Overview of an Automatic Distribution Fault Location System at the United Illuminating Company

Daniel Sabin, Elder Romero, Robert Manning, and Marek Waclawiak

***Abstract* — In 2008, United Illuminating Company (UI) began a pilot project to use power quality monitors to locate faults on distribution feeders supplied by 13.8 kV systems. Fault measurements captured by the meters are downloaded automatically, integrated into a relational database, and processed for reactance calculations. The reactance calculations are combined with detailed distribution circuit models and geographic information system data to build estimated fault location tables and web-based map displays. The systems are integrated on the company intranet and used in real-time by numerous groups within UI including power quality engineers, control room operators, field operations, and distribution planning. The algorithm used for waveform processing can distinguish between single-phase faults, multi-phase faults, subcycle faults, and feeder energizing magnetizing inrush. This paper will present an overview of some of the parameters and practices for finding faults at UI.**

***Index Terms*—fault location, power quality, power system restoration, power system transients, relational databases, geographic information system.**

I. Introduction

THE automatic fault location system (AFLS) on the distribution system of the United Illuminating Company (UI) was first put into use during 2008. It incorporates power quality monitors, database applications, up-to-date circuit models, and geographic information system (GIS) databases in order to provide automatic fault identification and fault location estimation. The AFLS has become a valuable tool for quickly and accurately identifying the location of faults on UI's 13.8 kV distribution system.

The AFLS uses measurements recorded at stations. These measurements are downloaded automatically and incorporated into a relational database. Calculations on these measurements estimate the reactance from the station to the fault. The calculations are based on phasor measurements derived from the voltage and current samples and calibration constants based on previous fault data and known locations. The result of these calculations is an estimated "reactance to fault," or XTF. The XTF values are compared with line models that estimate the positive-sequence and zero-sequence reactance between station and line structures. The estimated locations can be viewed via the corporate intranet and can be displayed geographically using maps derived from a GIS database. The calculated fault locations are typically available on the UI Company intranet within ten minutes after a line fault.

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II. Power Quality Monitoring at UI Company

Installation of monitors for recording power quality measurements at UI began in 1992 during the EPRI® Distribution System Power Quality Monitoring Project (also known as the EPRI DPQ Project) [3]. Monitors were installed to record long-term statistics on voltage sags and harmonic distortion at key distribution substations.

At present, the power quality system at UI consists of 70 monitoring locations including all 13.8 kV substation busses, three transmission lines, and eleven individual 13.8 kV circuits. The power quality monitors are installed on the secondary side of the substation transformer and monitor the bus voltage and current. Data is downloaded from the monitors using broadband communications (Ethernet) via the corporate network. Figure 1 illustrates the installation of the PQ monitors at the substation. The power quality monitors are accessible to other computers in UI via fiber optic wide area network connections. The monitors record mostly phase-to-neutral voltages, but a few locations have phase-to- phase voltage only.

III. Fault Identification and Location Process

A. *Fault Measurements*

Measurements are recorded on the distribution busses using power quality monitors installed on the secondary of 115kV/13.8 kV transformers. Each bus is typically supplied by two parallel transformers. These locations serve approximately 10 to 16 radial lines.

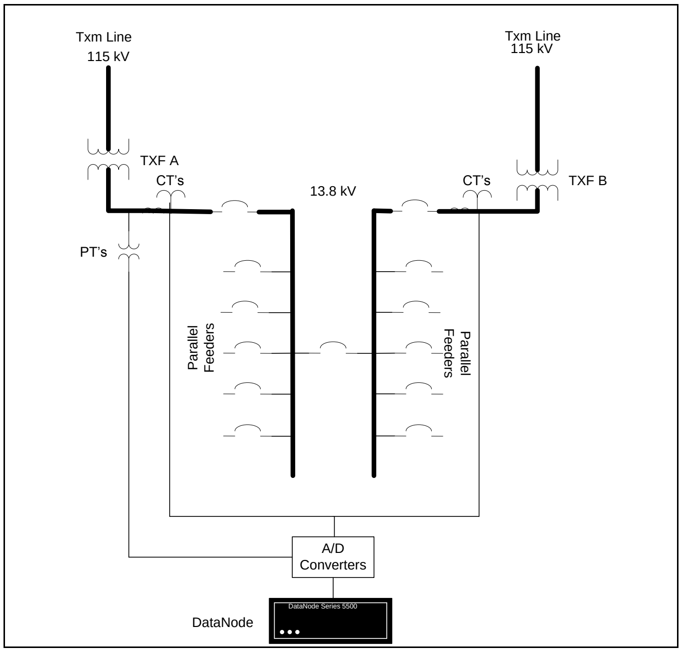

Figure 1: Typical Connection of Power Quality Monitor at UI Company

The total current to all feeders are monitored by a single Dranetz® DataNode® power quality monitor. The power quality monitor records the bus voltage and summed current supplied by both transformers. The decision to monitor the summed current has proven useful because some of the substations are configured with a fault current limiting scheme in which the bus is split automatically for faults over 10 kA. This means that the current measured by the fault is cut in half during the fault.

Figure 2 represents a single-line-to-ground (SLG) fault measured on a UI distribution feeder. The measurement was recorded upstream from the fault. Figure 3 presents an example of a SLG fault measured that becomes two-phase after about ten cycles.

Measurements by the power quality monitors are triggered using high and low rms voltage thresholds. When a voltage sag (less than 90% of nominal) or voltage swell (more than 110% of nominal) is detected, it will trigger voltage and current waveform samples and rms samples to be recorded. RMS voltage and current values and estimated reactance values to the fault are computed from the waveforms. The UI power quality monitors are configured to record voltage and current waveform samples at a rate of 512 points per 60 Hz cycle with two cycles of pre-trigger and two cycles of post-trigger data.

The power quality monitors communicate with a server via a broadband Ethernet connection. This allows the fault measurements to be downloaded from the monitors to the corporate network typically within one minute.

B. Circuit Models

The distribution circuit models are stored in Eaton®/Cooper Industries CYMDIST databases, which are extracted from UI Company GIS database. These models provide the geospatial coordinates for the nodes that comprise the line segments of distribution feeders in a Lambert conformal conic projection system. These coordinates are converted to the WGS 84 coordinate system so the maps can be displayed in standard GIS software systems as overlays on maps and aerial imagery.

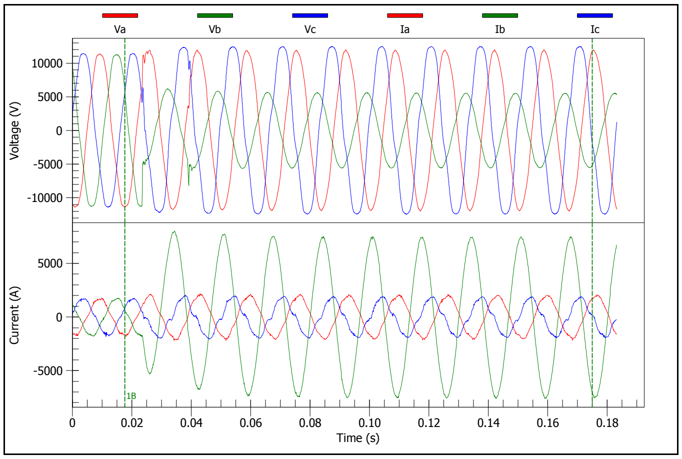

Figure 2: Example of a SLG fault on a UI Company distribution feeder

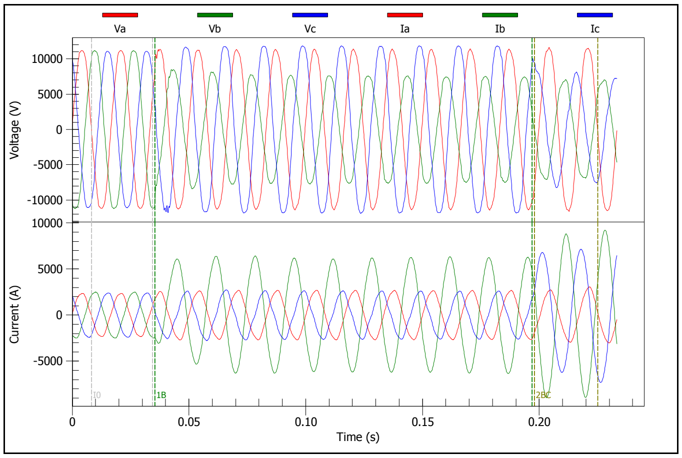

Figure 3: Example SLG Fault on a UI Company Distribution Line that Evolves to Become Two-Phase

The circuit models include conductor types used in different line sections that include positive-sequence and zero-sequence impedance characteristics. The number of phases for each line segment is also stored, as well as whether the line section is underground or overhead. The cumulative impedance to each underground and overhead structure is stored in a relational database. An example model is displayed in Figure 4.

C. Data Integration

Once downloaded from the substation, data from the power quality monitors is integrated automatically into PQView®, which employs a relational database for data storage [4]. The waveforms from the power quality monitors are stored in a proprietary database format provided by the monitor vendor.

The fault measurements are incorporated into the relational database usually within a few minutes of a fault occurrence. Once in the database, the measurements can be queried and analyzed directly using workstation computer applications or indirectly via intranet web applications.

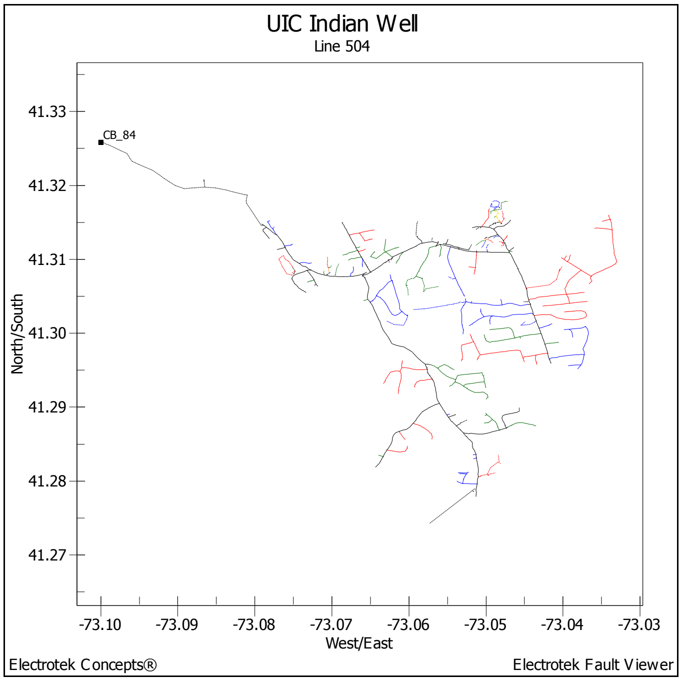

Figure 4: Typical Distribution Line Underground and Overhead Line Sections

D. Fault Identification

Each measurement downloaded by the remote power quality monitors is analyzed by a power quality database management and analysis software system for voltage characteristics and zero-sequence current characteristics that indicate a SLG fault has occurred. Other line-line voltage characteristics are examined that indicate that a two-phase or three-phase fault has occurred. Harmonic content and event duration are used to identify events as magnetizing inrush events. Zero-sequence and negative-sequence current content is used to search for other overcurrent events that are not faults but otherwise noteworthy for automatic notification.

A single measurement may be classified as more than one type of fault. This means that the AFLS is able to identify single-phase faults that evolve into multi-phase faults. As another example, the system is able to identify the start and end of each stage of a fault that begins as a transformer energizing transient but degrades into a fault condition.

E. Reactance Estimation

For SLG faults, the XTF is estimated using (1), where V_f is the magnitude of the voltage measured on the phase showing a voltage sag, N_T is the number of transformers in service during the fault, I_0 is the magnitude of the zero-sequence current, and θ is the phase angle between V_f and I_0.

$$XTF = \frac{V_f}{N_T k_1 I_0} \sin\theta \qquad (1)$$

The constant k_1 is a calibration factor that is determined using previous faults recorded at the bus in the recent past. The historical faults must have occurred when the network was in the same configuration as the fault that occurs in the present in order for the k_1 factor to be useful. Practical use of the fault location at UI indicates that the actual distance in reactive ohms for historical faults can be used to determine a value of k_1 that will estimate the reactance to fault for future events. The k_1 constant can be computed at the bus level for all lines supplied by a station, or can be computed for each line. The line-level k_1 constants typically are more accurate than the bus-level constants. This approach to SLG fault location using positive-sequence reactance only was first described in [5].

For multi-phase faults, a more traditional method is used for fault location. The approach described in IEEE C37.114 for single-ended impedance-based measurements has been applied successfully to the UI Company distribution faults [1]. This method requires computation of line-line voltage and current phasors before the fault and during the fault.

Calculation of SLG faults at substations that provide phase-to-phase voltage only is possible by using the zero-sequence source impedance at the substation, which is provided in the distribution circuit model, to estimate the zero-sequence voltage during the SLG fault. The estimated V_0 is then used to estimate the phase-to-ground voltages during the fault, which in turn can be used to estimate a reactance-to-fault.

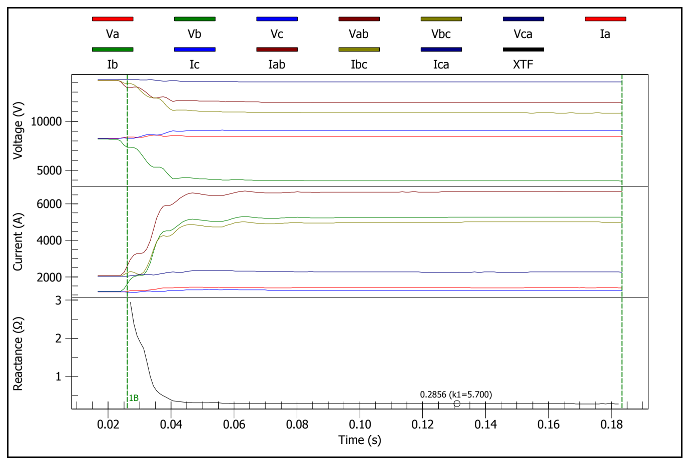

Figure 5: Calculation of Reactance-to-Fault for SLG Fault in Figure 2

F. Fault Location Visualization

There are multiple applications available for displaying estimates of fault location. Figure 6 presents an example one-line diagram showing the estimated fault locations as circles and the actual fault location with a callout annotation line. This estimate is for the SLG fault displayed in Figure 2. Multiple estimated locations are possible whenever a line has laterals. This one-line is visible via desktop computer programs or within a web page display. Figure 7 presents the same one-line diagram, but overlaid on an aerial map available from Google® Earth.

On the UI intranet, several applications provide system operators and engineering staff with estimated fault locations. In Figure 8, an example of a one-line diagram from another intranet web application is shown for the feeder with an estimated fault location. This map display was drawn using the ESRI® ArcGIS® API for Silverlight®. The lightning bolt icons represent the estimated (green) and actual (red) location of the fault. This application can also display the locations on satellite imagery.

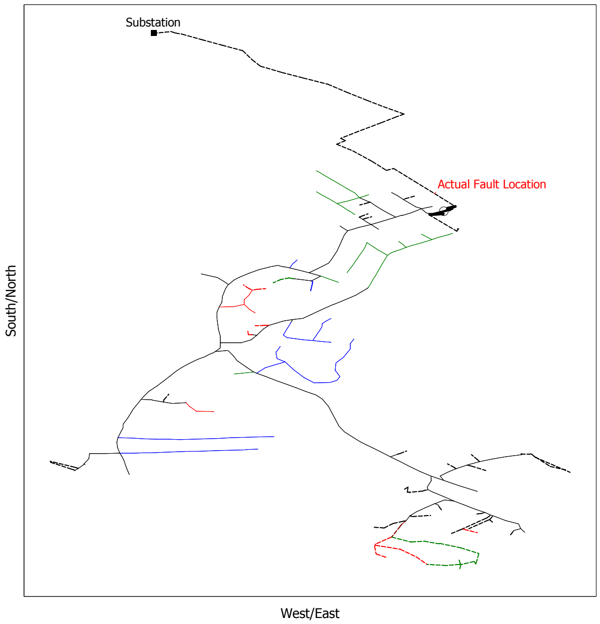

Figure 6: Example One-Line Diagram Showing Estimated Fault Locations and Actual Location with Coordinates for SLG Fault in Figure 2

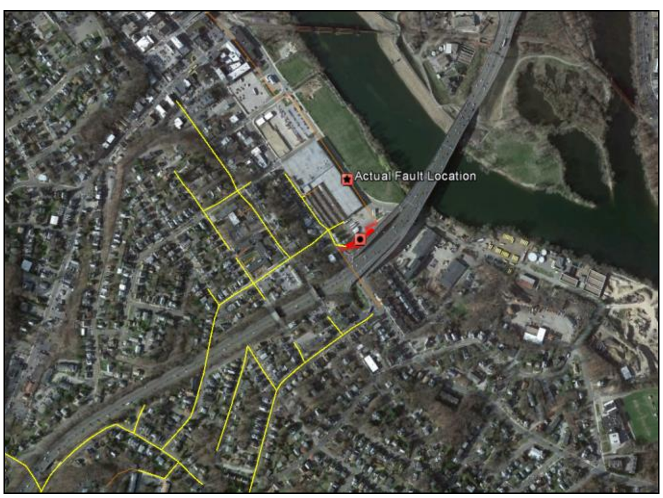

Figure 7: Example One-Line Diagram Showing Estimated Fault Locations and Actual Location Displayed with Aerial Map Data for SLG Fault in Figure 2

IV. Results

Satisfactory results have been obtained since the implementation of the AFLS at UI for SLG faults as well as multi-phase faults. The average error for all the faults in the system from 2005 to 2013 was 11.96%. The average error for SLG faults and multi-phase faults in for this time period was 12.55% and 10.92% respectively.

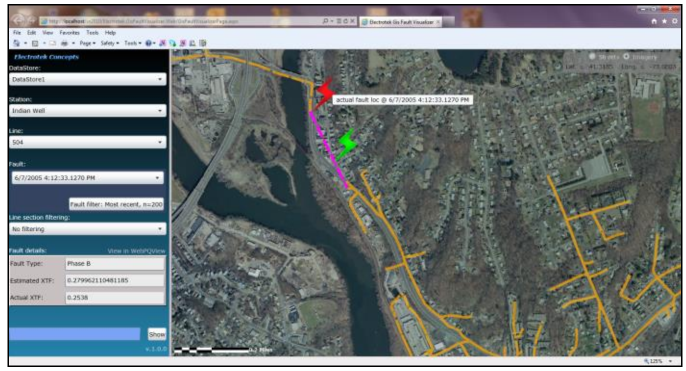

Figure 8: Example Street View Map of Estimated and Actual Fault Location

In some rare instances, the AFLS fails to calculate an XTF value for a fault. This typically occurs when there is insufficient event duration to calculate an XTF since the application requires at least one pre-fault voltage and current cycle and at least two cycles during the fault. Another reason that may lead to this situation is that a monitor did not record the fault event at all or it started recording in the middle of the fault. High impedance faults can also produce inconsistent and erroneous results.

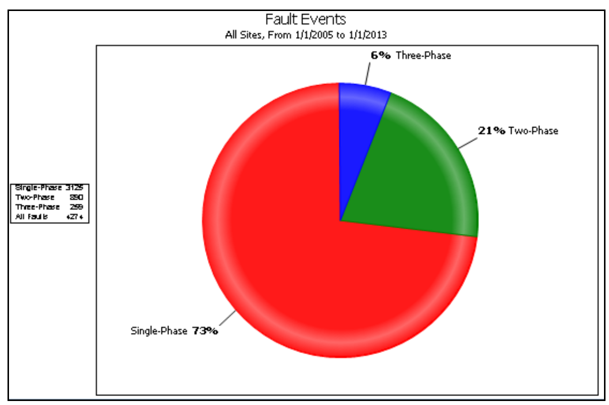

Figure 9: Fault Event Summary from 2005 to 2013

Figure 10 presents a summary of the faults identified by month by the AFLS from 2005 to 2013. Figure 11 presents a summary of the fault location accuracy as a distribution of error in ohms versus fault count.

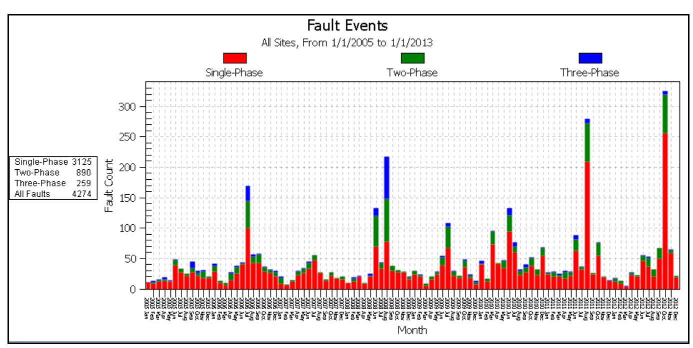

Figure 10: Fault Event by Month from 2005 to 2013

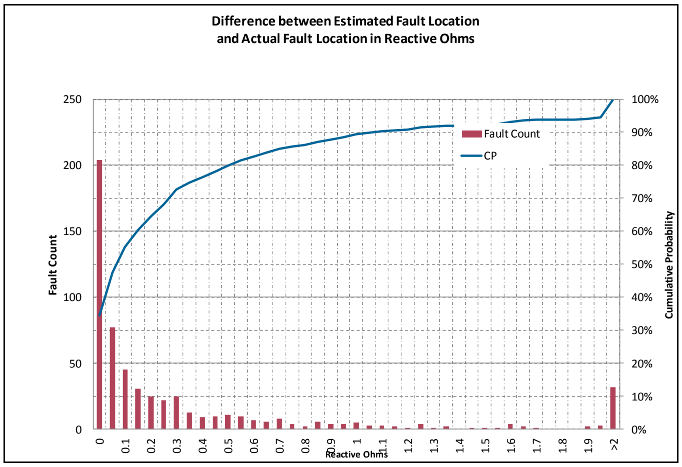

Figure 11: Fault Location Estimation Accuracy

V. Conclusion

The AFLS at UI was developed from 2008 to 2010. Regular usage by the system operators, operations engineers and others started in 2011. The AFLS has proven very dependable and has resulted in improved asset availability. The system has proven to be of great benefit to the company especially for underground faults in busy city streets. As system operators and operations engineering get more familiar and comfortable with the AFLS system, the company can expect significant benefits. These benefits include a reduction in time to find and repair faults and therefore a reduction in O&M expenses; reduced outage duration and therefore reducing CAIDI. Future enhancements to this system include detection of temporary (incipient) faults before they become permanent, which would further reduce O&M expenses and improve system reliability.

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VI. Biographies

Daniel Sabin is a Principal Engineer and Software Architect with Electrotek Concepts, Inc. in Beverly, Massachusetts, USA. He is currently the chief application architect of PQView. This software database application is used by electric utilities worldwide for managing and analyzing the gigabytes of measurements recorded by power quality monitors, digital fault recorders, and electronic relays. He has developed automatic fault location systems used by the Consolidated Edison Company of New York, the United Illuminating Company, and Detroit Edison. He was a project manager with the Electric Power Research Institute, Inc. (EPRI) and its subsidiary EPRI Solutions, Inc. from 2005 to 2008. He managed and completed power quality monitoring and distribution fault location projects. He has a Bachelor of Science degree in Electrical Engineering from Worcester Polytechnic Institute in Massachusetts and a Master of Engineering degree in Electric Power Engineering from Rensselaer Polytechnic Institute in New York. Dan is registered as a Professional Engineer in the State of Tennessee. He is the vice chair for the IEEE Transmission & Distribution Committee and former chair of the IEEE PES Power Quality Subcommittee. He was a member of the IEEE PSRC D26 Task Force on the Revision of C37.114 Fault Location Guide and the IEEE PSRC H4 Task Force for Revision of C37.111 COMTRADE Standard.

Elder Romero is a System Integrity Lead Engineer with The United Illuminating Company in Orange, Connecticut, USA. He has been with UI Company since 2002. He has a Bachelor of Science degree in Electrical Engineering from Binghamton University (S.U.N.Y. Binghamton) in 2002, an M.B.A. degree from Quinnipiac University and is currently pursuing a Master of Engineering degree in Electrical Engineering from Worcester Polytechnic Institute.

Robert Manning is the System Integrity Manager with The United Illuminating Company in Orange, Connecticut, USA. He has been with UI since 1988. Mr. Manning has held various positions in the areas of Distribution Operations, Planning, and Reliability. He has a Bachelor of Science degree in Electrical Engineering from Worcester Polytechnic Institute in Massachusetts and a Master of Business Administration from the University of New Haven in New Haven, Connecticut. Bob is a registered Professional Engineer in the State of Connecticut.

Marek G. Waclawiak received his Master’s Degree in Electrical Engineering from Politechnic of Lodz, Poland in 1976. Mr. Waclawiak is the Chief Electrical Engineer with the United Illuminating Company in New Haven, CT. He joined The United Illuminating Co. in 1985 after spending four years in Distribution System Network Design for the City Public Service of San Antonio in Texas. Mr. Waclawiak participates in R&D and Strategic Planning for Electric System at UI. Prior to his present assignment, he led UI’s System Integrity Group responsible for Reliability, Power Quality, Distribution Planning, and Distribution Standards. Mr. Waclawiak responsibilities also included Distributed Generation Interconnection issues, Power Quality efforts including the power quality monitoring system. Marek is a registered Professional Engineer in the State of Connecticut. Marek has worked as a member of the IEEE P1159 Working Group on Monitoring Power Quality and the IEEE Working Group on Harmonics.