Smart Substations

A Preliminary Assessment

1001965

Smart Substations

A Preliminary Assessment

1001965

Technical Progress, December 2001

EPRI Project Manager
L. van der Zel, Ph.D.

EPRI • 3412 Hillview Avenue, Palo Alto, California 94304 • PO Box 10412, Palo Alto, California 94303 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

ORGANIZATION(S) THAT PREPARED THIS DOCUMENT

Michael A. Lebow, P. E.

This is an EPRI Level 2 report. A Level 2 report is intended as an informal report of continuing research, a meeting, or a topical study. It is not a final EPRI technical report.

ORDERING INFORMATION

Requests for copies of this report should be directed to the EPRI Distribution Center, 1355 Willow Way, Suite 2478, Concord, CA 94520, Pleasant Hill, CA 94523, (800) 313-3774.

CITATIONS

This report was prepared by

Michael A. Lebow
893 Princess Drive
Yardley, PA 19067

This report describes research sponsored by EPRI.

The report is a corporate document that should be cited in the literature in the following manner:

Smart Substations: A Preliminary Assessment, EPRI, Palo Alto, CA: 2001. 1001965.

REPORT SUMMARY

For the foreseeable future, substation owners will be continuously challenged to maximize asset utilization and enhance equipment performance and reliability while, at the same time, responding to the economic pressures of the transition to a competitive industry structure. Innovative technologies and techniques will be required to prosper in this dynamic business environment. To help meet these needs, the Smart Substation project will evaluate and analyze the latest developments in transmission substation equipment and concepts and assess the implications for future designs. New station and component design concepts will be identified, developed, and demonstrated. This report sets the stage for the project by reviewing current trends and suggesting areas for further investigation.

Background

Industry restructuring and the growing number of bulk power transactions are stressing the transmission system in ways not originally intended. Grid owners are now striving to meet new economic performance goals. Maintenance activities are being reduced while fewer experienced personnel are available. Asset utilization must be optimized while new investments are closely scrutinized. To achieve the highest levels of performance at the least cost in this environment, future substation designs must utilize the best available technologies.

Objectives

The Smart Substation project objective is to assess the significance of the latest developments in materials, sensors, communications, monitoring, diagnostics, and data analysis to substations and equipment design. The most promising concepts for new substation equipment and technologies will be identified and pursued. Reliability, cost operation and maintenance aspects will be addressed. New solutions to substation and equipment design issues will be analyzed and developed. This report represents the initial phase of the project and will serve to identify and direct future project work.

Approach

Experts in substation components were solicited to provide the state-of-the-art and future direction for their technical areas. The results have been distilled into this report and combined with larger trends in technology developments and the utility industry. Technologies and products in other industries were examined for possible adaptation to substation applications.

Results

This report provides a common starting point for discussions among utility and research experts to plan and direct the next Smart Substation project efforts. Each major equipment type has been addressed along with the required communications and information technologies. Gaps in

knowledge were identified, as were promising subjects for additional investigation. Highlighted were several areas where additional attention could accelerate current trends to provide more timely application results. New concepts in organizing and utilizing substation monitoring data were presented.

EPRI Perspective

EPRI customers must be highly selective in deploying their investment capital. New substations need to use the best available technologies to reduce costs, improve reliability and asset utilization, and enhance the quality of service. To ensure that the utilities' requirements will be met and that the required technical solutions will be available, EPRI has initiated the Smart Substation project to review the trends in equipment development and identify areas that would benefit from additional research and accelerated development. The results of this phase of the project are a guide to substation technologies and a roadmap for planning new development efforts.

Keywords

Transmission substations
Substation equipment
Substation operations
Substation maintenance
Substation design

ABSTRACT

Industry restructuring and the growing number of bulk power transactions are stressing the transmission system in ways not originally intended. To achieve the highest levels of performance at the least cost in this environment, future substations must utilize the best available technologies. To help meet these needs, the Smart Substation project has been initiated to evaluate and analyze the latest developments in transmission substation equipment and concepts and assess the implications for future designs.

The objectives of the Smart Substation project are to assess the significance of the latest developments in materials, sensors, communications, monitoring, diagnostics, and data analysis to substations and equipment design. The most promising concepts for new substation equipment and technologies will be identified and pursued. Reliability, cost operation and maintenance aspects will be addressed. New solutions to substation and equipment design issues will be analyzed and developed. This interim report represents the results of the initial phase of the project and will serve to identify and direct future project work.

Experts in substation components were solicited to provide the state-of-the-art and future direction for their technical areas. The results have been combined with larger trends in technology developments and the utility industry and distilled into this report. Technologies and products in other industries were examined for possible adaptation to substation applications. Each major equipment type has been addressed along with the required communications and information technologies. Gaps in knowledge were identified, as were promising subjects for additional investigation. Several areas were highlighted where additional attention could accelerate current trends to provide more timely application results. New concepts in organizing and utilizing substation monitoring data were presented. This document provides a common starting point for discussions among utility and research experts to plan and direct the next Smart Substation project efforts.

ACKNOWLEDGEMENTS

Special thanks are extended to the following for their material contributions to this report:

Luke van der Zel, EPRI, Project Manager
Bill Blair, EPRI
Ben Damsky, EPRI
Steve Eckroad, EPRI
Aty Edris, EPRI
Barry Ward, EPRI
Bjorn Holm, Consultant
Thomas Traub, Consultant

CONTENTS

1
EXECUTIVE SUMMARY

Introduction

For the foreseeable future, substation owners will be continuously challenged to maximize asset utilization and enhance equipment performance and reliability while, at the same time, responding to the economic pressures of the transition to a competitive industry structure. Innovative technologies and techniques will be required to prosper in this dynamic business environment. New substations need to use the best available technologies to reduce costs, improve reliability and asset utilization, and enhance the quality of service. The Smart Substation project has been initiated to insure that the best available technical options will be available to the designers of future substations.

The Project

This project focuses on evaluating the latest developments in materials, sensors, communications, monitoring, diagnostics, and substation equipment to assess the implications for the future design of substations. New concepts in substations and equipment design will be analyzed and developed. Reliability, cost, operation and maintenance aspects will be addressed. Discussions and brainstorming workshops will be organized, and the most promising solutions for new substations and new equipment will be identified and pursued. A straw-man vision for the Smart Substation will be developed. This vision will include prospects for advances in materials, equipment, diagnostics, and communication infrastructure. The vision will address the technology solutions needed to simplify substation design, operation and maintenance in the long term. The functionality of substations will be revisited, including the role of FACTS, on-site generation, and energy storage. The need for each piece of equipment will be scrutinized. The applicability of the results to new green-field substations and to refurbishment of existing substations will be considered. Initially, the project is focused on transmission-level substations (132kV to 345kV) but some of the results well may be applicable to lower voltages.

The first phase of the project, resulting in this report, entailed an assessment of the current status of the more important substation technologies and a projection of development trends. To avoid commercial implications, utility experts were asked to review:

- Transformers
- Circuit Breakers
- Gas Insulated Switchgear
- Relaying and Protection

- Optical Measuring Systems
- Station Batteries
- Superconductors
- Energy Storage
- Information Technology
- Station Design

Detailed study of each of these topics would be beyond the scope of this report. Rather, starting from today's commercially available technology, the reviewers projected improvements expected in the next few years. Barriers and technical limits and potential areas for acceleration were identified. A longer-term vision for goals beyond the horizon was formulated and, where possible, a timetable proposed. Knowledge gaps and research and development work needed to expedite advancements have been identified, as have been opportunities for use of technologies available in other industries. This report provides a guide to the latest available developments for consideration in designing stations over the next few years and indicates areas where research can be focused to expedite developments necessary to meet utility needs beyond that time. It serves as a basis for planning discussions and work scope definitions for the following development phase of the Smart Substation project.

High Level Design Considerations

In addition to the normal evolution in equipment technology, several macro-level changes in the electric power delivery business were identified as having potentially significant influence on future substation design decisions.

- Increasing numbers of merchant generators, growing regional operating organizations, continuing competition and the appearance of merchant transmission all mean that new stations most likely will be at some time required to operate or connect in ways not foreseen in the original design. To maximize value and utility over their expected operating life, new station designs must be as flexible as possible to accommodate unexpected change.
- Regardless of the final form of industry restructuring, good financial performance will be required of grid asset owners. Maintenance practices, a major factor in equipment availability and a significant portion of controllable costs, will become an even more important core strength for the successful operator.
- System operation most likely will be directed by organizations that will not own or maintain the equipment. More information about equipment condition will be required to reliably accommodate bulk power transactions, to justify maintenance outages, and to understand how operating practices influence maintenance and life cycle costs.
- Many utility companies will continue to reduce staff. Correspondingly, there will be a decrease in the level of experience and expertise available for engineering, operation and maintenance. An inexperienced staff can lead to reduced safety, lower productivity and higher costs. New stations should require fewer personnel to operate and maintain and

utilize expert systems to assist inexperienced staff. Tools are needed to capture the retiring knowledge base and make it available to assist in engineering, operations, and maintenance decision making.

- Regulators will take more interest in equipment reliability and availability. Transmission performance indices will be established and tracked. Environmental and, in many areas, appearance concerns will grow.

Conclusions

Several specific hardware issues were identified for more detailed review. Manufacturers' response to the world marketplace is driving the development of the major substation components. However, there is a need to increase the utility knowledge base for the best operation and maintenance practices. Ongoing research is addressing advanced technologies, such as superconductivity. FACTS technologies are gaining wider acceptance as their benefits for improving transmission system reliability and transfer capacity become more recognized. More work is required to integrate these advanced systems with conventional station equipment in a manner to best address changing grid needs.

Higher reliability components will lead to a review of the optimum station bus arrangements. Lower capital investment and reduced equipment count could be achieved by moving away from the more traditional transmission station designs such as the widespread breaker-and-a-half scheme. The required level of reliability may be achievable with a single bus design. Proper reliability analysis and risk assessment would be required. However, although various groups have collected substation equipment failure data over the years, there is actually very little basis for performing substation reliability studies with reliability numbers based on specific equipment, operating and maintenance practices and environment. Understanding how to specify new equipment and to maintain it to optimize life cycle costs will be essential skills. Substation design and equipment must reflect the need for high availability and low maintenance costs.

Competitive business pressures will drive utilities to continue to seek out every possible economy in operating their systems. Minimization of maintenance costs and optimization of asset utilization will be key skills for the successful transmission owner. Achieving these challenging goals will be even more difficult if, as is now the trend, other parties such as RTOs will direct operations. Maintenance is one area where costs can be controlled through the acquisition and use of better information. The practical application of predictive maintenance is limited by the requirements for data-the measured parameters-and the need for knowledge that relates the measurement data to the change in equipment condition. The best available equipment condition information will be required to cost effectively schedule maintenance, to justify equipment outages, and to optimally load equipment. The marketplace has provided individual equipment monitors, e.g. for transformers, breakers, bushings, but these are expensive to deploy, and development and interpretation of their algorithms are from the vendors' perspective. There is a need for a more integrated total station approach that will avoid duplication of measurements and processing components, employ a common infrastructure and architecture, and utilize existing EPRI developments, such as Xvisor, effectively. In addressing this need, the Smart Substation project can accelerate the provision of valuable new tools for substation operators.

An area where the Smart Substation project can make a significant contribution is substation information technology. An integrated monitoring and diagnostic system would combine outputs of all monitoring sensors, intelligent electronic devices (IED) and digital fault recording devices (DFRs) into a single substation data set for integrated analysis and display. There is no fundamental difference among many of the information points required for operations, condition monitoring and maintenance. It is inefficient to convert and store a data point more than once. Just as it is often unnecessary to report that a parameter has not changed. It is possible to conceive of a substation database containing all of the data relevant to the station's operation. A combined data set would provide more timely and accurate information on the condition of a particular component than would isolated data. An integrated approach would consolidate the hardware and software needed for equipment monitoring into a single substation-based data acquisition, analysis, display and alarm system and be able to report on the condition of the primary asset, the substation. With the proper, intelligent processing, only report by exception need to be transmitted beyond the substation.

Substations must be operated at the most economic utilization level and optimally maintained. However, most all companies are reducing staff and experienced personnel are not replaced. The trend is toward larger utilities with more stations to operate. To keep power flowing in a reliable and economic manner the stations must become more autonomous. To accomplish this, more data about operating and equipment conditions must be measured. To the greatest extent possible this data should be processed, analyzed by expert systems, and stored at the station. There may not be anyone to review it on a routine and continuous basis at a central location and it would be inefficient and overburden the communications links to send large volumes of data to a remote location to extract meaningful information. Putting the processing power at the substation is the essence of the Smart Substation. Only responses to inquiries or requests for action need to be transmitted up to the next level of control. Data processing at the station level will be maximized. It will be an evolution away from the established command and control operation of today to more distributed, localized operation. Such an approach would be complimentary to conventional substation automation but requires different skills for implementation.

The explosive growth in telecommunications insures the continued development of electro-optic components. More powerful and less expensive microprocessors, analog to digital converters, data storage devices, communications systems and other components of the digital age will continue to appear with increased capabilities and reduced costs. Significant advances in software and expert systems programs are being driven by large market demands beyond the utility industry. The Smart Substation should take advantage of all the marketplace has to offer. Clearly more comprehensive utilization of digital tools and devices could be advantageous in operating and maintaining substations. Many digital systems have been developed. IEDs and digital relays are common. Some monitoring systems have been successfully used. All of these developments have been either oriented to a particular type of equipment or function. There has been no effort to approach the entire substation as a system and to develop an integrated digital solution to its operation and maintenance.

Optical measuring systems offer great promise to provide better information at reduced costs. Work is required to expedite the utilization of their digital outputs directly in metering and protection devices with the need for analog conversion and amplification.

The Defense Advanced Research Projects Agency (DARPA), the National Aeronautics and Space Administration (NASA), the process industry and the automotive industry- particularly for low cost, rugged sensors- have been identified as areas for detailed review for technologies adaptable to substation use.

Advanced algorithms for transformer and circuit breaker diagnostics need to be developed to detect all incipient problems that could lead to failure or the need for immediate maintenance. Examples are algorithms to diagnose partial discharge measurements and transformer main tank vs. LTC tank oil temperatures for the various types of load tap changers. Fundamental work is required to advance knowledge of the correlation between test data and insulation condition, particularly the dynamic behavior of gasses, moisture and chemicals of decomposition in transformers. Utility experts, rather than manufacturers, are best suited to direct development of diagnostic and maintenance algorithms. Utility development will assure that the results can be customized to reflect individual utility conditions and emphasis. Furthermore, knowledge of algorithms and their application will be a competitive differentiator among utilities rather than the “common denominator” approach taken by most monitoring system vendors.

The designs of the major substation components will change slowly, but the application of new monitoring, diagnostic, measuring and database systems can be expedited through focused research and development. Utilities can leverage their expertise and available digital technologies in this area. This report is a first step in the project. It provides a basis for discussions and workshops to review knowledge gaps, identify the most promising solutions for substation design and equipment, and select those for further work. Comments and suggestions from a broader selection of utility and industry experts will be considered in the next project phase and selected technologies from other fields reviewed in more detail. A straw man vision of the Smart Substation will be constructed. With these efforts, the Smart Substation project will identify and demonstrate those technologies now available and the work needed to make others available to meet the challenges of the future.

2 THE SMART SUBSTATION PROJECT

Introduction

As a result of industry restructuring and deregulation, substation owners and operators face a series of new, increasing and, at times, conflicting requirements in today's business climate. While utilities struggle with these issues, over the next decade, demand for electric power is expected to grow by about 25%. Currently however, only a 4% increase is planned in transmission capacity.[1] Operational stresses on the grid will increase significantly from this sustained increase in society's need for power. Additional pressure will come from the even more rapid growth in bulk power transactions and the resulting sustained performance requirements.

Regulatory agencies are beginning to act to spur new construction. FERC Order EL01-47-000 takes steps to provide utilities some financial incentives to upgrade tie lines and indicates the growing potential for intervention in transmission construction. At the same time, there is a pronounced regulatory move towards mandatory reliability standards for the transmission grid. Although substations have traditionally not been the major contributor to transmission outages, increased and unanticipated merchant power transactions, the corresponding increase in equipment loading coupled with new connections dictated by regulation and a significantly aging equipment population may rapidly change the situation. Grid, and by extension, substation performance will be under close observation by a growing list of interested parties-regulators, RTO's, power exchanges and those contracting for bulk power deliveries.

Coincidently, financial pressures have increased for the operating companies. There is a continuing need for transmission owners to reduce operating and maintenance costs to meet new corporate targets. Experienced personnel have retired and not been replaced. Uncertainty in investment return has resulted in a reduction in the capital available for new substation investments. Consequently there is a strong desire to extend equipment life while reducing the costs for substation design, construction and refurbishment.

In this environment, those substations that are built or upgraded must be extremely well conceived. The substations of the future must be economic to build, operate, and maintain. They must be environmentally friendly, designed to provide high reliability, maintainability and power quality while, at the same time, be flexible enough to accommodate connections and modes of operation that may be required in response to unforeseen business and regulatory changes. As in the past, technology innovations will provide many of the solutions need by substation designers to meet these growing challenges.

New functionality will be required of the coming generation of substations. Load flow control, energy storage, and current limiting are a few of the possibilities. Just as in other industries, a paradigm shift away from electromechanical systems to substation operation and control based on digital information and electronic control can be expected. More electronic and digital information systems are already being applied in the substation. Included in this trend are not only microprocessor relays and personal computers but also new control and condition monitoring systems. Substation automation has become a viable option. To minimize costs, the best principles of asset management must be built into the station design. Every consideration should be given to optimize not only the initial investment but also the costs of operating and maintaining the station over its operating life, life cycle costs (LCC).

Clearly it will be a formidable task to design substations to meet these requirements. The Smart Substation project is one effort to explore and leverage the changing technology market and assist in the efficient and timely integration and development of technical solutions required in meeting the challenges of today and those of the future.

Objectives

The object of the Smart Substation project is to assess trends and future developments in substations, substation equipment and technologies that may contribute to equipment and station designs. The project scope will consider materials, sensors, communications, monitoring, diagnostics, and data analysis developments. The project will present the state-of-the art in substations today, extrapolate developments expected in the next five to ten years and uncover barriers to and opportunities for technology advancements that may be addressed through cooperative research.

The major conventional components of a substation require expensive and extensive development best left to the manufacturers. These suppliers have become multinational corporations that respond to the international market place. Since the majority of power equipment demand has not been from North America, utilities here have had proportionally less influence on basic equipment innovation and new products. This has not been the case for other areas such as monitoring and diagnostics, communications and data management strategies. Forward thinking utilities and focused research and development programs have resulted in new systems and methodologies that are helping grid owner and operators meet today's challenges.

One of the major goals of the Smart Substation project is to continue that effort by viewing the substation in its entirety rather than just component-by-component and identifying needs that can be met through additional research or the application of developments from other industries. Although, by necessity, some of the needs identified will be equipment specific, others will be better addressed in an integrated fashion, treating the substation as a system. A second project goal is to develop a straw-man design for a substation utilizing the best available technologies to minimize costs while maintaining high levels of reliability and security. It is likely that the exercise of designing an integrated substation will further highlight and clarify technology gaps. Finally, the Smart Substation project will address the methodology required to quantify the benefits and enumerate the issues of applying the next generation equipment.

The emphasis of this project is transmission substations but it is expected that many of the ideas will be just as applicable to distribution substations. Similarly, although the approach is to consider a new station, many of the results may be used to retrofit or up-grade existing stations.

The ultimate goal is to present a vision for the Smart Substation of the future. This substation will be designed and built to provide the latest low-cost equipment, with diagnostic and alarm intelligence close to the component level, and the ability to communicate how the equipment is performing and when and what kind of maintenance is needed. Developments in materials, diagnostics, communications and sensors will be reviewed and their implications on new station construction and refurbishment evaluated. Technology solutions needed to simplify station design, and improve operation, maintenance and reliability will be identified.

Approach

This report is the results of the initial phase in the Smart Substation project. The goal here is to provide a starting point, a baseline of the state-of-the-art, and an overview guide to some of the latest available developments for consideration in designing stations over the next few years; to indicate areas where research can be focused to expedite developments necessary to meet utility needs beyond that time; and to provide a basis for planning discussions with researchers and industry experts to develop programs to meet those needs. The scope is not limited to monitoring and diagnostics but rather covers a broad range of components so as not to preclude other potential contributions to designing more flexible, secure, reliable and cost-effective substations. However, this report is not meant to be a compendium or catalog of products now, or soon to be, on the market. That task is left to the available supplier's literature.

There is no standard substation; in fact, there are only a few instances where two substations are identical. However, voltage, function, and the environment in which they operate can categorize substations. The highest voltages, 345 kV and above, are used for major power transmission systems, whereas 69 kV and below is typically used at the distribution level. Voltages in between these two extremes are used in both high voltage distribution or sub-transmission networks. Substations may also be separated into different types based on their functionality. Some have multiple voltages and serve multiple loads of different types. Other substations are simply interchanges where lines are split to serve two load areas or lines are combined to bring two or more power sources together to supply one load, and a few simply provide VAR support along transmission lines. Finally, some substations operate in deserts, others in areas of high humidity and high temperature, while still others operate in extremely cold conditions. Economic, environmental and reliability considerations all affect substation design. Because substations are often so unique, the approach taken here is to look at the major equipment types and design philosophies individually rather than at a theoretical station design.

The following chapters deal with each of the major components and technologies comprising a substation. Technologies that are expected to play a larger role in future stations, such as superconductivity, also have been included. The present state of the technology is reviewed. Near term trends, developments that are under way or that can be reasonably expected in the next few years are explored. The possible barriers to successful development and potential for accelerated progress are also examined. Finally, a longer-term vision of what may be accomplished is presented. Individual ideas and concepts are suggested for consideration in the next phase of the project.

This document is by no means all-inclusive. It is meant to be a first step, to stimulate thought, suggest areas for further investigation and focus attention on expected needs. Undoubtedly, equipment manufacturers are addressing some of the areas discussed but for commercial reasons have not publicized their efforts. Nonetheless, it is hoped that the considerations presented here will lay the groundwork for discussion of additional avenues for exploration and form the basis for the next steps required in the development of the Smart Substation. In turn, the Smart Substation can take its place as a key element in the development of the electronically controlled, highly reliable and secure power grid of the future.

3
TRANSFORMERS

Scope of Equipment Covered

Transformer and accessories, including load tap changing equipment.

Present State of Technology

Power transformers for substation application utilize oil-impregnated paper as conductor insulation, and pressboard for major insulation between windings and from windings to ground. This insulation is also part of the mechanical integrity of the windings and the core and coil assembly. Paper insulation when impregnated with oil is a very good insulator; however, paper has the capability of absorbing moisture from the oil and also creating water by breakdown of its cellulose fibers when heated. A paper/oil insulation system is economical, but has the following drawbacks:

- When oxygen is also present in the oil, the combined effect with moisture and operation at high temperature causes accelerated deterioration of the paper. This in turn will cause the paper to become brittle, mechanically weak, and lose dielectric strength.
- Moisture in the oil/paper system can result in the evolution of water vapor bubbles being expelled from the conductor insulation when it is suddenly heated to a high temperature, as is the case during a sudden increase in load.
- The rough surface of the major insulation is a factor in creating static electrification (a potential failure condition) when oil traveling at a high flow rate moves along its surface.

The winding material used for conductors today is almost exclusively copper, but aluminum has been used in the past. The heat created by the current flowing through the windings is conducted to the insulating oil, and must be removed by oil to air radiators, forced oil-to-air or oil-to-water heat exchangers. Oil is circulated through the windings by either natural convection or pumped oil. The pumped oil may or may not be directed through the windings. In addition, fans can be utilized to blow the hot air away from the external radiators or heat exchangers.

Modern day power transformer cores consist of multiple thin laminations of grain oriented, laser etched, silicon steel. The core is purposely grounded at only one point. Overheating of the core due to the unintended occurrence of a second ground can create undesirable gasses in the insulating oil. Likewise, the core can create gasses or become physically damaged when it is operated at high temperature. High core temperature can be caused by high magnetic flux densities from over-excitation or geomagnetically induced currents.

The core, like the windings, is also a source of heat that results from hysteresis and eddy-current losses in the core material.

High-voltage bushings are generally of a condenser design utilizing foils, conductive inks, or paints to grade the voltage from the conductor to ground. Bushings are susceptible to internal failure from condenser defects, moisture intrusion, thermal runaway and other causes. Contamination on the outer shell can cause an external flashover.

Load tap changers are of either the reactance or the resistance type. When operating properly, they perform their function very satisfactorily, but they are the biggest single maintenance item and cause of failure on large power transformers. Load tap changer contacts are susceptible to coking, and the drive mechanism is subject to mechanical failure.

Various monitoring devices are now being applied on substation power transformers. However, monitoring has yet to be fully embraced by utilities. Simple devices such as dissolved hydrogen detectors or LTC/main tank temperature differential measurements are fairly well accepted but other more sophisticated, single purpose devices are still uncommon. Diagnostic algorithms have been, and are being, developed to determine when maintenance should be performed and to alert the operator of abnormal conditions that could lead to failure.

Most power transformers manufactured in the world today are designed in accordance with either IEEE/ANSI C57.12.00 or IEC 76, and related standards. These standards cover such areas as service conditions, ratings, certain construction requirements, short circuit capability and factory testing requirements. Guidelines for the loading of power transformers are provided in IEEE/ANSI C57.91 and in IEC 354. Load tap changer performance requirements are covered in IEEE/ANSI C57.131 and in IEC-214.

Anticipated Near Term Trends

Based on previous work or with new initiatives, improvements that could be realized in the next five years are:

- Development of a main tank, continuous oil filtration systems that have the capability of maintaining the oil in as-new condition. This in turn will prevent decomposition chemicals of oil from attacking the cellulose and will therefore maintain the integrity of the complete dielectric system. EPRI has done work on this and has demonstrated a laboratory version of the filtration system. It has the capability of removing oxygen, moisture, acids and other chemicals, in addition to particles.
- Additional standardization of transformer designs among utility users would be beneficial by lowering the first cost and lead times of new transformer purchases.
- Additional standardization of transformer designs within a utility would be beneficial in reducing the number of spares kept in inventory.
- More field experience and improved knowledge would increase use of on-line monitoring and advanced diagnostics would result in lowering maintenance costs and improving

reliability. Monitoring and diagnostics will give advance warning of impending failures and consequently help extend life and delay replacement.

- Advancement of knowledge of the correlation between test data and insulation condition. Particularly the dynamic behavior of gasses, moisture and chemicals of decomposition.
- Development of accurate thermal models, not only for new, but also for already installed transformers. Such models will improve reliability by detecting cooling system abnormalities and the need for heat exchanger maintenance.
- Implementation of these thermal models into more sophisticated programmable winding temperature indicators would give systems that are more accurate under all conditions of operation.
- Increased use of fiber-optic thermal sensors embedded in the windings at the known hot spots will give a more accurate indication of loading limits.
- Implementation of dynamic loading of substation power transformers, utilizing accurate thermal models, will result in better asset utilization by maximizing their use, especially during emergency conditions.
- Increased use of non-cellulose insulation will allow emergency loading that is limited by the temperature of the insulating oil and not by the hottest spot in the insulation.
- Development of more sophisticated test techniques that can give a better indication of general or localized deterioration. Techniques such as partial discharge detection and location, time domain dielectric spectroscopy, frequency domain dielectric response measurements, polarization and depolarization current and return voltage measurements.

Potential Acceleration

Standardization of transformer designs among utility users will require a cooperative effort among interested participants. Standardizing voltage and MVA ratings and impedances may not be realistic to achieve. Standardization should be more likely achieved for accessories, including bushings, cooling equipment, load tap changer, control equipment and monitoring devices. Accessory “packages” could be developed, similar to what can be chosen when purchasing an automobile.

Standardization of transformer designs within a utility will require each utility to take a hard look at the different designs now being used as well as the designs planned for the future. The goal would be to minimize the number of designs to be purchased in the future and to reduce the number of spare transformers and accessories.

Utilities should, with EPRI’s assistance, implement the transformer diagnostic algorithms that have already been developed for use in MMW^2, and EPRI should continue the development of advanced transformer diagnostic algorithms. The results of the algorithms should give the utility user an easier to understand transformer diagnostic evaluation in terms of “green, yellow or red”.

Transformer manufacturers have developed accurate thermal models for the transformers now being produced. Methods need to be developed to determine similar thermal models for older, in-service transformers, utilizing whatever design information available and the results of field tests that may be needed to determine the constants to be used in the model.

With thermal models for these installed transformers, dynamic loading of important transformers, such as tie transformers, can be more widely implemented. This could be accomplished with enhancement of the present version of Dynamic Thermal Circuit Rating (DTCR) models [3].

Transformers utilizing non-cellulose insulation are already available, however, their use has been mainly for mobile transformer applications because of the higher cost. Development of a generic standard transformer specification for transformers utilizing non-cellulose insulation for use by EPRI member companies could help to widen the use of these units. The total owning costs of cellulose vs. non-cellulose transformer designs need to be investigated.

Development of a bushing tap coupler that can be used to capture multiple signals for various measurements such as PD, FRA and power factor would facilitate the installation of these condition-monitoring devices.

Barriers/limits of Technology

Barriers or limits to accomplishing the improvements in the previous section are, in some cases, organizational and not technological. The technological barriers or limits are:

The deregulation of the electric utility energy industry in the USA has resulted in many utilities divesting themselves of their generation to become regulated wires/delivery/T&D companies. With that divestiture went the energy business and perhaps 80% of the value of substation transformer loss evaluation. As a consequence, loss evaluation figures used in purchasing new units have dropped to approximately 20% of the value that was used before deregulation. This raises the specter of purchasing lower cost but less efficient power transformers in the future. Higher losses mean more heat to remove and the potential for heat related problems.

Although much has been learned, there are still significant gaps in the knowledge of the relationship among externally measurable parameters and internal transformer condition. Some specific areas where building on existing work would be most beneficial are:

- Advanced algorithms for transformer diagnostics need to be developed to detect all incipient transformer problems that could lead to failure or the need for immediate maintenance. Examples are algorithms to diagnose partial discharge measurements and transformer main tank vs. LTC tank oil temperatures for the various types of load tap changers.
- Algorithms for implementing the “water in paper activity” method for determining the amount of water in transformer insulation need to be finalized. An accurate and reliable device for monitoring the percent saturation of water in oil needs to be determined and identified.

- Accurate algorithms are needed to determine the condition of a load tap changer from the results of gas in oil or other types of testing.
- A simple test method to accurately determine the constants for a thermal model for an in-service transformer needs to be developed. The thermal model should be able to accurately determine not only the transformer top oil temperature, but also the winding hottest-spot temperature under all conditions.

Longer Term Vision

Desired Goals

The drivers for improvement include reduced capital investment, reduced maintenance costs, improved reliability, and long lead times for replacements. Needed are:

- The ability to be able to make accurate predictions of condition and remaining transformer life.
- Improved oil cooling systems with high efficiency and low maintenance requirements.
- A transformer whose maximum loading is limited by voltage drop rather than by winding insulation temperature, oil temperature or other thermal considerations.
- An operational and cost effective solid-state load tap changer

Technology Needed and Time Table

- Cost effective high temperature insulating fluid, five to ten years
- Superconducting windings, ten to twenty years.
- A non-mechanically driven load tap changer, five to ten years.
- Embedded transducers for condition assessment, five to ten years.

Opportunities for Use of Technologies In Other Industries

- Photonic transducers for temperature, pressure, light absorption, etc.

Knowledge Gaps and R& D Work Needed to Expedite Progress

- A transformer life assessment model.
- Development of a prototype transformer with superconducting windings
- A solid-state load tap changer.

4
CIRCUIT BREAKERS

Scope of Equipment Covered

Power circuit breakers rated at and above 69kV.

Present State of Technology

Power circuit breakers are generally classified by their dielectric and interrupting media.

SF_6 Circuit Breakers

SF_6 type circuit breakers have become the dominant technology at high voltages. The combination of the puffer concept with the use of extended nozzles resulted in a superior design that has swept the commercial market. Attractive models are available in reasonable sizes and costs. A number of manufacturers are able to offer units with high-speed operation and options of live tank or dead tank design.

This overwhelming commercial position has been further enhanced during the last dozen years as designs have been improved incrementally in terms of quality of seals and general construction, size – which has related improvements in weight and amount of gas required for operation – and voltage per break.

The size reduction has come from two major factors. The first has been the reduction of tank diameter. Higher field strengths are now possible as manufacturers have gained better modeling tools, design experience and learned the small but significant techniques of how to uniformly treat surfaces and to cast insulators without voids. The second factor has been the reduction in the number of breaks required for a given voltage.

The number of breaks is most significant since so many factors track almost linearly with it. With fewer breaks, the tank can be smaller, the number of parts can be reduced, and the strength of the mechanism can be minimized. A cascading set of benefits then ensues such as easier installation, a smaller footprint requirement, less maintenance effort and higher reliability.

SF_6 has a significant presence at medium voltage as well. These units typically have sealed gas containers for which maintenance is not anticipated. The type is used for a reasonable segment of the market today, although vacuum is still the more popular choice.

Environmental Considerations

In the past SF_6 breakers were seen as a major environmental improvement over oil breakers. It is true that some care is required when tanks are opened for maintenance, but the necessary steps are acceptable and procedures are now known and even tabulated as in the EPRI report on SF6 Handling Practices[4]. When the ozone "hole" was found in Antarctica, concern emerged that SF6 might be playing a role in ozone depletion. Careful studies established that fluorine, unlike chlorine, does not play a catalytic role in transforming ozone into other gases. Consequently SF6 has been cleared as far is ozone depletion is concerned.

SF6 does, however, contribute towards global warming. The "greenhouse effect" results when the atmosphere transmits incoming light from the sun, but absorbs the radiated light from the earth. Greenhouses work on this principle since ordinary glass transmits visible light, the major component emitted by the sun, but absorbs most infrared (IR) light which is emitted by the earth. SF_6 has an extremely intense absorption band at a wavelength of about 10.5 microns. This wavelength matches the peak of the radiation output from the earth, making it particularly significant. Another factor of importance is that this wavelength is one that is not subject to any absorption by water vapor as many other IR wavelengths are. Environmental scientists calculate that SF_6 gas is about 24,000 times more effective than CO_2 gas in contributing to global warming on a pound-for-pound basis.

Electric utilities account for about 80% of the world's use of SF_6, so the United States Environmental Protection Agency (EPA) has taken note and instituted a voluntary gas release reduction program. Parallel agencies in other countries are also acting or formulating plans. This is happening despite the fact that SF_6 is only responsible for about 0.1 to 0.2% of the manmade component of global warming because of the potential long-term impact of this very stable, long-lived gas. Today's EPA program consists of voluntary signing participating members to a Memorandum of Understanding (MOU) relating to their SF_6 policies and practices.

There is concern in the utility community that government involvement may expand. The EPA MOU only asks that leaks be fixed if the fix is economically justified, just the path the utility should follow to its own benefit. Some other countries have put limits on SF_6 use or imposed significant taxes on its use and the United States may one day take a similar path. There is a political controversy relating to global warming and this injects a further uncertainty about the future course of governmental involvement. Climate predictions are far from perfect and it is likely that there remain significant factors not yet understood so the further course of scientific study may also affect government policies. The consequence of all this environmental issue is that utilities are interested in finding alternative technologies.

Some negative aspects have been associated with SF_6 single pressure breaker developments and evolution. In the course of reducing size and use of materials, some models have suffered from weaknesses due to inferior materials and inadequate designs, such as sliding contacts wearing out prematurely or breaking, corrosion problems, bearing failures and seal failures. Mechanisms are now normally type tested to 10,000 operations. Improvements have been made in use of circuit breaker lubricants and weather protection for the mechanisms.

More components are now sealed for the expected life. More assemblies are not intended for maintenance. Performance monitoring systems are now often offered on new breakers.

Air Blast Circuit Breakers

Air blast breakers are not produced today for high voltages, but remain in the field in significant numbers. Their advantage is that the interruption medium is entirely benign and readily available from the surroundings. They also have short contact travel distances and so are well suited for fast action and for live tank designs. Their disadvantage is that substituting a nozzle does not add to the interruption voltage attained by an orifice; so more breaks are required compared with an SF_6 breaker. As a result, air blast breakers, if offered today, would be larger and more expensive than their SF_6 competitors. Air blast breakers have some advantages over SF_6 breakers in low temperature operation in not requiring heaters or gas mixtures to prevent liquefaction.

The older air blast breakers are reaching the end of their life and are being removed from service. These units have a reputation for poor seals and consequently a high need for maintenance and these factors also act to accelerate their removal from service. Air blast breakers require costly and complex compressors, air driers and air delivery systems. These systems also require high maintenance.

Air Magnetic Circuit Breakers

Air magnetic circuit breakers conduct fault current through coils to produce magnetic fields that push the electric arc into a lengthened path that then encounters solid material which it ablates. This ablation induces gas flow and further increases the arc voltage as it prepares the arc for interruption. Air magnetic breakers are applied at medium voltage where they are capable of introducing a significant degree of current limiting in the latter portions of the arcing period. This means that the device is interrupting a lower current arc and it further means that fault current has been brought back closer in phase to system voltage so the interrupting transient experienced by the breaker is significantly reduced. Because the arc must develop from a short length to a longer, convoluted length, air magnetic breakers are not suited for very fast action. Typically they require four or more cycles for interruption. Older designs were made with asbestos compounds in the chutes and this has been an environmental concern that has resulted in considerable retrofit activity. Many air magnetic breaker failures have been attributed to moisture in the arc chutes. More evidence is now emerging about breaker failures due to slow operation resulting from inadequate and old lubrication.

Oil Circuit Breakers

Oil breakers were the industry standard for many years. They have moderate cost and can be made in live tank or dead tank designs. It is difficult to achieve very high speeds with oil breakers. They are not popular today because of several factors. Increased environmental concerns have put more emphasis on issues relating to oil spills. There is the danger of fire, a significant factor for dead tank designs. Operation of oil circuit breakers involves more maintenance work on an ongoing basis and this is a problem in a time when most utilities have made reductions in their maintenance staff. For these reasons, oil is out of favor as an interruption medium. Replacement of existing oil breakers may be dictated by oil containment requirements, maintenance costs, ratings being exceeded and end of life of major components.

Vacuum Circuit Breakers

Vacuum circuit breakers have been very successful at medium voltages. These devices are economical, compact, and reliable and they require low maintenance. There is no environmental issue associated with the use of vacuum “bottles.” The contact stroke required is very short and this contributes to fast operation and small sized, simple mechanisms, both desirable attributes. Vacuum breakers dominate the market for medium voltage, but have not been successful at transmission class voltages. Vacuum devices have not succeeded at higher voltages when high current capacity is also necessary. It has also been found that vacuum breaks do not share voltage evenly when operated in series. This factor makes it even more difficult to achieve higher voltages, given that the voltage per break is limited.

There were major concerns when vacuum breakers were first introduced due to the facts that: 1) it is difficult to provide a visual confirmation of the break and 2) there were concerns that the vacuum would be lost over time and there would be no indication to the utility that the breaker consequently was incapable of interruption when called on. These concerns have receded as favorable experience has accumulated. Early versions of vacuum breakers had a tendency to produce high voltage transients due to current interruption before reaching current zero (chopping), which manufacturers have now overcome.

Anticipated Near Term Trends

Standardization of circuit breaker designs among utility near term users would be beneficial by lowering the first cost and lead times of new purchases.

Standardization of circuit breaker designs within a utility would be beneficial by reducing the number of spares kept in inventory.

Increased use of on-line monitoring and advanced diagnostics would result in lowering maintenance costs and improving reliability. Circuit breaker manufacturers as well as others are now offering on-line monitors with varying levels of complexity. Monitoring and diagnostics will give advance warning of impending failures and consequently help extend life and delay replacement.

Development of more sophisticated modeling or test techniques that can give a better indication of general or localized deterioration, particularly for contact deterioration, would add to the value of on-line monitoring.

Potential Acceleration

Standardization of circuit breakers designs for voltage and current classes has been the norm for many years. However auxiliaries, controls and bushing types can vary considerably. Standardization among utility users will require a cooperative effort among interested participants.

Standardization of circuit breaker designs within a utility will require each utility to take a hard look at the different designs now being used as well as the designs planned for the future. The goal would be to minimize the number of designs to be purchased in the future and to reduce the number of spares required.

Utilities should, with EPRI's assistance, continue the development of diagnostic algorithms for use in MMW^2.

Barriers/limits of Technology

Better wear models and algorithms for correlating measured parameters with breaker condition are required.

Longer Term Vision

Circuit Breaker / Disconnect Switch

Some manufacturers now offer a circuit breaker that also contains the disconnect and grounding switch functions along with measurement sensors. More of these multi-function devices, which reduce costs and most likely improve reliability, can be expected in the future. Optical sensors (see later chapter) are particularly well suited for these combination devices. Current standards and safety practices may have to be modified for wide spread application.

Solid State Current Limiting Breakers

Utility engineers faced with the challenges of integrating new generation into existing power systems, clearing faults more quickly or finding an alternative to SF_6 breakers will soon have a new product to meet all of their needs: a solid state current limiting circuit breaker. Electric utilities have long wished for a practical, reasonably priced, solid-state circuit breaker that could provide very reliable service with little maintenance. Environmental problems associated with SF_6, recently identified as a greenhouse gas, and oil, long a troublesome material, might be eliminated or minimized. Closing can be timed so as to minimize transients. Adding the function of current limiting, also a long-held dream, enhances significantly the value of the breaker. The largest challenge is to accomplish all this at a price that utilities can accept.

Advanced current interruption technology, utilizing high power solid-state components, has opened the door to high power control at a lower cost than ever before. The Solid State Current

Limiting Breaker (SSCLB) offers a viable solution to the transmission and distribution system problems caused by high available fault current. It appears that the time has now arrived when the selling price can be low enough to justify significant sales. By providing instantaneous (sub-cycle) current limiting, the SSCLB alleviates the short circuit condition in both downstream and upstream devices by limiting fault currents coming from the sources of high short circuit capacity. The advantages of added functions that a conventional circuit breaker cannot offer help to justify the higher cost associated with a solid-state breaker.

To interrupt the current, the SSCLB must rapidly insert an energy-absorbing element (linear or non-linear resistor) into the circuit to limit the fault current. In addition to limiting the fault current, the SSCLB can also limit the inrush current (soft start capability), even for capacitive loads, by gradually phasing in the switching device.

A solid-state breaker can offer the following advantages

- Limited fault current
- Limited inrush current (soft start), even for capacitive loads
- Repeated operations with high reliability and without wear-out
- Reduced switching surges
- Avoided environmental problems of SF_6 and oil.

By limiting the current, fault isolation and better network protection is achieved. This would alleviate most of the distribution system situations that result in voltage sags, swells, and power outages. Thus the SSCLB can substantially improve the power quality through fault current limiting and inrush current reduction.

High fault currents are known to be a factor in reducing transformer life, so it is expected that an advantage from the use of a current limiting breaker will be longer life with higher reliability for nearby transformers.

It is expected that the solid-state circuit breaker with current limiting capability can provide new functions, such as:

- Application in a few key locations is an alternative to large scale power system breaker up rate programs
- Surgical alternatives for Distribution Station duty relief
- Surgical up rating solutions that can increase capacity within station physical space limitations
- Potential for Power Quality improvements through sectionalizing
- Solutions for mitigating the effects of new generation at lower voltages within Distribution Systems

Principle of Operation

There are several ways a SSCL could operate. The simplest would be to carry steady state current through a pair of solid-state power electronic devices known as thyristors and, when a fault occurs, stop issuing firing or gating pulses for the thyristors. Since thyristors conduct in one direction only, it is always necessary to have a pair of them to carry AC. Once thyristors have been gated and turn on, they continue to conduct until the current they are carrying reverses polarity. They turn off at approximately the zero crossing, not unlike a conventional circuit breaker that clears at a current zero. Such a design would be fast acting when compared with a conventional mechanical breaker, but it would not reduce the fault current magnitude, only its duration.

Another approach would be to use current carrying devices that have the ability to be turned off during the normal half cycle current conduction period. Examples of this class are gate turn off thyristors or GTOs and insulated gate bipolar transistors or IGBTs. Given the proper signal during the fault, they will shut the flow off and achieve current limiting. They offer the advantage of simplicity, but they come with some disadvantages as well. They are more expensive, they have higher losses during ordinary conduction, and they require a significant turn-off gate pulse that adds cost and complexity.

EPRI is investigating adding a commutation circuit to the thyristors that carry the continuous current. There will be a capacitor, a small inductor and another pair of thyristors that will be gated on so as to allow the L-C circuit to oscillate. The current of this oscillation, at something like a kilohertz, will combine with the fault current to produce a quick current zero at which the power thyristor will clear.

Future Development

The first task is to determine the desired and useful range of specifications and ratings that should be developed. Because the SSCLB will be a new device with functionality that is not standard today, there is less guidance in this area and this step is both necessary and important. The involvement of protective relay action must also be factored into the design of the SSCLB.

The first phase of hardware development will have the goal of producing a circuit module capable of the current levels needed, but not the full transmission voltage. Prototypes of this circuit will be made and tested on a single-phase basis. After a suitable degree of confidence is established, work will proceed on the design, construction, and testing of a three-phase, medium voltage laboratory prototype unit. Prototypes will be made and shipped to participating utilities for field trials. After the test period, the host utilities will be asked to report and to comment on the performance of their units. At that time, EPRI expects the contractor to make a revised commercial version of this medium voltage device available on the open market.

The final phase will be the development of a 138 kV SSCLB. Because the modules are simply stacked in series for increasing voltage, this work will not start from scratch. There is very wide experience in constructing and operating large arrays of similar power electronics devices for AC to DC converters and for FACTS devices as high as 600kV.

After lab devices have been made and tested, EPRI will construct prototypes for field trials at participating utilities. Host utilities will be asked to report on their experiences with the devices.

5
GAS INSULATED SWITCHGEAR

Scope of Equipment Covered

SF_6 Gas Insulated Substations (GIS) for the purpose of this report include air entrance bushings, power cable connections, transformer connections, bus, breakers, disconnects, current and voltage measuring devices and surge arresters.

Present State of Technology

GIS advantages include compactness, protection against elements, safe operation and aesthetic compatibility.

The focus of this report is on GIS in North America, where market share for GIS has remained very low compared with worldwide use. Higher population densities and resulting high cost for land has in many European and Asian countries influenced the economics in favor of GIS versus air-insulated stations. Worldwide over half of new GIS projects are supplied on a turnkey basis. This is a reflection of the need to minimize construction risk on the part of the utilities and the specialized knowledge for successful installation.

Improvements in freestanding dead-tank design SF_6 circuit breakers have helped these types of breakers capture the largest portion of the high voltage breaker market in the US. Attractiveness of air-insulated stations has also been affected by traditional specification requirements, station layouts and availability of suitable land.

Many new SF_6-to-air bushings are now of composite construction, consisting of a fiberglass/epoxy inner cylinder which contains the SF_6 gas and provides structural strength. The external weather shed is silicone rubber. The lifespan of this construction is unknown.

Reliability issues with early versions of GIS created a poor reputation. GIS production in North America is comparatively small, with designs and many critical components primarily sourced from Europe or Japan. However, GIS bus and some components are still being produced in North America.

The stations being offered by overseas manufacturers are designed primarily for worldwide markets. Designs often differ from normal North American requirements in station layouts and safety requirements. The modifications needed to the standard designs have made GIS stations costlier in the North American market.

Dielectric failures in older stations and the need for very high reliability in many newer stations have motivated developments to diagnose GIS insulation integrity. This has resulted in acoustic and ultra high frequency (UHF) radio emission detection systems to detect partial discharge activity. Portable systems are being used to characterize partial discharge activity (and thus ageing) in solid insulation as well as detecting particles and other sources of partial discharge activity. UHF partial discharge detection systems are available for continuous GIS monitoring in new stations and for retrofit applications in existing stations.

The integration of digital protection, control and condition monitoring systems by manufacturers is changing GIS operations and maintenance practices. Digital protection relays are now standard. New data acquisition and control systems (SCADA) now normally include functions that are designed for maintenance information purposes as well as for operation. New methods in current and voltage sensing are in the process of becoming cost effective. The GIS suppliers normally offer equipment monitoring and diagnostic options. The integration of these systems and the use of fiber optics are becoming common.

Modular systems are used for primary GIS components as well as for secondary systems components. The features of secondary components may include various levels of self-supervision, monitoring and trend processing.

Anticipated Near Term Trends

Increased equipment loading and inability to build new or expand conventional stations to accommodate additional load has lowered the relative GIS costs compared with air-insulated stations. Manufacturing improvements have lowered the real GIS costs as well. Changes in the utility business environment and ownership are bringing about greater acceptance of changes. The above factors will increase the market share of GIS. This is expected even without further GIS technical improvements.

Utilities will need GIS for a larger part of expansion in order to accommodate urban load growth. GIS allows substations to be located where air insulated stations would be unacceptable and where other associated costs, such as distribution, can be reduced. Delays and controversy can be avoided by blending stations into normal urban environments.

The evolutionary development of GIS has resulted in higher integration, reduced opportunity for defects and more compact designs. Incremental improvements are continuing in interrupter technology, such as self-extinguishing features at medium voltages and resistance interruption at very high voltages.

Modular systems with fail-safe features and higher quality and production volumes have emerged. Digital computer technology, robust processors and integral peripherals have also contributed to more operational functionality. Combinations of disconnect and ground switches are offered at medium voltages. System monitoring with trend evaluation can now warn of potential problems and predict maintenance requirements. A high percentage of failures occur after maintenance. It is therefore important to perform maintenance only when it is required. These trends are expected to continue.

Decentralized computers monitor important components and sensors. Device positions, trip coils, energy storage status, SF_6 gas pressure and temperature and pump operations are examples of monitored parameters. The status acquisition, measured values, interlock status, operational readiness and other information are evaluated autonomously at the lowest possible level. Improvements in data acquisition integration and the use of processed information are expected to continue.

Potential Acceleration

Numerous special requirements are specified by various utilities. These requirements are often based on traditional approaches to the operation of air-insulated stations. As an example, safety requirements dictate visible breaks, which add size and complexity to GIS equipment, such as space for access and observation platforms. A review and comparison of specifications has the potential to reduce unnecessary requirements, thus allowing cost reductions due to standardizations. Such review could aim for alternate ways to achieve a desired level of system security and safety of operation.

Many formats are used for digital data collection systems. Standard formats for information at higher levels can accelerate acceptance of a transformation to intelligent systems for GIS operation and maintenance. This would apply to air insulated stations as well. This topic is further explored in the chapter on Information Systems.

Wiring for interlocking and controls are complex. Fiber optic cables can reduce wiring and complexity.

Redundancies, such as auxiliary switches and instrument transformers for separate functions can be eliminated.

Barriers/limits of Technology

The greenhouse gas property of SF_6 has introduced uncertainties about the future use of SF_6 based technology. Governments have become involved with concerns about the release of SF_6 gas. These concerns have not been resolved. The present economics does not take into account the potential harm from SF_6 release. Applications of taxes and regulations could change GIS use.

Present transformer technology and issues, such as oil containment, fire concerns, noise and size restrict transformer location alternatives, which also affects applications of GIS. SF_6 gas filled power transformers are now available, but costlier than oil filled ones.

Longer Term Vision

Desired Goals

The long-term use of GIS technology depends on acceptance of the use of SF_6 gas and the relative cost compared with alternatives. The undesirable SF_6 greenhouse properties probably make it necessary to deal with SF_6 release from existing equipment more aggressively[5]. This will affect existing SF_6 equipment reliability as well GIS reputation and acceptance.

The primary components of GIS, such as circuit breakers, disconnects and ground switches are still being incrementally improved and should continue to benefit from improvements. Changes in current and voltage sensing to optical systems (see Optical Measuring Systems Chapter) have the potential to accelerate integration of digital protection, control and data systems.

Maintainability can be improved by providing appropriate access and module replacement strategies. The criticalities of module locations need to be considered.

The complexity of GIS can continue to be reduced by the use of modules for secondary systems for measurement, control, protection and recording.

Drivers for Improvement

Most new GIS equipment and SF_6 gas handling equipment have a good reputation regarding SF_6 gas release. SF_6 gas release concern was not as high when older equipment was designed. Governments may dictate SF_6 control initiatives that will affect new as well as old GIS equipment. Methodologies should be developed and verified for sealing leaks on older equipment. Other considerations being equal, reducing the leak rate on installed equipment would extend its service life and reduce operating costs.

Maintenance costs due to repeated failures have in some cases resulted in complete replacement of old GIS with new GIS of a higher quality.

Technology Needed and Time Table

Many existing GIS stations have reached an age where reliability and maintenance costs have become serious issues. Replacement has become an option in the most severe cases. Monitoring in the older GIS stations is normally limited to SF_6 density and the status of the switching devices. Some monitoring devices are now available to collect data from current transformers, trip coils and auxiliary switches. The selection of monitors and their functions are relatively limited as yet, and designed primarily for free standing medium voltage circuit breakers. The demand for monitoring devices is increasing, particularly because of reductions in time based maintenance activities and the increased age of the early GIS stations. These problems may require comprehensive life extension programs. Development of mechanical and electrical monitoring systems suitable for retrofit should be part of such programs.

SF_6 leak detection technology is now readily available[6]. Present economic incentives are not necessarily sufficient to justify leak repairs. Many utilities therefore make extensive use of less costly temporary leak repairs, with mixed success. A method could be developed to take into account the true cost of SF_6 gas release, including greenhouse gas effect and reliability. The results may justify more attention to leak repair. Leak repair recommendations would also be useful.

Opportunities for Use of Technologies In Other Industries

New GIS monitoring systems now often include position sensors as one of the important inputs. This provides contact position against time for a circuit breaker and is relatively inexpensive for new installations.

Some circuit breaker testing machines designed for periodic testing also offer vibration signature input options. The timing and magnitude of vibration events are compared with known signatures. Vibration has been used successfully in numerous other applications and could be adapted for GIS condition monitoring use as well. This could be particularly valuable for retrofit monitoring applications where position sensors may not be easily applied.

Knowledge Gaps and R& D Work Needed to Expedite Progress

Modern GIS systems are often promoted to be maintenance free. However, actual field experience is short relative to the anticipated service life. The length of time equipment is expected to remain maintenance free could be addressed through research identifying any limitations such as seals, lubricants, contacts and insulation. Life cycle costs would then be easier to take into account and be more reliable. This could prevent the use of equipment with inappropriate quality and allow quality comparisons.

Retrofit UHF monitoring systems are available but may require extensive modifications for sensor installations. Acoustic sensors can provide complementary information, but are not offered for retrofit or new installations, only periodic measurements. This method might be useful for retrofit monitoring applications if further developed.

Monitoring GIS would require motion diagnostics in addition to electrical diagnostics. The motion systems offered for medium voltage circuit breakers could be used, but utilities have not found these systems sufficiently attractive for high voltage breakers yet. There is probably a market for such a device to monitor key data but its usefulness and reliability would need to be proven.

6
RELAYING AND PROTECTION

Scope of Equipment Covered

A vast variety of protection systems and equipment are offered in today's market place. A number of international suppliers compete vigorously by supplying product lines of many different designs. It would be beyond the scope of this report to deal in any detail with the different schemes and designs available. Therefore only general comments and trends are presented.

Present State of Technology

The latest generation of microprocessor relays possesses a significant amount of computing power. Microprocessor relays often can accommodate more complex system operation because of the inputs provided to the relay and the programming features included with the relay. In many cases, numerous functions are provided in the relay so that the number of discrete relays required for protection may be reduced substantially. Additional functions may be provided to protect a system from abnormal conditions that might not otherwise be considered based on the low occurrence of such conditions or because of other considerations.

Microprocessor relays often provide the relay engineer with many more options for providing protection than either their electromechanical or static relay counterparts. Once the inputs to the relay are obtained, the decision module can then be programmed to provide many protective functions with these inputs. This information can also be used to implement the transmittal of data remotely through SCADA or other data retrieval means.

Substation automation is the use of state-of-the-art computers, communications, and networking equipment to optimize substation operations and to facilitate remote monitoring and control of substations cost-effectively. Substation automation uses intelligent electronic devices in the substation to provide enhanced integrated and coordinated monitoring and control capabilities. Substation automation may include traditional SCADA equipment, but more often encompasses traditional SCADA functionality while providing extended monitoring and control capabilities through the use of non-traditional system elements.

In the traditional SCADA system, a host computer system (master station) located at the energy control center communicates with remote terminal units located in the substations. RTUs are traditionally "dumb" (non-intelligent) devices with very limited or no capability to perform local, unsupervised control. Control decisions are processed in the master station and then carried out by the RTU through the use of discrete electromechanical control relays in or connected to the

RTU. Discrete transducers, whose outputs are wired into the RTU, generate analog telemetry information (watts, VARs, volts, amps, etc.). Device status - breaker position, load tap changer position, etc.- is monitored by the RTU through sensing of discrete contacts on these devices. Monitored data is multiplexed by the RTU and communicated back to the master station computer in the form of asynchronous serial data.

Substation automation systems do include many of the same basic elements as the legacy SCADA system but with significant enhancements. A central operations computer system generally provides the master station function. Legacy RTUs may be incorporated into the automation scheme, particularly in retrofit situations, but are generally replaced with intelligent programmable RTUs and other intelligent electronic devices (IEDs) in an integrated LAN. Legacy transducers are replaced by IEDs that provide not only the traditional analog signals, but also a number of additional data values that can be useful to operations, engineering, and management personnel. IEDs communicate with RTUs and local processors via a substation LAN with an open communications protocol, thereby eliminating discrete transducer analog signals. Programmable logic controllers (PLCs) may be included, discretely or integrated into the intelligent RTU, to provide closed loop control and control functions, thereby eliminating the need for many electromechanical relays and interlocks. The integration of IEDs in the substation has been a major challenge for electric utilities and equipment suppliers. The primary obstacle has been the lack of standards for LAN communications protocols but the growing acceptance of UCA™ is changing the situation (see Substation Information Chapter).

All exchange of data among networked computers and devices in the automation scheme may be thought of as part of a network architecture, that is, a framework that provides the necessary physical and communications services to facilitate data exchange. Any number of internally consistent architectures can be chosen to permit the desired communications; however, many are proprietary. Proprietary networking solutions can prove to be highly effective and efficient from a functional standpoint, but they are not compatible with a multi-vendor environment that many utilities now demand. In a proprietary network, the network vendor is in control of what features are supported within the network. A vendor can decide not to support certain features, support them incompletely, or require the purchase of expensive upgrades to implement those functions. But proprietary networks do have the advantage that the user has access to a single point of contact and responsibility at the system vendor for all network functions, and these networks are generally guaranteed to "plug and play" without the user having to be concerned about architectures and protocols. In a network based on open products and standards, the user is no longer dependent on a single vendor to provide the functions and features needed or desired. The user also has the advantage of being able to solicit competitive prices among equipment vendors rather than being locked into one source of supply. But in an open environment, the user may have to take responsibility for overall network functionality, and has to take care in the selection of protocols and equipment to ensure "plug-and-play" compatibility.

Substation automation may take many different forms and levels of sophistication, depending on the philosophy of the implementing utility and the specific application. All systems contain a host processor. The substation host processor serves the following functions in the substation automation system:

- It provides local data storage for data acquired from the field devices.

- It provides a local human–machine interface, allowing a human operator to locally access system data, view system status, and issue system control commands.
- It can, if necessary, perform logical data processing and closed-loop control algorithms.
- It serves as a gateway for communications between the substation and the control center (SCADA host).

The substation host processor may be a single computer, such as a PC, or multiple computers in a networked or distributed computing environment.

IEDs are the second major component of an automation system. Examples of IEDs are electronic multifunction meters, digital relays, programmable logic controllers (PLCs) digital fault recorders, sequence of events recorders, voltage regulators, capacitor bank controllers, and electronic reclosers. Intelligent SCADA RTUs and PLCs can also be considered IEDs but are typically categorized separately. Many IEDs perform two functions within the substation. First, the IED provides its primary design function such as relaying, capacitor control, or voltage regulation. But by virtue of the fact that many of these IEDs have built-in instrument transformers, or are otherwise connected to the potential transformer (PT) and/or current transformers (CT) circuits of the substation, the IEDs also calculate and provide a large amount of power system data.

Data is retrieved from the IED by the substation host processor and/or a local RTU digitally via a serial data port or other network interface. This eliminates the need for discrete analog transducers, accomplishing a significant reduction in space and wiring, which can also lead to cost reductions. A single IED can often deliver hundreds of data values even though the utility user is only interested in a small subset of the total data set. The ability to filter the data reported by the IED has been limited as a result of both hardware and protocol-related issues. The goal is to provide the capability to filter or "mask" certain data registers at the IED level, as opposed to making this function protocol or host-dependent. IEDs should be individually addressable, preventing the need for a dedicated communications channel for each IED. IEDs should support open protocols. An important design consideration in development of IED interfaces is the data acquisition method. For example, the IEDs may be polled by the host device for changes (report by exception), or the IEDs may be sequentially scanned (full data dump).

The substation LAN is the final component in the system. It provides a means of physical data transfer between intelligent devices in the substation. There are two main distinctions between various LAN types: access method and physical media. The physical media used in LANs include coaxial cable, twisted-pair, and optical fiber. Optical fiber, because of its immunity to electrical effects, has distinct advantages in an electrical substation environment. An optical fiber LAN would be most appropriate for the Smart Substation. The access method can take various forms. The most common methods are carrier sense multiple access with collision detection (CSMA/CD), token ring, and token bus, and the Fiber Distributed Data Interface (FDDI), although a number of vendor-proprietary schemes are also in use.

The greater functionality offered by digital relaying ensures a growing acceptance by utilities. Still there is concern that, due to the nature of the digital electronic industry that supplies the components for these systems, care should be taken in adopting the technology. Clearly there are questions about whether one should expect the same service life as for electrical mechanical relays. Other issues that have been raised are:

- Premature obsolescence due to rapid development
- Hidden software bugs
- Lack of staff familiarity and training
- Difficulty in obtaining spare parts over the service life

Longer Term Vision

The latest generation of protection equipment is based on self-monitoring and digital relays have an inherently better reliability than the electromechanical relays used previously. This means that the type of redundancy traditionally used may not now be necessary. Rather than redundant lines of protection, modern digital systems with self-diagnosis and redundant circuits can provide the same level of protection. Mis-operations and maintenance will be reduced. It is also probable that future protection equipment will have built in redundancy with automatic changeover. Redundancy can also be achieved by automatic changes in neighboring protection schemes. Increasing the redundancy, only slightly increases the probably of correct relay function but at the same time increases the risk for unwarranted functions. Making protection redundant does not solve the problem of complexity or testing. Some think that the self-test facility of digital equipment reduces redundancy requirements. Adapting to the capabilities of the latest generation of digital relays will require a change in relaying philosophy that will only occur over time.

7
OPTICAL MEASURING SYSTEMS

Scope of Equipment Covered

Optical Voltage and Current Measurement Transducers 69kV and above

Present State of Technology

The ideal measuring device would be:

- Capable of supplying signals for all metering, protection, power quality and other IED applications
- Highly reliable with self-diagnosis
- Combine voltage and current metering accuracy transducers in a single package.
- Be lightweight and easily installed.

Optical transducers have all these characteristics.

The conventional technology for measuring substation currents and voltages is to employ iron core transformers for current and either iron core transformers or coupling capacitor voltage dividers for voltage. The design and application of these devices is well established and has been widely accepted for many years. More recently, the measurement of currents and voltages using optical sensors has established a small but growing acceptance. The primary driver for this increased interest has been the need to install many more metering points as a result of industry restructuring and merchant plant installations. At the same time the technology has advanced and the pricing has become competitive. New suppliers have entered the market place with a variety of offerings and designs.

Although not transformers in the classical sense, these devices are known as “optical CTs and VTs”. Development and commercial installations of optical CTs (OCT) is somewhat ahead of that for optical VT’s (OVT), with the first system installed in the field in 1986, but, more recently, there has been considerable progress in the design of accurate and cost effective OVTs. In addition there are on-going efforts to integrate OVTs and CVTs into the same structure and several such devices have been recently installed.

Unlike conventional, freestanding CTs and PTs, optical transducers are actually systems composed of four major elements.

- An optical sensor located at or very near the high voltage conductor.
- A high voltage insulating column to support the optical sensor.
- An electronic module that both produces the optical signal sent to the sensor, from LED's or laser diodes, and decodes the returning optical signal to produce an electrical signal proportional to the current or voltage.
- Fiber optic cables that run between the electronic module and the optical sensor.

OCT's and OVTs are categorized in the industry standards as low energy sensors.

Optical measuring systems have a number of beneficial characteristics not available from conventional devices. Among these are:

- High accuracy over a wide dynamic range.
- High bandwidth.
- No oil and hence no possibility of associated violent failures.
- Smaller size and lower weight providing increased flexibility in mounting and installation, especially at higher voltages.
- Increased galvanic isolation between the high voltage equipment and the control room.
- No ferro-resonance.
- No saturation concerns.
- The ability to use the output from the same sensor for both metering and protective relaying or for multiple relays.
- The ability to combine both voltage and current sensors in one system.

As with any new technical option, there are also other considerations. Among these are

- The technology is still relatively new and application knowledge and field experience is not widely available.
- The output of the electronic decoding of the optical signal is digital and a D/A conversion and power amplification is required to interface with most revenue meters and relays.
- There are no universally accepted methods for calibration.
- Reliability of the system, especially the electronics, is still a question. Many more equipment-service-years must be accumulated to establish long-term confidence.

Another issue has been the lack of applicable standards since the principles of operation of the optical systems are completely unrelated to the conventional technologies and their corresponding standards. However, there is on-going work to address this issue.[7]

Optical Current Sensors

There are two general types of OCTs available. Active OCTs, also referred to as hybrid, use a conventional iron-core CT sensor whose output is directly connected to an electronic signal-processing unit at the high voltage end of the column. The electronics are powered either from the line or optically through a fiber that also transmits either an analog or digital signal proportional to line current to the control house. Here, as with the other following devices, this optical to electrical conversion module produces a scaled and formatted signal suitable for use in metering or protective systems. This design substantially eliminated the need for oil or SF_6 dielectric insulation thereby reducing both size and weight. However, the placement of the signal-processing electronics at high voltage calls for considerable design expertise and extremely high reliability. This was the first application of optics to current measuring and many active OCTs have been installed on capacitor banks.

Passive OCTs work on an entirely different principle, the Faraday magneto-optic effect. An applied magnetic field rotates the plane of polarization of linearly polarized light. By measuring the change in polarization, the applied field and hence the current can be determined. Passive sensors have only optical components at the high voltage end. Electronics are connected to the optics by fiber and are usually located in the control room to provide both the necessary light source and to extract the current information from the returning light and develop an analog output current proportional to the current flowing through the sensor. Most product offerings are of this design and this is the technology that provides the benefits most associated with OCTs.

There are a number of possible optical component configurations that could be used in a passive OCT. However, to date, commercial systems have used either bulk sensors or wound fiber. Bulk sensors consist of a glass block with a central opening for the high voltage conductor to pass through. Polarized light from the electronics at ground potential is transmitted to the block by fiber optic cables and travels around the conductor in the presence of the magnetic field. The light leaves the sensor and returns to the electronics via another fiber. Wound sensors are composed of a section of specially designed optical fibers wound around the high voltage conductor. Polarized light enters the sensor, flows around the conductor and again returns to the electronics.

OCTs have a number of advantages. One of the most attractive is their wide dynamic range and bandwidth. It is possible to achieve 0.1% accuracy from 100% down to 1% of the full rating of the device. Since no oil is used for dielectric insulation, the threat of violent failure is eliminated. In addition, there will be no need to monitor the condition of the oil. The equipment is considerably lighter and smaller than a comparable iron-core unit. Therefore, the requirements for supporting structures and installation efforts are significantly reduced. Consequently, there is much more flexibility in locating a mounting site for an OCT, especially in retrofit applications.

Optical Voltage Sensors

There are two general types of OVTs available. Active, sometimes called hybrid, sensors use a conventional VT or capacitive divider but send their output to powered electronics at the base of the device column. The electronics generate either an analog or digital optical signal that is transmitted to the control house through optical fibers.

Passive OVTs use optical sensors that produce optical analog signals that are transmitted through fibers to the control house. Several different physical effects may be exploited for measuring voltage with an optical sensor. Both the Pockels effect and the piezoelectric effect require passing polarized light through or around the optical sensor and then decoding the modified light. In the Pockels effect device, the electric field modulates the polarization of the passing light. In the piezoelectric device, the electric field changes the length the light travels. As with OCTs, an electronic module is required to supply the originating light and to demodulate the returning optical signal. Most, but not all, OVT designs require SF_6 to insulate the optical sensor components from ground since they are placed in a region of high electric field stress. Because of the somewhat more challenging design requirements for optical voltage transducers, they were introduced into the market place later than optical current sensors. Hence, the learning curve for OVTs lags that for OCTs.

Anticipated Near Term Trends

The increasing use of optical systems is, in part, a response to industry restructuring. The recent growth in the number of new merchant power plants and the divestiture of plants from operating utilities along with increase bulk power transactions has produced a demand to meter power flows at many new locations and across a broad range of currents. Accurate revenue measurements must be made when the independent plant is generating power into the grid and also when it is in stand-by or start-up modes taking power from the grid. It is desirable to meter only from the high voltage side of the GSU to avoid complex metering schemes on the low voltage side or the station service transformer. Bi-directional metering with grossly different ranges, on the order of 1A versus 1000's of amperes is difficult to achieve with accuracy with conventional instrument transformers. Optical sensors provide a means to meter, with the required accuracies (Class0 0.2), over the dynamic range needed to cover both scenarios. They have the capability to generate two different outputs to feed high and low range meters. Their lightweight and small size make them even more attractive when metering must be installed in an existing substation. This type of application has been responsible for most all of the recent growth in the optical sensor market.

Due to their reduced need for oil or gas dielectric insulation and reduced size and weight, optical sensors are particularly well suited for applications in areas of limited space or not physically practical for conventional transducers. A free standing OCT weighs several hundred pounds in contrast to a conventional CT's weight of several thousand pounds. This allows OCTs to be mounted on or as part of other station structures, eliminating separate foundations and supports. Since there is no oil, OCTs can be mounted at any angle, including completely horizontally. Some manufacturers can also supply optical sensors as part of a live tank breaker design or integrated into GIS.

Today's prices for optical systems are competitive with conventional technology at the higher voltages. Many of the optical components are the same as those used in the communications industry and this bodes well for future prices decreases. The technology is still maturing and lower prices can be expected as experience is gained, volume grows and additional suppliers enter the market.

Barriers

Manufacturers of meters and relays have been reluctant to redesign their equipment to accept the natural, digital output of the optical system's electronic demodulators without accepted, international standards. Standards are now under development.[8 9 10] For the present however, digital to analog converters and power amplifiers are required to synthesize conventional outputs for the optical sensors. These additional components increase cost and reduce the reliability of the optical system. Digital interface of optical sensors to digital ready meters and relays would reduce costs and improve accuracy.

Most all optical systems use composite polymer, non-ceramic (NCI), insulating columns. Although they have many advantages over porcelain, notably low weight and shorter lead times, composites are more expensive. As production volume grows, these costs should drop. Another issue is the long-term performance of composite insulators. These insulators are made of organic materials, whose properties may change over the expected service life of substation equipment. EPRI, among others, has done and continues to do work to evaluate composite insulator through accelerated aging tests[11]. Additional testing of composite fiber optic system insulators has recently started at the 230 kV level and is expected to run for a minimum of three years. In addition to investigating the aging characteristic of the composite material, these tests will also address such questions as:

- Does the presence of fiber optics impact the insulator aging?
- Are there any performance issues at the entry and exit points of the fiber?
- Do the fiber optic cables themselves degrade?

Longer Term Vision

Commercial optical systems are still in the early stage of market acceptance. Suppliers are refining their designs and working with utilities to better serve the industry's needs. Because of the proprietary nature and the individual approaches taken, it is difficult to foresee what the specifics of future technical developments may be. One area that will clearly advance is that of OVTs. After a slower start, their technology is catching up to the level of OCTs. All suppliers have on-going development efforts and are watching the market to gauge the resources that will be applied to new developments.

Optical sensors have characteristics that are well suited to the Smart Substation and OCTs and OVTs will be key elements in the coming digital substation. In fact, their digital outputs, now a disadvantage, will be an advantage in the future. Optical voltage and current measurement systems generate digital signals in the process of demodulating the sensor's optical output. This digital information could be fed directly to other systems that now take analog currents and voltages and convert them to digital signal for their processing. Station IEDs such as microprocessor relays, digital fault recorders and condition monitors could all eliminate the front end A/D conversion that is now required. The digital outputs of optical systems are perfectly suited for direct connection to the communication network of the digital substation of the future.

Power quality monitoring involves the observation and measurement of the harmonic content but has been limited by the frequency response of conventional instrument transformers. Optical sensors have a very wide frequency response and dynamic range that makes their outputs very useful for detailed power quality analysis.

The ability for optical systems to provide more than one output signal means that there can be a dedicated path to the protection systems while the same information can be provided to other station IEDs.

With their smaller size and weight, optic sensors could be designed as integral parts of traditional substation components. One possibility is to design OCTs that could be mounted at the bushing of dead tank breakers, the more popular design in North America. One manufacturer now offers GIS equipment with integrated optical sensors.

8
STATION BATTERIES

Scope of Equipment Covered

A station battery is an electrochemical device that stores energy for future use in performing substation operations during power outages or other abnormal conditions. The energy is stored in chemical form and converted to electrical form during discharge. The cell is the basic building block for a battery. Combining cells in series sums their individual output voltage and delivers the same current as a single cell at the increased voltage. Paralleling cells delivers the sum of their currents at the voltage of a single cell. In station batteries power is almost universally delivered as direct current electricity at a dc voltage equal to the terminal voltage of the battery.

Integral to the electrochemical cells making up the battery are the charger and the dc ground detection system. Battery chargers are an essential part of the dc system. In addition to providing the float charging and equalizing charging, the battery charger also provides the continuous dc current required by the various substation dc loads. Ground detection is provided to indicate when there is a ground in the dc circuit. Ground detection is important for applications where a full floating system is required for operational or safety reasons. There are a number of methods of indicating a grounded output terminal.

Station battery size is usually specified in terms of ampere-hour (Ah) capacity and terminal voltage. The former specifies the duration of expected discharge at a particular current. For example, a 100 Ah battery will supply 100 A for one hour. Station battery installations range in size from a few tens of Ah, to several thousand Ah, depending upon the station size and equipment requirements. Terminal voltages typically range from 48 to 125 volts, though 250-volt systems are not unknown. Station battery costs lie in the range of $5K to well over $50K, for larger installations. As such, they do not represent a large fraction of the total substation equipment cost. However, failure of this component at the wrong time can lead to catastrophic substation damage (e.g., transformer fire) or to extended loss of service to customers. Thus, reliable designs and accurate condition assessment are important considerations for the station battery component of the substation.

Present State of Technology

Generally, two different types of electrochemical battery are in use: cells based on lead and sulfuric acid (known as “lead-acid” cells) and those based on nickel and cadmium (NiCad) cells). The former represent the overwhelming majority of systems in place today, primarily due to cost reasons. Within the lead-acid designation there are two broad categories of technology, the flooded-electrolyte cell type and the immobilized electrolyte type (also known – erroneously – as “sealed” lead-acid batteries). The latter, a relatively new technology, is not truly sealed but uses a regulating valve to control interior pressure. Thus, these cells are also known as valve-regulated lead-acid (VRLA) cells. NiCad cells used in station batteries are similar to the flooded-electrolyte lead-acid cell type in that cell plates are immersed in a liquid electrolyte and cell interiors are open to the atmosphere (unlike the common NiCad cells used in consumer electronic applications, which are sealed).

For station batteries, the choice of equipment type and design is only one ingredient for assuring proper functioning of the station battery subsystem. Perhaps even more important than the battery type are the conditions under which the battery is operated and maintained. These include the charging methods, temperature and air quality, and maintenance procedures to which the battery cells are subjected. The results of ongoing research and development efforts may mitigate the impact of some or all of these factors, as discussed later.

The charger must be correctly designed and properly adjusted for the particular cell stack to which it is connected. Overcharging the battery will decrease its rated life, increase the gassing, and could cause damage to the battery. Undercharging a battery could prevent it from meeting load requirements (battery duty cycle) during a critical time. Long-term operation of a battery in an under-charged condition will have detrimental effects on the battery life. To guard against improper charging cell voltages and currents should be properly monitored, preferably by an automated monitoring system.

Environmental conditions can lead to the accumulation of dirt and/or corrosion on the battery cell terminals and interconnections. This adds resistance to the circuit, reducing the amount of current available from the battery, and thereby lowering its overall duty cycle. Seepage of electrolyte near the base of the terminal posts or condensation of the electrolyte vapor on exterior cell surfaces (flooded cells only) can also cause accumulation of dirt and corrosion. Excessive accumulation of electrolyte-saturated dirt can lead to elevated ground currents and unsafe conditions for personnel working in the vicinity of the cell stack. Periodic, manual cleaning of the cells is required.

The substation location will determine the range of temperatures to which the battery is exposed. Proper ventilation and heating (when required) are provided to adjust for ambient temperature changes. However, the temperature of the battery has a direct effect on its performance and rated life and, therefore, should be monitored. Also, because the electrolyte volume in a cell changes with temperature (flooded-electrolyte cells only), the specific gravity reading must be adjusted accordingly.

The electrolyte level of flooded-cell batteries should be monitored to ensure that the level is somewhere between the high and low level indicator on each cell. If the level is too low, the plates become uncovered and could be damaged. If the level is too high, it could overflow during charging and necessitate additional maintenance.

Maintenance activities must be frequent and detailed enough to accommodate the above requirements, as well as to detect problem cells (e.g., low electrolyte levels or improper specific gravity), high resistance or loose connections, and other conditions that may lead to battery failure or loss of life. The importance of these factors varies somewhat among the various battery types discussed above.

Visual inspection and field measurements are the methods most frequently utilized to identify trouble modes in batteries. Other methods of detecting trouble in batteries consist of measuring the internal cell impedance, conductance, or other parameters susceptible to electronic surveillance. Visual inspection will establish the overall cleanliness of the battery, identify corrosion problems, and provide an indication of the charge level (for flooded-cell batteries). Field measurements (such as cell voltage, specific gravity, temperature, and interconnection resistance) will provide an indication as to the battery's capability of satisfying its design requirements. Accurate records are generally kept for all observed field conditions and measurements.

Finally, capacity tests per IEEE Std. 450-1995 are performed to ascertain the condition of the battery and its ability to meet its design requirements. Capacity tests, also called load-cycle tests, require that the battery be taken off line, given a deep discharge to complete the test, and then recharged prior to reinstallation. Because the battery must be taken off line to be tested, this test typically requires the paralleling of another equivalent battery or the use of a backup auxiliary system for the duration of the test.

Anticipated Near Term Trends

Improvements in station batteries in the next five years may be grouped into two areas: Improvements in the means used to store the energy to be used during an emergency, and improvements in the technologies associated with operating and maintaining the storage devices. Since it is not expected that alternatives to electrochemical batteries will become commercial within this period (see discussion in next section), minor improvements in existing battery types are all that may be expected. In the area of operation and maintenance technology, however, substantial gains may be expected.

Cell Technology Improvements

Flooded lead-acid and nickel cadmium technology may be considered mature for the purposes of designing a Smart Substation. Both types offer reliable and long-lived, albeit high-maintenance, solutions for station emergency power. NiCads are more expensive than lead-acid, but offer longer life and are more robust in the face of harsh temperature conditions. No major improvements in either performance or cost of these traditional cell types are envisioned. The major issues are those of reducing maintenance requirements and assuring reliability, as discussed later.

VRLA batteries offer the promise of reduced maintenance (e.g., no need to periodically add water), as well as smaller footprint. VRLA technology is nearing maturity, but some problems remain to be overcome. In particular, premature capacity loss (PCL) of VRLA cells in station service is a concern. Another concern is the greater susceptibility this cell type has to deleterious effects from overcharge and excessively high temperature during charge. Finally, VRLA cells are more costly than flooded lead-acid cells and do not have quite as long a life. Cell manufacturers worldwide are working on the PCL problem. Proper charger design and automated monitoring (see below) should mitigate the overcharge and high temperature problems. Cost may remain high.

Although not widely used in utility substations, VRLA batteries are extensively used in telecommunications applications. Thus, due to the large installed capacity of these cells and the economic pressures associated with obtaining reliable operation in the telecommunications industry, solution of the PCL problem may be forthcoming soon. However, there are some industry experts who believe that this cell type will never be as long-lived or reliable as the flood lead-acid cell.

Operation and Maintenance Improvements

Improved maintenance and operation for electrochemical cells in the near term will likely come from two quarters: improved cell technology, already discussed above (e.g., the VRLA battery) and automation of maintenance activities. The latter includes integrated monitoring and diagnostics sensors and software specifically designed for application to electrochemical systems. This new technology, currently under development, includes new techniques and equipment for measuring battery capacity without taking the battery out of service, and fully automated battery condition monitoring systems. The benefits will be reduced labor costs and increased accuracy in determining actual battery condition. The latter will enhance substation reliability as well as reduce capital equipment replacement costs.

New methods of measuring battery capacity using impedance or conductance are being developed and tested. These techniques have the following advantages:

- The battery can remain in-service.
- The equipment is relatively inexpensive when compared to other types of battery maintenance equipment and is very portable.
- The test procedure is quick and can be done by one person.
- The test provides a direct measurement of the conduction path of a cell (especially important for valve-regulated type batteries that do not allow visual inspection).

These are relatively new techniques, which could be accelerated in their accuracy and usefulness by more field-testing and by increased cooperation from the battery vendors (e.g., by providing baseline impedance and conductance values). More experience is needed with these techniques to assure that they can be used to replace the traditional methods of capacity testing, which are labor and time intensive.

Even newer and potentially more valuable are the new automated battery monitoring systems (BMS), of which the EPRI-developed *Cell Sense*™[12] product is a leading example. A BMS is essentially a full-spectrum automated condition monitoring system that uses specially developed cell sensors and field data acquisition equipment and that communicates with operations personnel via the utility SCADA system. Specialized data collection, data analysis, and maintenance computer programs are installed in the office computer to communicate with any number of field monitors.

Most of the critical items currently monitored by manual inspection can be monitored remotely with an automated BMS. As well, the EPRI *Cell Sense* system can automatically trend cell capacity, eliminating the more elaborate tests currently carried out. Although general appearance and cleanliness cannot be directly measured by the BMS, the consequences of poor conditions will be apparent through increased float currents, impedance changes, fluid level changes, or other measured parameters. The automated BMS is not a substitute for a thorough on-site inspection, but can significantly reduce the frequency of on-site maintenance and provide detailed information so the field technician can arrive prepared to remedy any developing situation. Moreover, because it continuously records and trends data, the BMS can provide a high level of confidence in the ability of the dc system to perform when needed.

The BMS is not yet inexpensive enough to be used in other than critical applications as it is still in its prototype development stage. However, with continued design and manufacturing development as well as increase production volumes, the system should reach cost-effective pricing. Further, the techniques for determining some parameters (e.g., capacity) need to be “proved out” by extensive field experience.

Longer Term Vision

Providing emergency power by means of electrochemical cells, regardless of type, has some inherent shortcomings. A major problem is the fact that an electrochemical battery installation is, perforce, made up of many similar (but not thoroughly identical) units, which must be all connected together by external means in order to obtain useful voltage and current. These facts, the multiplicity of units and the external connections, are what lead to many of the problems with batteries. Chargers treat all the cells as if they were identical when they are not. External mechanical connections are susceptible to loosening, corrosion, and ground faults. Another shortcoming is the fact that energy is stored as chemical energy instead of electrical energy, which is the form in which it is used. This leads to conversion inefficiencies and, more importantly, is an underlying factor in longevity.

The goals for a long-term replacement technology for electrochemical cells are the same as for the nearer term: increased reliability, longer life, and reduced maintenance cost. Other means of storing energy include mechanical storage (e.g., flywheels or mini-compressed air energy storage), or electrical storage (e.g., super-capacitors or superconducting magnets). Another technology being suggested for substation emergency power is fuel cells. These are essentially electrochemical batteries that operate by electrochemically “consuming” a fuel (e.g., hydrogen) instead of storing charge by chemical conversion. Each of these “alternate” technologies will have their own strong and weak points, of course. Moreover, none are expected to be perfect or even greatly better than batteries in every category. However, in the long run one of these technologies may prove to be better overall than electrochemical storage.

Flywheels would reduce the part count significantly over electrochemical cells but would introduce both machinery and moving parts. Flywheels will likely have longer life than batteries but are considerably more expensive right now for applications requiring hours of discharge, as some substation applications do. Research should continue to focus on creating lower cost "energy" wheels (flywheels designed for long term discharge rather than high power short duration discharges). Safety is also a concern that needs to be addressed.

Super-capacitors and superconducting magnets store energy as dc electricity, eliminating problems associated with conversion. Both are expected to be very long lived. But, super-capacitors have the same "many small units in series" problem that electrochemical cells have. Superconducting magnets are expensive and likely to remain so for the relatively large energy but low power emergency power application in a substation. Research on super-capacitors should focus on increasing the energy stored in single packaged units so that fewer units need interconnection, and on lowering costs. For superconducting magnets, a key research focus is on developing lower cost wire and conductor. The recent discovery of superconductivity in magnesium diboride is an exciting development in this direction.

Fuel cells require a source of fuel on site (either in tanks or piped in). Costs for current technologies are pretty high. Research should focus on reducing costs.

There is ongoing and significant research and development for all of these alternate technologies, for other applications. This should benefit their ultimate deployment for substation emergency power applications, though adaptations to the particular duty cycle required in a substation may be necessary. Another development upon which substations emergency power may ultimately be "piggy-backed" is the incorporation of large-scale energy storage plants within substations. These would be installed for other applications, such as providing power quality or peak shaving. However, once installed, they may also provide backup power when needed.

9
SUPERCONDUCTORS

Scope of Equipment Covered

Superconductors represent a new and revolutionary class of electrical conductor, characterized by zero (for DC currents) or extremely low (for ac currents) resistance. Since substations utilize electrical conductors throughout, the scope of equipment that is impacted by this new technology is potentially the entire substation.

Independent of voltage, function, or environment, all substations use the same generic components. In many instances, the same component – catalog item – is used for substations that operate under different environmental conditions, which may affect component and system longevity. The major components in a substation that would be impacted by the use of superconductors, include the following:

- Transformers
- Overhead wires and underground cables
- Bus systems
- Interrupters and switches
- Towers, shield wires, lightning arresters

Present State of Technology

Relevant aspects of today's commercially available technology for the major substation components likely to be impacted by the introduction of superconductors are discussed below.

Transformers

Power transformers are the heart of the electrical substation, and also are the most expensive component, both in capital and operating expense. Since transmission of electric power at the low voltages used by consumers is not practical on a large scale, transformers allow power to be generated, transmitted, distributed, and consumed at appropriate voltages each step along the way. It is not uncommon for electrical power to be transformed three to four times in going from generator to user. Almost every substation involves the conversion, by transformers, either from one voltage to another, or to several voltage levels.

Transformers consist of one or more windings of conductors wound around a magnetic core. In power transformers, the windings are insulated by paper, and in large transmission transformers the entire assembly is submerged in oil for cooling and insulation.

Transformer losses occur in both the windings (through ohmic resistance) and in the core (through magnetic hysteresis). Improved construction and newer materials have led to greater efficiency. However, higher efficiency is achieved at the expense of greater size and cost. These units are difficult to transport and install and, at some point, are not cost effective. Today's utility power transformers have losses that are less than 0.25-0.4% of total rating. The total losses in the U.S. power delivery system due to transformers are estimated to be between 4.5 – 5% of the electricity generated.

Heat is the enemy of transformers, causing breakdown over time in the insulating capability of the paper and sometimes producing conditions favorable to internal arcing and catastrophic failure. The oil in large transformers also presents environmental (spill) and fire hazards.

Overhead Wires and Underground Cables

Approximately 80 % of the power transmitted, in kW-miles, is overhead and about 20 % is in underground cables. Thus, most power that enters and leaves substations is by means of overhead wires. However, in urban and industrial/commercial areas underground cables predominate.

Bus Systems

The bus system in a substation is the network of conductors, insulators, and supports to which transmission lines, transformers, circuit breakers, disconnect switches, and other equipment are connected. Each voltage level in a substation has a separate bus system, which may or may not be comprised of the same components. Bus systems are selected and arranged to provide an orderly, efficient, economical, and environmentally acceptable layout of substation equipment and structures. Bus conductors may be either rigid (e.g., aluminum tubing) or stranded conductors (strain bus). Insulators electrically insulate the energized bus from its support structures and maintain phase separation. The insulator must also have sufficient strength to support the bus under short-circuit forces and severe mechanical loading. Structures are used to support the above-grade components in a substation. These structures include dead-end towers, bus supports, switch stands, and equipment supports.

Interrupters and Switches

A power circuit breaker is a device for closing, maintaining, and interrupting an electrical circuit between separable contacts under both load and fault conditions. As current levels increase, arcing between the opening contacts becomes more severe. The problem is more acute during faults or short-circuits, at which times practically instantaneous interruption of current is necessary as a protective measure for the connected apparatus. The principal techniques of arc interruption in use today include oil, air-magnetic, air-blast, vacuum, and SF_6 methods.

Disconnect switches are used to electrically isolate transmission lines or equipment, such as circuit breakers or transformers, and to sectionalize lines and feeders. Disconnect switches may be manually operated or power-operated. Disconnect switches cannot break load currents. The main duty of the switch is to provide an adequate insulating gap for the equipment it is isolating. The disconnect switch is often required to provide visual indication of an open circuit to satisfy safety concerns during maintenance.

Towers, Shield Wires, Lightning Arresters

Overhead lines carry power to most substations and are supported by towers as they enter the substation. The size and characteristics of the towers depends on the voltage level and the worst anticipated local weather conditions. A shield wire at the top of the tower almost always provides a ground voltage above overhead lines. It also connects to lightning arresters and protects the main conductors. This shield wire continues in one form or another throughout a typical substation.

Anticipated Near Term Trends

Programs are now underway to develop superconducting transformers, cables, fault current limiters, and motors; also superconducting magnetic energy storage (SMES). In the next five years these devices will likely only appear in substations individually, mostly in demonstration projects or in high-value “niche” applications. The development and deployment of an All Superconducting Substation will likely only occur over a much longer time frame.

Superconducting Transformers

Superconducting transformers have been under development since multifilament niobium-titanium (Nb-Ti) became available in the late 1960’s. The drive for many years with low-temperature superconductors (LTS) was to develop wires with very fine Nb-Ti filaments, less than 1-micron diameter, which would have low eddy current and hysteresis losses. With the advent of practical high temperature superconductors (HTS) in the early 1990’s, other approaches to transformer design became possible. Programs to develop HTS transformers are underway in the US, Europe and Japan.

In a superconducting transformer heat is not an issue since the transformer windings are cooled to cryogenic temperatures all the time. Superconducting transformers will operate at a constant temperature (30 – 65 K range, depending on coolant and bath for the insulation). They will be completely enclosed in a cryostat that provides environmental isolation. As result, the transformer would have extended life and would be capable of longer overload periods in emergencies. In a superconducting transformer, the cryogen – nitrogen or helium in liquid or gaseous form – replaces the insulating oil and a compact cryogenic refrigerator replaces the large oil cooling fins and pumps. The result is a smaller and lighter unit.

The losses in a superconducting transformer are approximately 2 to 5 % of those in a conventional transformer at room temperature. However, these losses must be removed by a refrigeration system that is driven by electric power. The combined system of transformer and refrigeration will be certified for some continuous operating power level. It will also be certified to operate at a higher power level. Losses will increase during overload and the temperature will rise, but by only a degree or so. Developers project that the life expectancy of superconducting transformers will not be affected by continuous operation at even twice rated capacity.

The windings of superconducting transformers are similar to those of superconducting fault current limiters. As a result, some superconducting transformers have intrinsic fault current limiting capability. It may be possible to develop this feature to a clear functional advantage in future superconducting transformers. This is particularly true for large transformers as fault current limiters are usually made for low power levels of 10's of megawatts.

In summary, a superconducting transformer will be:

- Smaller than a conventional unit, 70 % area (80 % with refrigeration)
- Lighter than a conventional unit, 50 % weight
- More efficient than conventional units, as much as 80% improvement

Superconducting Cables

The siting and environmental issues facing the expansion of transmission capacity have become increasingly more difficult over the years. The HTS power cable may be able to address some of these issues, especially in urban areas. The very high allowable current density in superconductors allows superconducting cables to carry more power than conventional cables of the same cross section. As a result, it is possible to retrofit with superconducting cables and increase overall system capacity. The old cables may be removed and new superconducting cables pulled without tearing up streets or removal of surface overburden. This approach is being used for a 24 kV, 3-phase cable system that has been installed at Detroit Edison's Frisbee Substation in Detroit, MI[13].

This represents a cost-effective niche application today for superconductors. While not yet a commercial enterprise, superconducting cables have already been tested in industrial and utility substation settings. Several cable projects are underway today employing HTS conductors.

Superconducting AC cables have a variety of loss modes that are associated with the alternating current and electric and magnetic fields. Some are unique to the superconducting material, others are well known from conventional cables. These losses produce heat in every meter of cable. There is also some thermal conduction of heat into the cable all along its length, and a significant quantity of heat enters the cable system at the places where the current transfers from ambient to the cryogenic environment. Thus, very short superconducting cables are not very efficient. The heat from all these sources appears at the operating temperature of the cable and must be removed by a refrigeration system. A refrigerator within a substation can cool superconducting cables as long as 5 kilometers.

In summary, superconducting cables will:

- Be smaller than conventional cables.
- Carry more power than conventional cable of similar size
- Be more efficient than conventional cables
- Have a constant operating temperature (about 70 K)
- Be contained in a cryogenic enclosure that provides environmental isolation

Fault Current Limiters

Several superconducting fault current limiter (FCL) designs have been proposed. Only a few of the designs appear to be both practical and economical. One was built and installed at a Southern California Edison (SCE) substation. The electrical portion of this FCL functioned as designed. Full power tests were not completed due to a vacuum leak that caused an electrical failure associated with the vacuum pump. The conductors and the iron core geometries in superconducting FCLs are similar to those in superconducting transformers. As a result, some effort to combine the function of the two technologies could be promising. The economics of an independent FCL would be particularly attractive where there are other superconducting devices because the refrigeration requirements of the device are relatively small.

Barriers

Cost is a principal barrier for commercialization of both superconducting transformers and cables. Both the wire and the refrigeration systems present hurdles to overcome in the quest to reduce cost. Most developers do not expect the HTS wire used in present cables and transformers, known as Generation 1 (Gen 1) wire, to ever be cost effective for mainstream application. A new generation of wire (Gen 2) is under development and holds the promise of reaching price levels approaching those of ordinary copper conductor ($20/kA-m versus $5 – 10/kA-m for copper). At these price levels, transformers fabricated with Gen 2 wire may be cost competitive with conventional units when efficiency, size, and environmental improvements are factored in. However, it should be pointed out that one major transformer manufacturer gave up development efforts recently out of a belief that cost goals for Gen 2 wire would never be met. An even newer development, the discovery in early 2001 of superconductivity in magnesium diboride (MgB_2) holds out the promise of being able to manufacture superconductors that are cheaper than copper. If this goal were reached then the barrier of wire cost would likely disappear.

Refrigeration, or cryogenics, costs are another barrier. Both capital and operating costs are of concern. Today's refrigerators cost $75 – 100/watt and operate at 15% of Carnot efficiency. One-third to one-half of the losses is in the compressor. Operating costs are high due to the fact that today's compressors operate at full capacity continuously, regardless of cooling load. Stageable cryocoolers, if they can be developed at low cost, would reduce operating expense. Government targets for cost and efficiency of cryogenics systems are $30/watt at 30% of Carnot efficiency. If these goals together with wire cost goals can be met, superconducting components should begin to enter the substation arena. In this regard, it is noted that first-of-a-kind units may require extensive maintenance and modifications.

Longer Term Vision

In the fullest implementation of superconductors in a substation it is possible to envision what may be called an “All Superconducting Substation.” While it is unlikely that any substation will be entirely superconducting, it is certainly conceivable that many conventional components can be replaced by either superconducting or cryogenic elements. As discussed above, researchers are already demonstrating replacement of some conventional substation components by superconducting components that are smaller and more efficient. In addition, other parts of the substation can be made to operate at cryogenic temperatures. For example, switchgear and relays can operate in liquid nitrogen, much as in a gas-insulated substation. The result will be a nearly completely contained substation that has few parts exposed to the environment. Superconducting magnets that have operated for thirty years and have been opened for inspection appear just as they were the day they were closed. Rather than quantifying the effects of near continuous operation for this period, the inspections found no changes at all. This can be explained by the fact that there is no overheating and there is essentially no chemical activity at cryogenic temperatures. There is no corrosion, and the cryogenic fluids are nearly inert.

Most efforts to develop superconducting technologies for power applications are aimed at intermediate power and voltage levels, where the largest market is expected. For example, the maximum voltage anticipated for superconducting transformers is about 230 kV, which is near the low end of the power transmission voltages today. In addition, there are many substations at voltages of 230 kV and higher that only provide VAR support and switching. As a result, the All Superconducting Substation may have a bigger impact in the area of distribution than for transmission.

An All-Superconducting Substation of the future may not be recognizable to today’s practicing engineer. Once power arrives at the substation, it would pass through bushings that lead from ambient to cryogenic temperature. Beyond that point all the elements of the substation will be enclosed in a stainless steel or aluminum structure, much like today’s high-pressure SF_6 gas insulated substation (GIS). Unlike SF_6, the gases used in the cryogenic substation (helium and nitrogen), are not hazardous and have no greenhouse effects. An advantage of using cryogenic electrical interconnections is the simplification of fluid transport among the cryogenic components and the refrigerator. One type of piping container can transport both cryogens and electrical power. In addition, the cryogenic enclosure for the superconducting substation can be extended to include underground cables up to about 5 kilometers in length.

Having multiple superconducting components in a single substation location would lower refrigeration costs by leveraging the capabilities of a single, larger cryogenics system. In addition, the larger refrigeration system could allow cost-effective addition of certain “non-traditional” substation components such as superconducting energy storage and superconducting FACTS devices.

Operation at cryogenic temperatures allows very long life. There is no corrosion, no overheating effects on insulation life, and no gas impurities. Overload, which will increase refrigeration requirements, can be accommodated by delivery of commercially available liquid nitrogen, rather than by reducing transformer life. Experience with superconducting magnets indicates that there will be no degradation, in fact, no physically measurable change in 30 years of operation.

Conventional safety procedures and regulations would apply to this substation. There would, however, be fewer bushings and there would be no need for shield wires beyond the initial set of bushings. The separation between components will be determined by voltage breakdown in a controlled environment rather than in an exposed environment with worker and public access. The voltage standoff capability of liquid nitrogen impregnated paper is only slightly below what is observed when the same insulation is immersed in oil. Thus, the size of a completely enclosed superconducting substation would be similar to that of a GIS today.

The All-Superconducting Substation will, in many respects, isolate its components from the environment. Thus, maintenance would be considerably less than for a conventional substation. Reduction in maintenance will depend on the function of the substation and the environmental conditions. Superconducting substation maintenance could be less than half that for conventional substations in hot and humid conditions. Maintenance of the refrigerator will replace most of the maintenance in a conventional substation. Cryogenic refrigerators have operated for many decades with scheduled annual and semiannual maintenance. The cost and effort for refrigerator maintenance, which is the same in almost all environmental conditions, is small and is well documented. Conservative calculations have been made to show that the All Superconducting Substation will have lower maintenance by about 40 %.

In summary, the All-Superconducting Substation:

- Is smaller—has only 75% of the area of a conventional substation.
- Is more efficient—superconductors have little or no resistance and thus have lower losses than conventional components.
- Has lower maintenance—as low as 60% of that of a conventional substation.
- Has greater power handling capacity—up to 3 times that of a conventional substation of the same area.
- Has improved performance—for example intrinsic fault current limiting in the transformers.
- Has extended life at high ambient temperatures or high loading
- Has reduced environmental impact: no oil, reduced cooling noise, mostly enclosed

Several areas of investigation are recommended for the All-Superconducting Substation:

- The addition of fault current limiting to the superconducting transformer should be studied. The nature of the superconducting transformer is such that it can be made to include fault current limiting.

- Research and development in superconductors should continue and be accelerated. The potential of new materials should be explored and exploited. Improved methods of making conductor, and of fabricating cable from conductor must be developed. Techniques for lowering manufacturing costs are also important.
- Development of lower cost and more highly efficient cryocoolers should be given greater priority.
- Maintenance costs for conventional and superconducting substations should be better quantified. There is great deal of information describing what maintenance should be for a substation, but little common or collected information regarding the cost of the maintenance.
- Several programs to develop superconducting magnetic energy storage (SMES) using HTS materials are underway. All are aimed at small energy storage systems. These should be continued and directed toward larger systems.
- FACTS devices include multiple solid-state switch components. In general, these components operate at ambient temperature and the heat they generate is removed by conventional cooling systems. There have been discussions of operating solid-state switches at cryogenic temperatures. However, to date, there has been little need for such devices as there were few superconducting or cryogenic devices that might use them effectively. This is an area for continued investigation since installation of a FACTS device on an All-Superconducting Substation would require either the development of components that would operate at about liquid nitrogen temperatures or one of the transition temperatures from ambient to cryogenic environment.

10
ENERGY STORAGE

Scope of Equipment Covered

Substations currently store energy only for the purpose of providing emergency backup power for substation equipment (see separate chapter for station batteries). The possibility of using energy storage for wider functions, such as to enhance customer power quality or to alleviate peak loading on substation feeders, has been proposed for several decades. However, due to the high cost of equipment and the lack of appropriate financial mechanisms for recovering that cost, there has been no implementation to date of this function beyond a few demonstration projects. Nevertheless, recent changes in the industry due to restructuring as well as increasing concern for power quality are creating conditions potentially favorable to the implementation of energy storage at transmission and distribution substations.

An energy storage system installed at a substation would generally consists of several subsystems: the storage device itself, power conversion equipment to provide for interfacing the storage device output characteristics (e.g., voltage, frequency) with the ac grid during both discharge and charge, a control system to implement the desired service, and ancillary structures and systems such as equipment housing, HVAC, and fire protection. For smaller systems (e.g., a few MVA) the entire energy storage system would likely be containerized and pad mounted, much as a transformer is mounted and connected. Larger systems providing multiple hours of storage at higher power levels would involve considerable expansion of the substation area to contain the many new subsystems.

Present State of Technology

Before identifying commercially available technology, it is appropriate to briefly describe the general categories of application for energy storage as the application in large part determines the type of technology to be used. Generally, applications may be classed in terms of a suite of parameters, as follows:

- Power
- Duration (of discharge)
- Duty cycle (events per year or day)
- Response time

The power quality application is nearest to commercial reality in a substation environment. Energy storage systems in power quality applications primarily mitigate the effects of voltage sags, though harmonic correction and voltage support (VAR correction) is also often achieved with the power conversion equipment used to interface the storage unit. This application is characterized by a low to medium power range (1 – 50 MW), short duration (1 – 10 seconds), a moderate to high duty cycle (10 – 300 events/year), and a very short response time (a few milliseconds). Technologies commercially available for this application include the lead acid battery, steel (slow speed) and composite (high speed) flywheels, and SMES (superconducting magnetic energy storage) units. Ultracapacitors are in a prototype development stage and will soon be available in commercial power quality systems as well. Lead acid battery and SMES systems are available in sizes up to several MW in a single, pad-mounted container. Flywheel systems are somewhat smaller in single package systems. All of these technologies lend themselves to a modular deployment wherein larger systems are achieved by paralleling the factory fabricated containers or modules. The ac system voltages at which these systems connect, range from 480 V to 15 kV. Today, systems with batteries, flywheels and SMES are being installed in dedicated utility distribution substations (or inside the plant facilities) for industrial customers that experience power quality problems.

Peak shaving for large customers and/or utility substations has also been demonstrated with a few commercial-scale systems in place. Peak shaving compensates for the very poor capacity factor that characterizes transmission and distribution feeders and equipment. By shaving peaks occurring at substations during, say, the afternoon, the energy storage plant permits deferral of substation and feeder upgrades. An extension of peak shaving, sometimes called load leveling, achieves economic benefit due to the on/off-peak energy price differential. Bulk power marketing or arbitrage is another similar application.

To date, only batteries have been used for peak shaving or load leveling. Worldwide, several plants as large as 20 MW and with discharge durations as long as four hours have been successfully demonstrated. The most common type of storage medium in this application is the lead acid battery, but advanced types such as the zinc/bromine, vanadium/redox, and sodium/sulfur batteries are being tested as well. This application requires small to large power levels (1 – 100 MW), medium to long durations (0.5 – 12 hours), moderate duty cycle (5 – 60 events/year), and slow response times (1 – 2 minutes). Load leveling may require up to 250 events per year. Compared to power quality, peak shaving places different demands on the storage medium such that, so far, the non-battery technologies have not become economically viable. These latter technologies tend to optimize in price and performance toward high power – short discharge and high duty cycle applications.

A third class of application for energy storage at the substation level is that of providing transmission and distribution system ancillary services such as spinning reserve, frequency regulation, energy imbalance (area control error) control, and voltage (VAR) support. Spinning reserve is similar to peak shaving in its requirements on the storage medium, but with a slightly faster response time needed (0.1 – 1 minute) and a generally shorter duration (5 – 15 minutes). Frequency regulation and energy imbalance both require extreme duty cycles, essentially continuous charge and discharge during long periods. For frequency regulation, response times must be fast (0.1 – 1 second) but durations are short. For energy imbalance control the storage duration is moderately long (up to 15 minutes) and the response time modest (10 – 30 seconds). Because these are transmission level services, the power level required is usually very large – 100 MW and more. Although, to date only smaller (10 – 20 MW) systems have been deployed. Lead acid batteries have been successfully used in commercial application for all three of these ancillary services, albeit in only a handful of facilities worldwide. Other battery technologies may be suitable as well. SMES would be suitable for frequency regulation and spinning reserve, but probably not for energy imbalance control because of the cost of providing long storage durations. While SMES is projected to be suitable at the high power levels required, it has not yet been demonstrated at those power levels. Flywheels and ultracapacitors at today's level of development are not expected to provide such high power applications.

Voltage support is primarily a function of the power conversion system operating in the reactive power quadrant, but experience with small SMES systems (3 MW) on distribution feeders has shown that a small amount of real power injection from an energy storage unit, delivered in the first moments of impending voltage collapse, can greatly enhance the dominant effects of reactive power injection. Thus, the requirements on the storage medium for the voltage support application are similar to those for the power quality application. And, the appropriate technologies are the same as well: SMES and ultracapacitors being the most promising.

Further out on the deployment horizon is the use of short duration, very high power storage devices in conjunction with FACTS devices to provide transmission system dynamic stability improvement. Power levels of 300 MW are the norm in this application. Storage duration is very small, only a few seconds, like power quality. Response time does not have to be as fast as for power quality but is still relatively short (0.25 second). Duty cycle is very modest – perhaps only a few events per year. Because of the high power levels involved for economic applications, storage technologies whose fundamental unit voltage is small (e.g., capacitors, battery cells, flywheels) are not well suited. That is because the power conversion unit, which is the major cost component in this application, optimizes at very high dc input voltages – several thousand volts. Building up to these high voltages with cells or modules of only a few volts each is not deemed practical. It is possible that future developments for ultracapacitors may yield single modules of several hundred volts output, in which case this storage type would become suitable as well.

11
FLEXIBLE AC TRANSMISSION SYSTEMS

Scope of Equipment Covered

Flexible AC Transmission System (FACTS) power-electronic based transmission system controllers.

Present State of Technology

Deregulation has resulted in a steep increase in the number of power transactions and merchant plants connections. As a result, the transmission system is required to meet greater demands and used in ways for which it was not designed. New transmission line construction is difficult, lengthy, and expensive. Congestion, the inability of the system to handle the desired power levels, has increased. These transmission constraints impact economic interchange, system stability, and quality of power delivery.

Kirchoff's Laws govern power flow on transmission networks. The results, in many cases, is an under utilization of transmission circuit capacity. In theory, a transmission system can carry power up to its thermal loading limits. But in practice, before reaching the thermal limit, systems often are constrained by stability and voltage limits. While some transmission circuits are loaded up to their thermal capacity other circuits may be far below their thermal capacity. FACTS technology provides a way to control the transmission parameters that affect circuit loading and hence a full control of point-to-point power flow.

Recognizing the difficulty of controlling power flows through conventional methods, EPRI put in place a FACTS technology development program. The program was executed through collaboration with utility members and manufacturers to field demonstrate the FACTS technology concept. The main thrust of FACTS technology is the use of reliable, high-speed power electronics, advanced control technology, advanced microcomputers, and powerful analytical tools and control methodologies. The replacement of passive and/or electromechanical devices (for example, mechanically switched capacitors) by active devices allows electrical power transmission circuits to operate ever closer to their thermal limit because the added control effectively increases the stability and voltage limits. To achieve this, FACTS controllers utilize advanced inverter-based, or voltage-sourced converter-based, power electronic controllers that provide, controlled, injected currents and voltage to the transmission networks. Injected current provides transmission voltage control and injected voltage provides compensation to transmission line impedance and phase angle. The combination of injected current and voltage results, therefore, in full control of real and reactive power flowing on the compensated transmission line.

FACTS covers several power electronics based systems used for AC power transmission. The following are the FACTS Controller which have been field demonstrated:

- Static Series Compensator
- Static VAR Compensator
- Static Synchronous Compensator
- Unified Power Flow Controller
- Interline Power Flow Controller

Thyristor Controlled Series Capacitors

Thyristor Switched Thyristor Controlled Series Capacitors (TSSC) is a controlled capacitor connected in series with a transmission line. TCSC provides a line impedance control, which can be used to regulate the power flow, damp power oscillation and/or subsynchronous resonance problem.

Static VAR Compensator

A Static VAR Compensator (SVC) is based on thyristor-controlled reactors (TCR), thyristor switched capacitors (TSC), and/or fixed capacitors tuned to filters connected in parallel with the line. A TCR consists of a fixed reactor in series with a bi-directional thyristor valve. A rapidly operating Static VAR Compensator can continuously control dynamic power swings under various system conditions. The main reasons for incorporating SVC in transmission systems are:

- Stabilize voltage in weak systems
- Reduce transmission losses
- Increase the transmission capacity
- Increase the transient stability limit
- Increase damping of small disturbances
- Improve voltage control and stability
- Dampen power swings

Static Synchronous Compensator

Perhaps today's most widely applied FACTS device is the Static Synchronous Compensator, the STATCOM. The basic building block of a STATCOM is a voltage source converter that uses gate-turn-off (GTO) solid-state switches to generate a voltage with controlled magnitude and phase angle. As an SVC, STATCOM is connected in shunt to provide reactive power support and transmission voltage control. Rather than employing passive capacitors and reactors, STATCOM can be seen as a voltage produced by a voltage source converter behind a reactance. It provides reactive power generation as well as absorption purely by means of electronic processing of voltage and current waveforms in the voltage source converter. This means that capacitor banks and shunt reactors are not needed for generation and absorption of reactive power resulting in a compact design with a small footprint. With the advent of SVC Light, still better performance can be reached in areas such as:

- Dynamic and steady-state voltage control
- Transient stability improvements
- Power oscillation damping in power transmission systems
- Ability to control both active and reactive power

The main parts of a STATCOM are located inside a prefabricated building. The outdoor equipment is limited to heat exchangers for cooling the power electronics, commutation reactors and the power transformer. The use of a high switching frequency for the gate-turn off solid state switches results in an inherent capability to produce voltages at frequencies well above the fundamental. This property can be used for active filtering of harmonics already present in the network. The STATCOM then injects harmonic currents into the network with proper phase and amplitude to counteract the harmonic voltages. The first large-scale STATCOM has been in operation since 1995 at TVA's Sullivan Substation in Johnson City, Tennessee. Co-sponsored by EPRI, TVA and Siemens, the +/-100 MVAR system has the capability to accurately maintain voltage on the 161 kV bus, as well as regulate the adjoining 500 kV bus voltage. The STATCOM allowed TVA to defer construction of an additional 161 kV line and the addition of a second tap-changing 500 kV transformer bank. Additional benefits have included enhancing the life of nearby system equipment and damping of system oscillations.

Unified Power Flow Controller

The most versatile FACTS equipment for a transmission line is the Unified Power Flow Controller (UPFC). The Unified Power Flow Controller (UPFC) has the ability to independently control the active and reactive power of a line. A UPFC can perform voltage support, power flow control and dynamic stability improvement in one and the same device. The Unified Power Flow Controller consists of two voltage source converters with a common DC link. One converter performs the main function of the UPFC by injecting an AC voltage with controllable magnitude and phase angle in series with the transmission line. The basic function of the secondary converter, connected in parallel with the line, is to supply or absorb the active power demanded by the primary converter at the common DC link. It can also generate or absorb controllable reactive power and provide independent shunt reactive compensation for the line. The UPFC is the first transmission controller able to simultaneously and selectively control all three parameters affecting power flow: transmission voltage, impedance and phase angle. It also provides the most accurate and dynamic response for reactive shunt compensation, series compensation and phase shifting. The Unified Power Flow Controller developed by Siemens, EPRI and AEP, gives grid operators the flexibility to overcome many of today's transmission constraints. An UPFC-equipped transmission line can independently control both real and reactive power flow to maximize line utilization and system capability. It can also be used to minimize the reactive current flow to reduce system losses. AEP's Inez Substation in Kentucky is the site of the world's first UPFC, which was put into service on a newly constructed, high capacity 138kV line in 1998. The world's largest voltage source converter, it has proven its capability to control power flow. In addition, it has proven the ability to independently control real and reactive flow and even to reverse flow if desired.

Interline Power Flow Controller

The Interline Power Flow Controller (IPFC), the latest in FACTS technology, provides the maximum flexibility in the control of power flow. The IPFC can link multiple transmission lines and dynamically route power from overloaded to under-utilized lines. The IPFC is one of the many control modes of the Convertible Static Compensator (CSC), which is now in operation at the New York Power Authority (NYPA). Use of a CSC can raise the limit of power transfer, relieve major transmission bottle necks, improve voltage control, defer construction of new transmission lines by maximizing use of existing assets, reduce system losses, increase system reliability and flexibility, and increase the effectiveness of bulk power transfer. The Convertible Static Compensator is comprised of two, ±100 MVA converters, the CSC is a single, multi-functional compensating system convertible to any compensation and power flow requirement, including controlled reactive shunt compensation, series reactive compensation, simultaneous shunt and series, real and reactive compensation, and even multi-line series real and reactive power compensation. In the IPFC mode, the CSC is the first device ever to allow interconnection of multiple transmission lines (in the NYPA case 345kV) and to do real and reactive flow management between lines. Power flow can be re-directed from one line to another or the reactive loading on one line can be passed along to another underutilized line.

Anticipated Near Term Trends

Future developments in FACTS technology will come in three main areas: semiconductor devices, control techniques, and packaging and construction. To meet the requirement for a particular converter design, semiconductors are arranged in series to achieve voltage ratings and parallel for current ratings. The combination of semiconductors is repeated for each phase. This naturally leads to a modular converter design. The compact, modular design of voltage-sourced converter FACTS systems enables them to be expanded, reconfigured or even relocated to meet the future demands of changing electric system. The life expectancy of FACTS devices is more than 30 years. However, the best locations of the device in the grid will likely change dramatically over this period of time.

A portable device allows owners to inexpensively and efficiently relocate the FACTS device many times over its effective life. Adding this type of modularity to a FACTS device would not significantly add to the cost of the overall system so long as it was included in the initial design.

Traction applications are a major driving force pushing IGBT module technology to higher demands on temperature cycling capability and general reliability improvements. Developments like AlSiC base plates and AlN substrates that improve thermal management have aided in this progress. Other improvements include the bonding and base plate technology as well as partial discharge immunity. A new generation of GTO holds significant promise for reducing the cost and complexity of FACTS systems. Now, innovative silicon concepts and newly identified non-silicon materials, including silicon carbide (SiC), diamond, and Group III nitrides, have led to new types of electronic devices that operate at much higher voltages and switching frequencies. It will take some time for these new materials to be ready for high power applications but they will eventually have a major impact. These semiconductor improvements will mean that fewer devices will be required for each converter. Costs and losses will be reduced and reliability improved.

Flow control devices such as FACTS have the ability to fundamentally alter flow patterns in AC networks. Operation of a system with many controllable flows requires the development of new operational approaches. With FACTS systems installed in proximity, the potential for undesirable interactions exists. New control algorithms and communications techniques will be required to optimally control multiple FACTS installations.

Longer Term Vision

It has long been suggested that the functionality and flexibility of FACTS devices could be significantly improved in many instances by the union of energy storage with the traditional FACTS controller. The energy storage media capable of operation with high voltage FACTS devices include battery energy storage (BES) and superconducting magnetic energy storage (SMES), as well as conventional capacitors. However, relatively little investigation has been performed to identify the potential applications of this unique dual power flow capability and to establish the preferred energy storage for these applications. Significant optimization of the designs and a better understanding of the potential applications are called for in order to investigate the conceptual designs, quantify the costs, and compare the storage media for such a union.

12
SUBSTATION INFORMATION TECHNOLOGY

Scope of Equipment Covered

The term "substation information technology" is new. It is meant to encompass all aspects and applications of digital information processing within the substation.

Present State of Technology

Applications for digital devices in the substation continue to grow. Microprocessor based relays; programmable logic controllers, monitoring and measuring systems are readily available. Substation automation is a prime consideration for any new major installation. However, today's systems are neither designed nor applied to the substation as an integrated entity. Protection, control, condition monitoring and maintenance functions all have common data requirements. Recognizing and exploiting these common needs requires taking an over-view approach. Substation automation projects have made progress in this direction but there are gaps, especially in condition monitoring and maintenance, that, when filled, could produce significant increases in asset utilization and operating economies. This will be an obvious area for investigation in the Smart Substation project. Substation information technology –that is defining and specifying substation control, protection and monitoring applications in digital systems terms- has the potential to bring forth new solutions.

Anticipated Near Term Trends

Restructuring and economic considerations are changing every aspect of the power delivery business. There is no reason not to expect these changes to continue for the foreseeable future. In the long run, grid-operating organizations will get much larger, with many more substations to maintain. At the same time, the number of personnel to oversee the stations and their expertise level will decrease.

On another front, the rapid pace of development of integrated circuits will continue. "Moore's Law," stating that the speed and power of computing chips doubles about every 18 months, continues to hold. Advances in semiconductor lithography, materials and cooling techniques occur almost daily. The explosive growth in telecommunications insures the continued development of electro-optic components. More powerful and less expensive microprocessors, analog to digital converters, data storage devices, communications systems and other components of the digital age will continue to appear. Significant advances in software and expert systems programs are being driven by large market place demands. The Smart Substation should take advantage of all the market place has to offer. Clearly more comprehensive utilization of digital tools and devices could be advantageous in operating and maintaining substations. Many applications have been developed. IEDs and digital relays are common. Some monitoring systems have been successfully used. All of these developments have been oriented to a particular type of equipment or function. There has been no effort to approach the entire substation as a system and to develop an integrated digital solution to its operation and maintenance.

To keep power flowing in a reliable and economic manner the stations must become more automated and autonomous. They must be operated at the most economic utilization level and optimally maintained. To do this, more data about operating and equipment conditions must be measured. But this information should, for the most part, be analyzed, interpreted and stored in the station. There may not be anyone to review it on a routine and continuous basis at a central location and it would be inefficient and overburden the communications links to send large volumes of data to a remote location to extract meaningful information.

To illustrate, consider transformer dynamic loading. Knowing the remaining capacity of a loaded transformer will be vital for optimum asset utilization and in order to respond to changing operating conditions (faults, short-term delivery contracts, etc). Algorithms can be developed to calculate this parameter based on load current, several temperature measurements at the unit, ambient temperature, and cooling status. Rather than sending all this data to a central computer, it makes more sense to do the calculations in the substation and only transmit the results. Of course many of these same parameters can be used for deriving vital information on other substation condition so it makes no sense to measure and store them more than once.

Putting the processing power at the substation is the essence of the Smart Substation. Only responses to inquiries or requests for action need to be transmitted up to the next level of control. Data processing will occur at the station level. It will be an evolution away from the established command and control operation of today to more distribute, localized operation.

A number of forces are driving towards a Smart Substation operated and controlled completely by digital technology.

- New players require new information. Regional Transmission Operators (RTOs) now require access to more power flow information and control over operations. This trend will continue. For example, in the near future one can foresee demand by RTOs for additional information about real-time dynamic circuit loading and equipment condition in order to better adjust power delivery and respond to system changes. Power exchanges require revenue data to clear day-ahead and hour-ahead transactions, again, as digital information.
- Microprocessor based relays are becoming more accepted as experience has been gained. Substation automation has gained a level of acceptance.
- Appropriate communication protocols have been developed and accepted by utilities and equipment suppliers.
- Fiber optic and other high-speed wide-area networks between major substations stations and controls centers are growing in number.

- New equipment condition monitors and diagnostic systems rely on microprocessors and personal computers for data analysis.

The direct data acquisition and control of field devices is an area that has been undergoing significant transition. Traditionally, the field devices were directly connected to RTUs, which provided a network interface and performed initial processing of the acquired data. The introduction of microprocessor technology has led to the development of IEDs, effectively allowing for the direct network access to the devices, as well as more processing being performed at the end device.

Digital signals are the natural language and communications mode for all these information exchanges. In order to maximize the benefits of this trend, it may be advantageous to consider the subject of substation information technology as a separate and distinct area. Just as the corporate enterprise recognized the need to centralize IT to better manage development and operation, application of the various interconnected substation digital systems will be better served with an integrated approach. The application of information technology in the substation requires the combination of computer and power systems knowledge.

Communications

The derivation of information from data collected in the substation and communication of that information within the station and to remote locations will be the foundation of the Smart Substation approach to station design. Fortunately, much work has been done in developing the basic concepts need to implement the needed communication's functionality. No discussion of the Smart Substation of the future would be complete without mention of the Utility Communication Architecture (UCA™) [14]. UCA is a communication architecture created by the EPRI as a "universal" information system for use across the electric and other utility industries. This common, open data communication protocol is now available for many substation IEDs and insures their interoperability. The increased use of UCA will minimize the cost of data integration and collection and will facilitate communication among different components from different vendors. UCA development has been on-going for several years and has an established and complete plan for future work. Consequently, UCA development does not need to be considered under the Smart Substation effort.

In response to the problem of custom protocols and inability of different manufacturer's devices to communicate, EPRI began the Integrated Utility Communications (IUC) program. This pioneering work began in the 1980's in an attempt to secure the advantages to both utilities and vendors of standardized communications architecture. MMS (Manufacturing Message Specification) is the application-level messaging protocol that UCA designers selected for use in real-time data exchange applications. MMS is an internationally standardized[15] messaging system for real-time networked data exchange and supervisory control. UCA is now a national specification under the IEEE and is in process to become an accepted international standard under the International Electrotechnical Committee (IEC). [16] [17]

UCA emphasizes vendor-independent communication and facilitates the use of distributed measurement, control, and communication schemes. UCA2 is being built on and extending the previous UCA work by EPRI. It provides the greater definition needed to make the architecture applicable to specific utility operations and to provide manufacturers a “build to” specification for substation devices.

UCA includes detailed object models, which define the format, representation, and meaning of utility data. Generic Object Models for Substation and Feeder Equipment (GOMSFE) acts as the “dictionary” which defines categories of information within an electric utility substation, the informational hierarchy in which the information is organized, and the naming conventions by which applications can access the information. GOMSFE is the dictionary of “names” used when describing equipment and functions within a substation. A UCA2 compliant intelligent electronic device (IED) in a substation will have all of its data and functions available to respond to these “names”. The development of models for other substation and feeder automation field devices is an ongoing process and the implementation of a Smart Substation may require additional terms for the GOMSFE dictionary. UCA is an effective, established response to the utilities’ desire to have easier integration of different vendors’ products. Its use will be key to the realization of a Smart Substation.

Data Bus

The growing use of digital electronic components in the modern substation naturally leads to discussion of a completely digital substation. Microprocessor relays, personal computers, equipment diagnostic and monitoring systems, SCADA RTUs, and optical current and voltage sensors all naturally operate in the digital realm. The ability to interconnect these and other devices through a substation high performance LAN would lead to many operating and economic advantages.

Optical voltage and current measurement systems generate digital signals in the process of demodulating the sensor’s optical output. This digital information could be fed directly to other systems that now take analog currents and voltages and convert them to digital signal for their processing. Microprocessor relays, digital fault recorders and condition monitors could all eliminate the front-end A/D conversion that is now required. Not only would the cost and complexity of these systems be reduced but, also, additional functionality would be possible. For example, a breaker condition monitor could make use of the highly accurate digital current and voltage waveforms from a breaker interruption, available at no additional cost to the monitoring system from the station optical measuring systems, to analyze the operating condition of the breaker. The alternative approach is independent data collection for breaker monitors. Since acquiring the waveforms and processing high accuracy A/D conversion is expensive, this has been one of the major factors limiting a full function, cost effective breaker monitor.

Of course there are a number of issues that must be addressed. Among these are:

- Sampling rates, anti-aliasing filters, and phase delays must be aligned between IEDs and the sensor electronics.
- Sampling must be synchronized

- Sharing of transducer signals requires multi-drop data buses with master-slave, client-server, or peer-to-peer designs.

In the Smart Substation, there will not be separate, stand alone systems for measurement, control, protection, and analysis. These functions will all converge and be integrated into one system with these components communicating to and sharing data with each other. There is a corresponding convergence in the data stream. The same data stream can be used in the millisecond range for protection, in the second range for control, in the minute range for condition monitoring and in the days, weeks, or longer time frame for maintenance decisions. More and better data will be available faster. Diagnosis will be more informed and quicker. Implementation costs for new equipment will be lower with “plug and play” facilitated by UCA and a set of already available measurement parameters.

There is no fundamental difference among many of the information points required for operations, condition monitoring and maintenance. It is inefficient to convert and store a data point more than once. Just as it is often unnecessary to report that a parameter has not changed. It is possible to conceive of a substation database containing all of the data relevant to the station’s operation. A substation fiber optic LAN could communicate digitized parameters to a centralized, redundant database in the substation. Systems in need of data could interrogate the database as required. Alarm systems, energy management systems, condition monitoring, even protection systems (although it would require a philosophical change) could all work from this database. Established compression and archiving techniques, with periodic off-loading of only high-value information to a corporate database would keep the size manageable. The addition of new functionality could be easily accomplished by simply connecting to the existing data store. Today’s commercially available 1.2 Gbit/s Ethernet systems and database servers and software could form the basis for a feasibility study to evaluate such a station LAN and identify any additional technologies needed. The trend toward a digital substation is inevitable. However, its arrival, with the accompanying operational and economic benefits, can be hastened by beginning preliminary design efforts by developing, from the utility perspective, a listing of functional requirements and preliminary specifications.

Condition Monitoring

Competitive business pressures will drive utilities to continue to seek out every possible economy in operating their systems. Maintenance is one area where costs can be controlled with the application of better information. Not enough maintenance leads to premature failures and expensive repairs. Excessive maintenance consumes valuable resources and increases the risk of inadvertent damage. Not only must the frequency of the maintenance be proper, the proper maintenance tasks must be performed. Reliability Centered Maintenance (RCM) has been established as the most effective approach. For the major station equipment, RCM analysis recommends condition based maintenance wherever possible. In predictive maintenance, equipment condition is monitored to detect parameter changes that indicate a degradation or impending failure. For the major components, predictive indicators can be used to schedule maintenance at the opium time, not too soon and not too late, to address normal wear and for detection of more random incipient failure conditions. The practical application of predictive maintenance is limited by the requirements for data-the measured parameters-and the need for knowledge that relates the measurement data to the change in equipment condition.

Substation Integrated Monitoring and Diagnostic System

Asset management, in different forms and under different names, has become recognized as one of the best processes for minimizing life cycle costs. Optimizing maintenance is a vital step in the asset management process and condition based maintenance has been established as the most effective approach for the major equipment types. To help determine when maintenance is appropriate, there are now a number of condition monitoring systems available for breakers and transformers from both the equipment manufacturer and third party suppliers. These systems operate independently, with their own measuring devices, communications channels and data processing circuits. In some cases they transmit raw data back to a central location receiving data from other stations for processing and display. In other cases, there is a local human-machine interface (HMI) and only a category alarm is generated from the equipment.

There is a need for a system that would provide an integrated approach to substation equipment monitoring and condition diagnosis by considering the substation as the primary asset and the equipment as component assets. It would be more efficient to combine the infrastructure required for each device monitored– communications, processing, HMI, and parameter measurements, when ever possible. After all, the same current waveform could be used by the algorithm for breaker contacts and for those for the associated transformer. Only sensor data need be gathered at the power equipment. All processing and alarming would be done by a substation integrated monitoring and diagnostic system (IMD). Such an approach would improve the quantity of data available to determine the condition or wear of substation equipment and reduce maintenance costs by providing the information required for a condition based maintenance program. It would allow data to be use in many applications. EPRI’s MMW could form the software basis for such a system.

An integrated monitoring and diagnostic system would combine outputs of all monitoring sensors, intelligent electronic devices (IED) and digital fault recording devices (DFRs) into a single substation data set for integrated analysis and display. A combined data set would provide more timely and accurate information on the condition of a particular component than would isolated data. IMD would consolidate the hardware and software needed for equipment monitoring into a single substation based data acquisition, analysis, and display and alarm system and be able to report on the condition of the primary asset, the substation. Only report by exception need to be transmitted beyond the substation.

Through the sharing of this monitoring infrastructure, the incremental cost of each parameter’s acquisition and processing would be reduced. This would encourage more comprehensive condition monitoring. IMD could also be a repository for site maintenance data. There could be an expert systems engine shared by several pieces of equipment. The substation could initiate its own request for maintenance and provide information on the scope of work required. Information from IMD systems could also be transmitted to a remote performance assessment tool, such as MMW, where in combination with other data, e.g. maintenance history, a complete picture of equipment condition could be constructed.

The substation database need not be limited to automatically collected data. Data gathered manually during inspections and maintenance of station equipment could be entered locally. Such data only would need to be entered one time. The IMD could verify the data as its entered and, if a problem were found, prompt the technician at a point when there is a much greater possibility for re-measurement than if the data has been transported to a remote location. Subsequent visiting maintenance personnel would have the complete history of the station equipment available to them locally without any additional effort. The IMD could filter data and only transmit significant changes in data points to a central repository.

In a period of reductions in maintenance staff, especially those with many years of experience, and the trend towards unmanned stations, IMD would be a valuable operating aid. IMD would provide information to remote maintenance and operating (for dynamic loading for example) locations only when their action was required. Critical decision making could be centralizes, as is today's organizational trend, but information processing could be pushed down to the lowest possible level.

Dynamic Thermal Circuit Rating

The Dynamic Thermal Circuit Rating program, version 2.0 (DTCR2.0) [18] calculates critical temperature and thermal ratings of transmission circuits using real time measured weather conditions, circuit load, and optional measurements of equipment thermal parameter. Multiple circuits may be modeled and their ratings calculated simultaneously. Each circuit may consist of one or more types of power equipment including transformers, cables, lines, circuit breakers, switches, CTs, buses, and line traps. Depending on the equipment modeled, weather measurement inputs may include air and soil temperatures, wind speed and direction and solar loading.

DTCR can provide operators with more accurate circuit ratings that will allow better informed decisions when contingencies arise or when there are pending economic power transfers. Since real-time ratings are usually above the more conservative static ratings, DTCR2.0 reduces operating restrictions. Typically EMS/SCADA only displays those circuits close to or above their rating. When DTCR2.0 calculates the actual rating, operators will not need to intervene as frequently.

As currently deployed, CTCR2.0 is designed to run on a personnel computer linked to the SCADA system with the SCADA system providing real-time data input files. The program provides a video display and writes calculation results to output files, which can be read by the SCADA system. An alternate architecture that would be more appropriate for a Smart Substation application would be to include DTCR functionality within the IMD. Since all of the required measurement data is acquired at the substation, it could be most readily processed at the station. Implementation of DTCR would be relative inexpensive compared to a stand-alone system. Using the DTCR algorithms, IMD could calculate ratings and only transmit information to the control center when requested or when crossing a preset threshold. IMD could compare calculated and measure equipment temperatures and detect discrepancies that would require intervention. For example, transformer cooling problems could result in a measured temperature higher than that calculated for the given load and ambient conditions. IMD would note the condition and communicate a specific maintenance request.

Smart Sensors

Smart sensor packages are recent developments. Such sensors consist of a primary sensing element, excitation control, amplification, analog filtering, data conversion, compensation, digital information processing, and digital communication processing. The sensor market is dominated by process industry applications while most advanced work is directed at military and aerospace applications. Commercially available sensors should be assessed for their possible adaptation to substation use through a systematic review.

Smart structures, employing smart materials, also known as smart materials and structures (SMS), encompass interacting sensors, actuators, and processors. Examples are piezoelectric materials, shape memory materials, conducting polymers, and chemical sensors. SMS has focused on high payoff situations in the space and aircraft industries but many other industries and a widening range of applications are now under development. EPRI conducted a review of this technology in 1997[19] but since the sophistication of such systems is in its infancy and they continue to evolve rapidly, an updated review is warranted.

Conventional sensors are available but the problem of cost effectively collecting and analyzing large amounts of data from many sensors still must be dealt with. Wireless telemetry of multiplexed signals may be an answer. Self-powering and remote interrogations of sensors are possible approaches for some applications. Economical multipurpose sensors are expected in the future. Application of sensors will be very price sensitive. As the cost of the sensor and associated data acquisition systems drop, more applications will become practical.

13
STATION DESIGN

Scope of Equipment Covered

This section deals briefly with some of the initial substation design considerations and their impact on the final configuration. Bus arrangement, equipment type and security issues are discussed. There is no standard substation; in fact, there are only a few instances where two substations are identical. However, voltage, function, and the environment in which they operate can categorize substations. Often, voltage is used to distinguish substation class, as follows:

- 345 kV and above
- 230 kV to 69 kV
- 69 kV and below

The highest voltages, 345 kV and above, are used for major power transmission systems, whereas 69 kV and below is typically used at the distribution level. Voltages in between these two extremes are used in both high voltage distribution or sub-transmission networks.

Substations may also be separated into different types based on their functionality. Some have multiple voltages and serve multiple loads of different types. Other substations are simply interchanges where lines are split to serve two load areas or lines are combined to bring two or more power sources together to supply one load, and a few simply provide VAR support along transmission lines. Finally, some substations operate in deserts, others in areas of high humidity and high temperature, while still others operate in extremely cold conditions.

Bus Arrangement

Transmission substation reliability of service and flexibility of operation are extremely important. Facilities are normally designed to allow equipment maintenance without circuit interruption. Multiple bus arrangements and extensive use of circuit breakers for switching provide added system flexibility. The actual station arrangement is determined by analyzing factors such as: the level of reliability required for the application, space available, initial costs and maintenance considerations. Most major transmission substations employ either a ring bus or breaker-and-a-half designs.

The ring bus arrangement is one of the more prevalent designs. It provides for circuit breaker maintenance since any breaker can normally be removed from service without interruption of service to other circuits. As a result, separate circuit breaker bypass facilities are not required. A number of equipment arrangements may be used to provide a ring bus configuration, depending on anticipated substation expansion and possible system modifications. Rather than expanding a ring bus to accommodate additional circuits, it is often more advantages to adopt a breaker-and-a-half scheme. The advantages of a ring bus include:

- Flexible operation
- High reliability
- Isolation of bus sections and circuit breakers for maintenance without disrupting circuit operation
- Double feed to each circuit
- No main buses
- Expandable to breaker-and-a-half configuration
- Economic design

There are corresponding disadvantages**:**

- Ring may be split by faults on two circuits or a fault during breaker maintenance resulting in undesirable circuit combinations on the remaining bus sections.
- Each circuit has to have its own potential source for relaying.
- There is a practical limit to the number of circuit positions.

The breaker-and-a-half configuration consists of two normally energized main buses. Electrically connected between the buses are three circuit breakers and, between each two breakers, a line is connected. In this arrangement, three circuit breakers are used for two independent circuits; hence, each circuit shares the common circuit breaker between them, so there are one-and-a-half circuit breakers per circuit. The breaker-and-a-half configuration provides for circuit breaker maintenance, since any breaker can be removed from service without interrupting any circuits. Additionally, faults on either of the main buses cause no circuit interruptions. Failure of a circuit breaker results in the loss of two circuits if a common breaker fails and only one circuit if an outside breaker fails. Essentially, this is the same basic equipment assemblage as described for the ring bus scheme. Frequently, substations are initially constructed with a ring bus arrangement and ultimately expanded into a breaker-and-a-half configuration to obtain additional flexibility and reliability required with the additional circuits.

Advantages:

- Flexible operation
- High reliability
- Can isolate either main bus for maintenance without disrupting service
- Can isolate any circuit breaker for maintenance without disrupting service
- Double feed to each circuit

- Bus fault does not interrupt service to any circuits
- All switching done with circuit breakers

Disadvantages:

- One-and-a-half breakers are required per circuit.
- Relaying is involved, since the center breaker has to respond to faults of either of its associated circuits.
- Each circuit should have its own potential source for relaying.

There has been some discussion in the industry that, due to the increased reliability and decreased maintenance demands of newer substation equipment, notably GIS and circuit breakers; transmission stations with single bus bar arrangement will be used in the future[20]. This would obviously be a problem for an N-x design but may make sense for probabilistic risk assessment criteria since substation failures contribute little to system unreliability. However, although various groups have collected substation equipment failure data over the years, there is actually very little basis for performing substation reliability studies with reliability numbers based on specific equipment, operating and maintenance practices and environment. Any data that does exist is based on older designs and is not readily applicable to equipment now available. With the increasing volume and magnitude of bulk power transactions and the potential for merchant plant connection points not originally planned, load flow within the substation may require more attention. There may be bus and equipment arrangements that more uniformly load station elements and reduce equipment costs.

Equipment Type

Air insulated switchgear (AIS) has the lowest first cost but also has relatively high maintenance costs due to the maintenance requirement of the various, stand-alone components-breakers, disconnect and grounding switches and conventional CT's and PT's. Gas insulated switchgear (GIS) has a higher initial cost but, for the more recent designs, lower maintenance costs. As the voltage increases, the difference in cost diminishes. GIS has a lower failure rate and lower maintenance requirements than AIS but on the other hand GIS normally has a longer repair time. Advances in the modularity of GIS components however, offer the possibility of component replacement rather than onsite repair. Space or pollution considerations can make GIS a more favorable choice.

One supplier now offers a hybrid alternative. The hybrid switchgear integrates the switching components and optical sensors into a gas insulated enclosure. Connections between the enclosures are made with air-insulated bus. It is claimed that this approach has a lower total-owning cost due to reduced maintenance costs and requires less area and foundation work than an AIS installation. This may well be the future trend. It would reduce the number of components but would produce the same dependence on one manufacturer for all the switchgear equipment and it's monitoring.

Security

In the aftermath of September 11, 2001, consideration of infrastructure security has a higher level of priority for substation designers than ever before. Infrastructure security has been addressed previously and a number of new efforts have been recently initiated. It is a broad subject and an in depth treatment is well beyond the scope of this report. The short discussion below serves only to outline the area

Physical Security

The issues of maintaining physical security of a substation are not unlike those for other facilities and conventional approaches such as surveillance, lighting and fencing are applicable. Unlike other possible targets however, power substations contain and are directly connected to vast amounts of potential energy that are capable of causing more damage than the triggering incident. For example, consider the consequences for a transformer subject to a bus fault with the protection disabled.

Traditionally substations are designed to protect against the consequences of random equipment failures not deliberate attempts at causing damage or disrupting power flow. The design of a more fault tolerant substation should be further investigated and concepts not before considered explored. For example, perhaps control, communications and protection should be more decentralized and distributed throughout the station. First and second lines of protection should not be in the same physical location. A line of transformer protection could be located at the unit with direct communication to the isolating breakers, by passing the control house. The design and layout of the critical dc control system should be reviewed. There could be redundant batteries removed some distance from each other or even distributed around the station. The design practices for the power distribution systems of modern naval vessels may offer solutions that could be adapted to substations. Clearly no station can be made invulnerable. However, there may be steps that can be taken, particularly to protect the more difficult to replace components, such as transformers, against more conventional threats.

More conventionally, fence height could be increased to protect against thrown objects or walls erected that would not allow viewing the yard to select targets. Transformer radiators could be positioned away from the station perimeter so as not to be so vulnerable. Non-ceramic insulators, which are more tolerant to damage, could be used instead of porcelain insulators. It will be quite challenging to develop layouts and designs that provide better physical security and any such undertaking should be preceded by a risk/benefit analysis. It can be expected however that design changes for improved security would also contribute to improved station reliability under normal operating contingencies.

Computer and Communication Security

One area where there is a clear and present danger is that of information security. These vulnerabilities have been previously highlighted in an EPRI report on communication security [21]. One of the features of the Smart Substation will be the addition of new data acquisition elements and further reliance on the transmission and processing of digital information. For a variety of reasons the substation of the future will be more reliant on robust, expansive and open information systems. Increased access to system data and communications among operational systems is vital across the board for continued improvements in the process of running the grid. Other entities may also have access to operational data previously kept internal. The Massachusetts Department of Telecommunications and Energy is installing an Internet based system to track utility response to power outages. When completed, the system is expected to have direct access to Massachusetts' utilities' outage management systems.[22] Increased access and more communications channels means greater security risks.

Even before the terrorist attacks of September 11, 2001, one Federal Government agency warned, "one person with a computer, a modem, and a telephone line anywhere in the world can potentially…cause a power outage in an entire region."[23] IT security will be a requirement for the Smart Substation. The benefits of more widely distributing operational and maintenance data through the utility must be weighed against any increased risk. In the past utility operating and SCADA systems were not particularly attractive targets to recreational hackers or cyber-thieves. However, given their critical role in today's society, utilities can be considered likely targets of cyber-terrorists. It can be expected that these attackers would be well equipped, possess technical knowledge of power system components, and have the time to refine their methods.

Modern digital substations may well represent the most significant information security vulnerability in the power grid. Energy Control Centers perform more vital functions but, by their very nature, are more isolated and protected. Many of the automated devices used to monitor and control equipment within transmission and distribution substations are poorly protected against cyber intrusion. Interconnections between control centers and corporate data networks, widespread use of dial-up modems, and use of public networks are other potential sources of vulnerabilities. While the RTUs on a network may be difficult to access outside of the dedicated serial lines, it may be only moderately difficult to penetrate SCADA through the corporate network if there are links for displaying system status and alarms via an intranet.

Three trends will increase the exposure of electric power control networks to attacks:

- The shift from proprietary control systems to open systems and standards with well published protocols.
- Increasing use of automation, outside contractors, and external connections, such as dial-in modems and the Internet, to reduce field staff and operating costs.
- The requirement to provide open access to transmission system information dictated under FERC orders 888 and 889.

Computer security considerations again lead to keeping as much information and control intelligence as possible local to the Smart Substation.

Self-Healing Substation[24]

The electric power infrastructure is a large, geographically dispersed, and inviting target, and in fact has been the objective of terrorism. However, it is difficult to predict how, where, and when a future attack may come. Near-term technology development is needed to improve understanding of the vulnerability of the power system, in general, and of substations, in specific, so that we can:

- Prevent attacks from occurring
- Minimize the damage if they do
- Speed recovery to an operational state

"Self-healing" substations can provide a response to this threat with their ability to restore partial functionality to damaged stations.

Following a terrorist attack (or, for that matter, other major damage), a system for self-healing of substations would achieve fast/optimal functional recovery using the remaining operational communications and control subsystems. Software could be developed to automatically reestablish substation operations with the operable parts of the damaged substation. The concept is to create a hierarchy of control devices, so the highest-level devices can interrogate each other and all lower level devices to determine which are working and which are not. The high-level devices would then reconfigure the remaining functioning intelligent electronic devices into the optimal secure communications and control network. This could be done within minutes of the disaster occurrence, and report the status of the remaining communications, control and protection system to the control center or its assigned backup. This software would be an extension of the existing UCA.

Currently, heavily damaged substations, caused by a terrorist attack (bombs, mortars, rockets) would either trip all breakers automatically and shut down, or would be shut down by the control center. Recovery would require manual operations and it could take days restore partial service. The proposed new system would be based on an intelligent network and devices that would determine which parts of the substation were still operable, and then would automatically reconfigure the operable parts to recover partial operational functionality. The reconfigured substation would communicate its current status to the control center within minutes, where operators would determine which parts of the substation it can control. Following a visual inspection by substation engineers, the crippled substation could then quickly be returned to service, possibly within hours. An additional benefit and byproduct of this new infrastructure is that it could be used for faster recovery from large natural disasters (earthquakes, hurricanes, or tornadoes).

The UCA provides interoperability among the communications and control devices used for real-time operations. UCA already provides many of the communication services to enable self-healing; however, security needs must be further addressed. The Smart Substation would require that the UCA be extended to include self-healing software for optimal recovery of substation operations.

System Security

The subject of national power network security has been under study for some time as part of the Complex Interactive Networks/Systems Initiative (CIN/SI) [25.] CIN/SI is a joint program sponsored by EPRI and the United States Department of Defense to develop new tools and techniques that will enable national infrastructure systems to self-heal in response to natural and deliberate disturbances. The objective of the project is to develop mathematical models that can be used to construct secure, robust and reliable operation of interdependent, critical infrastructure with distributed intelligence and self-healing abilities. The current approach for designing such a system calls for a reliance on agent technology. Agents are decision-making and control units that assess the situation by analyzing data from equipment sensors and other agents. CIN/SI calls for the use of context-dependent agents in three layers. For the power system, the lowest layer agent is at the substation. For it to be as effective as possible, it must have a complete picture of the status and condition of the substation components. This is in fact just an extension of the Smart Substation IMD and self-healing functionality discussed previously and further supports its development.

Longer Term Trends

Obviously the subject of infrastructure security is evolving and the thoughts presented here are just for the purpose of highlighting the need for and emphasizing this subject for consideration in future Smart Substation design. Infrastructure security undoubtedly will be addressed on multiple fronts with the federal government taking the lead. Many new efforts will be initiated. Recently, the Department of Commerce's National Institute of Standards and Technology awarded funding under the Critical Infrastructure Protection Grants Program to a number of companies and universities to research new information technology security efforts. Other efforts are sure to follow. Substations are the key link between power production and distribution to the end-users. The inherent redundancy and flexibility of the grid depends on the proper operation of the equipment in the substation and the ability this equipment provides to quickly respond to line faults and reconfigure power flows. Clearly, any efforts to enhance grid security must pay particular attention to substation issues.

14
CONCLUSIONS

High Level Design Considerations

In addition to the normal evolution in equipment technology, several macro-level changes in the electric power delivery business were identified as having potentially significant influence on future substation design decisions.

- Increasing numbers of merchant generators, growing regional operating organizations, continuing competition and the appearance of merchant transmission all mean that new stations most likely will be at some time required to operate or connect in ways not foreseen in the original design. To maximize value and utility over their expected operating life, new station designs must be as flexible as possible to accommodate unexpected change.
- Regardless of the final form of industry restructuring, good financial performance will be required of grid asset owners. Maintenance practices, a major factor in equipment availability and a significant portion of controllable costs, will become an even more important core strength for the successful operator.
- System operation most likely will be directed by organizations that will not own or maintain the equipment. More information about equipment condition will be required to reliably accommodate bulk power transactions, to justify maintenance outages, and to understand how operating practices influence maintenance and life cycle costs.
- Many utility companies will continue to reduce staff. Correspondingly, there will be a decrease in the level of experience and expertise available for engineering, operation and maintenance. An inexperienced staff can lead to reduced safety, lower productivity and higher costs. New stations should require fewer personnel to operate and maintain and utilize expert systems to assist inexperienced staff. Tools are needed to capture the retiring knowledge base and make it available to assist in engineering, operations, and maintenance decision making.
- Regulators will take more interest in equipment reliability and availability. Transmission performance indices will be established and tracked. Environmental and, in many areas, appearance concerns will grow.

General Conclusions

Major Equipment

The pace of change of technology for conventional transformers and breakers will be evolutionary. The manufacturers will take the lead and will primarily respond to the demands of the international market place. Advances in transformer and breaker monitoring are not so dependent on the equipment suppliers. Smaller players and, in fact those new to the power delivery industry, can move these technologies along. Established digital and communications products supplied for other markets will greatly assist progress and reduce costs.

Information Systems

The last few years have shown a marked growth in the number of IEDs used in substation applications. This change has been driven by a number of factors. Among them are:

- Increased recognition by utilities that the adoption of new technologies, rather than a "business as usual" approach, offers an economic way to respond to a list of new business and operating pressures.
- Recognition that microprocessor base systems can have the reliability and availability necessary for substation use.
- New suppliers entering the market place with new products.
- A changing mix of skills within the population of utility engineers resulting in a base of digital equipment applications knowledge.
- Continuing decrease in price and increase in capability of digital components driven by rapid growth in markets much larger than that for power delivery applications.

All of these drivers for change will remain and, in fact, strengthen over the next decade.

One that bears particular watching is the entrance of new suppliers. Once substation control and measurement parameters are converted into the digital world, they can be processed by any number of general-purpose systems. The large manufacturing and engineering base for these components can be exploited to build substation systems composed of "plug and play" subsystems. The number of engineers that can program a microprocessor vastly exceeds those who could successfully set an electromechanical relay. Applications knowledge will always be required but it may be well worthwhile to make certain that all the tools are in place for tapping the full potential of digital equipment suppliers. UCA™ and CIM have accomplished much in this area and work continues. Substation information technology -defining and specifying substation control, protection, and monitoring problems in digital systems terms- has the potential to bring forth new solutions.

Developments for substation LAN, an integrated monitoring approach, and substation asset management database all require digital expertise and can benefit from the depth of talent and suppliers in the field. When utility engineers gain more confidence in digital technologies, it is possible to imaging control, protection and condition monitoring integrated into a module at the power equipment level. Substations will be unmanned and operators will have to rely on remote control. Information from the substation will include equipment condition and will be directed both to operation and maintenance staff. As experienced personnel retire, both operation and maintenance staff will need help from expert systems. To reduce data transfers from the substation, as much local processing as possible, including expert system analysis should remain at the substation level.

Benefits Assessment

New technologies, especially in the early stages of acceptance, may command a price premium. At the same time they often offer new functionality and reduced maintenance costs. It is therefore important for prospective utility users to be able to fully evaluate all the benefits and total owning costs of a new solution. Provisions for tools for guidance in this decision making process should be considered for inclusion as a part of any development program.

Standards

The issue of industry standards deserves mention when discussing the development and application of new substations equipment. The acceptance of new technologies will be contingent on the existence of appropriate, applicable standards. The current standards of the relevant standards bodies have been developed and refined over many years and represent a combination of utility and supplier concerns. However, they often reflect the operating principles and limitations of the established technologies. Therefore it may be necessary to modify or add to the standards to accommodate the acceptance of new technologies. The efforts undertaken to supplement the standards to recognize the inherent differences of optical transformers is a good example of what may be required to realize the benefits of a new technology.[26]

Recommendations For Detailed Review

Equipment

Additional standardization of transformer designs among utility users would lower the first cost and lead times of new transformer purchases. Additional standardization of transformer designs within a utility would be beneficial in reducing the number of spares kept in inventory. Standardization of transformer designs among utility users will require a cooperative effort among interested participants. Standardizing voltage and MVA ratings and impedances may not be realistic to achieve. However, standardization should be more likely achieved for accessories, including bushings, cooling equipment, load tap changer, control equipment and monitoring devices. Accessory “packages” with various levels of options could be developed. Specifications and guidelines would need to be developed.

Development of a transformer main tank continuous oil filtration system that has the capability of maintaining the oil in as-new condition would prevent decomposition chemicals of oil from attacking the cellulose and therefore maintain the integrity of the complete dielectric system. EPRI has done work on this and has demonstrated a laboratory version of the filtration system. It has the capability of removing oxygen, moisture, acids and other chemicals, in addition to particles. Development and demonstration should continue, along with an attempt to quantify the benefits.

Development of a bushing tap coupler that can be used to capture multiple signals for various measurements such as PD, FRA and power factor would facilitate the installation of these condition-monitoring devices.

Transformer oil cooling systems have changed little over the years. A review of this function by heat transfer experts outside of the transformer industry may lead to innovative designs and improved oil cooling systems with high efficiency and low maintenance requirements.

Complete monitoring of GIS would require motion diagnostics in addition to electrical diagnostics. The motion systems offered for medium voltage circuit breakers could be used, but would require adaptation. Vibration sensors from other industries may be useful.

Advanced current interruption technology, utilizing high power solid-state components, has opened the door to high power control at a lower cost than ever before. The Solid State Current Limiting Breaker (SSCLB) offers a viable solution to the transmission and distribution system problems caused by high available fault currents, has no adverse environmental impact, and could be easily integrated with digital control and protection systems.

Optical measuring systems offer great promise to provide better information at reduced costs. Work is required to expedite the utilization of their digital outputs directly in metering and protection devices. At the present, digital to analog converters and power amplifiers are required to synthesize conventional outputs for optical measuring sensors. These additional components increase cost and reduce the reliability of the optical system. Digital interface of optical sensors to digital ready meters and relays would reduce costs and improve accuracy.

Composite polymer, non-ceramic (NCI), insulating columns are gaining wider acceptance. Characterization and aging test should continue in order to address remaining questions about service life and performance. Although they have many advantages over porcelain, notably low weight and shorter lead times, composites are more expensive. Increased use will lead to higher production volume and lower prices.

Integrated monitoring and diagnostics sensors and software specifically designed for application to battery electrochemical systems will reduce labor costs and increased accuracy in determining actual battery condition. Automated battery monitoring systems such as the EPRI-developed *Cell Sense*™ could be adapted to work with an integrated station monitoring system.

Information Technology

Substation digital systems today are neither designed nor applied to the substation as an integrated entity. Protection, control, condition monitoring and maintenance functions all have common data requirements. Recognizing and exploiting these common needs requires taking an over-view approach. Substation automation projects have made progress in this direction but there are gaps, especially in condition monitoring and maintenance, that, when filled, could produce significant increases in asset utilization and operating economies.

The explosive growth in telecommunications insures the continued development of electro-optic components. More powerful and less expensive microprocessors, analog to digital converters, data storage devices, communications systems and other components of the digital age will continue to appear with greater capabilities and reduced costs. Significant advances in software and expert systems programs are being driven by large market demands beyond the utility industry. The Smart Substation should take advantage of all the marketplace has to offer. Clearly more comprehensive utilization of digital tools and devices could be advantageous in operating and maintaining substations. Many applications have been developed. IEDs and digital relays are common. Some monitoring systems have been successfully used. All of these developments have been either oriented to a particular type of equipment or function. There has been no effort to approach the entire substation as a system and to develop an integrated digital solution to its operation and maintenance.

An integrated monitoring and diagnostic system would combine outputs of all monitoring sensors, intelligent electronic devices (IED) and digital fault recording devices (DFRs) into a single substation data set for integrated analysis and display. A combined data set would provide more timely and accurate information on the condition of a particular component than would isolated data. An integrated approach would consolidate the hardware and software needed for equipment monitoring into a single substation based data acquisition, analysis, and display and alarm system and be able to report on the condition of the primary asset, the substation. Only report by exception need to be transmitted beyond the substation.

To keep power flowing in a reliable and economic manner the stations must become more autonomous. They must be operated at the most economic utilization level and optimally maintained. To accomplish this, more data about operating and equipment conditions must be measured. But this information should, for the most part, be analyzed, interpreted and stored in the station. First, there won't be anyone to review it on a routine and continuous basis at a central location. Second, it would be inefficient and over burden the communications links to send large volumes of data to a remote location to extract meaningful information

Minimization of maintenance costs and optimization of asset utilization will be key skills for the successful transmission owner. Achieving these challenging goals will be even more difficult if, as is now the trend, other parties will direct operations. The best available equipment condition information will be required to cost effectively schedule maintenance, to justify equipment outages, and to optimally load equipment. The marketplace has provided individual equipment monitors, e.g. transformers, breakers, bushings, but these are expensive to deploy. There is a need for a more integrated station approach that will avoid duplication of measurements and processing components, employ a common architecture, and utilize existing EPRI developments, such as Xvisor, effectively.

The trend is toward larger utilities with more stations to operate. Most all companies are reducing staff and experienced personnel are not replaced. Substations must operate more autonomously. To the greatest extent possible data should be processed and stored at the station. Beyond the normal SCADA data, only specific requests for action need to be communicated to a control center. Dynamic loading calculations can be done locally with results transmitted on request or when loading reaches a trigger level. Communications requirements will be reduced and security increased.

UCA™ efforts should continue and all Smart Substation IEDs should be compliant.

Substation LAN architectures should be further investigated. Cost, security, and flexibility need to be considered. Maximum use of components and devices developed for general applications would reduce implementation costs.

Knowledge Base

Development of accurate thermal models, not only for new, but also for already installed transformers would improve reliability by detecting cooling system abnormalities and the need for heat exchanger maintenance when incorporated into an integrated monitoring system. Implementation of these thermal models into more sophisticated programmable winding temperature indicators would give systems that are more accurate under all conditions of operation. Implementation of dynamic loading of substation power transformers, utilizing accurate thermal models, would result in better asset utilization by optimizing loading, especially during emergency conditions.

Fundamental work is required to advance knowledge of the correlation between test data and insulation condition, particularly the dynamic behavior of gasses, moisture and chemicals of decomposition in transformers.

Advanced algorithms for transformer and circuit breaker diagnostics need to be developed to detect all incipient problems that could lead to failure or the need for immediate maintenance. Examples are algorithms to diagnose partial discharge measurements and transformer main tank vs. LTC tank oil temperatures for the various types of load tap changers.

Although various groups have collected substation equipment failure data over the years, there is actually very little basis for performing substation reliability studies with reliability numbers based on specific equipment, operating and maintenance practices and environment. Any data that does exist is based on older designs and is not readily applicable to equipment now available. This lack of data impedes the quantitative reliability analysis required to optimize station bus arrangements.

Technologies from Other Industries

It would potentially be productive to review technology developments in other industries that may be adaptable to substations. One that comes to mind is the automotive industry. Recent developments to improve the operating and environmental performance of automobiles have led to a family of rugged, inexpensive sensors and electronic control units. For example, accelerometers used for airbag triggers cost only a few dollars and may be applicable to use for measuring circuit breaker travel. The techniques and technologies used for oxygen sensors may help in developing an affordable, long-lived transformer dissolved gas sensor.

The process industry (PI) has been responsible for a number of developments that have benefited the power industry over the years. Supervisory control and data acquisition (SCADA) systems are now integral parts of power system control and operation. SCADA systems originated with the concept of computer control of plant processing equipment, such as used in the paper and petroleum refining industry. More recently, the PLC, programmable logic controller, was perfected for process control and now has many substation control applications. Software developed for the PI has found it's way to power delivery applications. One of the current PI trends is towards distributed control systems. Local control actions and status monitoring are performed by local microprocessors, enabling the central computer to be an information manager for the system. A review and assessment of the latest technology trends in the process industry would take some effort but may hasten what has been a slow but steady migration of technologies from there to power delivery.

Many diagnostic sensors have been developed as prototypes, but availability of suitable sensors is limited. This slows the introduction of condition-based maintenance. Several national agencies, including The Defense Advanced Research Projects Agency (DARPA) and the National Aeronautics and Space Administration (NASA), have developed vast arrays of potentially useful devices and technologies. A systematic review by personnel familiar with sbstation design, operation, and maintenance issues would be required to assess the applicability of these developments.

Next Steps

Economic and regulatory pressures on substation owners have resulted in staff reductions, cutting of O&M budgets, and replacement deferrals. Nonetheless, the need for new substations is being driven by a growing demand for electricity and unplanned bulk power exchanges. Utilities cannot afford for those substations that are built in the coming years not to employ the best possible technologies. Although the designs of the major components will only change slowly, the application of new monitoring, diagnostic, measuring and database systems can be expedited through focused research and development. This report is a first step. It provides a basis for discussions and workshops to review the most promising solutions for substation design and equipment, and select those for further work. Comments and suggestions from a broader selection of utility and industry experts will be considered and selected technologies from other fields reviewed in more detail. A straw man vision of the Smart Substation will be constructed. With these efforts, the Smart Substation project will identify and demonstrate those technologies now available and the work needed to make others available to meet the challenges of the future.

A GLOSSARY

AIS Air Insulated Switchgear

DTCR Dynamic Thermal Circuit Rating

EMC Electromagnetic Compatibility

FACTS Flexible AC Transmission System

FRA Frequency Response Analysis

GIS Gas Insulated Switchgear

HMI Human Machine Interface

IED Intelligent Electronic Device

IGBT Insulated Gate Bipolar Transistor

LCA Life Cycle Assessment

LCC Life Cycle Cost

NCI Non-ceramic Insulators

PD Partial Discharge

PLC Programmable Logic Controllers

PWM Pulse Width Modulation

RTO Regional Transmission Operator

RCM Reliability Centered Maintenance

RTU Remote Terminal Unit

SCADA Supervisory Control and Data Acquisition

SF_6 Sulfur-hexafluoride Gas

SMES Superconducting Magnetic Energy Storage

SSCLB Solid State Current Limiting Breaker

SVC Static VAR Compensator

TCSC Thyristor Controlled Series Capacitors

UPFC Unified Power Flow Controller

UPS Uninterruptible Power Supply

VSC Voltage Source Converter

B REFERENCES

1. *National Energy Policy*, May 2001,U.S. Government Printing Office, ISBN 0-16-050814-2.

2. EPRI Report 1001951, “Maintenance Ranking and Diagnostic Algorithms for Transformers,” 2001.

3. EPRI TR-105421, “Thermal Models For Real-Time Monitoring of Transmission Circuits,” 1995.

4. EPRI TR-113933, “Practical Guide to SF_6 Handling Practices”, 1999.

5. *Emissions of Greenhouse Gases in the United States 1999*, Energy Information Administration, United States department of Energy, DOE/EIA-0573(99), 1999.

6. EPRI Report 1000430, “Field Trial of Field Hardened Laser Camera for SF_6 Detection,” 2000.

7. ANSI/IEEE C37.92/D8.4, “Trial Use Standard for Low Energy Analog Signal Inputs to Protective Relaying,” September 2000.

8. IEC 60044-7, “Electronic Voltage Transformers,” 2000.

9. IEC 60044-8, “Electronic Current Transformers,” 2000.

10. ANSI C37.92, “Low Level Analog Interconnection Between Electronic Sensors and Protective Relays”

11. EPRI Report 1000719, “500-kV Non-Ceramic Insulator Aging Chamber: Final Report,” 2000.

12. EPRI TR-111092, “Battery Monitoring System: Phase 4- Field Evaluation,” 1998.

13. EPRI Report 1001337, “Field Demonstration of a 24 kV Warm Dielectric HTS Cable at Detroit Edison, 2000 Annual Progress Report,” 2000.

14. IEEE-SA TR-1550-1999, “Utility Communication Architecture (UCA™) Version 2.0,” November 1999.

15. International Organization for Standardization 9506.

16. IEC 61850-9-1,”Specific Communication Service Mapping-Serial Unidirectional Multidrop Point to Point.”

17. IEC 61850-9-2, “Specific Communication Service Mapping- ACSI Mapping on an IEEE 802-3 Based Process Bus.”

18. EPRI CM-112934, “DTCR 2.0: Dynamic Thermal Circuit Rating User’s Manual,” 1999.

19. EPRI TR-108377, “Smart Materials and Structures,” 1997.

20. CIGRE 23.99(WG01) 43, “Questionnaire Concerning Aspects On Planning, Design, Operation And Maintenance Of Future Substation”, August 2000.

21. EPRI Report 1001174, “Communication Security Assessment for the United States Electric Utility Infrastructure,” 2000.

22. “Massachusetts To Use Net To Look Over IOU’s Shoulders,” *Energy IT*, Vol.6, No 6, November 2001.

23. Remarks of John Tritak, Director of the Critical Infrastructure Assurance Office as quoted in “The Next Y2K?” *Utilities IT*, February 2000.

24. Based on Remarks of Bill Blair, EPRI, Internal EPRI presentation, November 2001.

25. Amin, M. “Toward Self-Healing Energy Infrastructure Systems,” *IEEE Computer Applications in Power*, January 2001.

26. EPRI Report 1001963, “Optical Voltage and Current Measurement Technology: Specification Reviews,” 2000.

About EPRI

EPRI creates science and technology solutions for the global energy and energy services industry. U.S. electric utilities established the Electric Power Research Institute in 1973 as a nonprofit research consortium for the benefit of utility members, their customers, and society. Now known simply as EPRI, the company provides a wide range of innovative products and services to more than 1000 energy-related organizations in 40 countries. EPRI's multidisciplinary team of scientists and engineers draws on a worldwide network of technical and business expertise to help solve today's toughest energy and environmental problems.

EPRI. Electrify the World

1001965

Printed on recycled paper in the United States of America

EPRI • 3412 Hillview Avenue, Palo Alto, California 94304 • PO Box 10412, Palo Alto, California 94303 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com