Integration of IEC 61850 GSE and Sampled Value Services to Reduce Substation Wiring

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Abstract—**This paper describes the impact of new local- and wide-area protection, control, and monitoring concepts based on system-wide exchange of real-time state and measurement information. Special emphasis is given to architectural implications and to differences imposed by primary equipment age and physical characteristics. Additional distinction is made regarding wiring reduction, yard construction, and system voltage level. The paper also analyzes the influence of the latest local-area and wide-area network communications technologies, including the methods for precise, network-based time synchronization and fixed rate messaging. Emphasis is placed on multivendor interoperability and the physical benefits derived from the expanded use of fiber-optic network communication.**

I. Introduction

Smart grid development and energy independence are becoming key drivers for various power system investments. Regardless of the hype often surrounding smart grid initiatives, the basic impetus becomes easier to understand once we realize that the percentage of total energy consumption in the United States used to generate electricity has been steadily rising over time (Table I).

TABLE I
GROWING IMPORTANCE OF ELECTRICITY IN THE UNITED STATES [1]

Year	Percent of Total Energy Consumption Used to Generate Electricity
1940	10
1970	25
2003	40

Other government studies show a strong correlation between economic growth and the amount of electric energy consumed by our society. This trend is likely to continue, proving that electricity is the fastest and most economical method to transport and distribute energy to a large number of consumers.

The primary vision of the smart grid is that of creating a fully automated energy exchange network that ensures a seamless two-way flow of electricity and information between an ever-increasing number of producers and consumers. A smart grid is reliable, dynamic, reconfigurable, intelligent, and self-healing. It enables real-time market transactions and seamless equal opportunity access for all participants.

While the available investment capital and the actual speed with which the smart grid can be implemented remain debatable, it is quite interesting to take a look at additional data from [1] and some well-known facts from the industry:

- The United States operates about 157,000 miles of high-voltage transmission lines (>230 kV).
- The average age of United States transmission lines is over 40 years.
- The average nationwide transmission and distribution losses in 1970 were around 5 percent. By 2001, losses grew to 9.5 percent because of congestion and lack of new transmission resources.
- Electricity demand grew by 25 percent over the last decade, while construction of new transmission facilities decreased by 30 percent.
- The average thermal efficiency of large generating plants is around 33 percent. Combined heat and electricity generation plants can reach 65 to 90 percent efficiency, but they need to be located close to the customer base.

The above data clearly show that energy independence and future growth cannot be achieved without a significant power system upgrade. This is especially true for power system protection and control equipment, which enables better utilization of existing power system resources, the addition of significant amounts of distributed and renewable sources, and support for bidirectional power flow.

System-wide communication is an essential component of the smart grid. Unfortunately, at least in the United States, over 50 percent of the power system protection devices are electromechanical relays, which simply cannot communicate. Depending on line loading and criticality, smart grid updates are also likely to affect a large number of first generation microprocessor-based relays, digital fault recorders, programmable logic controllers, and supervisory control and data acquisition (SCADA) systems. This in effect means that our industry is being faced with the prospect of upgrading and replacing almost all of the secondary protection and control equipment.

Protection and control upgrade work cannot happen overnight. It must be carefully planned, scheduled, and executed to maintain continuous service to customers. The cost of this upgrade will be significant, but even more significant is the amount of time and labor necessary to perform the upgrade. Given the task at hand, it is clear that the old method of simply replacing existing devices and custom-wiring each substation is not going to work. We need new technologies, new standards, and new industry practices.

This paper looks at current substation wiring practices as one of the key obstacles to a large-scale protection and control system update. It documents some of the technologies, options, and solutions available to utility planners. It also summarizes key standards and standardization efforts necessary for effective smart grid deployment.

II. Substation Wiring Practices

Substation wiring practices vary depending on the voltage level, equipment age, and associated apparatus technology. Older systems typically use an open-air switchyard design with air-insulated switchgear (AIS). This solution is prevalent in remote locations with inexpensive real estate. In urban areas, where space is at a premium, substations are typically constructed using gas-insulated switchgear (GIS). Since outdoor installations are less expensive, recent construction trends have moved toward mixed technology switchgear (MTS), combining the best properties of AIS with compact GIS breaker technology [2]. A typical AIS/MTS substation wiring diagram is shown in Fig. 1.

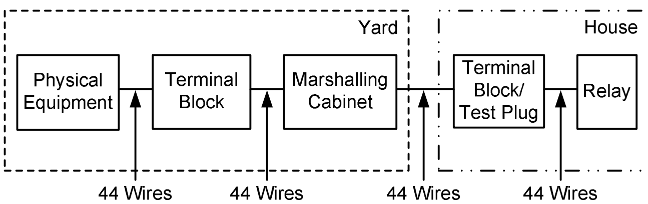

Fig. 1. Traditional wiring approach with relays in the control house

The horizontal data paths for information exchange between components, labeled "wires" in Fig. 1, represent pairs of copper wires conducting real-time state, binary, and analog measurement information. In this case, each data path includes a data source on the left and a data client on the right. Traditionally, copper is the primary interface between components in the yard and a centrally located control house. The number of conductors (44) is given as an illustration of typical in-service installations. Normally several multiconductor cables are used; separate cables are typically installed for breaker status (trip/close) and current transformer (CT) and potential transformer (PT) secondaries. Wiring runs are fairly long, spanning between 200 and 500 meters.

Although the number of wires (i.e., the total number of points being controlled) is relatively constant between components, the wire length and number of data paths are significantly reduced by locating the protection and control equipment in the yard, as shown in Fig. 2. This reduces the amount of material and labor involved and also makes it much easier to verify the wiring correctness, resulting in significant time savings during installation.

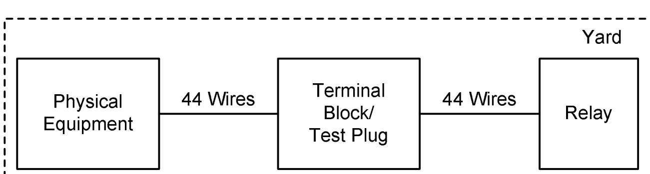

Fig. 2. Wiring approach for relays in the yard

Distributed protection with relays in the yard is a familiar concept, going back to the days of electromechanical relays (Fig. 3). It requires that the relays be mounted in environmentally sealed control cabinets, which makes it quite difficult to perform system maintenance. Protection engineers are exposed to the elements when servicing the devices, causing this approach to be somewhat unpopular with the workforce.

Fig. 3. Electromechanical relays in the yard

Microprocessor-based relays generally possess the ability to communicate, listen, decide, act, and remember, and many are designed for the harsh environmental conditions of installations similar to Fig. 3. Locating microprocessor-based relays in the yard significantly improves overall functionality, reduces size, and simplifies internal cabinet wiring. However, the main problem of testing and maintaining yard-mounted relays remains the same. Also, Fig. 2 illustrates that without the field-to-control house data path, the real-time information offered by microprocessor-based relays remains in the yard and is underutilized.

Over 50 percent of the wires within the data path from yard to house are associated with breaker control signals. It is therefore advantageous to use a hybrid approach in which the CT/PT wiring is retained, but the control wiring is replaced with a fiber-optic-based input/output (I/O) transceiver module and communications cable, as shown in Fig. 4.

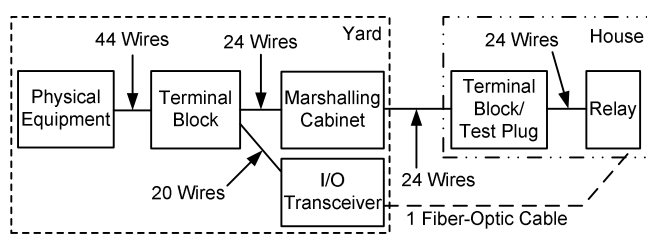

Fig. 4. I/O modules in the yard with fiber-optic communication

The I/O module approach (Fig. 5) provides significant wire savings and introduces the ability to monitor the health of the data connection. This practice has been field-proven for more than a decade via National Institute of Standards and

Technology-approved methods of protocol standardization. Digital communications standards created by a standards-related organization (SRO) and offered via a "reasonable and nondiscriminatory" license, such as MIRRORED BITS® communications, as well as other standards, such as IEEE C37.94, allow the constant exchange of digital messages. The transmission of digital messages over communications cables replaces copper conductors carrying up-to-date status information about a particular voltage level. Devices may use the connection health status to supervise the digital data path and differentiate between silence due to inactivity and silence due to a severed conductor. In addition to their primary functions, microprocessor-based relays also test their own performance, communications connections, and the equipment that they are monitoring. Reliability is improved because the number of unsupervised components, processes, apparatuses, and data paths is reduced.

Fig. 5. I/O modules in the yard

I/O modules minimize the number of unsupervised data paths between field sources and component data clients. This approach vastly improves the value of the data by confirming the availability and reliability of the methods by which they are collected and by alarming when a data path is broken. Finally, fiber-optic cables also offer galvanic isolation of the data paths between components.

Typical copper savings achievable with the distributed I/O approach are shown in Fig. 6.

Fig. 6. Refurbishment project showing the amount of copper wire replaced with fiber-optic-based I/O module technology

The "I/O in the yard" approach is suitable for older installations where the number of changes needs to be kept to a minimum. It is implemented using vendor-licensed point-to-point communications protocols or by using Ethernet and IEC 61850 Generic Object-Oriented Substation Event (GOOSE) messaging.

III. Ethernet-Based Technologies

Ethernet is fast becoming a convergence technology that unifies virtually all broadband services, including data, voice, and video. It has also found a place in safety-critical industrial systems and mission-critical substation networks.

Any discussion of Ethernet (which defines the physical and data link layers) would be incomplete without including network topologies and higher layer protocols created by SROs and standards development organizations (SDOs) such as the IEEE and the IEC. In the power system industry, Ethernet is often identified with the IEC 61850 set of protocols. Since IEC 61850 coexists with other protocols, it is easy to optimize a system for a wide variety of applications, including IEEE C37.118 synchrophasor transmission, legacy SCADA support (e.g., Distributed Network Protocol/Internet Protocol [DNP3/IP] and IEC 60870-5-104), and others.

For substation wiring reduction, of special interest are the IEC 61850 real-time protocols that are specifically optimized for reliable and timely data transmission: GOOSE (more generally called Generic Substation Event [GSE]) and Sampled Value (SV) services. Although very comprehensive, IEC 61850 stays true to the original charter of Technical Committee 57 (TC 57), which continues to develop it, to standardize "power system management and associated information exchange" [3]. Unfortunately, TC 57 does not define power system apparatus requirements or behavior, leaving space for further standardization by other technical committees. This creates additional uncertainty about the best way to apply IEC 61850 technology.

The situation can best be understood by going back to our wiring reduction example. Fig. 7 illustrates a straightforward approach of using IEC 61850-9-2 Sampled Values and GOOSE to digitize and transmit bidirectional information between equipment in the substation yard and the relay in the control house.

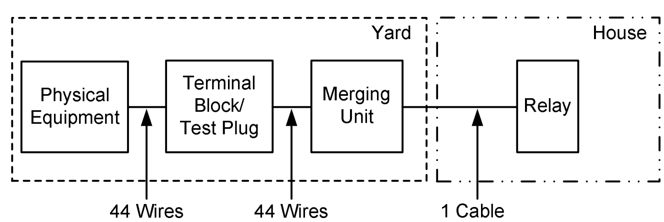

Fig. 7. Simplified diagram showing cable reduction potential with Ethernet-based merging unit technology

While conceptually very simple, the design in Fig. 7 does not take advantage of the Ethernet network capabilities. The Ethernet link between the merging unit and the relay is used as a dedicated point-to-point interface. Problems occur when trying to implement station-wide protection services such as bus differential, bus voltage sharing, and breaker failure, making it necessary to equip the merging unit with multiple outputs and custom time-synchronization services. This multi-cable type of system is commercially marketed by at least one vendor and is a closed proprietary solution. Unlike IEC 61850 protocols and SRO vendor protocols available for license, this multi-cable system will not exchange messages with other manufacturer systems. The data source and data client at each end of a data path must be from the same vendor because the communications protocols are proprietary modifications of GOOSE and IEC 61850-9-2 SV-type messages.

A more general interoperable standards-based approach with an Ethernet switch/local-area network is shown in Fig. 8.

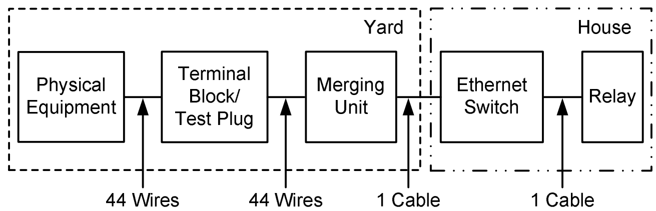

Fig. 8. Ethernet-based merging unit with an Ethernet switch

An Ethernet switch makes it possible to share the merging unit data with multiple clients such as relays. It also allows multiple relays to issue trip commands, implement breaker failure, enable operator or SCADA control, and perform other functions necessary in day-to-day operation. Furthermore, this interoperable approach based on the IEC 61850 standard supports bidirectional data path traffic as needed.

IV. Ethernet Hardware Development

Almost all protection devices designed over the past ten years support Ethernet communication. While initial devices treated Ethernet as a simple communications server add-on, we are currently witnessing the second generation of relays with native Ethernet support. New relays are designed to guarantee real-time performance for mission-critical GOOSE messages. Most advanced designs also offer seamless support for IEC 61850-9-2 SV process bus service. Fig. 9 shows a block diagram of the most recent process bus prototype. The merging unit device provides full breaker bay control and can be used to implement local protection. Actual protection elements implemented in the merging unit are application dependent and can be activated at user discretion, ranging from no local protection to full-featured distance relay protection.

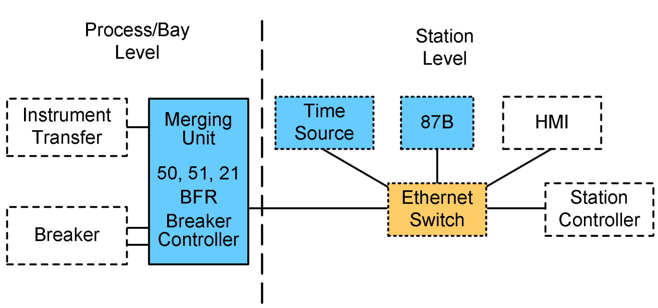

Fig. 9. Full-featured merging unit with local protection and control

For users with microprocessor-based relays in the yard, using the merging unit to implement local protection seems intuitive. However, for other installations, it is easy to show that the distribution of functions comes quite naturally [4] [5]. To begin with, in most retrofit (upgrade) installations, the merging unit is typically mounted in the immediate vicinity of the breaker cabinet (Fig. 10), making it a logical place to implement breaker control, lockout, and breaker failure relay (BFR) functions [6]. The inherent availability of local current measurements makes it easy to implement point-on-wave control along with metering and instantaneous overcurrent (50) and time-overcurrent (51) elements. The presence of voltage (depending on the actual wiring) enables local implementation of the distance function (21). Functions requiring network-based communication include synchronizer (requires bus voltage), pilot schemes, and sample-based bus differential (87).

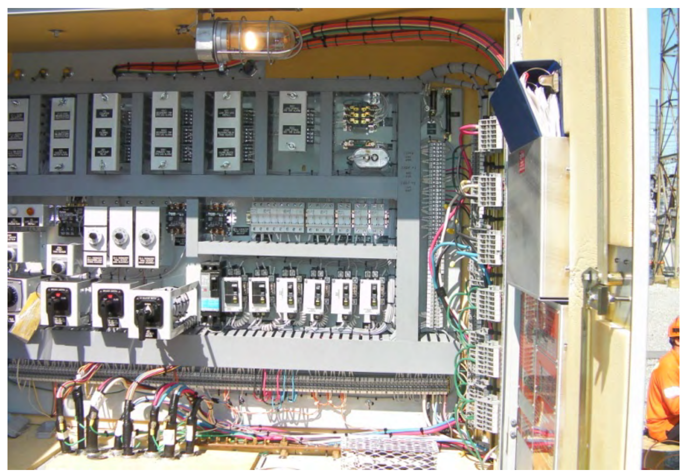

Fig. 10. Modern breaker cabinet with CT terminal blocks in a vertical row on the right-hand side

The uninitiated may argue that the approach proposed in Fig. 9 results in more complex merging unit hardware. This is not true because the merging unit contains virtually all the components of a relay, including chassis, power supply, galvanically isolated instrument transformer inputs, anti-aliasing filters, analog-to-digital (A/D) converters, time-synchronization circuitry [7], contact I/O circuitry, Ethernet interface, memory subsystems, and the merging unit management processor. The only difference between a protective relay and a “dumb” merging unit is the size and complexity of the associated firmware. Either device must support remote management and must be equipped with a full set of diagnostic features to minimize operator visits to the yard.

V. Input Interfaces

With the conventional high-energy instrument transformer interface (1 A, 5 A, and 67 V) being challenged by low-energy sensors and nonconventional (e.g., optical) instrument transformers [8], power system protection and control devices are now in the situation where they need to support new instrument transformer interfaces. Table II lists the most popular options and their uses.

TABLE II
RELAY SUPPORT FOR NEW INSTRUMENT TRANSFORMER INTERFACES

Type	Direction	Description
1 A, 5 A, 67 V	Input	Conventional CTs and PTs
20 mV, 200 mV, 2 V	Input	Optical CTs, PTs, and low-energy sensors (IEEE C37.92, IEC 60044-8)
UCA 61850-9-2 LE	Input	Ethernet-based digital interface
UCA 61850-9-2 LE	Output	Merging unit functionality

In the future, modern protective relays and merging units will need to be able to support all of the interfaces shown in Table II. Though actual interface usage will vary, IEC 61850-9-2 interfaces are expected to become quite desirable.

Conventional CT/PT interfaces will continue to be the rule in many retrofit applications.

In new installations, we expect to see emerging breaker designs (e.g., dead tank and sulfur hexafluoride [SF_6]) with integrated voltage and current sensors. Such breakers may be equipped with a standalone GOOSE-based breaker controller [9] and separate sets of combined current and voltage transducers with IEC 61850-9-2-compliant output.

Nonconventional instrument transformers (e.g., optical CTs, PTs, and capacitive voltage dividers) with IEC 61850-9-2 output are likely to populate the live tank high-voltage technology space, and Rogowski coils are expected to show up in SF_6 and low-voltage installations.

VI. Smart Grid Communication

System-wide communication is one of the key components of the proposed smart grid infrastructure. While most of the effort is directed toward ensuring bidirectional flow of customer information, it is important to remember that the bulk power system remains critical for the reliable operation of the smart grid. This means that operating data (i.e., time-critical communication) between transmission network controllers must be adequately secured and protected from the rest of the information technology (IT) network traffic. Protection is accomplished by using substation-hardened network components capable of providing strict traffic separation, bandwidth reservation and provisioning, traffic monitoring, and support for legacy synchronous communications (e.g., G.703, IEEE C37.94, and EIA-232). A communications multiplexer is capable of satisfying both network and operating data requirements.

When used within the substation, a communications multiplexer can be configured as a 24-port Ethernet switch with IEEE 1588-based time-synchronization capability and a backbone transport using gigabit Ethernet or Optical Carrier (OC-48; 2.488 Gbps synchronous optical network [SONET]). When used for intersubstation communication, the multiplexer is configured with a full-rack chassis that offers easy support for legacy interfaces. A wide-area multiplexer system configuration is shown in Fig. 11.

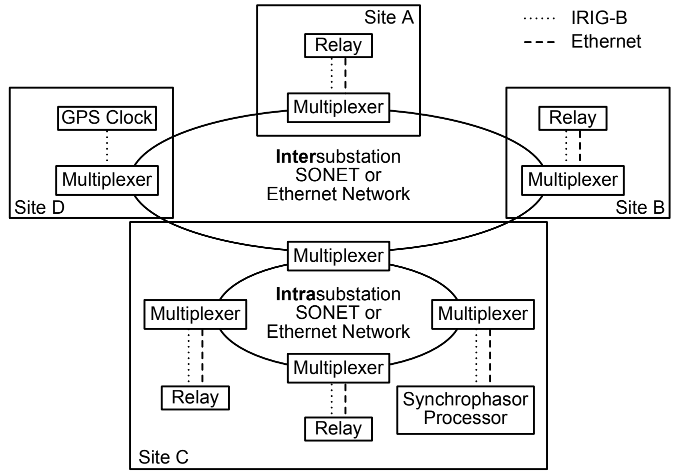

Fig. 11. Wide-area multiplexer network

Multiplexers are connected together in a ring with protected path switching to guarantee traffic restoration in less than 5 milliseconds. Furthermore, each of the intersubstation backbone multiplexers is equipped with a Global Positioning System (GPS) receiver. Receiver output is continuously measured and compared to a system-wide master clock reference (i.e., multiplexer network time) used to discipline local clock oscillators at each node [10]. As long as the nodes are communicating, the system guarantees a common time reference, which is maintained regardless of GPS signal availability. The system will function properly through an arbitrary number of GPS receiver failures. Should all links to the external absolute time reference be lost (i.e., all GPS receivers and all of the local Inter-Range Instrumentation Group [IRIG] inputs configured for this purpose), the network enters into a holdover mode. Holdover is based on statistical processing of all reference oscillators in the network, further minimizing oscillator drift. Overall timing is maintained across the entire wide-area network (i.e., the entire network stays together), thus eliminating any ill effects that would normally be associated with the holdover. End devices receive time using IEEE 1588 V2 Precision Time Protocol (PTP) or IRIG-B, depending on their capabilities, with the wide-area network acting as an IEEE 1588-distributed “grandmaster” clock.

VII. Conclusion

As shown in this paper, the smart grid initiative is expected to have a profound effect on how we design, build, and maintain power system protection and control resources. Old methods that use a large control house with conventional yard wiring techniques are simply not going to allow the kind of upgrades necessary to achieve the smart grid. Alternate methods requiring less labor and shorter deployment times are necessary.

The solution to this problem lies in wire reduction, which leads to smaller footprints, and prefabricated solutions based on international standards but flexible enough to be customized for individual project requirements. No single solution will be sufficient for every situation.

Due to feature-rich integration offered by modern microprocessor-based relay technology and associated wire-reducing digital communication, substation control houses are becoming smaller. Innovative solutions both reduce house size and move the relay intelligence closer to the power system equipment being protected.

Prefabricated modular control houses as shown in Fig. 12 will play an ever-increasing role in reducing overall project time.

Fig. 12. Substation control enclosures

This option simplifies the procurement and installation process dramatically and simplifies site preparation and permit acquisition. The system becomes a repeatable, pre-engineered, and pre-tested solution designed to customer specifications in a way similar to primary equipment.

Maintenance will be performed remotely, without direct intervention in the field. This requires the development of appropriate tools and testing and commissioning methodologies, as well as the revising and updating of internal standards. Time must also be allowed for the buildup of mutual trust between users and manufacturers. Users must become confident that the new systems are well thought-out, tested, reliable, and capable of satisfying new performance requirements. As shown in this paper, Ethernet-based IEC 61850 technologies and GOOSE- and Sampled Values-based virtual wiring can be used very effectively to lower the overall installation cost, reduce labor expenses, and shorten the required project time. International standardization is seen as a key enabling factor developing under the watchful eye of the National Institute of Standards and Technology, power system engineers, and the international community represented by IEC.

VIII. References

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IX. Biographies

David J. Dolezilek is the technology director of Schweitzer Engineering Laboratories, Inc. He is an electrical engineer, BSEE Montana State University, with experience in electric power protection, integration, automation, communication, control, SCADA, and EMS. He has authored numerous technical papers and continues to research innovative technology affecting the industry. Mr. Dolezilek is a patented inventor and participates in numerous working groups and technical committees. He is a member of the IEEE, the IEEE Reliability Society, CIGRE working groups, and two International Electrotechnical Commission (IEC) technical committees tasked with global standardization and security of communications networks and systems in substations.

David Whitehead, P.E., is the vice president of research and development at Schweitzer Engineering Laboratories, Inc. (SEL). Prior to joining SEL, he worked for General Dynamics Electric Boat Division as a combat systems engineer. He received his BSEE from Washington State University in 1989, his MSEE from Rensselaer Polytechnic Institute in 1994, and is pursuing his Ph.D. at the University of Idaho. He is a registered professional engineer in Washington and Maryland and a senior member of the IEEE. Mr. Whitehead holds seven patents with several other patents pending. He has worked at SEL since 1994 as a hardware engineer, research engineer, and a chief engineer/assistant director and has been responsible for the design of advanced hardware, embedded firmware, and PC software.

Veselin Skendzic is a principal research engineer at Schweitzer Engineering Laboratories, Inc. Mr. Skendzic earned his BSEE from FESB, University of Split, Croatia; his M.Sc. from ETF, Zagreb, Croatia; and his Ph.D. from Texas A&M University, College Station, Texas. He has more than 25 years of experience in electronic circuit design, has lectured at FESB, and has spent more than 20 years working on problems related to power system protection. Mr. Skendzic is a senior member of the IEEE, has written multiple technical papers, has 13 patents, and is actively contributing to IEEE and IEC standard development. He is a member of the IEEE Power Engineering Society (PES) and the IEEE Power System Relaying Committee (PSRC) and a chair of the PSRC Relay Communications Subcommittee (H).

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