DPQ Executive Summary

Keywords:
Harmonic
Momentary Interruption
Report
Sag/Swell
Transient

Abstract
An Assessment of Distribution System Power Quality is the most extensive distribution system power quality monitoring study ever commissioned. The project, commonly referred to as the "DPQ Project", was begun in the fall of 1989. Its primary goal was to collect, analyze, and report on distribution system power quality data at a national level with a degree of statistical importance. The twenty-seven month monitoring effort resulted in the collection and processing of over thirty gigabytes of power quality data, that now reside in the primary product of the project, the DPQ Database. Additional findings include guidelines for monitoring and modeling distribution system power quality events, and a library of monitoring case studies.

Power quality is one of the most important concerns facing electric utilities today. The increasing dependence on sophisticated electronic controls and automated manufacturing within customer facilities is resulting in a requirement for higher levels of reliability and power quality than were ever previously needed. The problem is compounded by the fact that customer equipment has become more sensitive and is now interconnected in extensive networks and processes. The result is that variations in the power quality that were never a concern can now be very expensive in terms of process shut-downs and equipment malfunctions.

One of the more important utility needs is an understanding of existing distribution system power quality levels. Often this information is not available because conventional monitoring systems and analysis techniques have focused on reliability and steady-state voltages and currents instead of the full spectrum of power quality variations that impact customer equipment. The data collection problem is compounded by the fact that there are many events that can cause a power quality problem. Analysis of these events is often difficult due to the fact that the cause of the event may be related to a switching operation within the facility or to a power system fault hundreds of miles away.

Some utilities are beginning to address this concern by taking a systems approach to solving power quality problems. They realize that in some cases significant savings are possible by providing higher levels of power quality, rather than having customers purchase distributed power conditioning systems (for example, UPS systems) with low efficiencies and power quality problems of their own. In order to remain competitive in an ever-changing utility environment, these utilities are therefore beginning to explore premium power services as a means of keeping their most important customers. However, before they can implement these services, they must first determine existing power quality levels. They must first ask, "What is the baseline?" Premium power cannot be offered to customers without first answering this critical question. This is the role of wide-scale power quality monitoring projects. Collecting the statistics for power quality phenomena, which have been largely ignored for decades, provides the means to begin the redefinition of electric power reliability.

This project represents one method developed to characterize power quality levels on distribution systems throughout the United States. The method utilized a specially-designed monitoring device and a number of software systems. In addition, the project included simulation studies to verify and improve analytical models for distribution system analysis. Programs, such as HarmFlo+ (EPRI/Electrotek HarmFlo+ Workstation) and the EPRI/DCG EMTP (Electromagnetic Transients Program), were utilized in a series of case studies that were performed to help identify measures to improve power quality from the supply system perspective. The result of the effort is a full set of guidelines for monitoring and modeling power quality phenomena on distribution systems.

Electric utilities are committed to supplying their customers with high quality power. Custom Power technology integrates modern power electronics-based technology with distribution automation and integrated utility communications to provide this high quality power. The contributions from the DPQ Project as a forerunner to this initiative are significant. The basic product of the DPQ Project will be a database of information describing power quality levels on distribution systems in the United States. It will be useful information in a general sense because it will provide manufacturers and customers with the knowledge that will allow them to define requirements for their equipment. More importantly, it will be critical information for any electric utility that wants to implement a premium power service or option. Future use of the DPQ Database will include:

1. Input for subsequent research in the areas of reliability and advanced distribution systems.

2. Input for Custom Power engineering and market research.

3. Baseline service quality, which can be used for industrial recruiting and service differentiation.

4. Prediction of equipment misoperation and/or failure.

An Assessment of Distribution System Power Quality should play an integral role in a utility's planned organizational response to a growing need for higher levels of power quality by a significant portion of the customer base.

Introduction

The EPRI Distribution System Power Quality Project

The EPRI Research Project, An Assessment of Distribution System Power Quality, was a comprehensive effort designed to assess utility power quality at the distribution level. Power quality has become a critical concern for virtually all electric utilities in this country and throughout the world. It is primarily due to the fact that customer equipment has become more sensitive and is now interconnected in extensive networks and processes. The result is that variations in the power quality that were never a concern can now be very expensive in terms of process shut-downs and equipment malfunctions.

The objectives of this research project were to:

1. design a statistically valid power quality measurement program that would enable assessments of power quality levels to be made at utility sites

2. perform measurements of power quality delivered to customers sufficient to describe the transient, harmonic, short- and long-duration voltage variation, and momentary interruption characteristics of present distribution supply systems

3. perform analytical, modeling and simulation studies to verify and/or improve analytical models by using the measured data

4. assess the limitations of a typical electric utility distribution system to supply loads that degrade power quality

5. perform studies to identify measures to improve power quality from the supply system perspective

6. determine the cumulative effect as the number of small (sensitive and/or polluting) loads is increased

7. provide a rational basis for the development of a recommended practice for providing solutions to power quality problems and improving system power quality levels.

Background

The term "power quality" has many different meanings, perhaps as many as those who attempt to describe its impact on system operation. The electric utility may describe power quality as reliability and quote statistics stating that the system is 99.95% reliable. The equipment manufacturer often defines power quality as the characteristics of the power supply, which may vary drastically for different vendors. However, the customer is the party ultimately affected by power quality-related problems, and the best definition should include his perspective. Considering each of these factors, the following definition is often used:

Power Quality Problem:

"Any power problem manifested in voltage, current, or frequency deviations that results in the failure or misoperation of customer equipment."

There are many events that can cause a power quality problem. Analysis of these events is often difficult due to the fact that the cause of the event may be related to a switching operation within the facility or to a power system fault hundreds of miles away.

As customers seek to increase utilization and efficiency, utilities strive to better understand power quality events and their effects on these customers. Utilities are creating special programs and organizations to deal with customer power quality needs.

A problem shared by both parties is the need for improved methods for the collection, analysis, and reporting of very large amounts of measured power quality data.

This project represents one method developed to characterize power quality levels on distribution systems throughout the United States. The method utilized a specially-designed monitoring device and a number of software systems. In addition, the project included simulation studies to verify and improve analytical models for distribution system analysis. Programs, such as HarmFlo+ (EPRI/Electrotek HarmFlo+ Workstation) and the EPRI/DCG EMTP (Electromagnetic Transients Program), were utilized in a series of case studies that were performed to help identify measures to improve power quality from the supply system perspective. The result of the effort is a full set of guidelines for monitoring and modeling power quality phenomena on distribution systems.

DPQ Project Accomplishments

The project, which was completed in December 1995, was a multi-phase, multi-year effort involving twenty-four EPRI member utilities. It is a key building block for the EPRI Custom Power initiative. Major accomplishments of the project included:

· Development and commercialization of a new power quality monitoring instrument (PQNode) and software (PASS TM)

· Establishment of a baseline for power quality information. This was achieved through a technical literature and standards review.

· Guidelines for monitoring distribution system power quality events (companion document: A Guide to Monitoring Distribution System Power Quality, EPRI TR-103208).

· Guidelines for simulating distribution system power quality events and cold load pickup (The Distribution System Modeling Guide for Disturbances and Cold Load Pickup, EPRI TR-106297.

· Extensive collection of power quality disturbance case studies illustrating waveforms that can be used as signatures for recognizing similar events (Library of Distribution System Power Quality Monitoring Case Studies, EPRI TR-106294-V3).

· A distribution system power quality database (DPQ Database) and statistical analysis program (PQView®).

· A recommended practice offering solutions to distribution power quality problems.

· Baseline information for utilities considering premium power and Custom Power alternatives.

The chief goal of the project was to provide baseline statistics regarding quantities that fall under the general category of distribution power quality, including:

1. Voltage Disturbances:
a) rms voltage variations
b) subcycle transients - impulsive and oscillatory

2. Steady-State Characteristics:
a) steady-state regulation
b) harmonic distortion
c) phase unbalance

DPQ Project Participants
The project utilized the participation of twenty-four "Host Utilities" across the continental United States to provide geographic and operating practice diversity. The site selection process resulted in the selection of 300 monitoring sites within the service territories of the utilities listed in Table E-01 and shown in Figure E-00.

Table E-01: Host Utilities for the DPQ Project

Boone Electric	Kansas City Power & Light - KEURP
Chattanooga Power - TVA	KPL Gas Service - KEURP
Cincinnati Gas & Electric	Long Island Lighting
Delmarva Power	Los Angeles Department of Water & Power
Duke Power	Massachusetts Electric
East Kentucky Power	Northeast Utilities
Elizabethan Electric - TVA	Pacific Gas & Electric
Empire District - KEURP	Public Service Gas & Electric
Florida Power Corp.	Rochester Gas & Electric
Georgia Power	Sierra Pacific Power
Gibson EMC - TVA	Snohomish Public Utility District
Houston Lighting & Power	
Illinois Power	

Figure E-00: Host Utility Locations

Since the selection of the host utilities was not random, it was necessary to determine that the choice of utilities was not biased. An examination of distribution system power quality-determining characteristics (flash density, customer mix, etc.) on a national level indicated that the utilities were representative of the range of conditions found throughout the United States.

The DPQ Project Site Selection Process

The DPQ Project began in the fall of 1989. The utilities participating in the project were EPRI volunteers, representing a wide variety of geographic regions across the United States. The sites chosen for monitoring at these utilities were selected as part of both a systematic and a controlled random sampling process. This involved collecting site information (which was considered critical in characterizing any given feeder with regard to power quality) from 1800 buses. These characteristics, known as strata, included transformer capacity (MVA), number of parallel feeders on the bus, feeder nominal voltage (kV), load type (urban, suburban, or mixed), and load density (residential, commercial, industrial, or mixed). These descriptors were used in a stratified, controlled selection of 100 buses from the 1800 in a manner that ensured both common and uncommon characteristics were represented in the study population. The feeder chosen for monitoring on each bus was selected via random sampling.

It was decided to place monitors at three locations on each of the 100 feeders. The first monitor would be located at or near the substation. The other two were chosen by a random sampling process involving sectionalizing of the feeders into homogeneous lengths of power quality. The section lengths were determined by isolating large loads and important distribution equipment such as capacitors, reclosers, sectionalizers, and line branches. Each feeder was divided into anywhere from three to twenty or more sections. Two sections were then selected using a random number table. The first section selected after the substation is often referred to as the "feeder middle" and the second is known as the "feeder end," but these designations are somewhat arbitrary since the selections were random.

The purpose of the site selection process was to identify one hundred feeders which sufficiently represented the range of characteristics seen on most distribution systems in the United States. This required us to use a controlled selection process to ensure that common and uncommon characteristics of the national sample were both well represented in the study population. When relating the results of our study to the national sample, weighting has to be employed. For instance, substation transformers of a 100 MVA rating represent less than 1% of the substations in the country. To represent that 1% exactly in the study population would mean that only one feeder could be selected for monitoring. However, one site would not produce accurate measurement results; they would be biased to that one location. Instead, two or more sites that have a 100 MVA transformer could be selected for monitoring. When extrapolating the results from the 100 feeder study population to the national sample, a weighting factor could be used that would effectively reduce the effects of the 100 MVA site by a fraction. Conversely, sites which are under-represented in the study population can have their weight increased when extending results.

Development of a State-of-the-Art Monitoring Device

During the initial phase of the project, a new monitoring device was developed -- the Basic Measuring Instruments (BMI) 8010 PQNode. See Figure E-01. This instrument permits simultaneous three-phase monitoring of steady-state quantities and disturbances. The PQNode was designed to monitor electromagnetic phenomena limited to waveshape acquisition of data to a spectral resolution of around 7 kHz and impulsive transient detection from 5 kHz to 1 MHz.

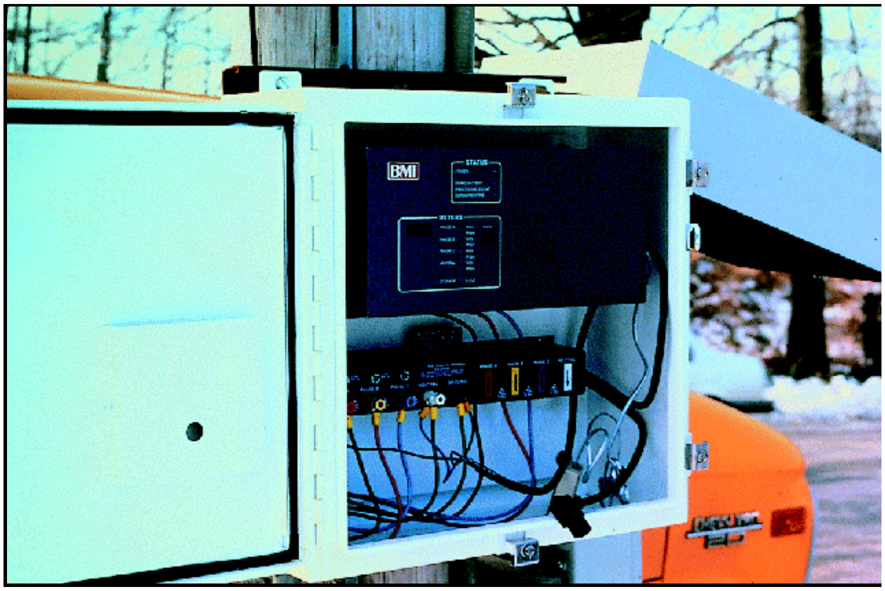

Figure E-01: Photograph of a BMI 8010 PQNode within a NEMA 4 Enclosure

These limits are designed to allow the collection of the most common types of disturbances found on distribution systems that are likely to affect customer systems, namely:

1. Subcycle transients: impulses, oscillatory transients

2. Short duration rms variations: sags, swells, interruptions

3. Long duration rms variations: over- and under- voltages, outages

4. Waveform distortion: harmonics

The measurement of all signals are made with a pair of high-speed, 14-bit analog -to-digital converters (ADCs) whose sample rate depends on the fundamental frequency. This permits more accurate measurements of higher order harmonics than a traditional 12 bit ADC would allow. With built-in 5-pole anti-aliasing filters, the PQNode can accurately analyze harmonics up to the 100th in voltage and the 50th in current.

A periodic sampling sub-system is provided in the PQNode to obtain long duration variation information, steady-state monitoring, and waveform distortion data. For this project, sampled waveforms were obtained every thirty minutes for harmonic and power analysis, and steady-state RMS data were sampled every fifteen minutes for steady-state variation information.

The instrument includes eight channels: four voltage and four current. This allows all phase voltages and currents to be monitored, as well as neutral voltage and current. Triggering can be initiated only by the voltage channels, any one of which starts the recording process. An additional requirement placed on the instrument design was that of recording all channel information when a trigger occurs, instead of only the triggered channel. This had been a frustrating drawback in earlier studies since the missing channel information could have helped identify the cause and better predict the consequences of a particular event.

The instrument was designed to be highly programmable to allow not only the thresholds to be changed, but also a change in its basic functionality (the "firmware") if desired. This is accomplished by uploading setups or new firmware to the instrument via serial port or modem. This feature was deemed important due to the natural evolution of a new instrument, and the likelihood of the monitoring objectives to change over the life of the project.

The software system developed for controlling the PQNodes and downloading the monitored data runs as a Microsoft Windows application. The principal component of the system is the PQNode Application and System Software (PASS®), which runs on the host utility's personal computer. PASS provides the means for remote PQNode setup, automated downloading of data, archiving of data, and for generating simple reports.

The DPQ Project Data Collection and Analysis Tasks

Though monitoring began in 1991 (instrument beta test phase), it was not until June 1993 that the "official" data collection phase began. This process continued until September 1995, at which time about 6.8 million individual power quality measurements (example illustrated in Figure E-02) had been collected.

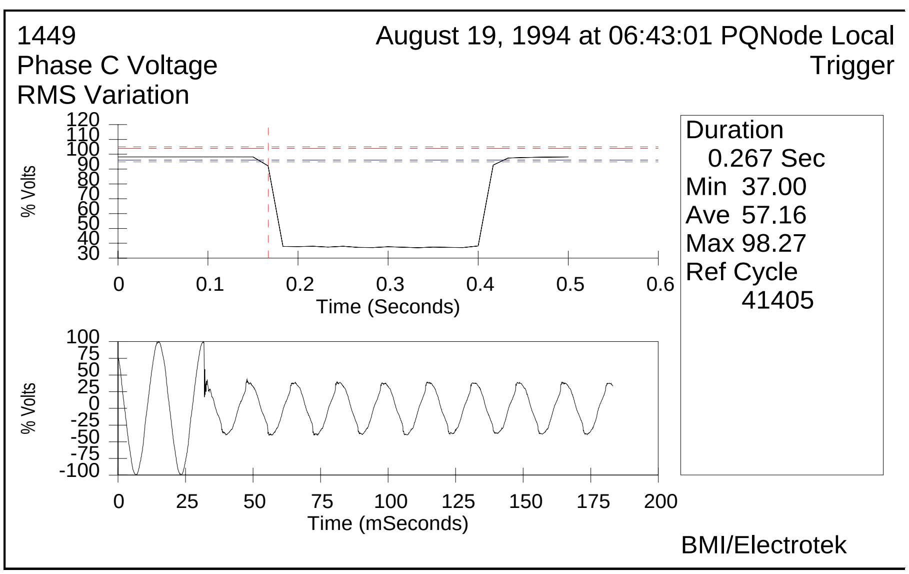

Figure E-02: Example of a Voltage Disturbance Categorized as an RMS Variation from EPRI DPQ Monitor

To allow each host utility to participate directly in the project, and to distribute computational and communications responsibilities, each host utility contributed a computer (at its premises) that was dedicated to controlling the monitors in its service territory.

The thresholds and steady-state sampling rates chosen resulted in a significant amount of data being recorded. On a per site basis, the steady state sampling resulted in about 134 kB of data per day with another 64 kB per day average for triggered events. This represents a total of 198 kilobytes per site per day or about 30 GB total for the project. In order to deal with this much data, an automated system for gathering the data and generating reports was developed.

As data was delivered to Electrotek during the data collection stage, PQNode measurements were restored from archive media in one month increments to a four-gigabyte database. Raw PQNode measurements were ultimately stored off-line on magneto-optical disks which allowed quick access to large archives of data.

A set of standard procedures were implemented to gather the data from the host utility computers located throughout the country into the main database at Electrotek. This data flow process is illustrated in Figure E-03.

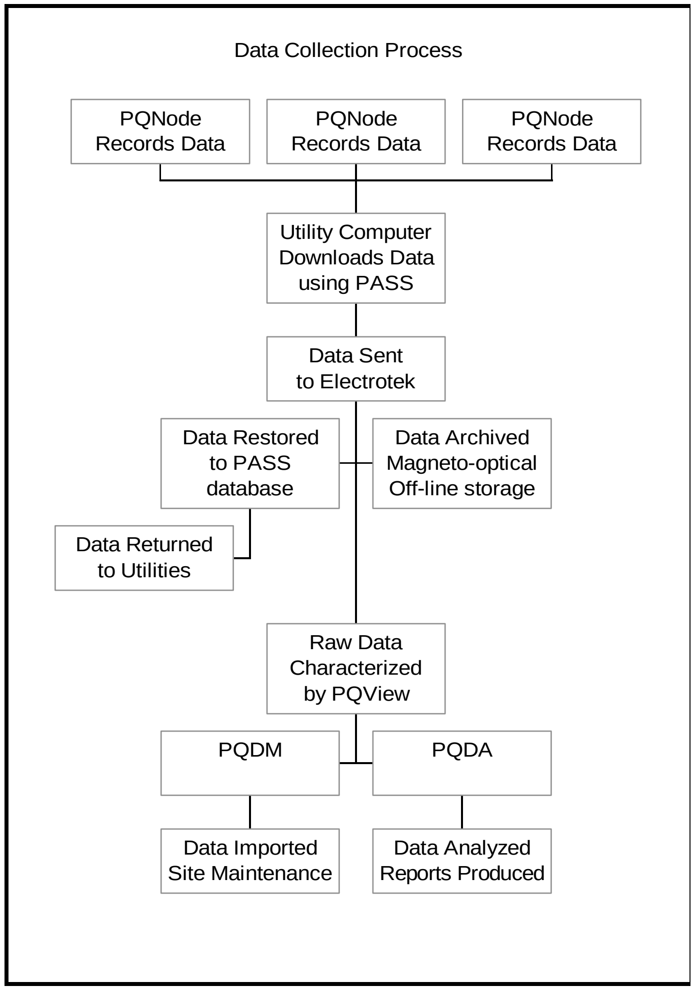

Figure E-03: Data Collection Flow Diagram for the EPRI DPQ Project

The software system designed to perform the power quality data analysis function for the project is known as PQView®. PQView is the Windows®-based software system which was designed to manage and analyze the power quality database produced by the DPQ system of monitoring instruments. It has two main modules: the Power Quality Data Manager (PQDM); and the Power Quality Data Analyzer (PQDA). With PQDM a user may characterize and load power quality data from a database of measurement files, then use PQDA's analysis tools to generate summary statistical reports. The two modules were orchestrated to allow the automated characterization of data and the production of reports.

Companion Reports for the DPQ Project

The deliverable reports for the EPRI DPQ Project consist of a report regarding the project's methodology for monitoring power quality, which was published during the initial phase of the project, and three primary components completed at the conclusion of the project. These documents include:

Guide to Monitoring Distribution Power Quality

The first phase of the EPRI DPQ Project included the site selection process, monitor development, and monitor installation. The final report for that phase can be obtained from EPRI as TR-103208, "A Guide to Monitoring Distribution Power Quality: Phase 1." The guide was designed to help utilities assess the implementation requirements of their own power quality monitoring, measurement, and analysis program. Much of the material contained in the guide is the result of actual experience gained during the EPRI DPQ Project.

Assessment of Distribution System Power Quality

The primary goal of this report is to present the statistics of power quality measurements collected during the EPRI DPQ Project. However, all aspects of power quality are addressed in order to establish a reference for the data results presented. The site selection process is fully described and serves as a useful model for monitoring projects which are designed to be compared with the DPQ Project. The specifications and capabilities of the project's monitoring instrument (PQNode), as well as the project's data collection process are explained. Triggering methods, characterization algorithms, and statistical analysis are presented for four power quality disturbance categories: rms voltage variations, transient overvoltages, harmonic distortion, and voltage regulation.

Library of Monitoring Case Studies

The Library of Distribution System Power Quality Monitoring Case Studies provides an extensive collection of power quality disturbance case studies. Each event is defined by waveforms recorded as part of the EPRI DPQ Project. These waveforms can be used as signatures for recognizing similar disturbances characterized by monitored waveforms. Each case study is presented such that readers with a wide range of technical experience should be able to benefit.

Modeling Guide for Disturbances and Cold Load Pickup

The modeling guide addresses a significant number of aspects related to modeling and simulation of distribution system analysis. The guide provides specifications to accomplish a wide range of power system simulations, including individual component models, feeder models, and simulation of important phenomena. Component and system models were developed using the EPRI/DCG Electromagnetic Transients Program (EMTP) and the EPRI/Electrotek HarmFlo+ Workstation.

Voltage Variations: Results and Observations

Overview of Distribution System Power Quality Concern

Voltage variations, such as voltage sags and momentary interruptions, are often the most important power quality concerns for customers. In general, customers understand that interruptions cannot be completely prevented on the power system. However, they are often less tolerant when their equipment misoperates due to momentary disturbances which can be much more frequent than complete outages. These conditions are characterized by short duration changes in the rms voltage magnitude supplied to the customer. The impact on the customer depends on the voltage magnitude during the disturbance, the duration of the disturbance, and the sensitivity of the end-use equipment.

Voltage sags and interruptions are inevitable on the power system, and are generally caused by faults on the utility system. Since it is impossible to completely eliminate the occurrence of faults, there will always be voltage variations to contend with. Storms are the most frequent causes of faults in most areas of the country. Even preliminary monitoring results from this project clearly indicated that a storm passing through an area can result in literally dozens of major and minor power quality variations.

On the utility system, protection schemes are designed to limit damage caused by unusual events like faults caused by lightning strikes, and to localize the impact of such events to the smallest number of customers. This is often accomplished with overcurrent protection devices, such as reclosers, sectionalizers, and fuses.

In general, voltage sags (sample previously illustrated in Figure E-02) are characterized by the magnitude of the voltage during the fault and the duration of the event. The characteristics of the event are affected by a number of system related items:

1. Fault location

2. Transformer connections

3. System protection practices (protection and coordination)

4. Reclosing practices (reclosing cycle)

Power quality complaints, which are related to voltage sags and interruptions, occur when either the customer has equipment which is very sensitive to these variations and is critical to the overall process, or the frequency of occurrence of the variation is interpreted as being unacceptable. Recently, due to momentary interruptions, utilities have been faced with rising numbers of complaints about the quality of power (example illustrated in Figure E-04). There are a number of reasons for this, with the most important being customers with more sensitive loads in all sectors (residential, commercial and industrial). The influx of digital computers and other types of electronic controls is the primary problem. Computer controls tend to lose their memory and the processes that are being controlled also tend to be more complex, taking much more time to restart. In addition, industries are relying more on automated equipment to achieve maximum productivity to remain competitive. Thus, an interruption has more impact now, than with loads common just a few years ago.

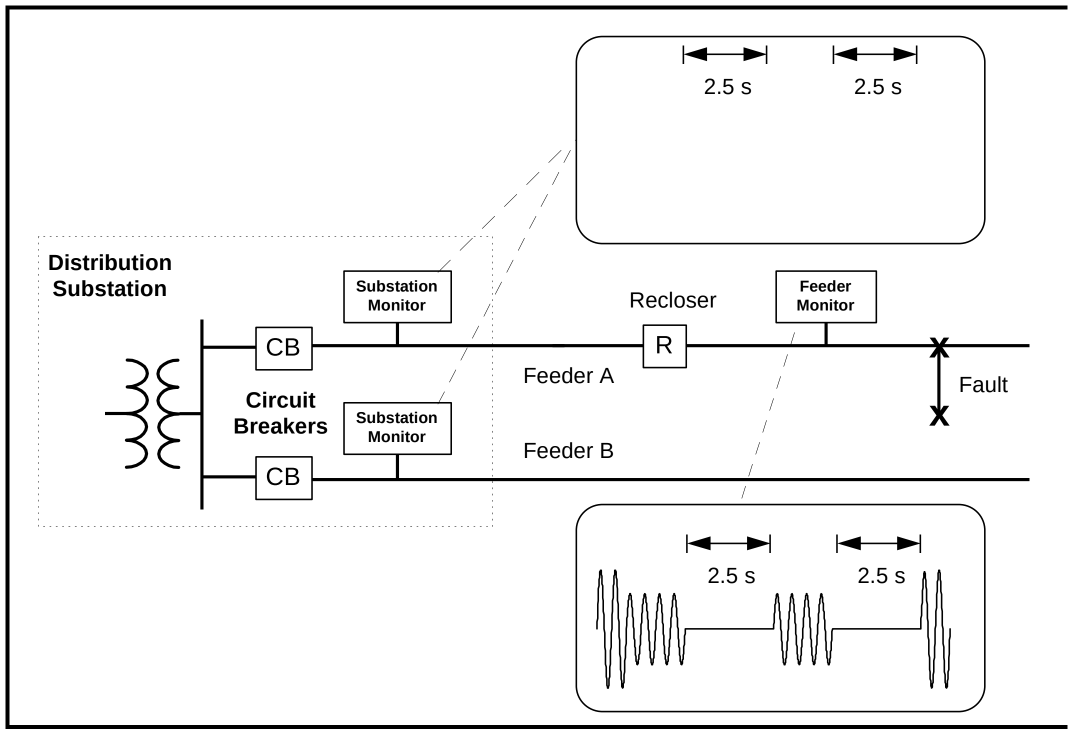

Figure E-04: Effects of Sags on Customers Upline and Downline of Faults

Sags and interruptions are not the only problems that face sensitive electronics. Longer duration increases and decreases of voltage, defined as overvoltages and undervoltages by IEEE Standard 1159-1995, are known to occasionally occur. Undervoltages are sometimes attributed to a purposeful reduction of voltage by the utility to decrease load during peak demand periods. These planned undervoltages, often called "brownouts," are sometimes implemented during hot summer days when air conditioning load is heavy and utilities do not have sufficient capacity to meet the high demand.

Important Results - Voltage Sags and Interruptions

Statistics regarding annual rms voltage variation levels were based upon the two years of monitoring between 6/1/93 and 6/1/95. During that period, a total of 277 instruments recorded 107,834 rms variations (three-phase measurements) during 146,661 monitor·days. The results indicated that 68% of the three-phase measurements involved one phase only, 19% involved two phases, and the remaining 13% involved all three phases.

An "rms variation measurement" is taken by the PQNode when the voltage on any of the monitored three phases rises above an upper threshold or falls below a lower threshold for a specified number of cycles. All of the instruments in the EPRI DPQ Project were set to trigger with the same settings (refer to statistical summary report for details).

A process known as power quality data characterization was used to convert the voltage variation measurements into representative quantities. The process involves the translation of raw data, downloaded from a monitoring instrument into characteristics which can easily be stored within a database and analyzed using database queries. Characterization may involve computing the Fast Fourier Transform for a voltage or current waveform sample, or it may involve computing the minimum, average, and maximum or an rms voltage variation component.

A measurement aggregation process was then applied. Aggregation refers to grouping components together into a whole. In the case of voltage sags and interruptions, all rms variation measurements (on all phases) that took place at a given monitoring location were grouped using a sliding variable-length
(i.e. 60 seconds) window. Each window would only be able to contribute one "event" when creating composite statistics. The rationale behind performing the aggregation is to provide a means for benchmarking system performance from a customer's end-use point of view. Although multiple rms variation events may occur within this period of time on more than one phase, a customer would interpret the entire series as only one power quality incident because any misoperation of equipment would occur only once during that time period. In essence, measurement aggregation is an estimate of customer perception of power quality events.

Figure E-05 illustrates the project's sag and interruption magnitude rate, using a one-minute aggregation, for the events recorded during the two year period (6/1/93 to 6/1/95). The results include the application of sampling weights and represent all project monitoring sites.

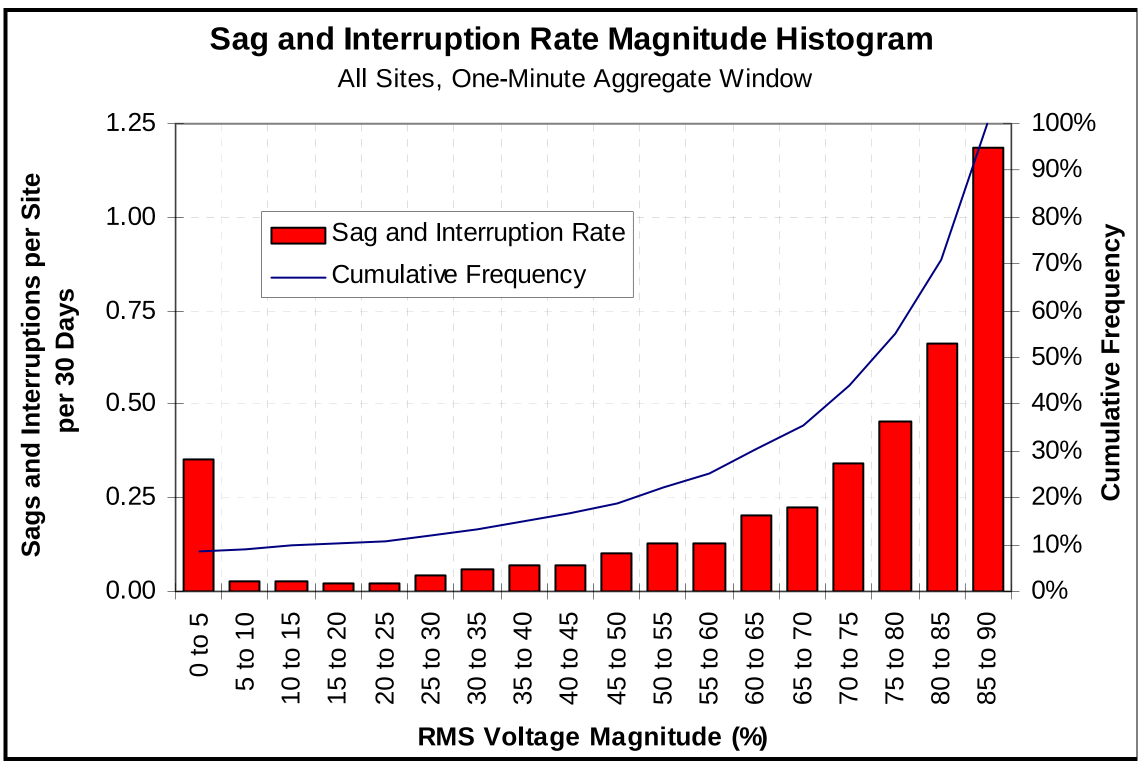

Figure E-05: Sag and Interruption Rate Magnitude Histogram, One-Minute Aggregation 6/1/93 to 6/1/95, Treated by Sampling Weights, All Sites

Figure E-05 represents equal weighting of each of the three sites on the feeder in order to arrive at an average feeder rate. How the rates differ, between the substation and feeder sites, is important because many of the feeders in the project had reclosers installed downline from the substation circuit breaker. Since the reclosers were capable of interrupting independently of the breaker, one would expect to see more interruptions at the feeder sites than at the substation sites (which only would experience an interruption if the substation breaker or a transmission breaker operated). Table E-02 summarizes the individual sag and interruption rates for substation and feeder monitors. As indicated in the table, the feeder interruption rate is approximately 140% of the substation value.

Average Yearly Rate	Substations Only	Feeders Only	Feeder Average
Interruptions V<10%	3.65	5.08	4.58
Sags 10%<V<90%	43.60	46.22	45.31
Sags and Interruptions	47.25	51.30	49.90

Table E-02: Summary of Sags and Interruptions per Site per 365 Days 6/1/93 to 6/1/95

Another interesting question regarding interruptions involves the number of recloser/breaker operations recorded during a single event. Results for the one-minute aggregation indicate that 87% of the events involve a single operation, 9% involve two operations, 2% involve three operations, and 2% involve greater than four operations. These rates would seem to substantiate the widely-held belief that a vast majority of power system faults are temporary in nature.

While Figure E-05 provides valuable information regarding average sag and interruption rates, an understanding of the range on values measured is also useful. Figure E-06 summarizes the number of one-minute aggregate periods during which the rms voltage dropped below 0.70 pu for each site. Normalizing by the number of days which the site's monitor was on-line and weighting using sampling factors resulted in a distribution centered around 15 incidents per year with a maximum of 82 and a minimum of 0. The mean and standard deviation were computed using ratio estimators, which means that the sites with larger sampling factors contributed more to the calculation of mean and standard deviation than the sites with smaller sampling factors. The mean and standard deviation were used to estimate the 95% confidence interval for the population of all feeders on the host utilities' distribution systems.

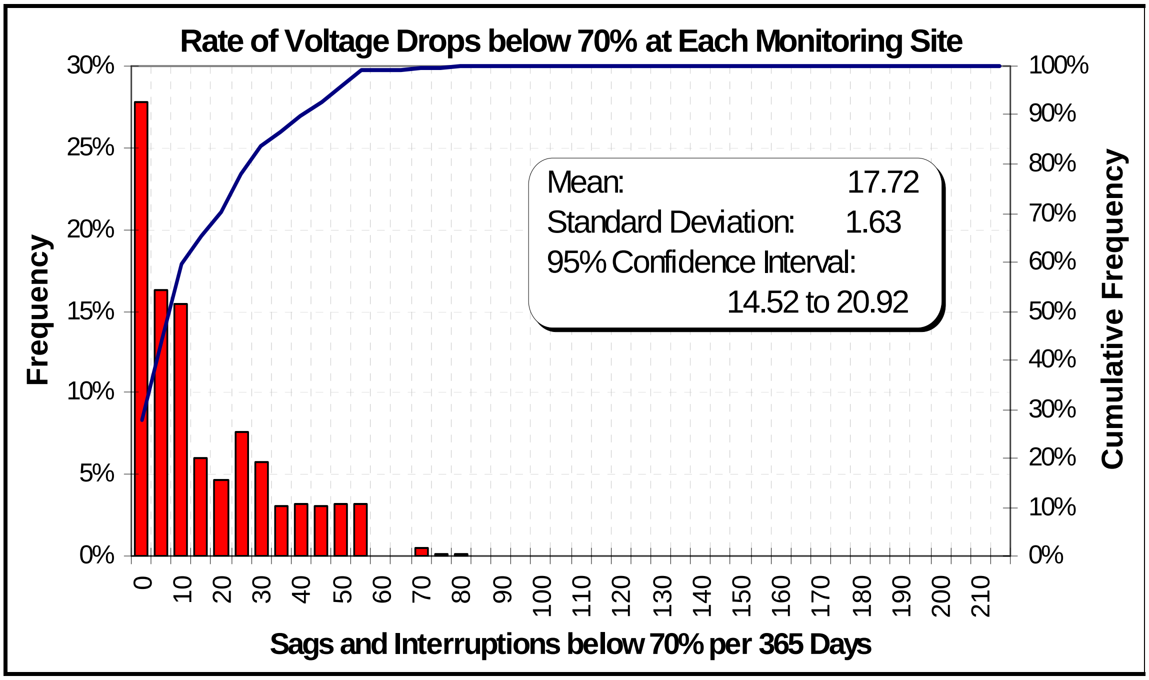

Figure E-06: Sag and Interruptions Below 70% Voltage per Site per Year, One-Minute Aggregation, 6/1/93 to 6/1/95

For this particular graph, it can be said, with 95% confidence, that the true mean rate of voltage which drops below 0.70 pu per site per year is between 14.52 and 20.92.

Another voltage variation interpretation, illustrated in Figure E-07, involves the three-dimensional presentation of the sag and interruption magnitude and duration rates. One-minute aggregation is again used to group measurement components, however, instead of using the magnitude and duration of the component which has the lowest voltage magnitude, the component of the aggregate period which had the largest volt·seconds area is plotted.

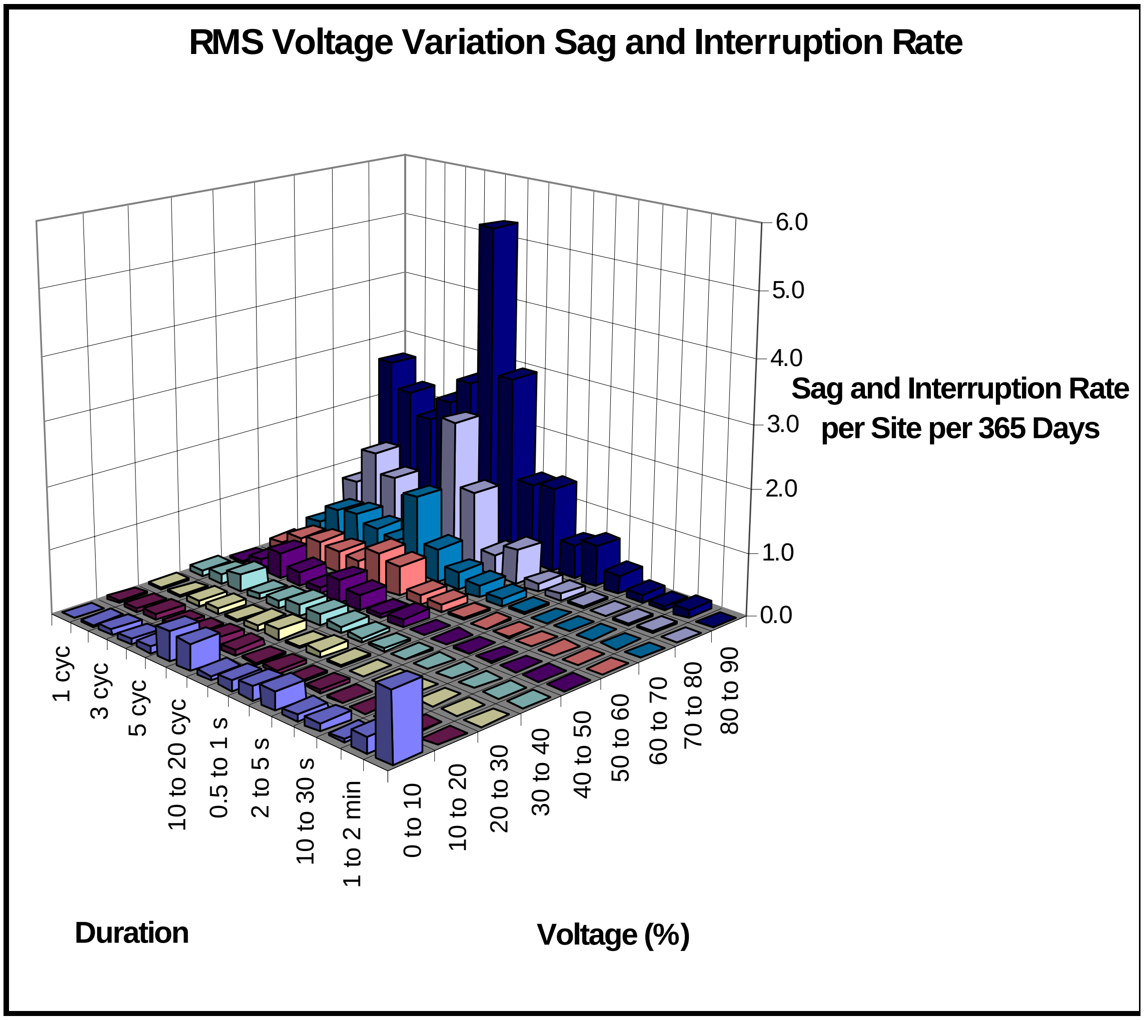

Figure E-07: Sag and Interruption Rate Magnitude Duration Histogram, One-Minute Aggregation, 6/1/93 to 6/1/95

An interesting fact concerning this graph is that most of the measurement components had durations less than 10 cycles and resulted in voltage drops of no more than 50%.

Practices to Improve Distribution System Power Quality Levels

Voltage sags and momentary interruptions are often the most costly power quality variations affecting industrial and commercial customers. Faults over a wide area of the power system (transmission and distribution network) can affect the operation of a facility that has sensitive end-use equipment. For most facilities, both transmission and distribution cases need to be evaluated to estimate the overall performance expected. For facilities that are supplied directly from the transmission level, only transmission faults usually need to be considered.

Variations in the fundamental frequency voltage can be evaluated with conventional analysis tools. Power flow programs provide system voltages as a function of load levels on the system. Fault programs (short circuit analysis) can calculate system voltage profiles during fault conditions for analysis of voltage sag concerns.

Analysis of large networks, such as those found in utility transmission and distribution systems, requires the use of computers and specialized programs. Hand calculations are suitable for estimating the characteristics of very simple circuits, but accurate calculation of voltage, power flows, or short-circuit currents throughout a utility system would be impractical without the use of a simulation program.
Voltage variation evaluation studies provide the means to determine the impact of various system-related parameters on the characteristic of the variation. Common factors include:

1. causes of fault conditions

2. effect of fault location

3. effect of transformer connection

4. effect of system protection practices

5. effect of reclosing practices

The most general approach to voltage sag analysis (illustrated in Figure E-08) would characterize the system voltage sag performance by analyzing the fault performance on both the transmission system and the distribution system. Computer calculations, using a short circuit analysis program, can be used to determine voltages around the system for any fault location. These calculations can be used to define an "area of vulnerability" for a particular customer. The likelihood of a fault can then be calculated from past fault records of the area, or from the fault performance of similar locations.

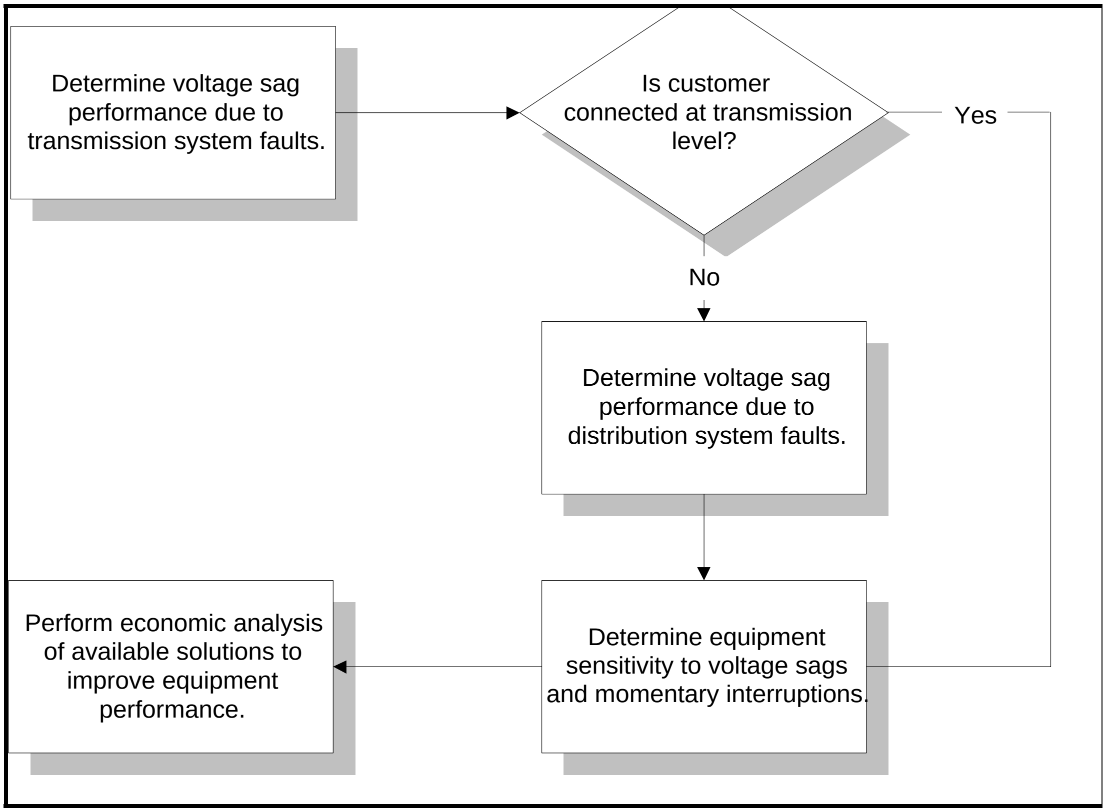

Figure E-08: Voltage Variation Analysis Methodology

Common steps in a voltage sag analysis study often include:

1. fault current and sag magnitude calculation

2. estimation of fault probability

3. determination of the area of vulnerability characteristic

4. determination of end-use equipment sensitivity

5. determination of the number of customer "events"

6. evaluation of possible solutions
   a) utility side (power system design)
   b) customer side (equipment design and/or power conditioning)

The concept of "area of vulnerability" is often used to evaluate the likelihood of a customer being subjected to voltage sags lower than a critical value. The expected voltage sag performance is developed by performing short circuit simulations to determine the customer voltage as a function of fault location throughout the power system. This information can be used directly by the end-user to determine the need for power conditioning equipment at sensitive loads throughout the facility.

In general, there are three levels of possible solutions to problems caused by voltage sags and momentary interruptions:

1. Power System Design: Faults on the power system are the ultimate cause of both momentary interruptions and voltage sags. Any measures taken to reduce the likelihood of a fault will help reduce the incidence of sags and interruptions to customers. These measures can include using underground circuits, tree trimming, and increased application of surge arresters for lightning protection on distribution circuits. On transmission circuits where lightning may be the most prevalent cause of faults, reducing tower footing resistances is one of the measures that can improve the lightning performance of lines.

The utility distribution system protection philosophy will also impact the problems experienced by customers during fault conditions. It is very possible that residential and commercial customers are affected by momentary interruptions, but are not impacted by most voltage sags.

The number of interruptions experienced by customers can be reduced by clearing faults further out on the feeder with fuses and downline protective devices, rather than interrupting the entire feeder at the substation. Many utilities have changed their coordination philosophies as a result of this consideration. In the past, the substation breaker or recloser was set to open and reclose to see if a fault was temporary before any downline devices operated. This prevented a long duration outage on any part of the feeder but exposed the entire feeder to a short interruption (30-60 cycles). The trend now is to allow a downline fuse to operate and clear the fault. This exposes one branch of the feeder to a long duration outage but the rest of the feeder only experiences a voltage sag for the fault duration (2 seconds or less).

2. End-Use Equipment Design: It is possible to make the end-use equipment being used in customer facilities less sensitive to voltage sags and momentary interruptions. Clocks and controls with low power requirements can be protected with a small battery or large capacitor to provide ride through capability. Motor control relays and contactors can be selected with less sensitive voltage sag thresholds. Controls can be set less sensitive to voltage sags unless the actual process requires an extremely tight voltage tolerance. This solution requires coordination with equipment manufacturers, but the trend seems to be in the direction of increased ride through capability. For instance, most programmable logic controllers use switched-mode power supplies that have a ride through capability of about four cycles. Therefore, it should not be necessary to trip these controllers under short voltage sag conditions.

3. Power Conditioning Equipment: This option involves the addition of power conditioning equipment at individual end-use loads that are sensitive to voltage sags and/or interruptions. The power conditioning requirements depend on the types of voltage sags that can be expected and the possible durations of interruptions.

Voltage sags down to approximately 60% of nominal voltage can be managed with constant voltage transformers (CVTs and ferroresonant transformers). These transformers can provide a constant voltage to the load for even more severe voltage sags if they are oversized. These power conditioners function by operating a transformer in its saturated region to make it less sensitive to variations in the input voltage. Ferroresonant transformers can protect equipment for virtually all voltage sag conditions that can be caused by single line-to-ground faults on parallel feeders or on the transmission system.

For voltage sag protection of larger loads, magnetic synthesizers or motor-generators (MG) can be used. Magnetic synthesizers use saturated transformers to construct a new, clean, three-phase 480 volt source. Magnetic synthesizers can ride through voltage sags down to about 60% of nominal and also provide voltage regulation.

Motor-generator sets also help ride through voltage sag conditions due to the inertia of the motor and generator. However, standard motor-generators can only ride through several cycles of a complete interruption. The addition of a flywheel (increased inertia) can increase the ride through capability to 1-2 seconds. This may be sufficient to handle many momentary interruption problems.

For the most part, uninterruptible power supply (UPS) systems are required if equipment must be completely protected from interruptions. If momentary interruptions are the only problem (as opposed to long duration outages), the UPS system can be designed with minimum battery backup. Larger battery systems (to provide backup for interruptions lasting up to 15 minutes) can be designed if longer duration interruptions are anticipated.

For short duration interruptions and voltage sags (less than 2 seconds), superconducting storage devices are being developed to protect entire plants or portions of larger plants at the service entrance.

Transient Overvoltages: Results and Observations

Overview of Distribution System Power Quality Concern

Transient voltages and currents are a result of sudden changes within the electric power system. Opening or closing of a switch or circuit breaker causes a change in circuit configuration and the associated voltages and currents. A finite amount of time is required before a new stable operating point is reached. Lightning strokes to exposed distribution circuits inject a large amount of energy into the power system in a very short time, causing deviations in voltages and currents which persist until the excess energy is absorbed by dissipative elements (surge arresters, load resistance, conductor resistance, grounding system, etc.). A principal effect of both these events is a temporary departure of power system voltage and current from the normal steady-state sinusoidal waveforms.

All transients are caused by one of two actions:

· connection or disconnection of elements within the electric circuit

· injection of energy due to a direct or indirect lightning stroke or static discharge.

Opening or closing of switches is a very common occurrence, whether it be normal cycling of loads at the utilization level, or utility operations on the transmission and distribution system. Lightning and static discharge are less common, but the potential effects are obvious. The mechanism may also be unintentional, as with the initiation of a short circuit.

Transient overvoltages and overcurrents are classified by peak magnitude, frequency, and duration. These parameters are useful indices for evaluating potential impacts of transients on power system equipment. The absolute peak voltage, which is dependent on the transient magnitude and the point on the fundamental frequency voltage waveform at which the event occurs, is important for dielectric breakdown evaluation (e.g. equipment insulation strength). Some equipment and types of insulation, however, may also be sensitive to rates of change in voltage or current. The transient frequency, combined with the peak magnitude, can be used to estimate the rate of change.

Transient characteristics are dependent on the combination of initiating mechanism and the electric circuit characteristics at the source of the transient. Circuit inductances and capacitances - either discrete components such as shunt capacitance of power factor correction banks or inductances in transformer windings, or stray inductance or capacitance resulting from proximity to other current carrying conductors or voltages - are responsible for the oscillatory nature of transients.

Natural frequencies within the power system depend on the system voltage level, line lengths, cable lengths, system short circuit capacity, and the application of shunt capacitors. On utility distribution circuits
(4.16-34.5kV), transient frequencies between 300 Hz and 3 kHz are common. The lower frequencies occur when there are distribution capacitor banks and the higher frequencies are associated with the distribution lines themselves.

Capacitor energizing (illustrated in Figure E-09) is one of the more common distribution system transient events, and is generally considered to be a normal event on a utility system. The transient overvoltages which result are usually not of concern to a utility, since peak magnitudes are just below the level in which utility surge protective devices, such as arresters, begin to operate. However, because of their relatively low frequency content, these transients will often pass through step-down transformers to adversely affect secondary customer loads.

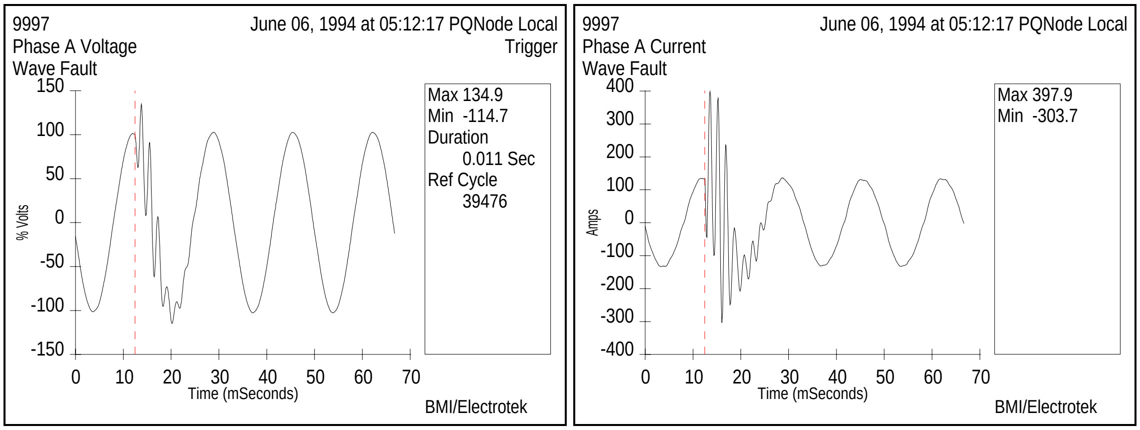

Figure E-09: Typical Capacitor Switching Measurement with Characteristic Oscillatory Signature

The peak voltage magnitude depends on the instantaneous system voltage at the moment of energization, and can reach 2.0 times the normal system peak voltage (per-unit) under worst-case conditions. The magnitude is usually less than this due to system loads and damping (resistive elements). Typical distribution system overvoltage levels range from 1.1 to 1.6 per unit. Transient frequencies due to utility distribution capacitor switching usually fall in the 300-1000 Hz range.

Important Results - Capacitor Switching Transients

Statistics regarding capacitor switching transients were based on six months of monitoring from 3/1/95 to 6/1/95. During this period, the monitoring instruments had a full-scale voltage setting of ±1000 volts (compared to ±250 volts during the rest of the project) to avoid clipping for some of the higher magnitude transients. There were 257 monitors recording data, resulting in 41,674 monitor·days of data during the period (1389.13 monitor·months). These sites collectively recorded 84,779 "waveshape fault" measurements, which averages to about two waveshape faults per site per day. Considering that there were three phases for each measurement, a total of 254,337 phase measurements needed to be analyzed. Each phase measurement contained four cycles of voltage data. The application of the waveshape filters (refer to the statistical summary report) identified 15,803 waveshape fault measurements which were recorded due to a voltage transient that resembled capacitor switching.

A measurement aggregation process was then applied. Aggregation refers to grouping components together into a whole. In the case of capacitor switching, all waveshape fault measurements (on all phases) that took place at a given monitoring location were grouped using a sliding one-minute window. Each one-minute window would only be able to contribute a single peak magnitude and duration pair toward creating composite statistics. The rationale behind performing the aggregation is to provide a means for benchmarking system performance from a customer's end-use point of view. Although multiple switching events may occur within a one minute period of time on more than one phase, a customer would interpret the entire series as only one power quality incident because any misoperation of equipment would occur only once during that time period. In essence, measurement aggregation is an estimate of customer perception of power quality events.

Three characteristics of the capacitor switching transients were evaluated in detail from the measurement results:

1. transient voltage magnitude

2. duration of the transient (period of time for the oscillation to decay)

3. primary frequency component in the transient oscillation

Each of these can be important in terms of the impact on customer end-use equipment. The magnitude is likely to be the most significant because it can impact end-use equipment directly. However, the frequency content of the transient is also important. Under certain system conditions, resonances with customer low voltage power factor correction can cause magnification of the capacitor switching transient on the low voltage system. The overall duration of the transient will determine the length of time that customer equipment must be able to withstand the transient condition.

Figure E-10 illustrates a summary of the magnitude and duration of the capacitor switching events recorded during the six-month period. By grouping several columns of data together, it can be said that a duration of a capacitor switching measurement between 5.0 and 7.0 ms (>5.0 and <= 7.0 ms) with a peak magnitude between 1.05 and 1.15 pu (>1.05 and <= 1.15 pu) was recorded on average 0.722 times per 30 days per site.

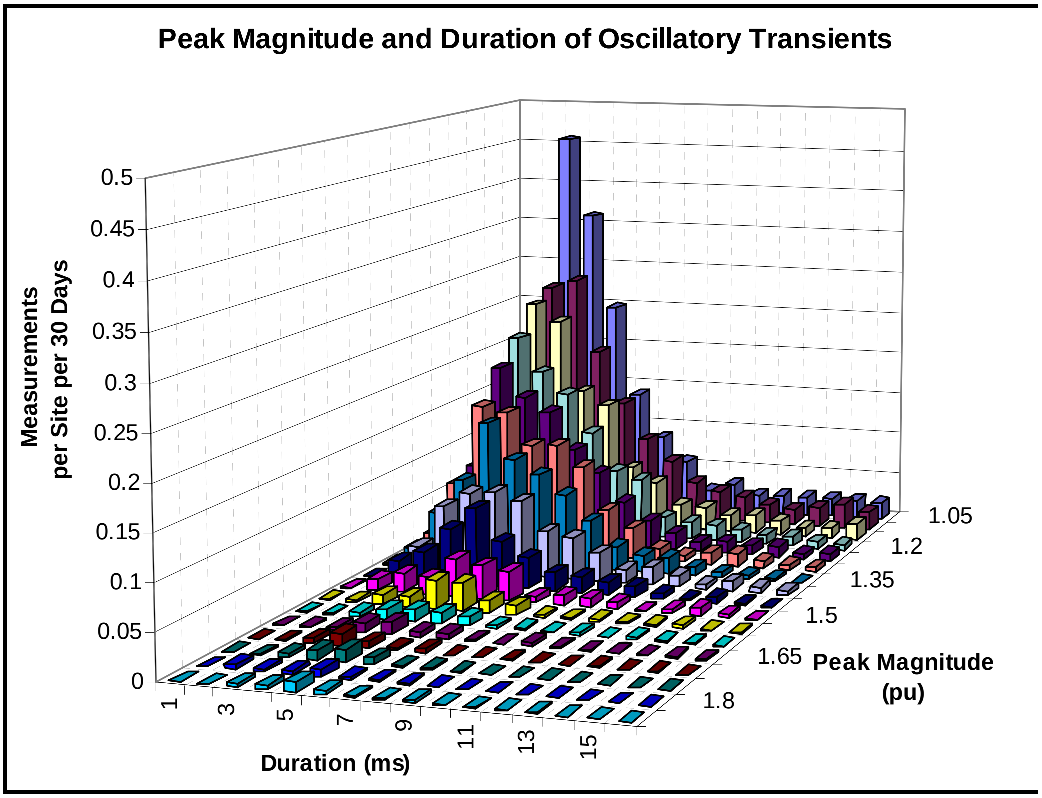

Figure E-10: Magnitude and Duration of Oscillatory Transients 60 Second Aggregate Events, 3/1/95 to 9/1/95,Treated by Sampling Weights,

Project results also indicate that the vast majority of capacitor switching transients have very low transient magnitudes, with approximately 65% of the magnitudes being less than 1.2 per unit. In addition, less than 10% of the transients have magnitudes that exceed 1.4 per unit.

The principal frequency component of the transient is determined by performing a Fast Fourier Transform (FFT) on a single cycle of the waveform following the trigger of a disturbance. The highest single component in the FFT output is called the principal frequency of the transient. Figure E-11 shows that capacitor switching transients are generally less than 800 Hz (about 80% of the transients) with a few cases ranging all the way up to 3000 Hz. These higher frequency cases are probably caused by back-to-back switching (two capacitors close together) or line switching events that are not capacitor switching.

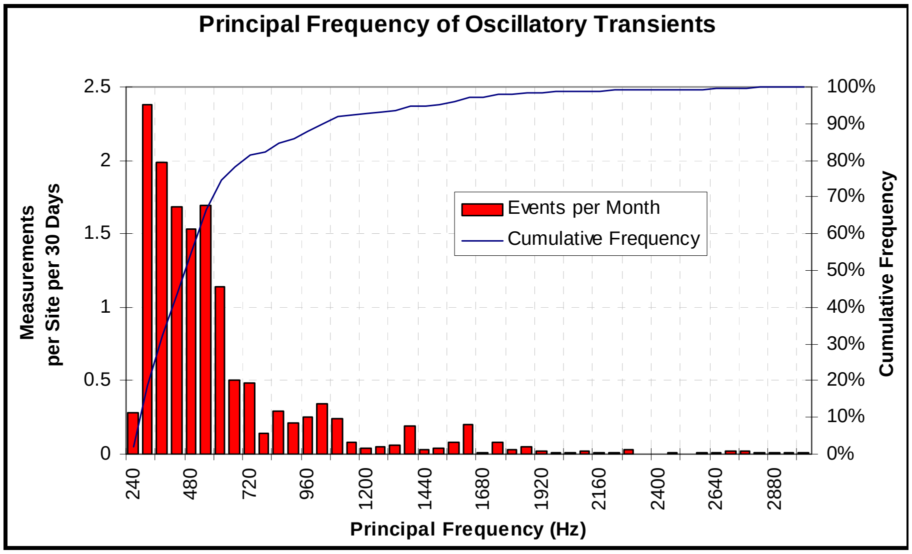

Figure E-11: Histogram for Frequency of Oscillatory Transients, Measurement Events, 3/1/95 to 9/1/95, Treated by Sampling Weights, All Sites

It is also interesting to look at the time-of-day that the capacitor switching transients occur, as this may be important for customers that are adversely impacted by these events. Many utilities utilize time clocks to switch capacitors in at a certain time in the morning and then out again in the evening. Even if the capacitor control is based on the load characteristics, it is most likely to come in sometime in the morning. Figure E-12 summarizes the monitoring results that indicate that most of the transient events occurred between 5:00am and 10:00am.

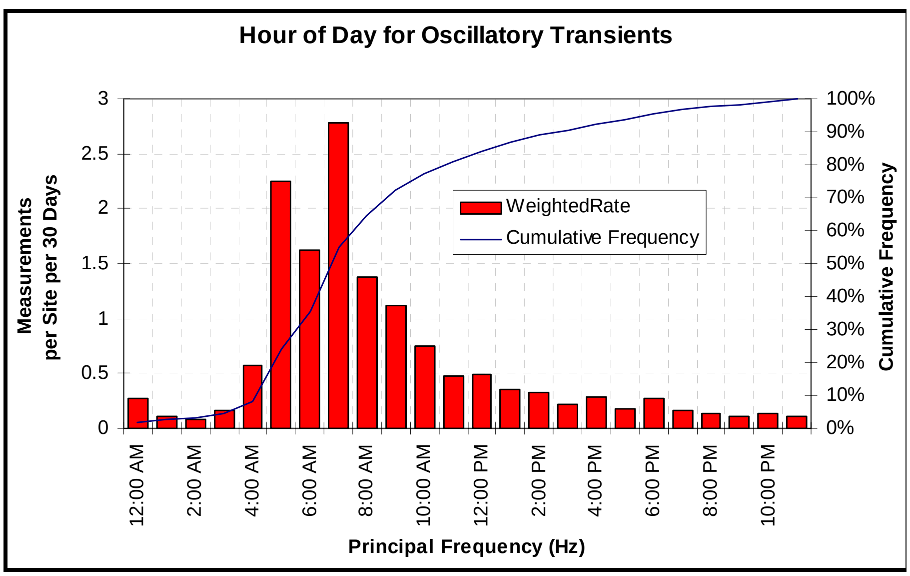

Figure E-12: Histogram for Time of Day of Oscillatory Transients Measurement Events, 3/1/95 to 9/1/95, Treated by Sampling Weights, All Sites

Practices to Improve Distribution System Power Quality Levels

It is important to note that the capacitor switching transients summarized in the previous section generally do not cause any problems for equipment on the electric utility distribution system. They are below levels that cause arresters to operate or dissipate any significant amount of energy, and they are well below the insulation withstand levels of distribution equipment. Therefore, measures to reduce capacitor switching transients are almost always associated with concerns with the sensitivity of customer end-use equipment to these transients or possibly with the concern for magnified transients within the customer's low voltage system. With this in mind, it is clear that the problems can be resolved either by reducing the transients at the switched capacitor bank or changing the characteristics of the customer system that is sensitive to the transients.

Distribution and customer system power quality problems, caused by capacitor bank switching, can be controlled using a number of different methods. The first step is identifying the problem, then the utility and customer need to work together to determine the best engineering and cost effective solution possible. Previously applied solutions include:

· The capacitor energizing transient can be controlled by using preinsertion resistors or inductors, or by using synchronous closing control. Synchronous closing refers to independent contact closing of each phase near a voltage zero. These technologies can be applied to a number of different switching devices, and have become generally accepted for distribution system applications.

· Metal oxide varistors (MOVs) can be applied to the distribution system to limit the "local" transient voltages to the arrester's protective level (maximum switching surge protective level, typically 1.8 - 2.5 per-unit) at the point of application. The primary concern associated with MOV application is the energy duty during a switch restrike event. Although a rare occurrence, a restrike generally results in the highest duty for arresters located near the switched capacitor bank. This is not likely to provide much benefit for customers since very few capacitor switching transients exceed 1.8 per unit, even without arresters.

· High energy MOV arresters can be applied to a customer's low voltage system. The arresters should limit the overvoltage to approximately 1.8 per unit. The energy rating of the arrester should be evaluated, since the duty (during capacitor switching) is often on the order of several thousand joules. This may provide some benefit in cases where there is significant magnification of the capacitor switching transient, but the arresters may not be able to prevent nuisance tripping of sensitive loads, like adjustable-speed drives

· Harmonic filters can be used for power factor correction. The tuned filter changes the response of the circuit and usually reduces the overvoltage level seen at the low voltage bus. This is generally the best way to avoid problems with magnified transient voltages and still achieve a desired level of power factor correction within a customer facility. Additional protection can be achieved by placing MOVs across the capacitors.

· Series inductors, or "chokes", can be installed on the drives to reduce the probability of nuisance tripping. Chokes for this application are commercially available, and a size of 3% of drive rating is usually sufficient. Isolation transformers with similar impedance ratings will also provide protection.

Each of the technologies previously described has been utilized in the field with varying degrees of success. The criteria by which these devices are evaluated, however, is changing significantly. For example, design requirements often state that protection of utility equipment (i.e. transformers) is the primary factor. However, the recent concern for customer systems has prompted a number of utilities to seek a "transient-free" solution. In addition to the overvoltage design limits, there are a number of other factors that have delayed the widespread application of mitigation technologies. One obvious obstacle is cost, however, an equally important reason has been reliability.

Harmonic Distortion: Results and Observations

Overview of Distribution System Power Quality Concern
A fundamental objective of electric utility operations is to supply each customer with a constant sinusoidal voltage. The voltage signal at any point within the power system is ideally a constant sinusoidal signal which repeats at a rate of precisely 60 times per second, or 60 Hz. Although not perfect, the voltage signal produced by power system generators approximates a perfect sinusoid with a rather high degree of accuracy. Almost all load equipment connected to the electric power system has been designed to operate from a sinusoidal voltage source.

Harmonic distortion of the distribution system voltage originates with nonlinear devices on the power system. Nonlinear devices produce non-sinusoidal current waveforms when energized with a sinusoidal voltage. Examples of these devices include adjustable-speed drives (ASDs), switching power supplies (including computers and other office equipment), fluorescent lighting, battery chargers, saturated transformers, and arc furnaces. Nearly all of these are nonlinear and are shunt elements, the bulk of which are loads.

Harmonic distortion problems range in severity from nuisance tripping of customer end-use equipment to complete failure of very expensive utility and customer equipment. Fortunately, distribution system harmonic distortion levels are generally constrained within acceptable limits, such that neither customer processes nor utility equipment are affected.

Most power systems can absorb far more harmonic current than engineers might think. A large percentage of the problems occur when capacitors cause the system to be in resonance condition (shown in Figure E-13), thereby increasing the voltage distortion levels. Effects of harmonic distortion include heating in rotating machinery, failure of capacitor banks, telephone interference, and increased losses in system equipment.

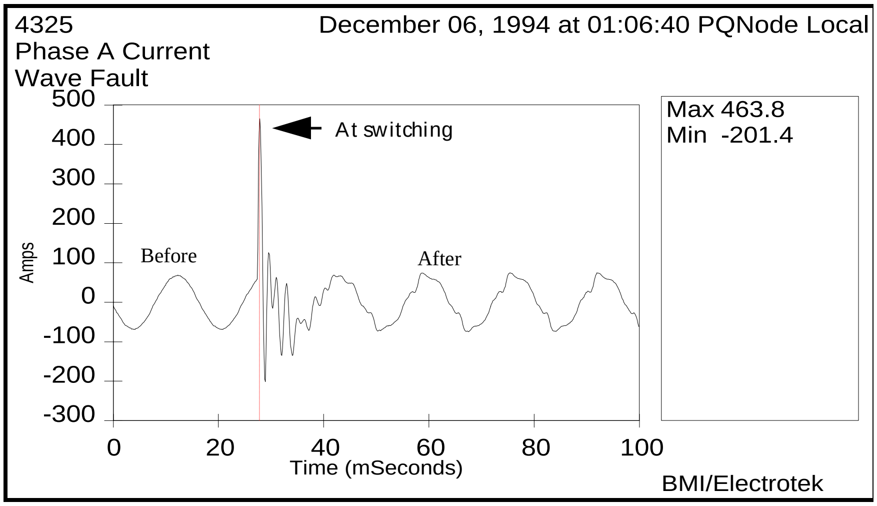

Figure E-13: llustration of a Distribution Feeder Current Before and After Capacitor Bank Switching (showing harmonic resonance)

Harmonics have existed on electric power systems for many years. Recently, however, much more attention has been given to monitoring and analyzing the presence and effects of harmonics on utility and customer devices than in the past. This new concern is the result of significant increases in harmonic distortion on many electric power systems in the last fifteen years. Two factors contributing greatly to this trend are:

· The increasing size and application of nonlinear equipment, which produces the majority of harmonic distortion on distribution systems. Power electronics comprise a large part of this increase in nonlinear equipment. The percentage of electric power that passes through these devices is increasing because of the additional energy efficiencies and flexibility that they offer.

· Increased application of utility and industrial capacitors to increase the utilization of existing distribution system infrastructures. Utilities are installing an ever increasing number of capacitors on transmission and distribution systems for voltage control and loss reduction. Additionally, utilities are encouraging customers, through their rate structures, to install power factor correction capacitors in order to obtain additional capacity from the existing distribution system equipment.

IEEE 519-1992 provides a recommended practice for controlling harmonics on the power system. This standard divides the responsibility for controlling harmonics between the customers that have nonlinear loads generating harmonics, and the supplying utility that may have system characteristics that magnify the harmonics due to resonance. Customers need to limit the amount of harmonic current that is injected onto the utility system. Utilities need to make sure that the overall system voltage distortion is acceptable so that connected utility and customer equipment will not be impacted. The harmonic distortion levels measured in this project are compared with the recommended levels from IEEE 519-1992 for reference.

Important Results - Harmonic Distortion Levels

In order to assess harmonic distortion levels, a one-cycle waveform was measured at half-hour intervals at each monitored location. The voltage waveforms consisted of 256 samples per cycle, while the current waveforms consisted of 128 samples per cycle (refer to Figure E-13). By sampling all three voltage and current phases for a total of 160,073 monitor·days, 6,043,954 steady-state measurements from 277 different sites were collected between 6/1/93 and 9/1/95. However, the full-scale voltage settings were changed on 3/1/95 to expand the monitoring instrument's ability to record large-magnitude voltage transients (i.e. capacitor switching). In doing this, the monitor lost its precision for small changes in voltage, which directly effected its capability to assess harmonic distortion. Therefore, the harmonic distortion data analysis period did not include these last six months. During the initial twenty-one month period, 5,003,969 three-phase steady-state measurements were collected, providing over fifteen million waveforms upon which to base the overall harmonic statistics.

For each three-month quarter of the project, basic statistics for each site were computed for voltage total harmonic distortion (THD) and the 2nd through 13th harmonics. Some of the statistics included 5th percentile and 95th percentile values. Also known as the CP05 and CP95 values of the site's distribution, they are excellent measures of lower and upper limits. As a basic interpretation, 5% of the samples were less than the 5th percentile, and 5% of the samples were larger than the 95th percentile. The arithmetic mean was also calculated for each site by summing all of the values of the distribution and dividing by the number of samples. The voltage THD and harmonic components were normalized using the fundamental (60 Hz) voltage component of each sampled waveform (V1).

Total harmonic distortion, or THD, is the most common quantity used to characterize the overall quality of the voltage waveform with respect to harmonics. It is defined as the ratio of the root-mean-square of the harmonic content to the root-mean-square value of the fundamental (60 Hz) quantity, expressed as a percent of the fundamental.
Voltage THD is given by:

See: Figure Eq-01.

$$\% \, THD \quad = \quad 100 \times \frac{\sqrt{\sum_{h=2}^{\infty} V_h^2}}{V_1}$$

Figure Eq-01: Voltage THD

Figure E-14 summarizes the harmonic voltage distortion and individual voltage harmonic components based on all of the monitored sites. The histogram gives the average of the CP05, mean, and CP95 values for all of the 277 sites. For instance, the mean voltage THD is 1.57%. This is the average of the mean THD values for each of the 277 sites.

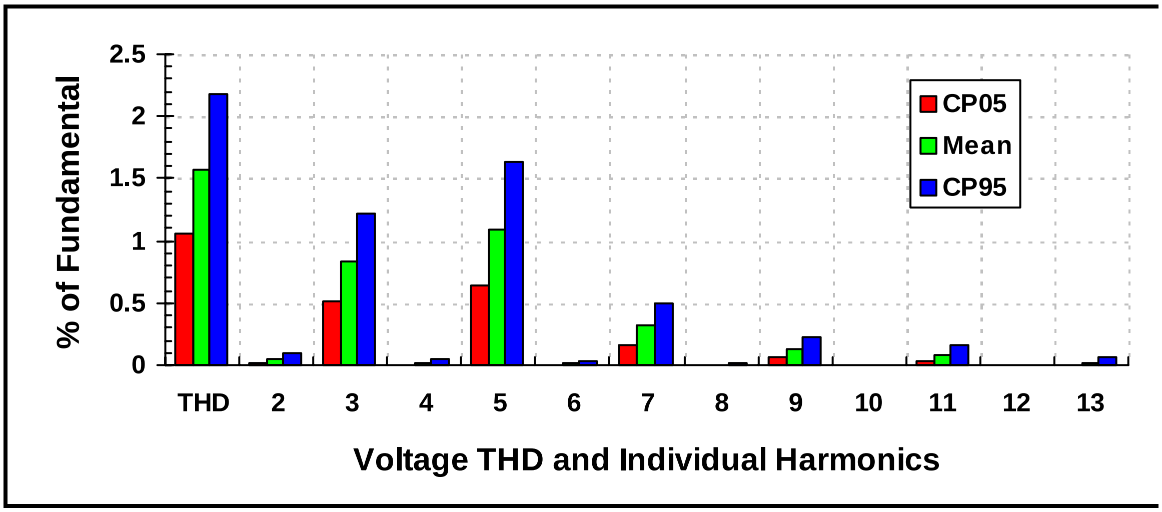

Figure E-14: Voltage THD and Individual Harmonics, 6/1/93 to 3/1/95, Weighted, All Days, All Sites

The average of all the C95 values of the individual sites is 2.2%. This is the value that would generally be compared with the 5% limit specified in IEEE 519. It is clear that, on the average, distribution system harmonic voltage distortion levels were well within the standard.

The voltage distortion on distribution systems is dominated by the third and fifth harmonic components. In the overall statistics, the fifth harmonic is most often the highest. The average of all the CP95 values for the fifth harmonic component was approximately 1.7%. IEEE 519-1992 specifies that individual voltage harmonic components on the distribution system should be less than 3%. Again, on the average, individual voltage harmonic components were well within this limit.

Figure E-15 provides the whole distribution of voltage THD CP95 values for all of the project sites. This is provided to illustrate the percentage of sites that have a CP95 value that exceeds the IEEE 519 recommended limit of 5%. The mean of these values is 2.2%, as was shown in Figure E-14. The distribution shows that only about 3% of the sites have a voltage THD CP95 value that exceeds 5%. This shows that the instances of harmonic problems are relatively rare, but that they can occur. Usually, voltage distortion levels exceeding 5% is an indication that there is a resonance condition that magnifies the harmonic distortion.

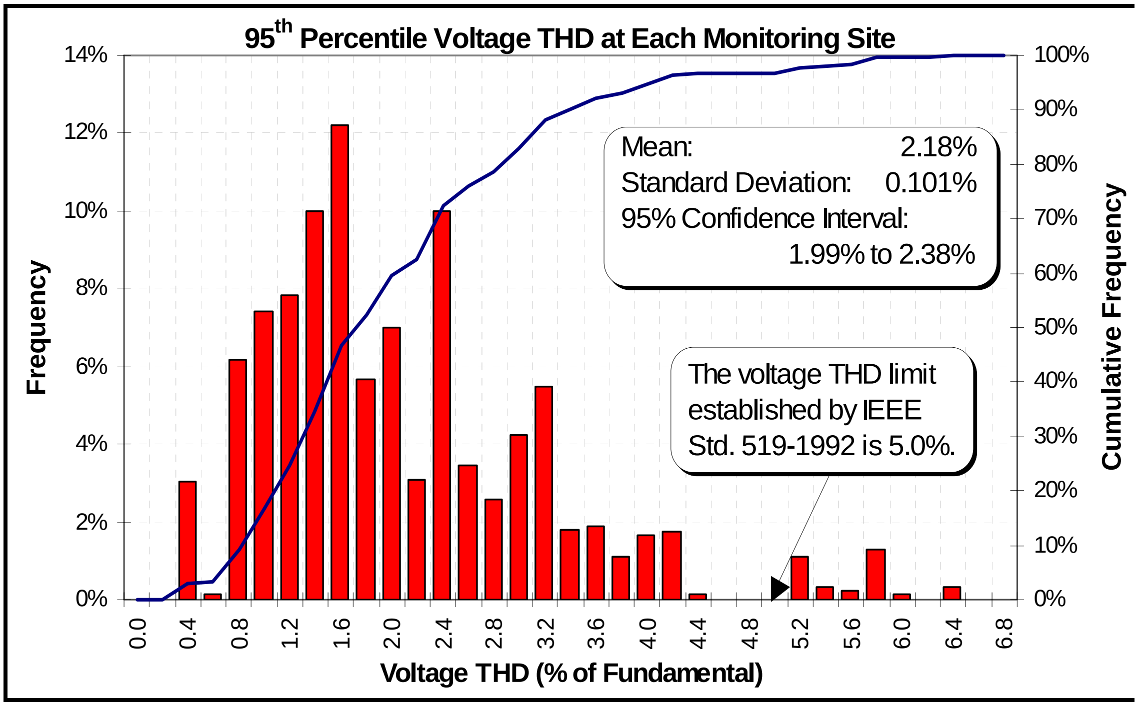

Figure E-15: Distribution of CP95 Voltage THD at Each Monitoring Site, 6/1/93 to 3/1/95, Treated by Sampling Weights

For evaluating harmonic current distortion, IEEE Standard 519-1992 presents another method for quantifying distortion levels. Total demand distortion (TDD) is the ratio of the total harmonic current to the maximum value of fundamental frequency load current. This is more useful as a means to normalize Ihrms than is current THD.

Current TDD is given by:

See: Figure Eq-02.

$$\%TDD = 100 * \frac{I_{rms}}{I_L} = 100 * \frac{\sqrt{\sum_{h=2}^{\infty} (I_h)^2}}{I_L}$$

Figure Eq-02: Current TDD

IEEE 519-1992 specifies harmonic current limits for individual customers that are a function of the short circuit ratio at the point of common coupling (PCC) with the utility. Since monitoring in this project was actually at distribution feeder sites, rather than at individual customers, the IEEE 519-1992 limits cannot be directly used for comparison. However, it is interesting to compare the project results with the most stringent limits in IEEE 519-1992.

Figure E-16 summarizes the total demand distortion and individual components based on all of the monitored sites. The histogram gives the average of the CP05, mean, and CP95 values for all of the 277 sites. For this calculation, the demand current is calculated for each site as the rms current that is exceeded only 1% of the time (99% percentile value). From the histogram, the mean current total demand distortion is 1.82%. The average of all the CP95 values is about 5.4%, which exceeds the most stringent IEEE 519-1992 recommendation of 5%.

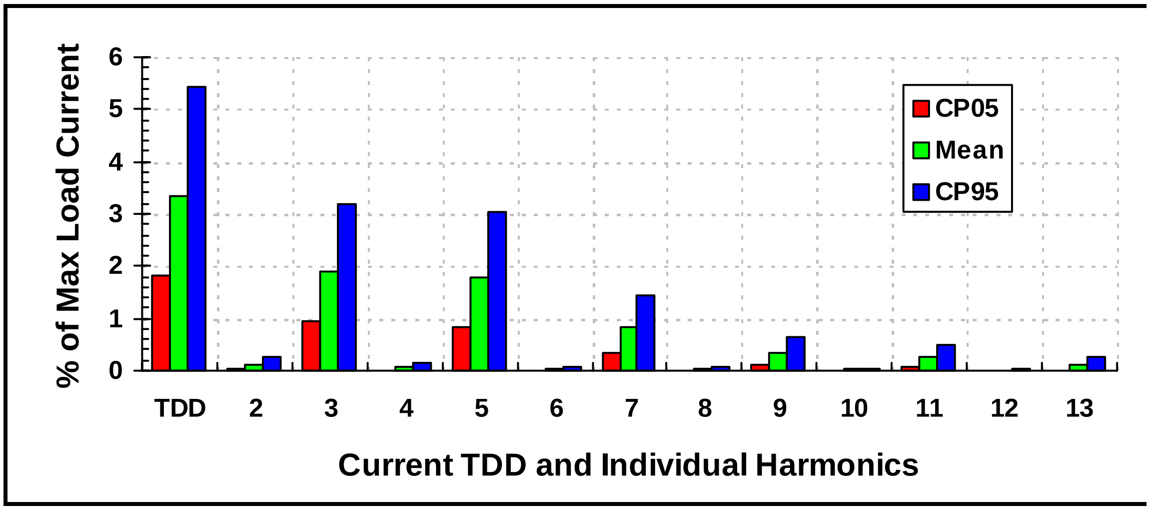

Figure E-16: Current TDD and Individual Harmonics 6/1/93 to 3/1/95, Treated by Sampling Weights, All Substation Sites

This probably means that many individual customers have total demand distortion levels that exceed this most stringent limit. However, they may be well within the limit that applies to them based on the short circuit ratio at their PCC. The limit for TDD could be as high as 20%, depending on the short circuit ratio.

Figure E-17 provides the whole distribution of current TDD CP95 values for all of the project sites. This is provided to illustrate the percentage of sites that have a CP95 value that exceeds the IEEE 519 recommended limit of 5% (most stringent limit). The mean of these values is 5.4%, as was shown in Figure E-16.

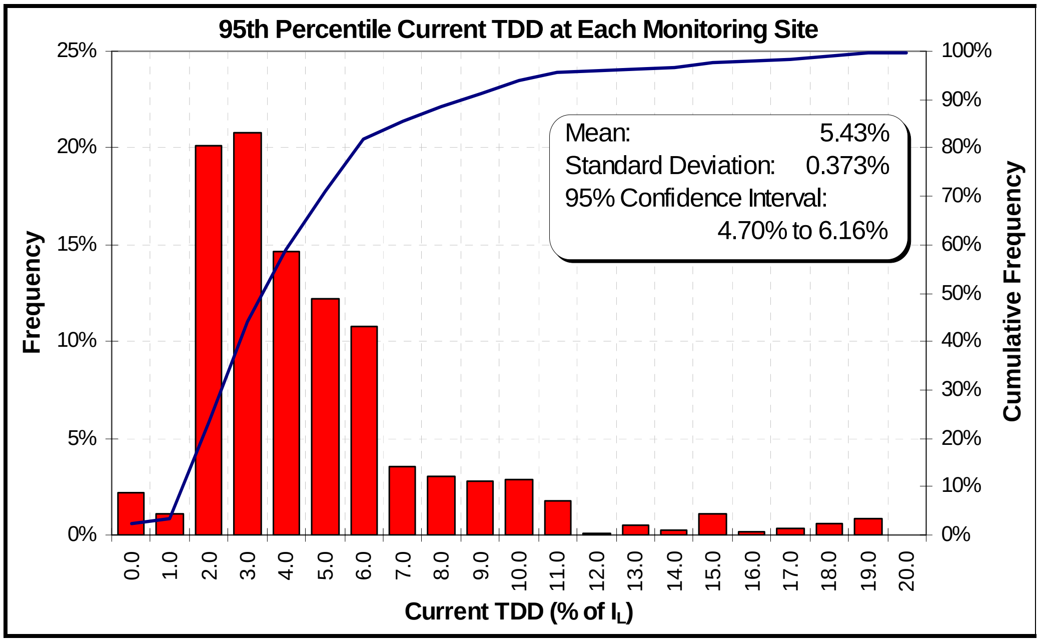

Figure E-17: Distribution of CP95 Current TDD at Each Monitoring Site 6/1/93 to 3/1/95, Treated by Sampling Weights

The distribution, however, shows that only about 30% of the sites have a current TDD CP95 value that exceeds 5%. In fact, less than 10% of the sites have a current TDD CP95 value that exceeds 10%.

Practices to Improve Distribution System Power Quality Levels
Current trends in distribution system design and operation are dictating that distribution engineers monitor the levels of harmonics present on their systems and analyze the potential effects that those levels can have on customer end-use and utility system equipment. Furthermore, any planned voltage support or power factor correction modifications should be carefully studied in order to determine the effects these changes might have on system resonances.

The development of cost-effective solutions to harmonic distortion problems requires a comprehensive approach which typically includes site surveys, harmonic measurements, and computer simulations. A typical procedure, often used for harmonic analysis, includes:

1. Preliminary assessment. Simple calculations can be used to determine the system resonant frequencies. Existence of resonances (high or low impedances) near characteristic harmonic frequencies of loads which have been identified as harmonic sources is an early indication of potential trouble.

2. Harmonic measurements. The primary purpose of measurements is to characterize the behavior of harmonic sources, and to provide preliminary data on the severity of the

distortion problem. Measurement data is also extremely valuable for validating detailed computer models.

3. Computer simulations. Once a representation of the significant components in the power system has been developed and verified as accurate by comparison to measurement data, a wide range of conditions can be investigated. System configurations that create resonances can be identified, and alternative configurations can be examined.

4. Solution development. Harmonic current and voltage levels, determined through both simulation and measurement, are evaluated against recommended limits, such as IEEE Standard 519-1992. If harmonic voltage distortion levels are not within acceptable limits the frequency response characteristics of the system can be altered by changing capacitor bank sizes and/or locations, or by installing harmonic filters. Post-solution monitoring may be used to verify the correct operation of mitigation equipment.

When mitigation of harmonic distortion is required, one of the options is to apply a filter at the source of harmonics, or at a location where the harmonic currents can be effectively removed from the system. The most cost-effective filter is generally a single-tuned passive filter, which will be applicable for the majority of cases. Passive filters are made of inductive, capacitive, and resistive elements. They are relatively inexpensive compared with other means for eliminating harmonic distortion, but they have the disadvantage of potential adverse interactions with the power system. They are employed either to shunt the harmonic current off the line or to block their flow between parts of the system. Passive filters must be carefully designed to avoid unexpected interactions with the system.

Another possible mitigation method is the application of active filters. Active filters are relatively new types of devices for eliminating harmonics. They are based on sophisticated power electronics and are much more expensive than passive filters. However, they have the distinct advantage that they do not resonate with the system. They can be used in very difficult circumstances where passive filters cannot operate successfully because of where the parallel resonance lies. They can also address more than one harmonic at a time and combat other power quality problems such as flicker. They are particularly useful for large, distorting loads fed from relatively weak points on the power system. Active filters can typically correct for power factor as well as harmonics.

Finally, the question often arises concerning what to do about widely dispersed, small sources of harmonic currents that cause excessive voltage distortion on medium voltage distribution systems. The basic problem is that the path taken by these currents is too long, either electrically so that they cause excessive voltage distortion or physically so that they cause communications interference. Therefore, the basic solution is to shorten the path for the offending harmonic currents so that they do not travel all the way back to the substation, as is their general tendency. The general idea is to distribute a few filters tuned to the principal offending harmonics well out toward the end of the feeder (shown in Figure E-18). This shortens the average path for the harmonic currents, reducing the opportunity for telephone interference and reducing the harmonic voltage drop in the lines. This keeps the voltage distortion on the feeder to a minimum.

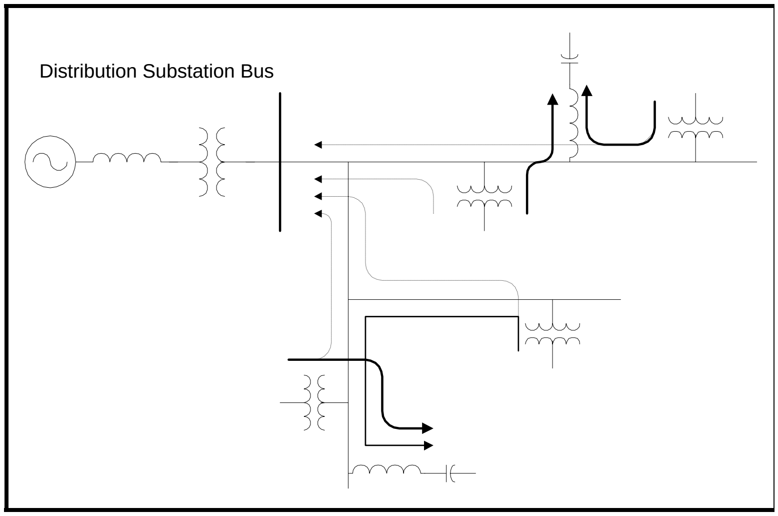

Figure E-18: Altered Harmonic Current Flow with Distributed Filters