Series-Compensated Line Protection Challenges in the CREZ Region

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***Abstract*—While series compensation of transmission lines is not new technology, it is becoming more prevalent due to significant changes in the way grids are being operated. Compensating lines makes better use of transmission line investments and available right of way. However, series capacitors create many challenges for protection engineers. These challenges are mitigated using modern protective relays, robust telecommunications channels, and advanced transient simulation tools to validate protection systems. The Lower Colorado River Authority (LCRA) in the United States is protecting a series-compensated line on their transmission grid for the first time as part of the Competitive Renewable Energy Zone (CREZ). This paper discusses experiences in designing, setting, and validating the new protection system.**

I. Introduction

The Competitive Renewable Energy Zone (CREZ) is a region in the United States located within the Electric Reliability Council of Texas (ERCOT) interconnection with a strong potential for renewable energy resource development. A vision for building nearly $5 billion in CREZ transmission projects was established by a Public Utility Commission of Texas (PUC) order in 2008 [1]. These projects were designed to increase access to renewable energy and allow the flow of wind power from West Texas and the Panhandle areas to load centers in the central and eastern parts of the state.

As a transmission service provider within the ERCOT region, the Lower Colorado River Authority Transmission Services Corporation (LCRA TSC) was assigned several 138 kV and 345 kV CREZ transmission projects. These projects included the 345 kV double-circuit, series-compensated lines from Big Hill to Kendall. Big Hill is a new 345 kV substation in Schleicher County near San Angelo, Texas, and Kendall is an existing 345 kV substation in Kendall County near San Antonio, Texas. The line route is approximately 140 miles long with series compensation and shunt line reactors on each line at two locations. Each location provides approximately 25 percent compensation, with an overall compensation of 50 percent. The lines, designated as T-558 and T-559, respectively, each are conductor rated at 5,000 A with a capacity of 3,000 MVA. Overall, each line is rated at 3,600 A (2,150 MVA) due to the series capacitor ratings.

II. ERCOT Nodal Operating Guide Requirements for CREZ Line Protection

In 2010, in response to the PUC order [1], ERCOT developed an operating guide revision request (OGRR) titled "CREZ Facility Protection and Control Requirements." Following the transition from the ERCOT zonal marketplace to the ERCOT nodal marketplace, this OGRR was replaced with a similar nodal operating guide revision request (NOGRR), which "provides more stringent protection and control requirements for all new CREZ 345 kV facilities" [2]. The NOGRR was unanimously approved by the ERCOT Technical Advisory Committee and subsequently went into effect as a part of the ERCOT Nodal Operating Guides [3]. The guides explicitly list forty-five 345 kV CREZ lines that are subject to a higher level of protective relay system redundancy and relay pilot channel performance and testing requirements.

Specifically, Section 6 includes the following:

> For protective relay systems that utilize a propagation-delay-sensitive operating principle and a communication channel with potentially significant propagation delay, time-synchronized "end-to-end" testing of the protective relay system shall be performed to verify that communication channel performance (including alternate routes) is adequate for proper operation.
>
> For transmission facilities with series compensation, dual communication-aided protection should be used. At least one of the two protective relay systems should be differential type; and for any transmission line that has dual communication-aided protection systems, at least one of the two protective relay schemes should be of a differential type in any location where an adequate communications infrastructure exists or is planned and there are no mitigating circumstances (e.g. tapped loads). [3]

The following telecommunications requirements are found in Section 7:

> For each new Competitive Renewable Energy Zone transmission line … an associated communications path should be established to provide a high degree of dependability, security, and immunity from interference. Additionally this communications path should support high bandwidth (155 mb/s or greater), low latency (unidirectional delay no greater that one millisecond per 100 miles), and be engineered to meet 99.999% availability with capacity reserved

for regulated utility protection, monitoring and control. Redundant communication paths are required unless this necessitates retrofitting existing facilities. [3]

The language of the Nodal Operating Guides serves as a basic design requirement for ERCOT transmission service providers assigned to the various CREZ transmission projects and establishes a minimum performance expectation.

III. Relay and Telecommunications Redundancy

In order to comply with the ERCOT Nodal Operating Guide requirements, LCRA had to assess their telecommunications infrastructure in this area and develop a new line protection standard. LCRA had previously protected several 345 kV transmission lines. Generally, a combination of directional comparison blocking (DCB) schemes, differential relaying, and phase and ground step distance and ground time-overcurrent backup was used. Power line carrier or direct relay-to-relay fiber was often used for the relay pilot channel.

After evaluating the options and requirements, LCRA opted to install dual differential protection schemes on the Big Hill to Kendall lines. Dual differential schemes are advantageous on a double-circuit, series-compensated line due to the following factors:

- Differential elements are not impacted by mutual coupling, current reversal during adjacent line faults, or the series capacitor voltage inversion effect [4].
- Weak infeed from nonconventional sources, such as wind turbines at either terminal, is not a concern.
- Differential schemes have good sensitivity for high-impedance faults and are not impacted by varying line loading levels.
- They offer good performance for evolving and/or cross-country faults.
- They do not depend on power line carrier equipment or fault directionality determination.

In the application of the dual differential schemes, LCRA chose two separate manufacturers, per LCRA TSC practice. Key requirements included series compensation logic and the ability to automatically transfer from a primary pilot channel to a standby pilot channel. Secondary (preferred) requirements included phasor measurement capabilities, traveling wave (TW) fault location, and line charging current compensation.

Each protective relay system includes full dc supply, control scheme wiring, potential transformer (PT) wiring, and current transformer (CT) wiring redundancy. Panel control switches and test switches are also included to allow local function disabling and relay isolation for testing or maintenance. Each protective relay system includes dual relay pilot channels to further mitigate the possibility of failure that could delay timely fault clearing. Each relay pilot channel is continuously monitored and individually alarmed to operations staff to reduce the likelihood of a hidden, latent failure on a pilot channel not in active use. Ground time-overcurrent and phase and ground step distance elements are used for backup fault clearing. Zone 2 is used for backup protection on the protected line, and Zone 4 is implemented at each terminal to account for the breaker failure scenarios where there is a breaker-and-a-half configuration at the opposite terminal.

Two optical ground wire-based (OPGW-based) synchronous optical network (SONET) rings were designed to serve the relay pilot channel needs and other telecommunications requirements of the planned LCRA TSC CREZ facilities. In the case of the Big Hill to Kendall line protection, both primary and standby channels are provided by the east CREZ SONET ring. On other LCRA TSC CREZ transmission lines, the west CREZ SONET ring or direct fiber is used.

The east and west CREZ SONET rings support LCRA TSC line relaying in the CREZ region, as shown in Table I. In an attempt to further reduce single points of failure or when required by another utility, certain transmission lines use direct fiber for their relay pilot channel.

Table I
SONET Ring Configuration

CREZ Transmission Line	Relay A		Relay B	
	Channel 1	Channel 2	Channel 1	Channel 2
North McCamey to Odessa	21-A PT2 direct fiber	21-A PT3 SONET west ring	87-B CHX SONET west ring	87-B CHY direct fiber
Bakersfield to North McCamey	21-A PT2 direct fiber	21-A PT3 SONET west ring	87-B CHX SONET west ring	87-B CHY direct fiber
Bakersfield to Big Hill	21-A PT2 SONET west ring	21-A PT3 SONET west ring	87-B CH1 SONET west ring	87-B CH2 SONET west ring
Big Hill to Kendall (T-558)	87-A CH1 SONET east ring	87-A CH2 SONET east ring	87-B CH1 SONET east ring	87-B CH2 SONET east ring
Big Hill to Kendall (T-559)	87-A CH1 SONET east ring	87-A CH2 SONET east ring	87-B CH1 SONET east ring	87-B CH2 SONET east ring
Big Hill to Twin Buttes	21-A PT2 SONET east ring	21-A PT3 SONET west ring	87-B CH1 SONET east ring	87-B CH2 SONET west ring
Sand Bluff Station to Divide	21-A PT2 direct fiber	21-A PT3 SONET west ring	87-B CHX SONET west ring	87-B CHY direct fiber

IV. SONET Ring Design and Early Testing

The east and west CREZ SONET rings each cover a large geographical footprint and involve the cooperation of several ERCOT transmission service providers. The east CREZ SONET ring covers 357 miles, while the west CREZ SONET ring covers 476 miles. A geographical overview of the east CREZ SONET ring is shown in Fig. 1.

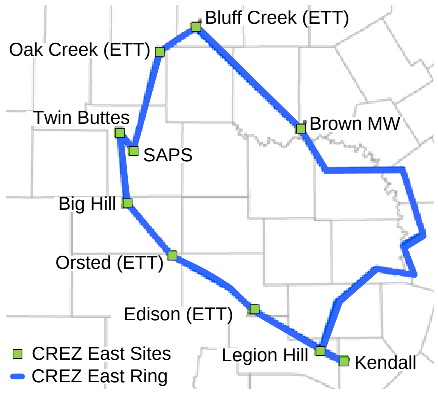

Fig. 1. East CREZ SONET ring.

The SONET ring physical layer is primarily fiber-optic OPGW but also includes some microwave hops. The overall latency limits are established by the relay manufacturer specifications. Longer channel delays result in slower tripping times, and at some point, the differential function ceases operation. For the line differential relays chosen, the acceptable latency limit ranges from 35 to 66 milliseconds, with a maximum channel asymmetry requirement of no more than 3 milliseconds. This is the allowable time frame before the relay differential function fails and disables itself to maintain security. For other CREZ lines using a DCB scheme, the latency limit is 33.3 milliseconds, based on a 2-cycle Zone 2 distance short delay setting. Based on the SONET ring design, a latency of 10.4 milliseconds on the east ring and 8.9 milliseconds on the west ring is expected when taking into account the total fiber mileage, termination delay, and repeater delay. Note that the east ring is shorter in terms of mileage but includes a microwave hop, which adds more latency than if it were fully OPGW-based. The actual measured roundtrip latency on the east ring, as measured by the T-558 87-A line relay at the Big Hill terminal, is shown in Table II. The Channel 1 delay of 5.5 milliseconds is on the short path, which is essentially the line route; the Channel 2 delay of 11.4 milliseconds is on the long path, which is essentially the longer way around the full ring. Both channels perform well in terms of measured channel asymmetry, which can be problematic for differential element functionality.

Prior to implementing the SONET ring design in the field, a test system was set up in the telecommunications laboratory at LCRA. The intent was to verify the SONET electronics and that the line relays would function as intended with acceptable performance. This test was performed prior to the selection of the relays; however, similar relays with dual pilot channels were used. From this testing, a better understanding was achieved of the relay response to SONET level switching and channel failover scenarios (e.g., short path to long path and vice versa). Good experience was also gained by relay technicians and engineers in the interpretation of the telecommunications equipment alarms and flags, as well as in the use of voltage and current test sets to produce end-to-end fault simulations. This technique was later used in the field to verify relay performance during commissioning and prior to line energization.

TABLE II
87-A Snapshot of CREZ East Ring Measured Channel Timing

Channel Timing	Primary Channel 1 (ms)	Standby Channel 2 (ms)
Roundtrip delay	5.5	11.4
Transmit delay	2.6	5.7
Receive delay	2.5	5.7
Asymmetry	0.32	0.04

A key consideration in proper operation of the differential scheme is the channel synchronization [5]. The two 87L relays have to time-align their measurements to make a differential calculation. Modern 87L relays provide many options. The two relays can rely on channel-based synchronization (the so-called ping-pong method) or time-based synchronization with a clock synchronized to the Global Positioning System (GPS). Synchronizing the relays to an absolute time reference such as GPS time allows precise alignment of the measurements—even in the presence of asymmetrical channels where the travel time in each direction is different. However, using GPS time synchronization means that the GPS system and the satellite-synchronized clocks at both terminals become critical elements of the protection. For this reason, selecting time-based synchronization requires the user to specify fallback modes for the loss of a time signal at either terminal. The following are the fallback modes:

- Disable 87L protection.
- Force the affected channel out and switch channels (primary channel to a hot-standby channel).
- Fall back to channel-based synchronization.
- Fall back to channel-based synchronization but disable the channel if channel switching is detected.

Because neither the primary nor the standby channel uses a direct dedicated fiber pair (both go into a SONET system), time-based synchronization was considered. However, because the east and west CREZ SONET rings are designed to minimize asymmetrical channels, channel-based synchronization was chosen for both the normal and standby channels to eliminate the possibility that an unavailable time source would impact the protection system.

V. Transposition Study

With most large transmission projects, various studies are conducted during the planning and/or design phase to develop the optimal design. One such study was commissioned in 2009 to determine if the increased line losses and phase current unbalance due to a lack of transpositions along these lines were significant enough to justify the cost of transposition structures along the line length [6]. The payback on this investment is a function of the expected loading level over the lifetime of the lines. Initially, it was determined that the construction and placement of transposition structures were not warranted. However, this study was completed prior to determining the location of the series capacitor sites, which were ultimately planned for 34.8 miles (25 percent) and 87.53 miles (63 percent) from Big Hill. The location of the two intermediate series capacitor stations presented an opportunity to accommodate a full line transposition without incurring the cost of transposition structures. Accordingly, in May 2012, the line transposition was incorporated prior to completing the final line design.

As a result, the phasing (shown in Table III) was established for each line segment. This line phasing was taken into account in the model power system testing and ultimately allows for better relay performance (i.e., sensitivity) by reducing the inherent phase current unbalance on each line.

TABLE III
CONDUCTOR PHASING

Big Hill to Orsted		Orsted to Edison		Edison to Kendall	
T-558	**T-559**	**T-558**	**T-559**	**T-558**	**T-559**
C	A	B	C	A	B
B	B	A	A	C	C
A	C	C	B	B	A

In addition to the line transpositions, mutual coupling effects must be taken into account due to their impact on protective relaying. Although line differential elements are not impacted by mutual coupling effects, ground step distance and ground time-overcurrent backup elements are affected. In this case, the mutual coupling zero-sequence impedance on each line segment is significant and is approximately equal to 65 percent of the zero-sequence impedance on each line segment due to the close proximity of the conductors in this lengthy double-circuit arrangement [7].

VI. End-to-End System Angle Analysis

Due to the location of this double-circuit transmission line in the ERCOT region, if both lines trip or are taken out of service, there is a strong potential to develop a large static voltage angle across the line. The voltage angle developed is a function of the generation dispatch behind either terminal of the line. A large angle can hinder line reclosing and restoration attempts; therefore, the maximum anticipated line angle must be studied so that the synchronizing relay can be set properly.

Based on an LCRA study, an angle exceeding 50 degrees was anticipated during the winter off-peak season, coinciding with high levels of CREZ region wind generation, as shown in Fig. 2. This value was compared with an angle baseline study performed by ERCOT using historical state estimator and phasor measurement unit (PMU) data, shown in Fig. 3. This independent analysis yielded a maximum expected line angle from Big Hill to Kendall in excess of 40 degrees under certain peak wind generation scenarios. It is expected that as the CREZ expansion continues, these angle differences will tend to decrease as the network becomes more tightly connected in an electrical sense.

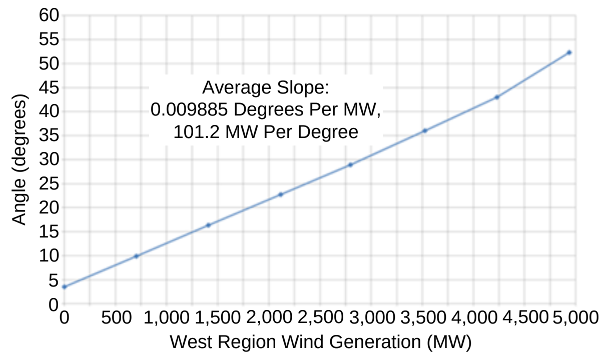

Fig. 2. LCRA line angle study (voltage angle across open Big Hill to Kendall breakers versus west region wind generation).

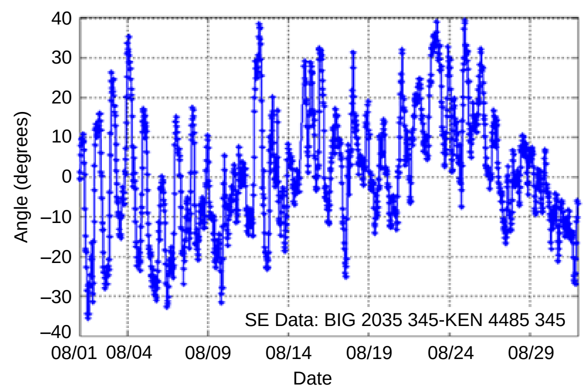

Fig. 3. ERCOT angle baseline analysis.

In response to these possibly large angle differences, synchronism-check element settings were developed to allow an angle up to 75 degrees and 1.09 per unit bus or line voltage. Circuit breaker closing capability at this angle was verified. Phasor measurement functionality is also enabled in the 87-A line relays at each terminal and is transmitted back to a phasor data concentrator (PDC) and visualization software package. This provides operations staff with situational awareness of the measured system angle during normal operation and restoration. Fig. 4 shows a recent snapshot of an approximately 7-degree voltage angle difference across the closed line during a winter off-peak line loading condition of approximately 360 A.

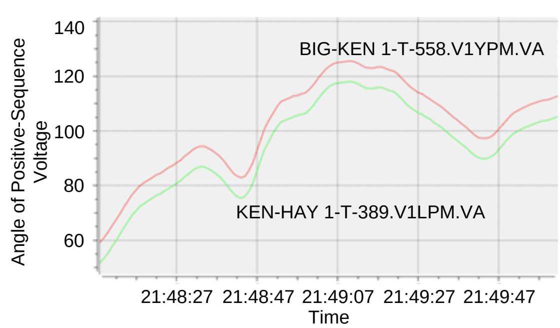

Fig. 4. Winter off-peak voltage angle on December 10, 2013.

TABLE IV
LINE RECLOSING OPERATING CONDITIONS

Contingency	Isolation		Restoration	
	Big Hill	**Kendall**	**Big Hill**	**Kendall**
Line clearance	Supervisory control and data acquisition (SCADA) open (second)	SCADA open (first)	SCADA close (synchronized)	SCADA close
Single-line fault	Trip	Trip	Time delayed (follower) synchronized reclose, except if 3LG	Autoreclose (lead), except if 3LG
Double-line fault	Trip	Trip	Time delayed (follower) synchronized reclose, except if 3LG	Autoreclose (lead), except if 3LG
Platform fault	Trip if detected, receive DTT	Trip if detected, receive DTT	Block close via 86TT until isolated	Block close via 86TT until isolated
Shunt line reactor fault	Trip if detected, receive DTT	Trip if detected, receive DTT	Block close via 86TT until isolated	Block close via 86TT until isolated
Shunt line reactor circuit switcher failure	DTT	DTT	Block close via 86TT until isolated	Block close via 86TT until isolated
Series capacitor bypass (1 through 4)	Restrain	Restrain	NA	NA

VII. TRIPPING AND RESTORATION SCENARIOS

Several tripping and restoration scenarios (shown in Table IV) were developed and documented in order to familiarize operations staff with the behavior of this double-circuit transmission line during contingencies. Special consideration was given to the reclosing sequence, which leads from Kendall and follows with a synchronism-check close at Big Hill if Kendall is successful. Per LCRA TSC practice, logic was implemented to avoid initiating reclose for a three-phase fault, due to a decreased likelihood of success and the system impact of reclosing into a three-phase fault. Reclosing is also staggered to avoid closing all the breakers at either terminal at the same time if both double-circuit lines trip at the same time. Reclosing timing and logic were tested during the model power system testing.

Direct transfer trip (DTT) logic is implemented (also via the CREZ east ring) to enable tripping from the series capacitor sites for various conditions, such as a series capacitor platform fault, shunt line reactor fault, or shunt line reactor circuit switcher failure. In a similar fashion, a trip signal is also sent from each line terminal to the series capacitor sites to bypass each series capacitor for an internal line fault detected by the line relaying. Due to previously identified subsynchronous resonance concerns, if one series capacitor bypasses, it is expected that the series capacitor at that same station (Edison or Orsted) on the adjacent line will also bypass. This keeps the line impedances and the power transfer capabilities the same on each parallel line during unfaulted line conditions. Based on this condition, all four series capacitors could potentially bypass at the same time. For any normal switching insertion or bypassing of the series capacitors, this switching operation is not expected to cause any operation of the line relays.

VIII. POWER SYSTEM MODELING OVERVIEW

In order to verify proper operation of the relay settings on the Big Hill to Kendall lines, LCRA recognized the need to test preliminary relay settings in an environment that would more fully reproduce the dynamic behavior of a series-compensated transmission line under fault conditions. This is where model power system testing becomes necessary. This was performed using a Real Time Digital Simulator (RTDS®), which is built to solve electromagnetic transient simulations in real time. It uses advanced parallel processing techniques to achieve the speed necessary to maintain a real-time operation. This parallel processing is provided by multiple processor cards housed in one rack of equipment. As the size and complexity of the modeled system increase, additional racks of equipment can be used. The network solution technique is based on nodal analysis, based on the Dommel solution algorithm [8]. The maximum number of nodes in a single rack network solution is 144, further expandable with additional racks. A system with 1,728 nodes could potentially be modeled.

The RTDS was used for the power system modeling and closed-loop testing for this project. Building a power system model that accurately and completely represents the characteristics of the power system can be very challenging, in part due to the large amount of power system data that must be gathered, especially when multiple utilities are involved. Other challenges include the selection of proper test scenarios and the extent of modeling behind each terminal. Accurate modeling allows observation of the transient response of the system in great detail. It is essential to obtain a reduced system equivalent of the area of interest without affecting the electrical characteristics of the complete power system.

In this regard, it was determined that the reduced system would consist of the line(s) under test and the series capacitors and shunt reactors on the line(s), as well as the shunt capacitors, adjacent lines, autotransformers, and equivalent sources behind each terminal up to two buses back, which allows for a better representation of the power system dynamics. A portion of the system model is shown in Fig. 5. The reduced model also has transfer impedances between the buses. It is important to model the transfer impedances in detail as they establish a good power flow and short-circuit current match between the reduced and complete power system models. A number of iterations may be required before a desired reduced system equivalent is developed that can test the protection system while taking into consideration the hardware and computational limitations based on the number of racks available in the RTDS.

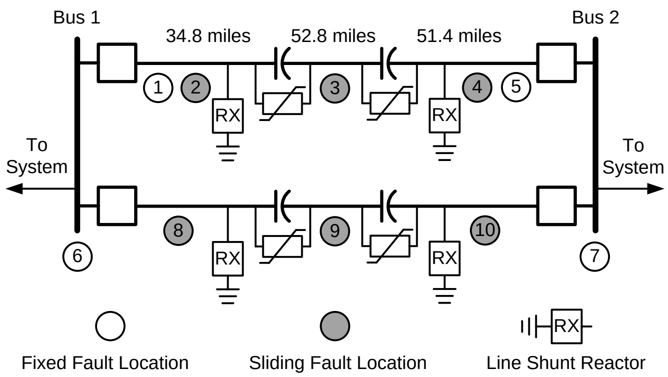

Fig. 5. Reduced system model.

The transmission lines were modeled with the physical geometry of the towers taken into consideration. Relaying was simulated for the adjacent lines. Because the adjacent lines were not the focus of the testing, it was necessary to mimic the protection behavior of these lines to understand if there would be an impact on the line under test during external faults. These simulated relays controlled breakers for the appropriate lines and included adjustable breaker opening and closing times to match the breaker characteristics.

The model built needed to test the protection system for worst-case conditions. Therefore, it was important to develop a variety of operating scenarios with weak and strong source conditions behind each terminal. Accurate load flow for the different operating scenarios needed to be modeled in such a way that real-world conditions were represented. The RTDS was configured to provide real-time voltage and current waveforms from the system model to the relays under test.

IX. Testing Performed and Results

Model power system testing primarily focuses on the behavior of power system transients on the physical protection systems. Nonlinear devices such as the metal oxide varistors (MOVs) that protect capacitors from overvoltage respond to instantaneous peak values instead of a phasor magnitude and angle. The MOV may also have a spark gap or bypass breaker across it, which bypasses the series capacitor completely when triggered. The duration of the MOV conduction, its bypass, and its effect on protective relay elements vary considerably with each fault type, point-on-wave location, and strong or weak source system. Thus, steady-state simulations are completely inadequate for testing series-compensated systems. The relay settings are generally developed based on the steady-state studies of the power system. The relay response to these nonlinear devices varies considerably when compared with the steady-state conditions. RTDS testing exposes these settings and relay elements to the expected transient conditions and verifies the suitability of the settings in real time. This closed-loop testing, unlike static simulation programs, allows observation of how the physical protection systems respond to the power system directly.

As previously described, the LCRA TSC lines under test were two mutually coupled, series-compensated transmission lines with the series capacitors located at approximately one-third and two-thirds of each line for a total of 50 percent compensation. Each transmission line was protected by dual primary differential protection relays at each end. The output contacts from the relays were connected to the RTDS, allowing for monitoring and data collection from each relay. The breaker status, modeled in the RTDS, was provided to the relay input contacts, along with other necessary control elements to make the protection scheme function. For example, the relay provided trip and close signals to the breakers modeled in the RTDS, allowing for the opening or closing of the breakers in real time.

The initial phase of testing verified the power flow and short-circuit results of the RTDS model compared with the results obtained from the steady-state model. The next phase verified the proper interfacing of the RTDS to the relays and checked whether the relay measured the proper current and voltages for the load flow simulated in the RTDS. Establishing a proper interface between the RTDS and the relay is essential in accurately capturing the real-time response of the relay in accordance with the power system condition.

The next phase in the testing included selecting and applying a set of internal and external faults to verify the proper relay programming. Some single-phase faults were applied along the line at select locations to verify proper trip and reclose functions. The relays operated correctly with a three-pole trip and reclose. A three-line-to-ground fault was simulated at the same locations. The relays operated correctly with a three-pole trip and no reclose, as per the settings. For external faults, the relay differential elements restrained and maintained security, just as expected. Next, the batch tests, consisting of thousands of faults, were applied on the system in an automated sequence for three different load flow cases, fully exploring the relay performance under different system conditions.

At each fault location, all ten possible fault types were applied (AG, BG, CG, ABG, BCG, CAG, AB, BC, CA, and ABC). All faults were applied at fault inception angles at 0, 45, and 90 degrees, referenced to the A-phase voltage at one end of the transmission line. This allowed for 30 faults per fault location (48 total locations) for all three load flow cases. Additional contingencies were investigated, including the series capacitors bypassed, faults with resistance, and Zone 1 margin. In all, a total of approximately 12,500 internal and external faults were applied on the system during the batch tests. Depending on the amount of data being collected and the fault locations, load flows, contingencies, and so on, several thousand faults could be generated overnight. In a week of testing, tens of thousands of faults could be applied to thoroughly test the protection system.

A number of special tests were performed to validate the relay settings. For a list of typical tests and the importance of them, refer to [9]. Event reports were captured from the relays, as required, to help document problems discovered. A Microsoft® Excel® spreadsheet was created to capture and analyze the vast amounts of data from the batch tests and to create a graphical representation of the results for easy analysis. Some of the special tests performed were Zone 1 margin, switch on to fault (SOTF), high-impedance faults, recloser tests, cross-country faults, and batch tests.

A. Zone 1 Margin

Subharmonic frequency transients can cause the impedance estimation to oscillate [10], which may cause an overreach of the Zone 1 distance elements. Line-end single-phase-to-ground and line-end phase-to-phase faults were simulated for both terminals to record the mho ground and phase loops to verify the calculation against the line impedance [11]. This impedance oscillation is shown for the mho ground element for a line-end fault in Fig. 6.

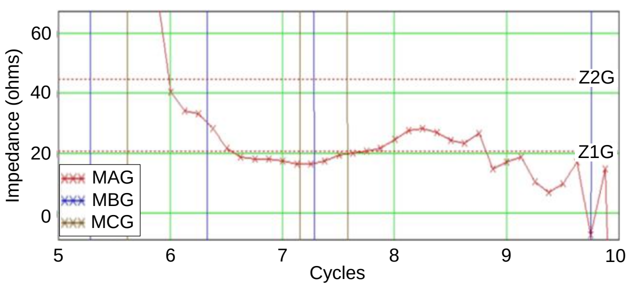

Fig. 6. A-phase ground mho loop calculation.

These impedance trajectories vary depending on the phase and point on wave where the fault occurs. It would be difficult and time-consuming to find the worst-case measurement to set the Zone 1 reach. Instead, a reach setting is chosen and then batch tests built specifically to test the Zone 1 reach are performed. This test applies every fault type at both buses for all load flow and operating scenarios and then increments the point on wave by 0 to 110 degrees in 5-degree increments.

The Zone 1 phase distance reach was set to 22.24 ohms secondary and the Zone 1 ground distance reach was set to 17.68 ohms secondary in the relays. The reduced reach of the ground distance element was due to the mutual coupling of the transmission lines. Faults were applied on Bus 1 and Bus 2 to test for overreaching of the Zone 1 elements. There was no overreaching observed; however, it was discovered that the overreaching Zone 2 ground distance element failed to assert for out-of-zone, single-line-to-ground faults for the 87-B system relays. Investigation revealed that these relays have an adaptive restraint function. This function effectively reduces the reach of the distance element and is intended for use with Zone 1 elements to prevent overreaching with a series capacitor in front of the relay. This function should not be enabled for Zone 2 elements. The function was turned off for the Zone 2 elements, and the testing was repeated to verify that the overreaching elements properly asserted for remote bus faults. Table V lists the lowest impedance measured by the two relays for several manual shots at the line end.

TABLE V
LINE-END FAULT IMPEDANCE MEASUREMENTS

Terminal	Fault Type	Impedance (ohms)
Bus 1	Single phase	10.96
Bus 1	Phase to phase	2.36
Bus 2	Single phase	16.23
Bus 2	Phase to phase	4.42

Once the batch tests were completed and it was validated that there was no Zone 1 overreach, faults were then simulated along the line to test the dependability of the Zone 1 elements. The results are shown in Fig. 7 for the two relays from Bus 1. Similar results were achieved from the relays at Bus 2.

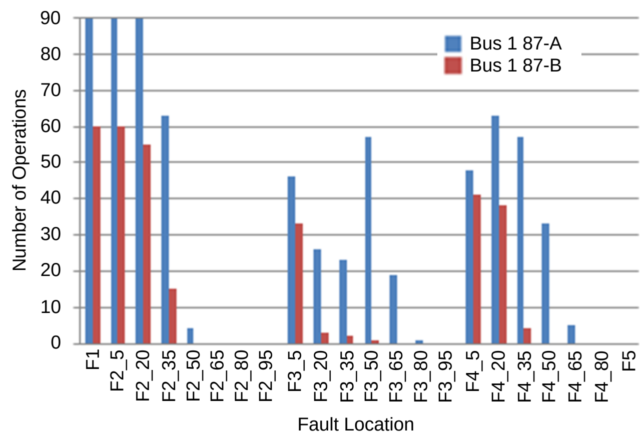

Fig. 7. Zone 1 coverage from Bus 1 87-A and 87-B.

A description of the fault location and its corresponding line length is shown in Table VI.

TABLE VI
FAULT LOCATION REFERENCE

Fault Location	Line Percentage (%)	Fault Location	Line Percentage (%)
F2_5	1.25	F3_50	44.05
F2_20	5.01	F3_65	49.74
F2_35	8.77	F3_80	55.44
F2_50	12.53	F3_95	61.14
F2_65	16.29	F4_5	64.88
F2_80	20.05	F4_20	70.43
F2_95	23.81	F4_35	75.97
F3_5	26.96	F4_50	81.52
F3_20	32.66	F4_65	87.06
F3_35	38.35	F4_80	92.61

This series of tests confirms the need for line current differential for line protection and illustrates why it is necessary to have robust pilot channels. The number of trips from the Zone 1 elements is very low, resulting in high-speed coverage without pilot protection being very limited.

B. SOTF

This testing was performed by opening the breakers at both ends of the line, applying a fault, and then closing in one breaker. Both single-line-to-ground and three-line-to-ground faults were simulated. Depending on the location, the relays either tripped on phase instantaneous (50P1), differential, or Zone 2.

Table VII and Table VIII show the elements in the relay that picked up for each fault type at the specified location.

TABLE VII
BUS 1 SOTF TESTS

Location	Fault Type	87-A	87-B
Close in	Single phase	SOTF/ differential	SOTF/ differential
Close in	Three phase	SOTF/ differential	SOTF/ differential
Line end	Single phase	SOTF/ differential	SOTF/ differential
Line end	Three phase	SOTF	SOTF

TABLE VIII
BUS 2 SOTF TESTS

Location	Fault Type	87-A	87-B
Close in	Single phase	SOTF/ differential	SOTF/ differential
Close in	Three phase	SOTF/ differential	SOTF/ differential
Line end	Single phase	SOTF/ differential	SOTF/ differential
Line end	Three phase	SOTF	SOTF

C. High-Impedance Faults

Single-phase high-impedance faults were applied at the zero-sequence center of the line. The zero-sequence center is the point where the zero-sequence current contribution from both terminals is approximately equal. This test establishes the sensitivity of the relays. The fault impedance was then increased until the relays no longer operated. The relays were able to detect faults with impedance up to 350 ohms with the differential elements.

D. Recloser Tests

This series of tests allowed the function of the reclosing scheme to be verified. Different fault types, such as a permanent fault, fault during recloser reclaim time, and fault after reclaim time, were simulated for verification. The reclaim time is the time it takes for the recloser to reset after a successful reclose.

E. Cross-Country Faults

Cross-country faults are simultaneous or near simultaneous faults occurring in different parts of the power system (i.e., from one transmission line to another). In this application, an external single-phase fault was applied on the adjacent mutually coupled line, followed by an internal single-phase fault after a specified time delay. This was done to ensure that the protection system was secure for the external fault, yet still dependable for the internal fault. This series of tests was applied at various locations along the line, with the relays only operating for the internal faults.

F. Batch Tests

Batch tests were performed for internal and external faults. This consisted of running every fault type at varying points on wave for all fault locations in every load flow scenario. From these batch tests, text files were generated, recording all the relay operations for each individual fault. These text files were then imported into a Microsoft Excel spreadsheet, which allowed for the results to be charted visually and analyzed further. For instance, the relay trip times for the various differential elements were averaged for each fault location, so an average trip time for internal faults was established. Table IX shows the operating time of the phase differential elements, and Table X shows the operating time of the negative-sequence and/or zero-sequence differential elements.

TABLE IX
PHASE DIFFERENTIAL OPERATING TIMES

Terminal	Relay	Minimum (ms)	Average (ms)
Bus 1	87-A	20	29
Bus 1	87-B	28	36
Bus 2	87-A	21	29
Bus 2	87-B	27	35

TABLE X
SEQUENCE DIFFERENTIAL OPERATING TIMES

Terminal	Relay	Minimum (ms)	Average (ms)
Bus 1	87-A	20	28
Bus 1	87-B	23	37
Bus 2	87-A	20	28
Bus 2	87-B	23	37

To evaluate the relay response for internal faults, the average operating times for the various fault locations along the transmission line were plotted. Fig. 8 and Fig. 9 show the internal operating times for the 87-A and 87-B relays from both terminals for faults along the line.

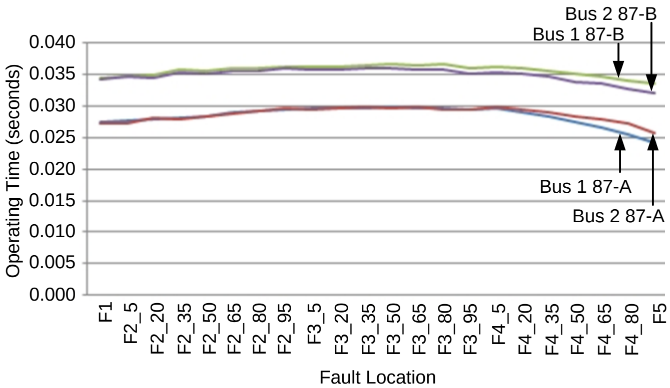

Fig. 8. Phase differential operating times.

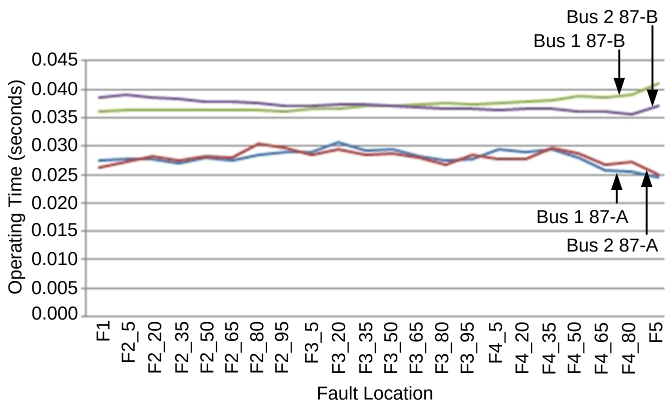

Fig. 9. Sequence differential operating times.

These results could be further expanded to show minimum and maximum operating times for the fault locations or any other statistical analysis to be performed.

X. Field End-to-End Fault Simulation Testing

To meet the ERCOT Nodal Operating Guide requirements previously discussed, end-to-end field testing involving the use of GPS-synchronized power system simulators was conducted at each terminal. COMTRADE transient event data files generated from the model power system testing were used in field testing to verify the actual field wiring, final relay settings, and physical operation of breaker reclosing sequences. A set of three internal and two external fault events was chosen. Each set included four types of fault events: AG, AB, ABG, and ABC. A total of 20 COMTRADE files were imported into each power system simulator.

Initial testing on the 87-A relaying system included simulating all internal faults via the primary communications channel. Differential, distance, and overcurrent elements were analyzed after each fault simulation to verify proper trip operation. External faults were then applied to verify that the relaying system restrained from tripping on line differential and the communications interface delays were accounted for between each relay. The same test process was then performed through the standby communications channel. The testing was then repeated for the 87-B relaying system. Fault simulation results were recorded for each relaying system and kept as objective evidence. At this point, no relay settings were modified as a result of the testing, primarily because extensive model power system testing had already been conducted.

Autoreclosing and DTT schemes were also tested to verify proper equipment operation. Circuit breakers at each terminal were closed, and an internal AG fault was applied. All circuit breakers tripped and successfully reclosed in the proper sequence. The DTT scheme test involved simulating a breaker failure operation at one end and verifying the remote ends would receive a trip signal through the primary and standby communications channels.

Additionally, the DTT functionality testing was coordinated and performed with the series capacitor owner. A test plan was developed and conducted to confirm the series capacitor transmit and receive status signals and proper operation at the Big Hill and Kendall line terminals. Table XI and Table XII show the transmit and receive peer-to-peer relay communications signals included in the test.

Table XI
Transmit Signals

Transmit Bit Label	Signal to Series Capacitor Site	Action Taken at Series Capacitor Site
1	87-A and 87-B relay trips	Bypass series capacitors at Edison and Orsted
7	Leader circuit breaker (CB) status	Trigger Sequential Events Recorder (SER)
8	Follower CB status	Trigger SER

Table XII
Receive Signals

Receive Bit Label	Signal From Series Capacitor Site	Action Taken at Line Terminal
1	Series capacitor flashover status	Trigger SER
2	Bypass CB status	Trigger SER
3	Bypass motor operated switch (MOS) status	Trigger SER
4	Isolation MOS A status	Trigger SER
5	Isolation MOS B status	Trigger SER
6	Series capacitor platform fault, reactor fault, reactor circuit switcher failure	Trip and lock out line CBs
7	Communications failure	Disable autoreclosing

XI. Relaying Performance

On November 25, 2013, a winter storm system moved through West Texas, traversing the Big Hill to Kendall lines in the section between Big Hill and Orsted. Due to precipitation and cold temperatures, ice built up on the conductors, which

TABLE XIII
EVENT HISTORY

No.	Line	Time (CST)	Phasing	87-A Big Hill Targets	87-A Kendall Targets	Restoration
1a	T-559	10:23 a.m.	B-C	87LB/C/Q, Z2P 3.25 cycles	87LB/C/Q, Z2P, Z4P 3.0 cycles	Reclose attempted from Kendall, tripped back open
1b	T-559	*t* + 40 cycles	B-C	NA	87LQ, Z2P, Z4P 3.0 cycles	Restored by SCADA at 15:53 CST
2	T-558	10:31 a.m.	B-C	87LB/C/Q, Z2P, Z4P 3.25 cycles	87LB/C/Q, Z2P, Z4P 2.75 cycles	Reclose attempted from Kendall, held closed; measured line angle at the time of closing was 1 degree
3a	T-558	10:35 a.m.	B-C	87LB/C/Q, Z2P, Z4P 3.25 cycles	87LB/C/Q, Z2P, Z4P 2.75 cycles	Reclose attempted from Kendall, tripped back open
3b	T-558	*t* + 30 cycles	B-C	NA	87LQ, Z2P, Z4P 3.0 cycles	Restored by SCADA at 15:50 CST

led to ice shedding. The ice shedding caused a series of phase-to-phase faults, with two events on T-558 and one event on T-559. These events were the first since the lines were energized in early September 2013.

It is often said that the job of a system protection engineer is not done until a correct operation for the first internal fault and proper restraint for the first external fault have been verified. In this instance, the three faults provided an opportunity for this verification on both lines, and all four line terminals operated as expected for each fault. Notably, due to system conditions, the series capacitors were not inserted at the time of these events, so they did not provide a test of the most challenging fault-clearing scenario.

The three faults and associated reclose attempts are summarized in Table XIII. The clearing time is defined as the longest duration that a protection element is picked up, including breaker clearing time, during the event. None of the faults were cross-country (i.e., each fault was contained to a single line). In each case, the line relaying attempted to reclose one time, which is a part of its design. Following the unsuccessful reclose attempts, operations personnel chose to keep each line out of service until the storm passed. Due to the remote location of these lines, a patrol was not immediately available.

One key point from the post-disturbance analysis was that during each reclose into a fault condition from the Kendall terminal, the 87LB and 87LC phase differential elements did not assert in the 87-A relay. Because the fault duty recorded during this event (when energized from a single terminal) was significantly less than the 5,000 A line rating, this demonstrated the benefit of the negative-sequence differential element (87LQ), which responds to the negative-sequence current and can therefore be set very sensitive. The negative-sequence differential element was originally disabled in the 87-A relay per LCRA TSC practice, but was ultimately enabled during the course of the model power system testing. This behavior during the initial fault and the reclose attempt can be seen in the oscillography from the Kendall terminal of the T-558 transmission line, as shown in Fig. 10.

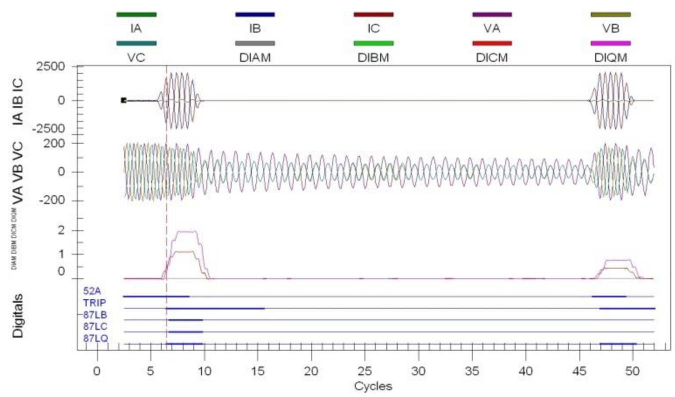

Fig. 10. Reclose attempt.

Table XIV describes the elements from Fig. 10.

TABLE XIV
OSCILLOGRAPHY ELEMENT DESCRIPTION

Elements	Description
IA, IB, IC	Phase currents (A)
VA, VB, VC	Phase neutral voltages (kV)
DIAM, DIBM, DICM	Phase current differential magnitudes
DIQM	Negative-sequence current differential magnitude
52A	Breaker status
87LB, 87LC, 87LG	Differential element operation
TRIP	Relay trip

For the initial fault, the B-phase, C-phase, and negative-sequence differential elements operated and cleared the fault. During the three-pole open, there was no current on the line and the voltage was slowly decaying due to the resonance of the shunt reactors and the line capacitance. On the reclose attempt from the lead terminal, the phase differential magnitude increased but did not get above the pickup setting due to no current contribution from the remote terminal, so it did not operate. However, the negative-sequence differential did operate. This is where the sensitivity of the negative-sequence element played an essential role in detecting the reclose on to the fault.

XII. Traveling Wave Fault Location Results

Fault location on a 140-mile line is important. However, impedance-based fault location is simply not possible on a series-compensated transmission line. For this reason, LCRA decided to include TW fault location systems on these lines.

A fault on the transmission line generates TWs that propagate from the fault location to the line terminals [12] [13]. The multiple events on November 25, 2013, provided a good opportunity to compare the fault location capabilities of different technologies deployed on the transmission lines. Each 87-A line relay includes a TW algorithm, and each line terminal is also equipped with a standalone TW fault locator (SA TW). At the time of the initial project design, the 87-A line relay TW algorithm was unavailable, so in order to guarantee adequate fault location capability on these series-compensated lines, a standalone system was justified. Since that time, the 87-A relay TW firmware became available and was upgraded to include this functionality. Table XV shows the results that were obtained from each device during the faults on November 25, 2013.

For each fault, the two methods tended to agree and reported a distance within 0.6 miles of each other (less than 0.5 percent of the total line length). This functionality will be further confirmed during the next line fault that occurs with the series compensation in service, which will be a more challenging fault location scenario.

Table XV
Fault Location Distance Comparison (in miles)

No.	Line	87-A Big Hill	SA TW Big Hill	87-A Kendall	SA TW Kendall
1a	T-559	26.24	25.71	112.86	113.34
1b	T-559	NA	NA	79 attempt not reported	79 attempt not reported
2	T-558	21.81	21.25	117.29	117.80
3a	T-558	26.26	25.73	112.84	113.32
3b	T-558	NA	NA	79 attempt not reported	79 attempt not reported

XIII. Conclusion

LCRA faced numerous challenges in designing, constructing, and ultimately protecting the Big Hill to Kendall double-circuit, series-compensated transmission lines. Analyzing various aspects of the line design such as transposition, mutual coupling effects, and the potential for a large line angle improved their chances for success. Applying dual differential relaying with redundant pilot channels allowed LCRA to effectively meet the ERCOT Nodal Operating Guide requirements. Proceeding with the model power system testing allowed for verification of preliminary protective relaying settings and provided data files for use during field commissioning. Based on a post-disturbance review of initial events, line relaying performance has met expectations to date.

Without the intensive and accurate testing provided by model power system testing, assurance that the protection scheme is accurate and reliable would simply not be there. It is highly recommended for series-compensated transmission lines and other complex line protection applications to be tested in this way. RTDS testing requires a team of engineers with a diverse set of skills and expertise in relay applications, relay settings, and the operating practices of the transmission system being studied. They must also be able to determine realistic load flow and source conditions, model transient simulations, and develop a thorough test plan to challenge the relays under realistic conditions.

XIV. Acknowledgment

The authors gratefully acknowledge LCRA employees Ryan McGary, Charles DeWitt, and Cole Dietert for their contributions.

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XVI. Biographies

Genardo T. Corpuz received his B.S.E. degree in electrical engineering from the University of Texas-Austin in 2005. He is a licensed professional engineer in the state of Texas and currently works at the Lower Colorado River Authority (LCRA) in Austin, Texas. His work experience includes substation design and system protection.

Kristian (Kris) Koellner supervises the system protection department at the Lower Colorado River Authority (LCRA) in Austin, Texas. Prior to joining LCRA in 2010, Kris worked at Salt River Project (SRP) in Phoenix, Arizona, for 16 years. Throughout his career, Kris has worked in the areas of distribution planning, power quality, and, most recently, system protection. Kris graduated with a B.S.E. degree in electrical engineering from Arizona State University and is registered as a professional engineer in the state of Texas. Kris served as the 2012 Chair of the ERCOT System Protection Working Group (SPWG).

Jordan Bell received his B.S. degree in electrical engineering from Washington State University and joined the engineering services division of Schweitzer Engineering Laboratories, Inc. in 2008. He presently holds the position of protection engineer. Jordan performs event report analysis, relay settings and relay coordination, fault studies, and model power system testing using a Real Time Digital Simulator (RTDS®).

Siddharth S. Rajan received his B.E. in electrical engineering from Anna University, India, in 2010 and an M.S.E. in electrical engineering from Arizona State University in 2012. He currently works as a protection engineer in the engineering services division of Schweitzer Engineering Laboratories, Inc. His work experience includes power system modeling and protection.

Amit Somani received his M.S.E.E. from the University of Idaho in 2003 and his B.S. in electrical engineering from BVM Engineering College, India, in 2000. He joined the engineering services division of Schweitzer Engineering Laboratories, Inc. in 2003 as a protection engineer. His area of interest and experience is in power system protection and control. He is a member of IEEE and a registered professional engineer.

Michael J. Thompson received his B.S., magna cum laude, from Bradley University in 1981 and an MBA from Eastern Illinois University in 1991. He has broad experience in the field of power system operations and protection. Upon graduating, he served nearly 15 years at Central Illinois Public Service (now AMEREN), where he worked in distribution and substation field engineering before taking over responsibility for system protection engineering. Prior to joining Schweitzer Engineering Laboratories, Inc. (SEL) in 2001, he was involved in the development of several numerical protective relays while working at Basler Electric. He is presently a principal engineer in the engineering services division at SEL, a senior member of the IEEE, chairman of the Substation Protection Subcommittee of the IEEE PES Power System Relaying Committee, and a registered professional engineer. Michael was a contributor to the reference book *Modern Solutions for the Protection, Control, and Monitoring of Electric Power Systems*, has published numerous technical papers, and has a number of patents associated with power system protection and control.

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