Correlating Protective Relay Reports for System-Wide, Post-Event Analysis

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***Abstract*—The Blue Ridge Electric Cooperative has successfully implemented an automated system to collect intelligent electronic device (IED) oscillography reports. They are now participating in a pilot project to develop software that provides analysis of IED oscillography reports together from across their system.**

During a power system fault, IEDs provide high-accuracy, time-stamped power system measurements in the format of a high-sample-rate oscillography report. Traditionally, these oscillography reports are analyzed in order to understand the specific details of a fault and the IED operation during the fault.

Bringing IED oscillography reports together from across a system into one analysis application improves post-fault analysis efficiency and reporting. It also enables the identification of trends over time, leading to improved system reliability. This paper shares the initial results and benefits that Blue Ridge Energy Cooperative has achieved by bringing IED oscillography from across their system together in one application.

I. Introduction

Blue Ridge Electric Cooperative (BREC) is a customer-owned nonprofit that has served Upstate South Carolina since 1940. Its service territory covers Anderson, Greenville, Oconee, Pickens, and part of Spartanburg county with more than 7000 miles of power lines, consisting of 75 percent overhead and 25 percent underground lines. BREC began converting their substations from electromechanical to microprocessor-based relays in the early 2000s.

Today, BREC has over 200 IEDs installed across their system. They use automated collection software to consolidate their data for post-fault system analysis. Even with automated collection, the fault analysis process is time-consuming and complex [1]. It often involves interacting with multiple software applications in order to fully understand the impact of a fault. Analysis of the event report, determination of fault location, monitoring of weather conditions, and documentation of root causes are all performed through separate software applications. Consolidating these data into one system-wide post-event analysis application will make it easier for BREC engineers to see the complete picture and reduce the time spent translating results from one application to another.

BREC also realizes the immense value in mining the database of automatically collected event reports for trends and repetitive conditions. By identifying issues from this analysis, mitigating actions can be taken prior to an outage, thereby improving the reliability of the system for BREC's 65,000 customers and safety for BREC's line crews.

This paper presents the methods, goals, and results of the system-wide event analysis software pilot project deployed at BREC.

II. Traditional Event Report Analysis Process

BREC's process for fault indication and analysis has changed over time. Initially, BREC relied on circuit breaker status indication communicated using their SCADA system for fault indication. It was straight forward; if a breaker tripped and locked out unexpectedly, it was assumed a fault had occurred on the associated line and a lineman or engineer was dispatched to the site. Upon arrival, they would check the protective relays for indication. The relays installed at that time were either electromechanical or solid-state. This meant that the relay would display a flag or target to indicate that it had, in fact, tripped the circuit breaker. To gather more information about the fault, BREC personnel would then patrol the line for damage.

Consider applying this process to a faulted overhead distribution line. Inspecting a line in this manner provides mixed results. Any temporary faults that cause the protective relay to trip and successfully reclose a breaker are not indicated by the SCADA system. Instead, this fault would only be analyzed if a customer called BREC and reported that their lights blinked a few times. Such a call may be received days after the actual event occurred.

If a permanent fault occurs on the line and the breaker successfully locks out, determining the actual cause of the fault is still not guaranteed. If the obstruction is still present when the line is physically inspected, the cause of the fault may be easily identifiable, such as in the case of a fallen tree. If a fault results from a partially failed insulator, however, the cause would be much harder to identify. Often, if a line inspection finds nothing wrong, power would be restored. If the line energizes successfully, the source of the fault may never be identified.

As BREC installs new technology on their system, fault indication and data collection improves. For example, in the early 2000s BREC began replacing older relays with microprocessor-based relays with event recording capabilities and installing serial communications processors to communicate remotely with each relay. This allows BREC to collect more data, and to collect those data faster, than previously possible. The communications infrastructure also improved, allowing their SCADA system to send indications from the field each time a relay generates an event.

In comparing the effect of this new technology to BREC's previous process, we see significant improvements. First, both temporary and permanent faults are indicated remotely to BREC through their SCADA system. In addition, event reports the relay generates contain significantly more data than could be obtained from electromechanical relays or line examination. Finally, the event reports can be collected remotely, making data collection much faster.

Although fault indication and data collection has improved, analyzing faults can still be tedious. Consider a permanent fault on an overhead line with the improvements to BREC's system. Multiple event reports are generated (at least one each time the relay trips the breaker). These event reports each need to be collected, time-aligned, and examined individually.

The issue of time-aligning event reports is compounded when the events are obtained from multiple relays, which may be necessary after an evolving fault. Conductor slap (or conductor galloping), a type of evolving fault that can occur on a radial distribution line when high currents resulting from a downstream fault cause upstream conductors to move and make contact with one another, can create an upstream fault [2]. To understand such a fault, event reports must be collected from different relays. If these event reports are not properly time-stamped, the personnel doing the analysis must manually subtract the difference in time stamps between the relays for every fault.

In general, this process requires significant effort when multiple events are compared. BREC must collect, analyze, and classify each event that occurs. Information from each event report must be manually logged and organized in the Outage Management Software (OMS) or trending software. This manual process may introduce errors if an event report is either not collected or incorrectly logged.

III. New System-Wide Analysis benefits—Automatic Event Report Collection

The foundation of any system-wide post-event analysis solution is automated event report collection from digital protective relays. Automated event report collection is described in detail in reference [3]. By automating the process of collection, a utility can transition from only collecting data from a digital relay when a fault occurs to collecting data as soon as it becomes available. In addition to making more data available for analysis, automated collection eliminates the time spent driving to the substation or dialing in to the substation to collect event records. The benefits of an automated event report collection system from an analysis perspective will be shared throughout the paper.

BREC's automated event report collection system is shown in Fig. 1. When a fault occurs, the protective relay(s) in the substation generate an event report and store it in nonvolatile memory on the relay. A communications processor in the substation detects the newly generated event report and collects the event report off of each protective relay. The centralized event report collection server is then notified, and the event report is collected from the communications processor and stored in a centralized database for long-term archiving and compliance. The system-wide post-event analysis software described in this paper connects to this centralized database.

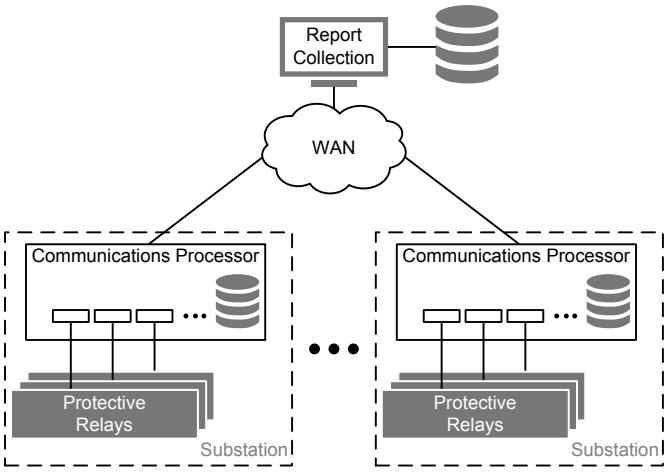

Fig. 1 BREC's automated event-collection system architecture

IV. New System-Wide Analysis benefits—Automatic Grouping of Fault Data

When a fault occurs in a given system, multiple IEDs may detect the fault condition and generate event reports. For a fault on a distribution feeder (see Fig. 2), this may include a primary feeder protection relay, a backup feeder protection relay, a recloser, a voltage regulator, and relays protecting other feeders in the substation. The yellow indicators in Fig. 2 represent digital relays that may detect the fault and generate an event report, and the red indicator represents the relay that generates an event report and issues a trip to clear the fault.

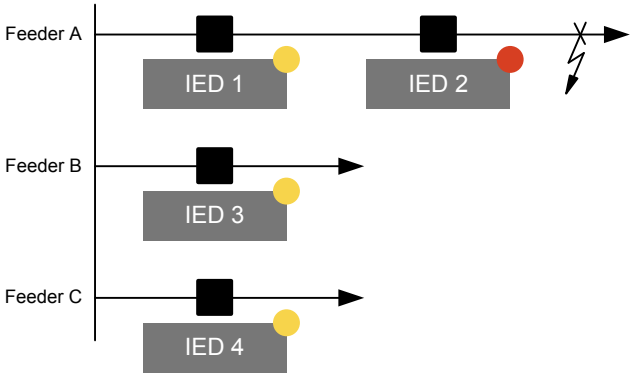

Fig. 2 Example distribution feeder showing event reports generated for a fault

In addition to multiple IEDs generating event reports for a fault condition, it is common for a single IED to generate multiple event reports for a fault. For example, an IED may generate an event report in response to its protection element picking up, and then generate a second event report when a trip is asserted after a time delay. Similarly, a recloser control may generate an event report when it issues a trip, and then generate a second event report upon reclosing. Fig. 3 shows the oscillography from two event reports together as part of a distribution feeder fault at Blue Ridge Electric Cooperative.

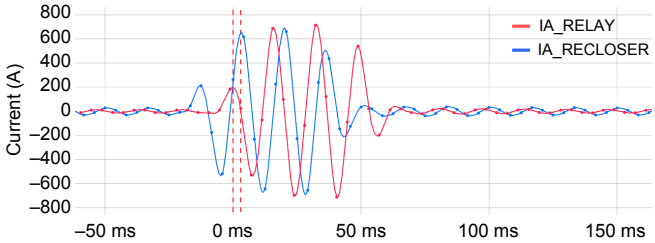

Fig. 3 Feeder relay and recloser event reports time-synchronized in post-event analysis software

Whether multiple relays generate event reports for a fault, a single relay generates multiple event reports, or both occur, engineers can save time during fault analysis by having all associated event reports automatically grouped together by a centralized software application.

The simplest criteria for automatically grouping event data is time. If a collected event report has a time stamp that is within *X* seconds of another event report in the database, then the event reports are likely related to the same fault and should be grouped for consolidated analysis. If the time separation between two event reports is greater than *X*, then two event analysis groups should be created (as shown in Fig. 4). The time *X* is configurable, and one second is used on Blue Ridge Energy Cooperative's system with good results.

Fig. 4 Example of distribution feeder event reports showing time-based grouping with a one-second grouping threshold

There are several potential challenges with automatically grouping event reports based on time stamp, including the following:

- Multiple, unrelated faults may occur at similar times in a power system.
- The time-stamp method of grouping requires all IEDs to have precise time synchronization.

By implementing a simple power system connection model, the time-stamp method of grouping event reports can be improved. For example, when grouping event reports with similar times, the location of each event report in the system can be compared. If the event reports are from the same geographic region, then they are grouped together as one fault. If the event reports are from different geographic regions, then they are separated out into multiple faults.

V. New System-Wide Analysis Benefits—Automatic Fault Location

A. Automatic Fault Location Calculations

When a fault occurs, it is imperative for a utility to quickly restore power to as many customers as possible. This requires locating the fault and performing any required repairs prior to re-energization. Historically, utilities have relied on linemen to patrol the line, which is a time-consuming and expensive process. Today, many utilities use fault location estimates generated by digital protective relays to speed up the fault-locating process and to implement automatic isolation and partial restoration. Fault location algorithms have been deployed in digital protective relays since the first digital protective relay was produced [4]. In many cases, the digital protective relay uses multiple fault location algorithms and then chooses the best fault location estimate based on the fault type.

Given the importance of rapid power restoration for their customers, some utilities perform additional fault location calculations using data from multiple relay-generated event reports. By employing multiple fault location algorithms, the utility gains greater confidence in fault location estimates and potentially improved accuracy. Traditionally, engineers perform these calculations by hand or use custom analysis tools. Recently, software applications have become available that perform these calculations automatically [5] [6]. These applications automatically collect all event records for a fault, calculate multiple fault location estimates, and present them to an engineer or operator for analysis. For transmission systems, additional fault-locating methods employing reports from both ends of the line provide improved fault location results [7]. Distribution fault location is more challenging due to the radial nature of distribution feeders; a calculated fault distance will often lead to multiple possible fault locations. By combining digital relay event reports, recloser event reports, the feeder model, and faulted circuit indicators, software can provide a more accurate fault location estimate for distribution feeders [8].

B. Geospatial Display of Fault Location Results

In addition to using automatically calculated fault location estimates, utilities can reduce outage time by displaying the fault location estimates directly on a Geographic Information System (GIS) model of their power system. The fault-locating algorithms described above usually output results in distance along the line from the substation or percent of line length. Because power lines are rarely a straight line from end to end, converting these distances into physical locations can be challenging. Some utilities will trace out the distance from the substation using the Google Earth™ mapping service by following satellite imagery of the power lines to get an initial location for line crews to investigate. For utilities with a GIS feeder model, software can automatically plot the calculated fault location on a map, enabling line crews to take the most direct route to the fault location. Fig. 5 shows a GIS map with the location of lines and poles for BREC's Oakway substation Feeder 6. A subsection of this feeder (indicated by the orange rectangle in Fig. 5) is shown overlaid on satellite imagery in Fig. 6.

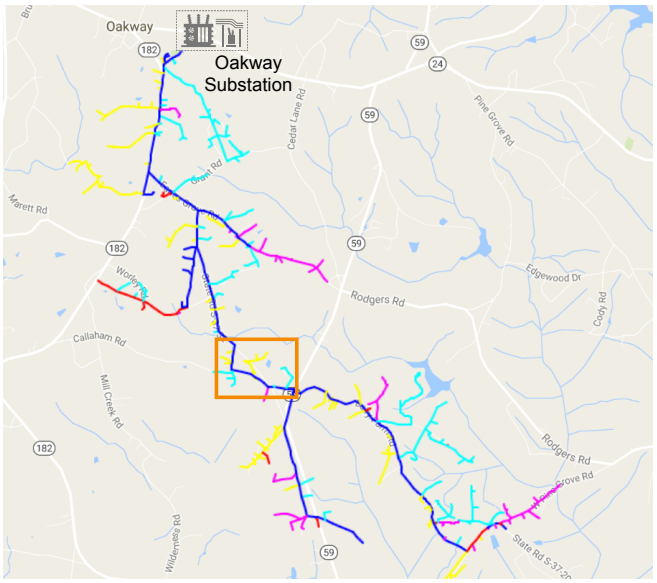

Fig. 5 Software GIS display of Feeder 6 from BREC's Oakway substation (the orange rectangle is a subset shown in Fig. 6)

When a fault occurs on the feeder, the fault location estimate is calculated from a combination of the fault current and fault type reported by the digital relay in the Oakway substation (see top left corner of Fig. 5) and the feeder segment impedance values. The fault location estimate is then represented by a range to account for possible error. This range is indicated with orange highlighting overlaid on the distribution line, as shown in Fig. 6.

Fig. 6 Subsection of Oakway substation Feeder 6 with fault location range overlay

C. Correlating Fault Location and Lightning Strike Data

One of the first questions an operator or engineers asks during initial fault analysis is whether there is a storm or other weather event in the area of the fault. Faults caused by lightning are common during storm conditions. Application program interfaces (APIs) are available that provide accurate lightning strike GIS coordinates within seconds of the lightning strike. These data can then be overlaid with the fault location estimates on top of the GIS map. In cases where there is lightning in the area of the fault, operators and engineers have an immediate indication of the likely root cause of the fault. For the Oakway Feeder 6 fault described earlier, engineers concluded that the cause was lightning. Fig. 7 shows the lightning strike location (lightning symbol) provide by the weather service and the actual fault location reported by the line crew (fault symbol) overlaid on the map. In 2016, ten percent of outages on Blue Ridge Electric Cooperative's system were attributed to lightning.

Fig. 7 Lightning strike and actual fault location for a fault on Oakway Feeder 6

D. Combining IED Fault Location Estimates With FCIs

As previously discussed, the radial nature of distribution feeders makes fault locating challenging. For any given fault, there may be multiple estimated fault locations that need to be investigated. Faulted circuit indicators (FCIs) can be integrated into a distribution system to narrow down the number of possible fault locations [4]. In the case of the Oakway Feeder 6 fault, there were three possible fault regions (indicated in Fig. 8) calculated from the fault current measured by the relay in the substation (at the top of Fig. 8) and the feeder segment impedance values. BREC engineers were able to determine which of the possible locations was most probable by incorporating lightning strike data into the process. If the lightning data had not been available, the same determination could be achieved by placing wireless FCIs at locations A and B in Fig. 8. If the fault occurred at Location 1, the FCI at location A would communicate back to the software that a fault was downstream of location A. Similarly, a fault at Location 2 would trigger the FCI at location B. If neither FCI triggered, the fault must be at Location 3.

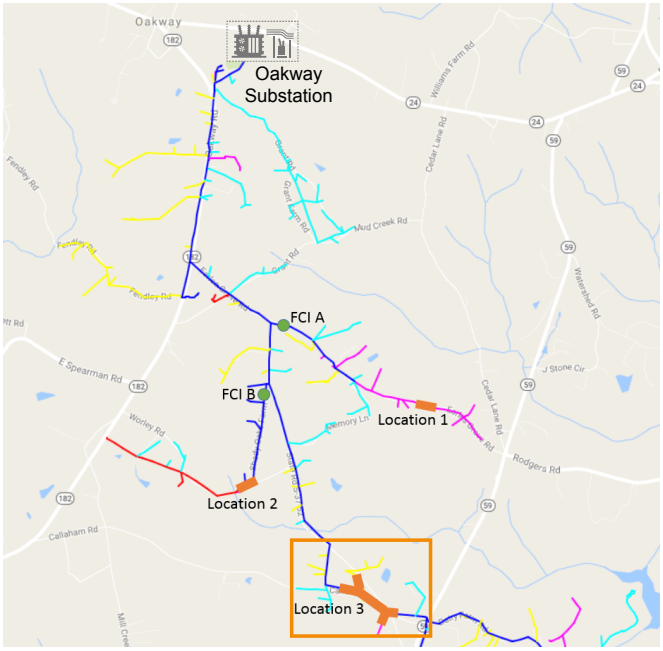

Fig. 8 Software GIS display of Feeder 6 from BREC's Oakway substation with fault location estimate and FCI information overlay

VI. New System-Wide Analysis Benefits—Investigation of Fault Trends and Statistics

A historical database of faults, and the event reports associated with them, provides insight into fault trends that may otherwise be difficult to detect. For many utilities, there is simply too much information to analyze it all manually. This is especially the case for distribution utilities. Blue Ridge Electric Cooperative uses a historical database of faults and event reports to identify repetitive conditions that may be an indication of an issue. By identifying these repetitive conditions, mitigating actions can be taken prior to an outage, thereby improving the reliability of the system.

A. Investigation of Faults Across BREC's System

Fig. 9 shows a breakdown of faults by substation at Blue Ridge Electric Cooperative for a three-month period. The digital relays in the Marietta substation generated the most faults during that period of time.

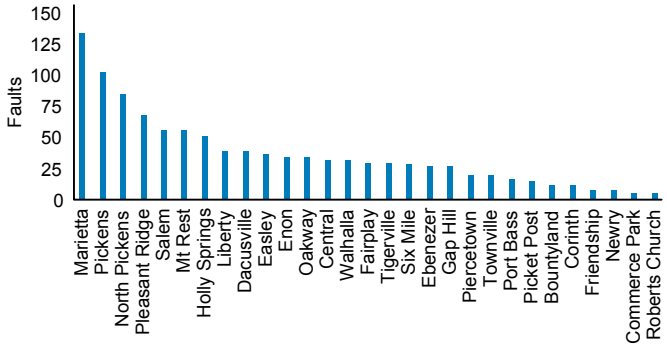

Fig. 9 Number of faults per substation in BREC's system (01/16–03/16)

By drilling down into the Marietta substation, a breakdown of faults per feeder over the three months can be seen (Table I).

TABLE I
NUMBER OF FAULTS PER FEEDER AT THE MARIETTA SUBSTATION (01/16–03/16)

Location	Number of Faults
Marietta Circuit 1	52
Marietta Circuit 2	48
Marietta Circuit 3	37

At any breakdown level, Blue Ridge Electric Cooperative personnel can see the breakdown of these faults over time to see if the fault frequency is consistent or if an outlier exists (which prompts further investigation). Table II shows that for the three feeders in the Marietta substation, there were significantly more faults generated in January than in February or March.

TABLE II
NUMBER OF FAULTS PER MONTH AT THE MARIETTA SUBSTATION IN 2016

Month	Number of Faults
January	78
February	38
March	21

Drilling down into the month of January (Fig. 10) for further investigation reveals that majority of the faults occurred on January 22nd and 23rd. Each of the faults occurring on those days can then be investigated to identify any commonality between the faults. Commonalities such as fault type or fault location might point to an underlying root cause of the outlier. In this particular case, the spike in faults on January 22nd and 23rd was caused by a major ice/snow storm. The Marietta substation is located in a very rural region of BREC's system just off the southern edge of the Appalachian Mountains. When a major storm like this occurs, the faults can be labeled with the appropriate cause code. This allows the faults to be categorized and grouped appropriately for record-keeping and future statistical analysis. While this is a simple example, the principle can be extended to identify trends in faults across an entire system. For example, BREC has used this method of fault trending in the past to detect a defective batch of insulators on a distribution feeder.

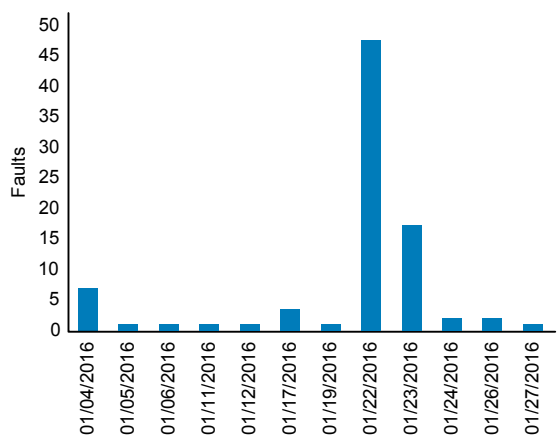

Fig. 10 Breakdown of faults at the Marietta substation in January 2016

B. Incipient Fault Detection and Location

Incipient faults are conditions that would eventually lead to a failure. These conditions can sometimes be identified through analysis of fault history and operational data. By automatically computing and archiving fault locations for each historical fault in the database, the software can then present fault location statistics for any line. If multiple intermittent faults occur in the same location over a set period of time, an engineering support team can be sent to investigate that section of the power system for damage. Detection of incipient faults prior to failure allows the utility to make necessary repairs as a part of scheduled maintenance activities rather than as an emergency restorative action. This results in improved safety for line crews and significant cost savings.

C. Additional Statistics

In addition to investigating faults and their locations over time, a historical database of faults enables the generation of statistics that provide greater awareness of the overall grid performance. These additional statistics include:

- Faults by fault current
- Faults by duration
- Faults by cause code
- Faults by phase
- Faults by waveform signature

VII. Conclusion

This pilot software system has been successfully deployed at BREC. The automatic grouping of event reports from digital relays during a fault has simplified the post-event analysis process. Assigning cause codes and linking faults to the OMS system has made the archiving and compliance portion of analysis more efficient. BREC is excited about the future work to be completed in the software, including more data-mining and fault-locating capabilities.

VIII. References

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IX. Biographies

Eric McCollum is the System Reliability Specialist for Blue Ridge Electric Cooperative and is directly responsible for the collection and mitigation of outages on the system. He has nearly 30 years of experience with electric distribution systems. Eric has worked on outage data collection on the Blue Ridge system, actual restoration of the Blue Ridge system, and similar responsibilities on sister systems in the Southeast.

Jared Bestebreur is an engineer at Schweitzer Engineering Laboratories, Inc. and serves as the synchrophasor and relay event analysis software product manager. He has supported the implementation of wide-area monitoring systems around the world. Jared holds a B.S. degree in electrical engineering from Washington State University. He is also an active member in the North American SynchroPhasor Initiative (NASPI) community.

John C. Town received a B.S. degree in electrical engineering in 2009 and an M.S. degree specializing in power systems in 2014, both from Michigan Technological University. From 2008–2012 he worked for Patrick Energy Services (renamed to Leidos in 2013) in Novi, MI, designing transmission and distributions stations. The scope of his work included protection and control schemes, SCADA systems, and physical substation designs. From 2012–2014 he was employed at PowerSouth Energy Cooperative located in Andalusia, AL, working in the system protection department designing system protection schemes and developing relay settings for transmission and distribution systems. Additional responsibilities included testing microprocessor relays and commissioning protection system designs. He joined Schweitzer Engineering Laboratories, Inc., in 2014 and currently works as a field application engineer focusing on system protection.

Andy Gould, E.I.T., received a B.S. in electrical engineering technology in 2013 from UNC Charlotte. Beginning in 2012, Andy worked as an engineering intern for Schweitzer Engineering Laboratories, Inc., focusing on transformer monitoring, moisture and gas diagnostics, and load tap changer (LTC) applications. In 2013 he joined SEL full-time as an automation application engineer supporting customers with remote terminal unit (RTU), SCADA, communications, and security applications.