annual Meeting, 2-6 May 1993 Page(s):128 - 136

5. **Optimal reactive power and voltage control for radial distribution system,** Yutian Liu; Peng Zhang; Xizhao Qiu; Power Engineering Society Summer Meeting, 2000. IEEE, Volume 1, 16-20 July 2000 Page(s):85 - 90 vol. 1

6. **Innovative volt/VAr management provides payback,** Dixon, M.; Transmission and Distribution Conference and Exposition, 2001 IEEE/PES, Volume 1, 28 Oct.-2 Nov. 2001 Page(s):461 - 468 vol.1

7. **Autodaptive volt/VAr management system,** Dixon, M.; Rural Electric Power Conference, 2001, 29 April-1 May 2001 Page(s):D4/1 - D4/8

8. **Control strategies for capacitor voltage equalization in neutral clamped shunt compensator,** Mishra, M.K.; Joshi, A.; Ghosh, A.; Power Engineering Society Winter Meeting, 2001. IEEE, Volume 1, 28 Jan.-1 Feb. 2001 Page(s):132 - 137 vol.1

9. **A novel scheme for mitigation of line current harmonics and compensation of reactive power in three phase low voltage distribution systems,** Ashari, M.; Nayar, C.V.; Islam, S.; Power Electronics Specialists Conference, 2000. PESC 00. 2000 IEEE 31st Annual, Volume 3, 18-23 June 2000 Page(s):1324 - 1329 vol.3

10. **Voltage control problems on modern distribution systems,** O'Gorman, R.; Redfern, M.A.; Power Engineering Society General Meeting, 2004. IEEE, 6-10 June 2004 Page(s):662 - 667 Vol.1

11. **Operation of a DSTATCOM in voltage control mode,** Mishra, M.K.; Ghosh, A.; Joshi, A.;, IEEE Transactions on Power Delivery, Volume 18, Issue 1, Jan 2003 Page(s):258 - 264

12. **A heuristic and algorithmic combined approach for reactive power optimization with time-varying load demand in distribution systems,** Youman Deng; Xiaojuan Ren; Changcheng Zhao; Dapu Zhao;, IEEE Transactions on Power Systems, Volume 17, Issue 4, Nov. 2002 Page(s):1068 - 1072

13. **Voltage control performance enhancement by adding energy storage to shunt connected voltage source converters,** Steurer, M.; Eckroad, S.;, 2002. 10th International Conference on Harmonics and Quality of Power, Volume 2, 6-9 Oct. 2002 Page(s):590 - 594 vol.2

14. **A new approach to load balancing and power factor correction in power distribution system,** Ghosh, A.; Joshi, A.; IEEE Transactions on Power Delivery, Volume 15, Issue 1, Jan. 2000 Page(s):417 - 422

15. **Hybrid control of multiple inverters in an island-mode distribution system,** Liang, J.; Green, T.C.; Weiss, G.; Zhong, Q.-C.; Power Electronics Specialist Conference, 2003. PESC '03. 2003 IEEE 34th Annual, Volume 1, 15-19 June 2003 Page(s):61 - 66 vol.1

16. **Distribution system service restoration using a heuristic search approach,** Hsu, Y.-Y.; Huang, H.-M.; Kuo, H.-C.; Peng, S.K.; Chang, C.W.; Chang, K.J.; Yu, H.S.; Chow, C.E.; Kuo, R.T.; Power Delivery, IEEE Transactions on Volume 7, Issue 2, April 1992 Page(s):734 - 740

17. **Load following functions using distributed energy resources,** Li, S.; Tomsovic, K.; Hiyama, T.;

Power Engineering Society Summer Meeting, 2000. IEEE, Volume 3, 16-20 July 2000 Page(s):1756 - 1761 vol. 3

18. **Feedback control of production-distribution systems with unknown demand and delays,** Blanchini, F.; Pesenti, R.; Rinaldi, F.; Ukovich, W.;, IEEE Transactions on Robotics and Automation, Volume 16, Issue 3, June 2000 Page(s):313 - 317

19. **Consumed power control of time deferrable loads for frequency regulation,** Kondoh, J.; Aki, H.; Yamaguchi, H.; Murata, A.; Ishii, I.; Power Systems Conference and Exposition, 2004. IEEE PES , 10-13 Oct. 2004 Page(s):1013 - 1018 vol.2

20. **Discrimination of capacitor transients for position identification,** Pericolo, P.P.; Niebur, D.; Power Engineering Society Winter Meeting, 2001. IEEE, Volume 2, 28 Jan.-1 Feb. 2001 Page(s):872 - 877 vol.2

21. **Direct load control for reducing losses in the main and laterals of distribution systems,** Wehbe, A.; Salehfar, H.; Power Engineering Society Summer Meeting, 2002 IEEE, Volume 3, 21-25 July 2002 Page(s):1593 - 1598 vol.3

22. **Consortium for Electric Reliability Technology Research under competition,** Overholt, P.N.; Power Engineering Society Summer Meeting, 2002 IEEE, Volume 3, 21-25 July 2002 Page(s):1716 - 1717 vol.

23. **FPSO electrical systems-lessons learned [ship power systems],** Brown, R.R.; Petroleum and Chemical Industry Conference, 2002. Industry Applications Society 49th Annual, 23-25 Sept. 2002 Page(s):111 - 118

24. **The power buffer concept for utility load decoupling,** Logue, D.; Krein, P.T.; Power Electronics Specialists Conference, 2000. PESC 00. 2000 IEEE 31st Annual, Volume 2, 18-23 June 2000 Page(s):973 - 978 vol.2

25. **Disturbance accommodation control versus conventional control, in LFC of a two area distribution system in a deregulated environment**, Paradkar, A.; Davari, A.; Feliachi, A.;, 2003. Proceedings of the 35th, Southeastern Symposium on System Theory, 16-18 March 2003 Page(s):98 - 102

26. **Design of the control system for thyristor switched capacitor devices,** Zhang Jianhua; Dai Guanping; Xiao Gang; Zhao Jie; Zhang Hui; Wang Shuying; Transmission and Distribution Conference and Exposition, 2003 IEEE PES, Volume 2, 7-12 Sept. 2003 Page(s):606 - 610 vol.2

27. **Distribution voltage and reactive power control at Georgia power company,** Welch, L.E.; Transmission and Distribution Conference and Exposition, 2003 IEEE PES, Volume 3, 7-12 Sept. 2003 Page(s):1226 - 1228 vol.3

28. **Some new aspects of design and implementation of TCR for load balancing and power factor correction in distribution systems,** Dehnavi, G.R.; Shayanfar, H.A.; Mahdavi, J.;

Saran, M.M.; Power Tech Proceedings, 2001 IEEE Porto, Volume 1, 10-13 Sept. 2001 Page(s):6 pp. vol. 1

29. **Simultaneous phase balancing at substations and switches with time-varying load patterns,** Dilek, M.; Broadwater, R.P.; Thompson, J.C.; Seqiun, R.;, IEEE Transactions on Power Systems, Volume 16, Issue 4, Nov. 2001 Page(s):922 - 928

30. **Improvement in the performance of on-load tap changer transformers operating in series,** Smith, C.A.; Redfern, M.A.; Potts, S.; Power Engineering Society General Meeting, 2003, IEEE, Volume 3, 13-17 July 2003 Page(s):

31. **Integrated volt/VAr control in distribution systems,** Borozan, V.; Baran, M.E.; Novosel, D.; Power Engineering Society Winter Meeting, 2001. IEEE, Volume 3, 28 Jan.-1 Feb. 2001 Page(s):1485 - 1490 vol.3

32. **Active power line conditioner with a neural network control scheme,** Tong Mei; Shu Xiaowu; TENCON '02. Proceedings. 2002 IEEE Region 10 Conference on Computers, Communications, Control and Power Engineering, Volume 3, 28-31 Oct. 2002 Page(s):1508 - 1511 vol.3

33. **Application of binary integer programming for load transfer of distribution systems,** Chen, C.S.; Kang, M.S.; Hwang, J.C.; Huang, C.W.;, 2000. Proceedings. PowerCon 2000. International Conference on Power System Technology, Volume 1, 4-7 Dec. 2000 Page(s):305 - 310 vol.1

34. **A rule-based expert system with colored Petri net models for distribution system service restoration,** Chao-Shun Chen; Chia-Hung Lin; Hung-Ying Tsai;, IEEE Transactions on Power Systems, Volume 17, Issue 4, Nov. 2002 Page(s):1073 - 1080

Distribution Systems Automation

1. **Evaluation of cost benefit analysis for the reconfigured distribution system,** Momoh, J.A.; Caven, A.C.; Transmission and Distribution Conference and Exposition, 2003 IEEE PES, Volume 2, 7-12 Sept. 2003 Page(s):643 - 648 vol.2

2. **An advanced flexible and reliable distribution system**, Nara, K.; Hasegawa, J.; Energy Management and Power Delivery, 1995., 1995 International Conference on. Proceedings of EMPD '95, Volume 1, 21-23 Nov. 1995 Page(s):55 - 60 vol.1

3. **Network reconfiguration at the power distribution system with dispersed generations for loss reduction,** Joon-Ho Choi; Jae-Chul Kim; Power Engineering Society Winter Meeting, 2000. IEEE, Volume 4, 23-27 Jan. 2000 Page(s):2363 - 2367 vol.4

4. **Study on mathematical model of urban distribution system optimal rush-maintain path,** Sun Caixin; Liu Lifeng; Zhou Quan; Bi Weimin; Deng Qui; Ma Yimin; Wang Kaijun;, 2002. Proceedings. PowerCon 2002. International Conference on Power System Technology, Volume 2, 13-17 Oct. 2002 Page(s):1077 - 1081 vol.2

5. **Coordinated comprehensive design of distribution systems at medium and low voltage levels,** Ganjavi, M.R.; Electricity Distribution, 2001. Part 1: Contributions. CIRED. 16th International Conference and Exhibition on (IEE Conf. Publ No. 482), Volume 5, 18-21 June 2001 Page(s):6 pp. vol.5

6. **Automatic restoration system,** Ohara, A.T.; Takiguchi, C.S.; Transmission and Distribution Conference and Exposition: Latin America, 2004 IEEE/PES, 8-11 Nov. 2004 Page(s):681 - 685

7. **System planning to achieve automation of network operation and reduction of operation costs,** Connor, T.; Petrossian, E.; Horn, H.; Electricity Distribution, 2001. Part 1: Contributions. CIRED. 16th International Conference and Exhibition on (IEE Conf. Publ No. 482), Volume 5, 18-21 June 2001 Page(s):5 pp. vol.5

8. **The development of an intelligent and integrated gateway system for the automation systems in power utilities,** Kim, M.S.; Hyun, D.H.; Transmission and Distribution Conference and Exhibition 2002: Asia Pacific. IEEE/PES Volume 1, 6-10 Oct. 2002 Page(s):2 - 5 vol.1

9. **Oversea distribution automation system based on Japanese experience,** Fujisawa, A.; Kurokawa, N.; Transmission and Distribution Conference and Exhibition 2002: Asia Pacific. IEEE/PES, Volume 2, 6-10 Oct. 2002 Page(s):1164 - 1169 vol.2

10. **The benefits of implementing distribution automation and system monitoring in the open electricity market,** Rong-Liang Chen; Sabir, S.;, 2001. Canadian Conference on Electrical and Computer Engineering, Volume 2, 13-16 May 2001 Page(s):825 - 830 vol.2

11. **Distribution automation simulator,** Gupta, R.P.; Tiwari, G.; Electric Utility Deregulation, , 2004. (DRPT 2004). Proceedings of the 2004 IEEE International Conference on Restructuring and Power Technologies, Volume 1, 5-8 April 2004 Page(s):161 - 166 Vol.1

12. **Designing the next generation of real-time control, communication, and computations for large power systems,** Tomsovic, K.; Bakken, D.E.; Venkatasubramanian, V.; Bose, A.; Proceedings of the IEEE, Volume 93, Issue 5, May 2005 Page(s):965 – 979

13. **Advanced distribution system automation,** Kojovic, L.A.; Day, T.R.; Transmission and Distribution Conference and Exposition, 2003 IEEE PES, Volume 1, 7-12 Sept. 2003 Page(s):348 - 353 Vol.1

Power Quality in Distribution Systems

1. **Analysis and design of a new voltage sag compensator for critical loads in electrical power distribution systems**, Aeloiza, E.C.; Enjeti, P.N.; Montero, O.C.; Moran, L.A.; Industry Applications Conference, 2002.. Conference Record of the 37th IAS Annual Meeting, Volume 2, 13-18 Oct. 2002 Page(s):911 - 916 vol.2

2. **Analysis and design of a new voltage sag compensator for critical loads in electrical power distribution systems,** Aeloiza, E.C.; Enjeti, P.N.; Moran, L.A.; Montero-Hernandez, O.C.; Sangsun Kim;, IEEE Transactions on Industry Applications, Volume 39, Issue 4, July-Aug. 2003 Page(s):1143 - 1150

3. **Power quality monitoring system at Austin Energy,** Vatani, M.; Transmission and Distribution Conference and Exposition, 2003 IEEE PES, Volume 3, 7-12 Sept. 2003 Page(s):1052 - 1053 vol.3

4. **Establishment of typical harmonic voltage levels in radial distribution systems,** Robinson, D.A.; Gosbell, V.J.; Perera, B.S.P.; Mannix, D.J.;, 2000. Proceedings. Ninth International Conference on Harmonics and Quality of Power, Volume 3, 1-4 Oct. 2000 Page(s):1053 - 1058 vol.3

5. **Power quality assessment via physically based statistical simulation method,** Meliopoulos, A.P.S.; Jalali, S.; Henneberry, S.; Cokkinides, G.J.; Power Engineering Society Winter Meeting, 2000. IEEE, Volume 4, 23-27 Jan. 2000 Page(s):2613 - 2618 vol.4

6. **Voltage sag mitigation through distribution system design,** Lakervi, E.; Power Engineering Society Winter Meeting, 2000. IEEE, Volume 4, 23-27 Jan. 2000 Page(s):2879 - 2880 vol.4

7. **Impacts over the distribution grid from the adoption of distributed harmonic filters on low-voltage customers** Tostes, M.Ed.L.; Bezerra, U.H.; Silva, R.D.S.; Valente, J.A.L.; de Moura, C.C.M.; Branco, T.M.M.;, IEEE Transactions on Power Delivery, Volume 20, Issue 1, Jan 2005 Page(s):384 - 389

8. **A 35-kV system voltage sag improvement,** Daniel, M.S.;, IEEE Transactions on Power Delivery, Volume 19, Issue 1, Jan. 2004 Page(s):261 - 265

9. **Voltage sag mitigation through distribution system design,** Lakervi, E.; Power Engineering Society Winter Meeting, 2000. IEEE, Volume 4, 23-27 Jan. 2000 Page(s):2879 - 2880 vol.4

10. **Current limiting devices: a new concept for improving power quality,** Gronqvist, J.; Andersson, G.; Ekstrom, A.; Advances in Power System Control, Operation and Management, 1997. APSCOM-97. Fourth International Conference on (Conf. Publ. No. 450), Volume 2, 11-14 Nov. 1997 Page(s):532 - 536 vol.2

11. **Working with high-tech customers on power quality issues,** Vatani, M.; Bayer, S.;, 2004 57th Annual Conference for Protective Relay Engineers, 30 Mar-1 Apr 2004 Page(s):70 - 79

12. **Considering power quality in expansion planning of distribution systems,** Vuinovich, F.; Sannino, A.; Ippolito, M.G.; Morana, G.; Power Engineering Society General Meeting, 2004. IEEE, 6-10 June 2004 Page(s):674 - 679 Vol.1

13. **An on-chip voltage regulator using switched decoupling capacitors,** Ang, M.; Salem, R.; Taylor, A.; Solid-State Circuits Conference, 2000. Digest of Technical Papers. ISSCC. 2000 IEEE International, 7-9 Feb. 2000 Page(s):438 – 439

14. **High reliability and improved power quality in low voltage distribution systems for nonlinear critical loads: an evaluation,** Wiechmann, E.P.; Pino, E.J.; Carranza, J.A.; Industrial Electronics Society, 1998. IECON '98. Proceedings of the 24th Annual Conference of the IEEE, Volume 2, 31 Aug.-4 Sept. 1998 Page(s):848 - 853 vol.2

15. **Voltage sag analysis taken into account in distribution network design,** Heine, P.; Lehtonen, A.; Lakervi, E.; Power Tech Proceedings, 2001 IEEE Porto, Volume 3, 10-13 Sept. 2001 Page(s):6 pp. vol.3

16. **Advanced voltage regulation method at the power distribution systems interconnected with dispersed storage and generation systems,** Joon-Ho Choi; Jae-Chul Kim;, IEEE Transactions on Power Delivery, Volume 15, Issue 2, April 2000 Page(s):691 - 696

17. **A voltage sag supporter utilizing a PWM-switched autotransformer,** Dong-Myung Lee; Habetler, T.G.; Harley, R.G.; Rostron, J.; Keister, T.; Power Electronics Specialists Conference, 2004. PESC 04. 2004 IEEE 35th Annual, Volume 6, 20-25 June 2004 Page(s):4244 - 4250 Vol.6

18. **Implementation and performance of cooperative control of shunt active filters for harmonic damping throughout a power distribution system,** Jintakosonwit, P.; Fujita, H.; Akagi, H.; Ogasawara, S.;, IEEE Transactions on Industry Applications, Volume 39, Issue 2, March-April 2003 Page(s):556 – 564

19. **Rating issues of unified power quality conditioners for load bus voltage control in distribution systems,** Su Chen; Joos, G.; Power Engineering Society Winter Meeting, 2001. IEEE, Volume 2, 28 Jan.-1 Feb. 2001 Page(s):944 - 949 vol.2

20. **Functions and configurations of quality control center on FRIENDS,** Ise, T.; Transmission and Distribution Conference and Exhibition 2002: Asia Pacific. IEEE/PES, Volume 1, 6-10 Oct. 2002 Page(s):590 - 595 vol.1

21. **Universal custom power conditioner (UCPC) with integrated control,** Changjiang Zhan; Ramachandaramurthy, V.K.; Arulampalam, A.; Fitzer, C.; Barnes, M.; Jenkins, N.; Power Engineering Society Winter Meeting, 2001. IEEE, Volume 3, 28 Jan.-1 Feb. 2001 Page(s):1039 - 1044 vol.3

22. **Study of distribution system unified conditioner (DS-UniCon),** Man-Chung Wong; Ying-Duo Han; Liang-Bing Zhao;
Power Electronics and Motion Control Conference, 2000. Proceedings. PIEMC 2000. The Third International, Volume 3, 15-18 Aug. 2000 Page(s):1365 - 1370 vol.3

23. **Implementation and performance of cooperative control of shunt active filters for harmonic damping throughout a power distribution system,** Jintakosonwit, P.; Fujita, H.;

Akagi, H.; Ogasawara, S.;, 2002. 37th IAS Annual Meeting. Conference Record of the Industry Applications Conference, Volume 1, 13-18 Oct. 2002 Page(s):51 - 58 vol.1

24. **DSP- and GPS-based synchronized measurement system of harmonics in wide-area distribution system,** Ukai, H.; Nakamura, K.; Matsui, N.; IEEE Transactions on Industrial Electronics, Volume 50, Issue 6, Dec 2003 Page(s):1159 - 1164

Communications in Distribution Systems

1. **Upgradable distribution for broadband networks,** Takano, J.; Tanaka, N.; Takasaki, Y, 2003. ICCT 2003. International Conference on.; Communication Technology Proceedings, Volume 2, 9-11 April 2003 Page(s):1472 - 1475 vol.2

2. **Designing the next generation real-time control, communications and communication system for the electricity infrastructure**, Bose, A.; Power Engineering Society General Meeting, 2004. IEEE, 6-10 June 2004 Page(s):2 Vol.1

3. **Communications architecture in modern distribution systems,** Roth, P.D.; Electricity Distribution, 2001. Part 1: Contributions. CIRED. 16th International Conference and Exhibition on (IEE Conf. Publ No. 482), Volume 3, 18-21 June 2001 Page(s):5 pp. vol.3

4. **Power line communications,** Majumder, A.; Caffery J,Jr.; Potentials, IEEE, Volume 23, Issue 4, Oct-Nov 2004 Page(s):4 8

5. **Mutual fluctuations between carriers in a broadband millimeter-wave communication system,** Wong, T.; Ming Yan; 2001. CriMiCo 2001. 11th International Conference on Microwave and Telecommunication Technology, 2001 Page(s):270 – 271

6. **Modeling and simulation of power line channel,** Soo-Young Jung; Tae-Hyun Kim; Myung-Un Lee; Wook-Hyun Kwon; Power Engineering Society General Meeting, 2004. IEEE , 6-10 June 2004 Page(s):793 - 797 Vol.1

7. **Millimeter-wave indoor/outdoor wireless access systems and their technologies,** Ogawa, H.; Radio and Wireless Conference, 2003. RAWCON '03. Proceedings, 10-13 Aug. 2003 Page(s):5 - 8

8. **Application of information technology in substation automation,** Gohokar, V.N.; Dhande, T.M.; Kabra, S.S.; Power Systems Conference and Exposition, 2004. IEEE PES, 10-13 Oct. 2004 Page(s):635 - 639 vol.2

9. **LMDS systems and their application,** Nordbotten, A.; Communications Magazine, IEEE, Volume 38, Issue 6, June 2000 Page(s):150 - 154

10. **Satellite Internet services using DVB/MPEG-2 and multicast Web caching,** Linder, H.; Clausen, H.D.; Collini-Nocker, B.; Communications Magazine, IEEE, Volume 38, Issue 6, June 2000 Page(s):156 - 161

11. **Future vision distribution system and network,** Sato, K.; Katsumoto, M.; Miki, T.;, 2004. ISCIT 2004. IEEE International Symposium on Communications and Information Technology, Volume 1, 26-29 Oct. 2004 Page(s):274 - 279 vol.1

12. **A wireless sensor concept for managing electrical distribution networks,** Nordman, M.M.; Lehtonen, M.; Power Systems Conference and Exposition, 2004. IEEE PES, 10-13 Oct. 2004 Page(s):1198 - 1206 vol.2

13. **New infrastructural needs for improving efficiency of future distribution systems,** Venkata, S.S.; Power Engineering Society General Meeting, 2004. IEEE, 6-10 June 2004 Page(s):2278 Vol.2

14. **Common management architecture for third generation wireless networks,** Rayes, A.; Wireless Communications and Networking Conference, 2000. WCNC. 2000 IEEE, Volume 3, 23-28 Sept. 2000 Page(s):1060 - 1064 vol.3

15. **Delivering broad band Internet over power lines: what you should know,** Collier, S.E.; Rural Electric Power Conference, 2004, 23-25 May 2004 Page(s):A1 - 1-11

16. **Implementation options for the distribution system in the 802.11 wireless LAN infrastructure network,** El-Hoiydi, A.; 2000. ICC 2000. 2000 IEEE International Conference on Communications, Volume 1, 18-22 June 2000 Page(s):164 - 169 vol.1

17. **Data acquisition in distribution system with the GSM network,** Haipeng Wang; Rong Zeng; Jinliang He; Xinfia Sheng; Jun Zou;, 2002. Proceedings. PowerCon 2002. International Conference on Power System Technology, Volume 3, 13-17 Oct. 2002 Page(s):1768 - 1771 vol.3

18. **Technical considerations for wideband powerline communication-a summary,** Olsen, R.G.; Power Engineering Society Summer Meeting, 2002 IEEE, Volume 3, 21-25 July 2002 Page(s):1186 - 1191 vol.3

19. **Mobility and routing protocols for 802.11 extended service sets,** Hauser, J.P.; Baker, D.J.; Military Communications Conference, 2003. MILCOM 2003. IEEE, Volume 2, 13-16 Oct. 2003 Page(s):1036 - 1041 Vol.2

20. **Implementation of AMR system using power line communication,** Park, B.S.; Hyun, D.H.; Cho, S.K.; Transmission and Distribution Conference and Exhibition 2002: Asia Pacific. IEEE/PES, Volume 1, 6-10 Oct. 2002 Page(s):18 - 21 vol.1

21. **Robotic platform for monitoring underground cable systems,** Jiang, B.; Stuart, P.; Raymond, M.; Villa, D.; Mamishev, A.V.; Transmission and Distribution Conference and Exhibition 2002: Asia Pacific. IEEE/PES, Volume 2, 6-10 Oct. 2002 Page(s):1105 - 1109 vol.2

22. **Application of the DSP technology in feeder terminal unit (FTU),** Yongpeng Meng; Shenli Jia; Zongqian Shi; Transmission and Distribution Conference and Exhibition 2002: Asia Pacific. IEEE/PES, Volume 3, 6-10 Oct. 2002 Page(s):2100 - 2105 vol.3

23. **Deriving the signal-to-noise ratio probability of error and performance measure matrices for distribution line carrier signals propagation (using bus impedance approach),** Amoura, F.K.; Abu-Elhaija, W.S.;, IEEE Transactions on Power Delivery, Volume 19, Issue 1, Jan. 2004 Page(s):96 - 104

24. **Effect of wind on foliage obstructed line-of-sight channel at 2.5 GHz,** Pelet, E.R.; Salt, J.E.; Wells, G.;, IEEE Transactions on Broadcasting, Volume 50, Issue 3, Sept. 2004 Page(s):224 - 232

25. **Ethernet in substation automation,** Skeie, T.; Johannessen, S.; Brunner, C.; Control Systems Magazine, IEEE, Volume 22, Issue 3, June 2002 Page(s):43 - 51

26. **A general polling algorithm using a wireless AMR system for restoration confirmation,** Fischer, R.A.; Laakonen, A.S.; Schulz, N.N.;, IEEE Transactions on Power Systems, Volume 16, Issue 2, May 2001 Page(s):312 - 316

27. **A resource reservation and distribution system over satellite-terrestrial network,** Qinghua Zheng; Chunsheng Chu; , 2004. Proceedings. The 8th International Conference on Computer Supported Cooperative Work in Design, Volume 2, 26-28 May 2004 Page(s):673 - 678 Vol.2

Other Publications

These are primarily corporate reports, some of them in draft form.

1. Technical and System Requirements for Advanced Distribution Automation, EPRI, Palo Alto, CA, June 2004. 1010915.

2. *UCA Object Models for Distributed Energy Resources*, E2I and EPRI, December 2003.

3. *Studies of Distribution Operations to Aid in Determining Object Models for Distributed Energy Resources*, E2I and EPRI, December 2003.

4. Feero, Dawson, and Stevens, “CERTS White Paper on Protection Issues of the MicroGrid Concept”, DoE, March 2002.

5. EnerNex Corporation, *Distribution Automation Benchmarking*, Hydro Quebec, July 2004.

6. *SCE Distribution Circuit of the Future*, http://www.epri-intelligrid.com/intelligrid/docs/SCEs_Distribution_Circuit_of_the_Future_to_CEIDS_by.pdf

7. KC Associates, Inc., *Client-side Requirements for Distribution Automation Communications*, EPRI Draft Report, June 2005.

Web Links

For information on EPRI IntelliGrid Initiatives: www.epri-intelligrid.com

For information on DoE GridWise Initiatives: www.gridwise.org

For information on IEC 61850: http://www.ucausersgroup.org/IEC61850docs.htm, or http://www.uci-usa.com/UCI_Projects/IEC61850_Guidelines_Projects.htm

For information on IEC 61968 and 61970: http://www.cimusers.org

For information on IEEE 1547: http://grouper.ieee.org/groups/scc21/1547/1547_index.html

Export Control Restrictions

Access to and use of EPRI Intellectual Property is granted with the specific understanding and requirement that responsibility for ensuring full compliance with all applicable U.S. and foreign export laws and regulations is being undertaken by you and your company. This includes an obligation to ensure that any individual receiving access hereunder who is not a U.S. citizen or permanent U.S. resident is permitted access under applicable U.S. and foreign export laws and regulations. In the event you are uncertain whether you or your company may lawfully obtain access to this EPRI Intellectual Property, you acknowledge that it is your obligation to consult with your company's legal counsel to determine whether this access is lawful. Although EPRI may make available on a case-by-case basis an informal assessment of the applicable U.S. export classification for specific EPRI Intellectual Property, you and your company acknowledge that this assessment is solely for informational purposes and not for reliance purposes. You and your company acknowledge that it is still the obligation of you and your company to make your own assessment of the applicable U.S. export classification and ensure compliance accordingly. You and your company understand and acknowledge your obligations to make a prompt report to EPRI and the appropriate authorities regarding any access to or use of EPRI Intellectual Property hereunder that may be in violation of applicable U.S. or foreign export laws or regulations.

The Electric Power Research Institute (EPRI)

The Electric Power Research Institute (EPRI), with major locations in Palo Alto, California, and Charlotte, North Carolina, was established in 1973 as an independent, nonprofit center for public interest energy and environmental research. EPRI brings together members, participants, the Institute's scientists and engineers, and other leading experts to work collaboratively on solutions to the challenges of electric power. These solutions span nearly every area of electricity generation, delivery, and use, including health, safety, and environment. EPRI's members represent over 90% of the electricity generated in the United States. International participation represents nearly 15% of EPRI's total research, development, and demonstration program.

Together…Shaping the Future of Electricity

Printed on recycled paper in the United States of America

1010671

ELECTRIC POWER RESEARCH INSTITUTE

3420 Hillview Avenue, Palo Alto, California 94304-1395 • PO Box 10412, Palo Alto, California 94303-0813 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com