New and Emerging Solutions for Sampled Value Process Bus IEC 61850-9-2 Standard – An Editor's Perspective

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1. INTRODUCTION

Over the past three decades, microprocessor-based protection and control systems have revolutionized the way we manage and operate the power system. Aided by modern network communications, they provide unprecedented insight into network operation, empowering transmission system operators to respond to ever-changing market forces and energy demands. Fiber-optic communications technology has become a preferred choice for intersubstation communications. Fiber-optic technology has long been recognized for its ability to safely bridge the high-voltage (HV) potential and its immunity to electromagnetic disturbances present in the HV switchyard. Optical current and voltage transformers promise to make primary system measurements safer and more precise, while at the same time enabling size reduction of the primary system plant.

The low-power instrument transformer (LPIT) and intelligent switchgear revolution has, however, been very slow in coming. Switchyard wiring is still predominantly copper with well-established 1 A/5 A and 120 V secondary level standards remaining the most trusted choice in both retrofit and greenfield applications. Cost, quantity, and the sheer number of individually terminated copper conductors have long fostered a dream of a fully digital substation based on fiber-optic communications technology. However, this dream cannot be realized without a strong set of interoperable international standards that are mature enough to compete with the tried-and-true analog interface.

While the industry waits for the availability of nonconventional instrument transformers that directly support digital communications, the merging unit (MU) concept has grown faster than expected. An MU has conventional copper connections to the primary equipment and acts as an I/O module (Figure 1) to digitize analog measurements and binary statuses, alarms, and controls. The MU publishes the I/O as digital messages over fiber-optic communications links to provide significant wire reduction. The expected and predictable receipt of messages permits the subscriber to immediately detect disruption to the message delivery and 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 and offered via a "reasonable and nondiscriminatory" license (e.g., MIRRORED BITS® communications) as well as other standards (e.g., IEEE C37.94) allow the constant exchange of digital messages. Sampled Value (SV) process bus technology is another method described in the IEC 61850 series of standards that promises to bring the digital substation dream to fruition. Discussion about IEC 61850-based systems can often be frustrating, frightening, and exhilarating at the same time. Sometimes it seems change is taking too long; at other times it appears to be moving too fast. Regardless of perception, the shift to more powerful digital communications technologies cannot be stopped. This paper reports on the lessons learned and the latest standardization efforts undertaken by the international community.

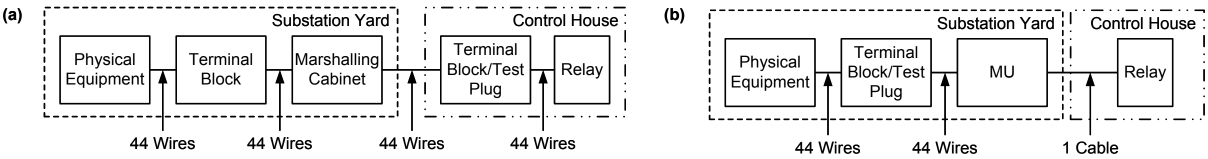

Figure 1: (a) Traditional wiring approach with relays in the control house; (b) simplified diagram showing cable reduction potential with Ethernet-based MU technology

2. PROCESS BUS CONCEPT

As previously introduced in [1], Ethernet is gaining fast acceptance for packet-based message exchange to support data, voice, and video services. When applied with pre-engineered design and hardware that performs packet management with precision, it can be used for mission-critical substation networks. IEEE standards define the physical and data link layers of Ethernet technology. However, implementation is also very heavily influenced by the network topology and communications protocols chosen.

In the power industry, IEC 61850 packet-based protocols are associated with Ethernet by design. These protocols include manufacturing messaging specification (MMS) for SCADA and engineering access and real-time protocols for signal exchange to support communications-assisted protection and automation. These real-time protocols are also used to communicate I/O via digital messages for substation wire reduction where the data acquisition function is installed remotely from the relay and control devices. IEC 61850 multicast protocols include GOOSE, more generally called generic substation event (GSE), and SV services [1]. Other protocols often coexist on the same Ethernet LAN and include IEEE C37.118 synchrophasor transmission, SCADA support via IEEE 1815 DNP3, IEC 60870-5-104, and others.

As discussed in more detail in [1], applications for the real-time protocol services (GOOSE and SV) include replacing wires traditionally used for information exchange between components. The horizontal data paths, labeled “Wires” in Figure 1, represent pairs of copper wires conducting real-time state, binary, and analog measurements. In this case, each data path includes a data source on the left and a data client on the right. A typical bay requires 44 conductors. Figure 1(b) illustrates an MU that performs the analog-to-digital (A/D) function for the information formerly conveyed by those copper conductors at the control house and instead publishes the information in a digital message over a single cable. This replaces those 44 copper links with a single fiber cable (or two fiber cables for redundancy). Common protocols include IEC 61158 EtherCAT®, IEC 61850-9-2 Sampled Value, and IEC 61850 GOOSE to digitize and transmit bidirectional information between equipment in the substation yard and the relay in the control house.

Although very comprehensive, IEC 61850 was created to standardize power system management and associated information exchange and intentionally does not define power system apparatus requirements or behavior. This leaves the need and opportunity for further related standardization by other technical committees. It also creates additional uncertainty about the best way to apply IEC 61850 technology and leads to newer process-bus-related standards, including the IEC 61869 series maintained by IEC Technical Committee (TC) 38 (Instrument Transformers).

While conceptually very simple, the design in Figure 1(b) does not illustrate Ethernet network topologies or additional capabilities that can be provided via multiple concurrent paths for digital messages. The Ethernet link in Figure 1(b) between the MU and the relay is illustrated as a dedicated, private bandwidth, point-to-point interface. For a complete substation with multiple data clients performing protection and automation, this method requires multiple cables from the MUs so that each data consumer has a unique one when trying to implement station-wide protection services, such as for bus differential, bus voltage sharing, and breaker failure. This makes it necessary to equip the MU with multiple communications interfaces and custom time-synchronization services. In order to implement a standardized multicable system, it is necessary to use private bandwidth protocols such as IEC 61158 EtherCAT. A more general, interoperable, standards-based approach with an Ethernet switch network is shown in Figure 2(a).

An Ethernet switch makes it possible to share MU 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 traffic as needed.

Figure 2(a) shows a general SV-based digital substation that illustrates the process bus concept using standalone MUs (SAMUs). According to this concept, the data acquisition system is installed as close as possible to the primary system HV apparatus and the high-quantity substation yard copper wiring is replaced with a much smaller number of fiber-optic communications cables.

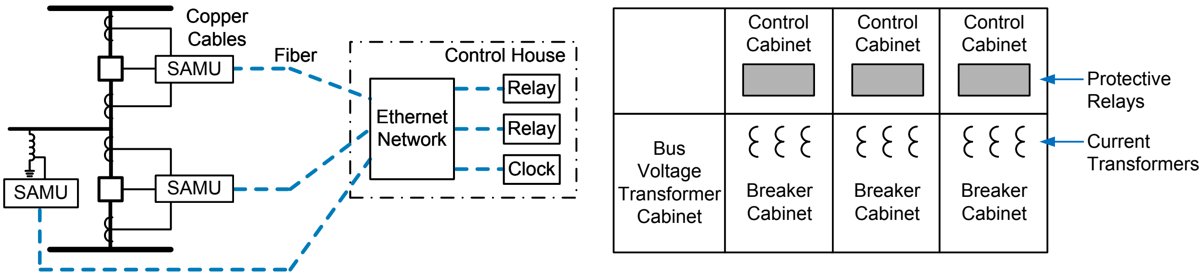

Figure 2: (a) Process bus concept applied to an air-insulated HV substation; (b) typical metal-enclosed MV switchgear

Whenever possible, a single optical fiber is used to carry many measurements. Figure 2(a) shows a typical dual bus, breaker-and-a-half topology with conventional instrument transformers and breakers served by three SAMUs. An SAMU is a time-synchronized data acquisition device capable of converting the secondary measurements provided by instrument transformers into a continuous stream of samples, which are subsequently streamed over the fiber-optic-based communications network. Protective relays and control equipment are still located in the substation control house with the network equipment, allowing instrument transformer data to be streamed to multiple consumers or clients at multiple destinations.

Although the general concept always applies, there are many ways in which the basic technology can be tailored to meet particular design goals. For example, conventional instrument transformers can be replaced by their modern optical equivalents. Optical current transformer implementation can use individual fiber-optic pairs for each phase with measurement electronics located inside the substation control house or may alternately locate the measurement electronics in the HV yard while delivering digital data to the fiber-optic network using the standardized SV output. An instrument transformer with digital output can be integrated into HV equipment to enable a greatly reduced footprint, intelligent breakers, disconnect switches, grounding switches, and so on.

Equally interesting changes are possible in the substation control house. Parts of the Ethernet network can be distributed throughout the substation yard, or multiple relay functions can be consolidated in a purpose-built computer. Network topologies are not fixed either, ranging from simple point-to-point links, which are exceptionally easy to configure and maintain, to highly configurable software-defined network topologies. While the digital messages and associated data exchange are well defined in the standards, the preferred equipment configurations and best practices used to design the substation have not been agreed upon, which has resulted in a wealth of devices that interoperate but cannot be combined into a coherent protection and control system. Early adopter utility experiences and manufacturer competition are playing a major role in bringing some order to this emerging market.

A process bus concept discussion would be incomplete without looking at the SV application in the medium-voltage (MV) space. Figure 2(b) shows a typical arrangement and distances found in MV metal-enclosed switchgear applications.

It is easy to see that an MV system is very compact with protective relays located in the immediate vicinity of the breakers. Distances between the instrument transformers and protective relays are very small, seldom exceeding 5 meters, with excellent equipotential bonding common to all devices in the cabinets. MV applications provide very little opportunity for copper reduction and can be made reasonably safe through the use of insulated bus technology and arc-resistant switchgear construction. Intelligence is distributed, with the protective relays assigned to each breaker creating an intelligent switchgear interface. Instrument transformers are so close to protective relays that the conventional SAMU approach makes very little sense. Regardless of the lack of value derived from wire reduction, distributed intelligence inherent in metal-enclosed MV applications can still benefit from SV-based process bus technology, as shown in Figure 3(a).

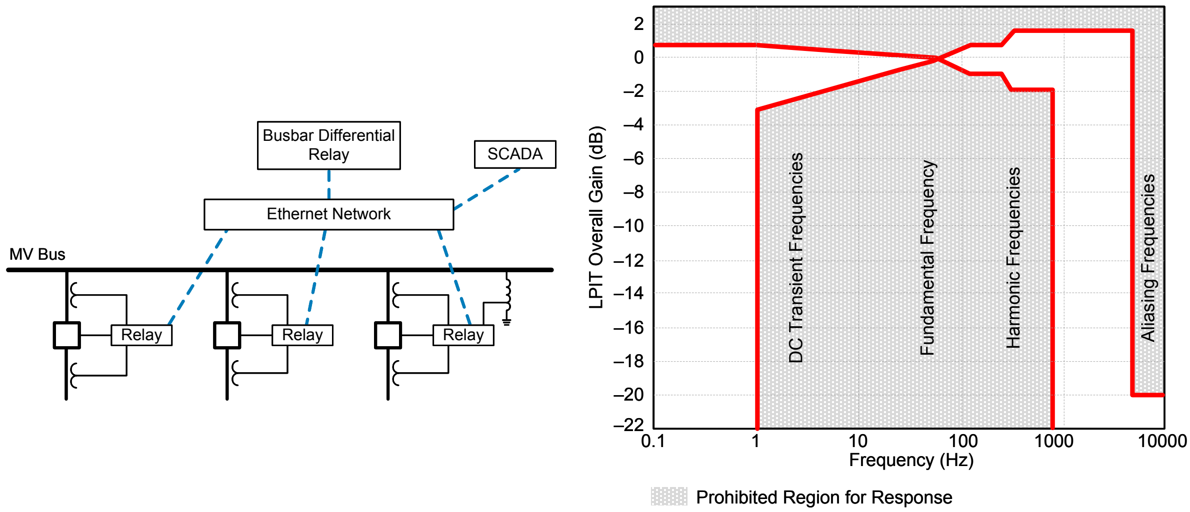

Figure 3: (a) Process bus concept applied to a metal-enclosed MV switchgear; (b) frequency response mask concept

Contrary to the open-air, HV substation concept, which tends to use SAMUs and concentrate intelligence inside the substation control house, MV applications foster distributed intelligence with direct data exchange and cooperation among peers [2]. Data exchange is used in cases when protection and control functions cannot be executed locally, such as to support busbar differential protection, implement transformer differential, share bus voltage across the relay lineup, or establish differential protection across an MV cable used to connect independent switchgear sections. Process bus data sharing is especially beneficial in cases where the conventional current and voltage transformers are replaced with low-energy sensors. Examples of such sensors include Rogowski coils and resistive voltage dividers, which take very little space but cannot be hardwired to multiple relays like with conventional bus field sensors. SV-capable relays with peer-to-peer data exchange capability and built-in low-energy sensor support are of special interest for space-critical applications and complex MV systems found in offshore applications and high-density data centers.

3. INSTRUMENT TRANSFORMER STANDARDS

The act of separating the data acquisition system from the applications it serves creates a new set of challenges and standardization opportunities. It requires close cooperation between multiple technical committees. In the case of SV systems, interested committees include IEC TC 57 (Power System Management and Associated Information Exchange), which created and is maintaining the data models and communications mechanisms defined in the IEC 61850 series, and IEC TC 38, which is tasked with defining signal processing and apparatus-level requirements defined in the IEC 61869 standard series. On the consumer side, IEC TC 95 (Measuring Relays and Protection Equipment) is interested in making sure data produced by MUs are appropriate for protection, that the devices themselves meet the stringent requirements described in the IEC 60255 series, and that they will be accurate enough to calculate synchrophasors described in IEC 60255-118-1. IEC TC 77A (Low Frequency Phenomena) is interested in power quality applications of SV. Finally, the IEC TC Subcommittee 17A (Switching Devices) is interested in SAMU coordination with IEC 62271-3.

All of these standards are in effect establishing new lines of responsibility and a new “contract” between the sources (LPIT and SAMU) and the consumers (relays and meters). The following subsections provide an overview of the key instrument transformer standards being developed by IEC TC 38 and present some of their more interesting features.

3.1 IEC 61869-6: Additional General Requirements for Low-Power Instrument Transformers

IEC 61869-6 defines the general requirements applicable to LPITs. Because LPITs may use electronics and digital signal processing techniques, this standard defines the expected frequency response and anti-aliasing filter requirements that are common to a large number of devices, including SAMUs and instrument transformers with built-in digital outputs. The frequency response mask concept is shown in Figure 3(b).

Based on this concept, the frequency response (gain) of the LPIT with digital outputs or an SAMU must fall in the unshaded areas. A similar requirement is provided for the phase fully defining the expected device performance. Figure 3(b) shows that a device compliant with IEC 61869-6 can be ac- or dc-coupled, but when ac coupling is involved, the device is required to preserve signals with frequencies higher than 1 Hz. This requirement establishes a new contract between the instrument transformer and the device using the SV data. For example, in the past, protective relays were allowed to assume that all instrument transformers were of the same type, matching each other, and could therefore simply be added to form a differential zone. With the 1 Hz frequency mask requirement in place and no standardized behavior below 1 Hz, relay manufacturers are now responsible for ensuring that their protection scheme operates correctly for an arbitrary LPIT or SAMU combination. For example, the SAMU or MU can be dc-coupled or behave as a first-order 1 Hz, 0.1 Hz, or 0.2 Hz high-pass filter. In short, the SAMU or MU has to stay within the frequency mask limits, but those limits are fairly relaxed. A frequency mask requirement is creating new work for both LPIT and relay manufacturers, but it also establishes clear lines of responsibility, defining the best- and worst-case waveforms a subscribing device may receive. Specialized devices such as phasor measurement units (PMUs) may require better phase accuracy but can now use common terminology defined in IEC 61869-6 to express phasor measurement values.

3.2 IEC 61869-9 Digital Interface for Instrument Transformers

IEC 61869-9 defines the instrument transformer digital interface requirements. The standard is based on IEC 61850-9-2 and is, in effect, an interoperable profile (subset) of IEC 61850-9. IEC 61869-9 replaces the unofficial Utility Communications Architecture (UCA) guideline known as IEC 61850-9-2LE, which was used for early SV implementations. With the release of IEC 61869-9, contents of the original UCA guideline are finally within the care of IEC and are further enhanced by lessons learned in numerous pilot installations. The IEC TC 38 working group, which is in charge of the new standard, took the opportunity to use the guideline as the lowest common denominator that must be supported by all devices, while giving developers freedom to add support for configurable data sets, embedded logical nodes with signal processing capability, and a new consolidated sample rate set. Required backward compatibility with UCA guidelines also ensures that early adopters of SV, LPIT, and SAMU technology will not be left stranded by providing an upgrade and replacement path for equipment already owned.

IEC 61850-9 defines improved time-synchronization capabilities based on the IEEE 1588 and IEC 61588 Ethernet-based synchronization standards and also defines new sampling rates necessary to support dc measurements aimed at closed-loop control applications. Input filtering and filter delay issues are addressed by giving the responsibility for group delay compensation to the LPIT or SAMU. This approach allows new devices with digital output to be specified using the same phase and magnitude error terminology and accuracy classes used to specify conventional instrument transformers. The standard also defines the maximum latency (internal processing) delay allowed for various applications, as shown in Table 1.

Application	Maximum Processing Delay
High-bandwidth dc control	25 µs
Time-critical, low-bandwidth dc control	100 µs
Protective and measuring	2 ms
Quality metering	10 ms

Table 1: Maximum internal processing delay times documented by IEC 61869-9-2

3.3 IEC 61869-13 Standalone Merging Unit

IEC 61869-13 defines apparatus aspects for the SAMU. An SAMU is envisioned as a self-contained data acquisition device capable of converting the conventional instrument transformer output to instantaneous digital samples and publishing those samples to substation devices using an SV service defined in IEC 61869-6 and IEC 61869-9. IEC 61869-13 is still in development as of early 2017.

IEC 61869-13 defines the required type tests, insulation, electromagnetic compatibility (EMC), and safety requirements for SAMU devices. Recognizing the fact that new devices will typically be mounted in the immediate vicinity of the HV breakers, IEC TC 38 based their recommendations for the standard on the wealth of information available from yard-based relay installations. They concluded that new SAMU devices will be exposed to very similar conditions and must therefore meet or exceed the general capabilities defined in the IEC 60255 series of standards. IEC 60255 describes the product safety requirements for measuring relays and protection equipment in order to determine clearance and creepage distance and withstand test voltage. This standard details the essential safety requirements to minimize the risk of fire and hazards caused by electric shock or injury to the user. SAMU EMC requirements defined in IEC 61869-13 match IEC 60255-26 with the safety requirements based on IEC 60255-27. Special consideration is also given to gas-insulated systems (GISs), which may be exposed to higher stress.

One topic of particular interest to the protection community is SAMU behavior under dynamic (fully offset) fault conditions. In dealing with this issue, IEC 61869-13 encourages SAMU manufacturers to use a nonsaturating front end. When using saturable components (e.g., auxiliary current transformers commonly found in protective relay front ends), SAMUs must pass a fully offset, close-open-close-open (C-O-C-O) sequence prescribed in the standard and declare the highest X/R ratio for which IEC 61869-13 requirements for such sequence can be met. The same approach is used for linear ac-coupled inputs. Typical test waveforms are illustrated in Figure 4 and Figure 6.

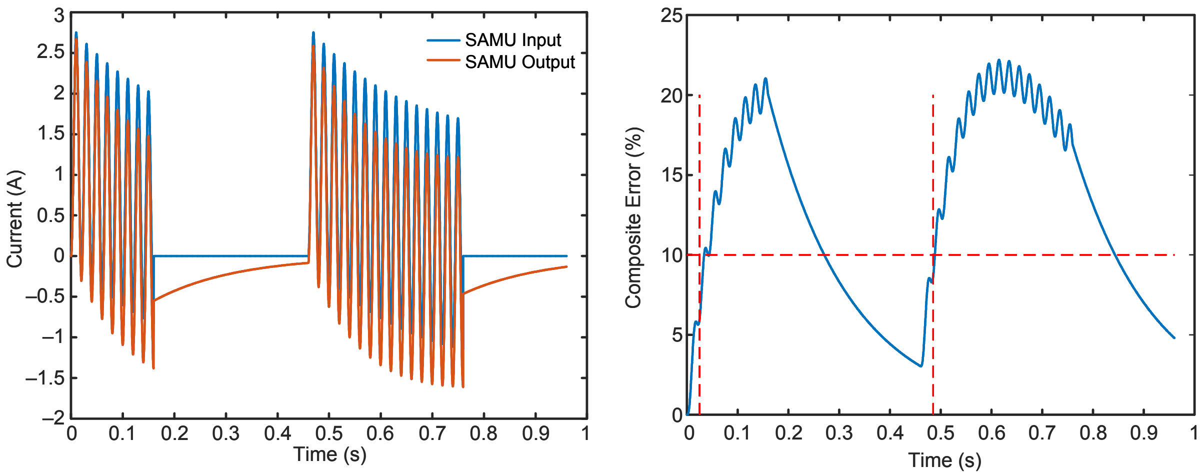

Figure 4: (a) Fully offset, C-O-C-O sequence waveform after passing through a 1 Hz, high-pass filter; (b) composite error calculated for waveforms in Figure 4(a)

Figure 4(a) illustrates the effects of a linear, first-order, 1 Hz, high-pass filter, which is the highest cutoff frequency allowed by the frequency response mask defined in IEC 61869-6. The high-pass filter modifies the slowly decaying exponential component without significantly affecting the 50 Hz signal. Modification is best illustrated by calculating the composite error (i.e., instantaneous difference between the two signals expressed in percent) shown in Figure 4(b).

Note that composite error grows very fast, reaching the 10 percent mark around 26 ms after the fault initiation. At the same time, it is clear that the root-mean-square (rms) and phasor values of the fault current remain unaffected by the high-pass filtering function, as shown in Figure 5.

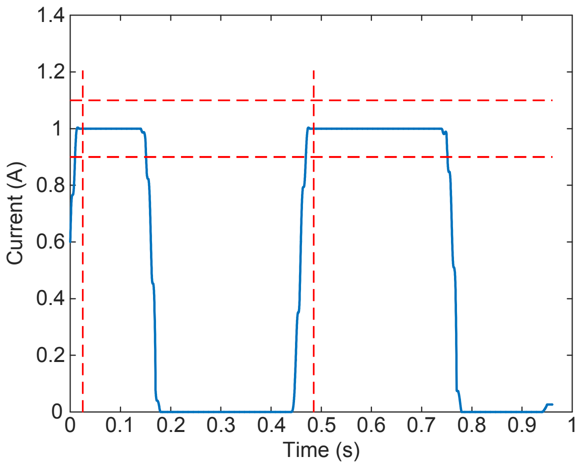

Figure 5: Cycle-based rms value calculated for waveforms in Figure 4

The most conventional protection functions, such as time-overcurrent or distance protection, use rms or phasor measurements and are unaffected by the slow exponential wave component. It would therefore be unfair to impose lower cutoff frequency requirements on all MUs and SAMUs. At the same time, high-performance, sample-based differential protection elements require good matching of the dc component in order to operate. Such high-performance functions complete their work within the first cycle (often in 3 to 8 ms), meaning a trip will already be initiated by the time the high-pass filter is able to affect the input waveform. IEC 61869-13 recognizes the above applications by requiring that the composite error observed during the first 25 ms of the fault remains within the 10 percent margin and applies the rms-based criteria once the 25 ms have expired. The proposed approach captures the needs of high-performance differential protection while at the same time ensuring that the SAMU output works well with rms- and phasor-based protection schemes. This approach also shows that the 1 Hz high-pass filter corner frequency defined in IEC 61869-6 is a good compromise between the two applications. Because the new dynamic response requirements are based on real-life protection schemes and have a precisely defined test, they are equally applicable to designs using conventional input magnetics, which could partially saturate. In effect, saturation is allowed as long as the errors introduced by it do not exceed the 10-percent limits, as illustrated with dashed lines in Figure 4.

Responding to the needs of the power measurements community, IEC 61869-13 includes an informative annex that shows how the well-known accuracy classes defined separately for the instrument transformer and the SAMU can be combined to estimate the accuracy of the resulting digital output.

4. FUTURE WORK

With the ink barely dry on IEC 61869-6, IEC 61869-9, and IEC 61869-13 at the CDV stage, it is hard to imagine the need for additional changes. However, SV technology and associated applications are developing very fast. New applications are constantly brought forward with the need for SV signals to serve all substation applications, resulting in new work areas that should be considered for the next revision cycle, including the following:

- Full-length UTC time-stamp support
- Automated transducer data exchange
- Power quality application support
- High sample rate and emerging application support

4.1 Full-Length UTC Time-Stamp Support

The latest revision of the synchrophasor standard, IEEE/IEC P60255-118-1, includes an annex that describes the use of SV measurements as inputs to the PMU. A PMU used in this way simply becomes a signal processing application that can be implemented anywhere SV streams are available. One IEC 61869-9 weakness identified in the annex is the lack of a full time stamp, which is normally replaced with a simple counter that rolls over every second. To operate with such time stamps, PMUs will be forced to obtain time independently and reconstruct the full date and time information required at the PMU output. An alternative approach is to abandon the use of legacy, 1 pulse per second, signal-based time distribution and configure the LPIT and SAMU devices to output the full time stamp. The full time stamp is already supported by IEC 61850-9-2, meaning it is simply an option that is likely to be added in the next revision of IEC 61869-9.

4.2 Automated Transducer Data Exchange

The MU concept is exceptionally powerful for innovating new opportunities for system-wide applications via LPITs. To gain the full benefits brought forward by LPIT technology, it is often necessary to use individual device correction (calibration) factors, which are currently printed on the device nameplate. Correction factors have large numbers of decimal places that must be manually entered into the end device. The entry process is time-consuming and error prone, so much so that it is seldom used. IEC 61869-6 foresaw this challenge when defining the LPIT connector interface and left a pair of pins for an embedded memory device capable of storing the LPIT nameplate data and individual correction factors for each device. This interface is known as a transducer electronic data sheet (TEDS), which has a new work item proposal being opened in IEC TC 38 to fully define the interface. At the time of the publication of this paper, it is expected that the TEDS interface will be based on the core principles described in IEEE 1451.4 with the new instrument transformer-specific templates defined by IEC TC 38.

4.3 High Sample Rate and Emerging Application Support

Going forward, it is unrealistic to expect that SV sample rates will be limited to the currently preferred values of 4.8, 14.4, or 96 kHz, which are currently the highest defined rates. New applications such as traveling-wave-based (TW-based) fault location [3] and TW-based protection already operate with sample rates at or above 1 MHz [4]. Field records similar to the HV line reclosing example shown in Figure 6 show strong TW reflections and extra information that is often discarded by traditional protection systems.

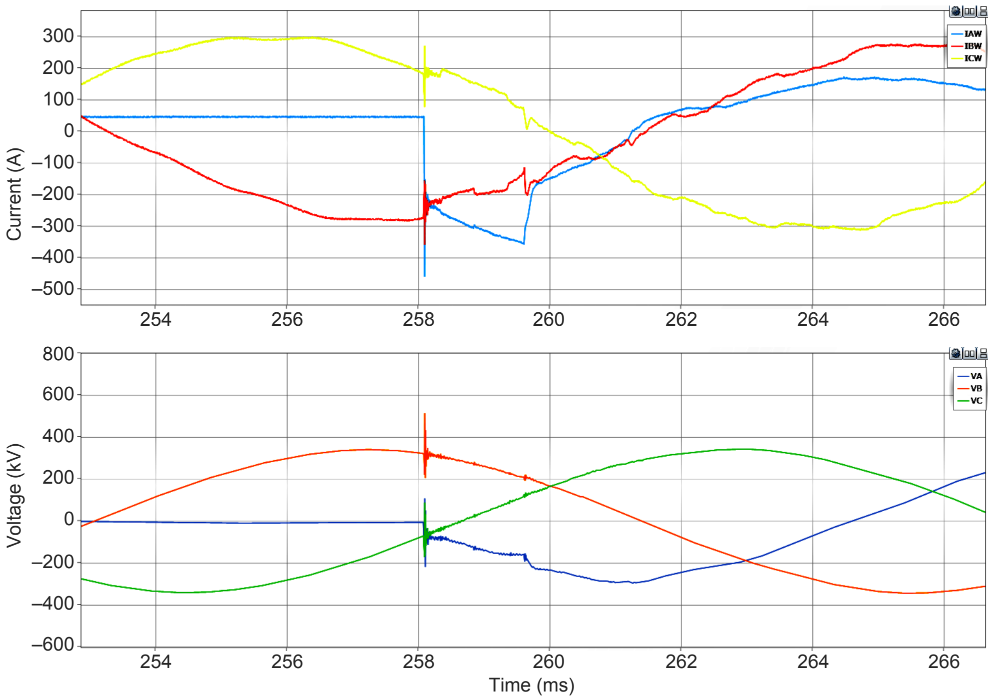

Figure 6: TW waveform example showing successful reclosing on a 400 kV line

TW applications, unfortunately, do not map well to the SV streaming service. The data are very sparse and most of the time carry very little information (difference) between neighboring samples. The bandwidth necessary to stream the raw data is very high, suggesting that data compression and more intelligent encoding will need to be employed. This work may take some time to mature before justifying associated standardization efforts.

5. CYBERSECURITY

Cybersecurity remains one of the weak spots for the SV-based digital substation concept. While the cryptographic protection of SV data is not a major concern, source authentication, data tampering, real-time overhead, and network infrastructure protection are very important for wide-range technology deployment. Currently, standardized SV systems offer no inherent protection and rely on the network topology or the network infrastructure devices for additional support. Direct point-to-point links are presently the simplest topology-based solution. Deep packet inspection and whitelisting methods supported by software-defined networking (SDN) are the most advanced methods to maximize the security and dependability of confidential and deterministic signal delivery. Standardization work in this area continues, with most contributions likely to originate in IEC TC 57 and IEEE network standards communities.

6. CONCLUSION

The digital substation process bus concept based on SV technology continues to be of major interest to practicing power engineers. In order to reach a mature and fully interoperable system, as with all digital substation applications where data flow is performed by digitized message exchange, large amounts of technical details need to be fully documented and standardized. International efforts in this domain span over a decade and continue at a vigorous pace. This paper provides an overview of recent standards adding to the wealth of knowledge describing this technology, explains various options and the relationship among different standards, and identifies some of the future work required in this space.

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