Practical Experiences and Lessons Learned in Adapting PG&E Line Protection Standard for IEC 61850 Digital Secondary Systems

Shashank Bodhankar
Pacific Gas and Electric Company

Ashish Sharma, Rachel Oelsner, and Priyadharshini Guruprasad
Schweitzer Engineering Laboratories, Inc.

Presented at the
2026 PAC World Conference
Delft, The Netherlands
June 22–25, 2026

Practical Experiences and Lessons Learned in Adapting PG&E Line Protection Standard for IEC 61850 Digital Secondary Systems

Shashank Bodhankar
Pacific Gas and Electric Company

Ashish Sharma, Rachel Oelsner, and Priyadharshini Guruprasad,
Schweitzer Engineering Laboratories, Inc.

USA

1. Introduction

As described in [1], the global energy industry is undergoing a transformation and is facing increasing pressure to modernize infrastructure, increase reliability, and enhance operational efficiency. In response to this, Pacific Gas and Electric Company (PG&E) initiated the development of a comprehensive strategy for adopting digital secondary system (DSS) technology. Reference [1] describes how the utility refined an ideal five-phase strategic roadmap to a practical three-phase approach aligning with business needs and timeline.

The first phase of the condensed approach was the development of a laboratory environment to validate the core concepts and development of technical guidelines for the subsequent phases. Central to this effort was the adoption of IEC 61850 as the foundational requirement. The benefits and expectations of IEC 61850 are covered in [2] [3]. The primary reasons for the adoption were the possibility of mature and comprehensive software-defined engineering workflow for data model-based design for standardization of electric design and template development. A key objective of the laboratory phase was migrating the existing traditional protection and control (PAC) philosophy to an IEC 61850-based digital system encompassing station and process bus (PB) implementation.

The authors outline the key considerations involved in migrating line differential protection (87L)—valued for its speed, sensitivity, and selectivity—to an IEC 61850-based architecture using Sampled Values (SV) and GOOSE messaging. A central guiding principle in this migration was preserving the existing operational sequence and maintaining consistent electrical technician experience throughout the transition.

The IEC 61850 laboratory is located at the utility training center, which features a de-energized substation consisting of four 115 kV circuit breakers and two 115 kV/21 kV transformers. The facility provides a safe environment for testing, training, and integration into the utility learning academy. While the utility uses various bus configurations—including single-bus single-breaker, double-bus single-breaker, main and auxiliary bus configuration, double-bus double-breaker, ring bus, and breaker-and-a-half (BAAH) configurations—the utility prefers to use the BAAH configuration as the final state of the substation. Consequently, for the laboratory implementation, BAAH configuration was chosen to validate PAC applications including line protection, transformer protection, and breaker failure protection. Fig. 1 shows the single line of the system under test including Process Interface Units (PIU) and protection relays with their zones of protection.

The IEC 61850 project scope encompasses the implementation of a station bus with Manufacturing Message Specification (MMS) communication services and an independent redundant PB network utilizing merging units (MUs) to deliver SV, GOOSE, and Precision Time Protocol (PTP). The PAC system is designed as two fully fail-independent subsystems—System A and System B—to ensure high reliability and security. A local human-machine interface (HMI) will provide station monitoring and control, as well as visibility into PAC equipment performance.

To validate interoperability and incremental deployment strategies, a remote substation at the opposite end of the line was simulated using a traditional line current differential relay. An IEEE C37.94-2017, *IEEE Standard for N times 64 kbps Optical Fiber Interfaces between Teleprotection and Multiplexer Equipment* communications link was established between the DSS relays and the conventional relay. This remote-end configuration enabled verification that DSS technologies can be introduced in stages without adversely affecting existing external substations or legacy protection schemes.

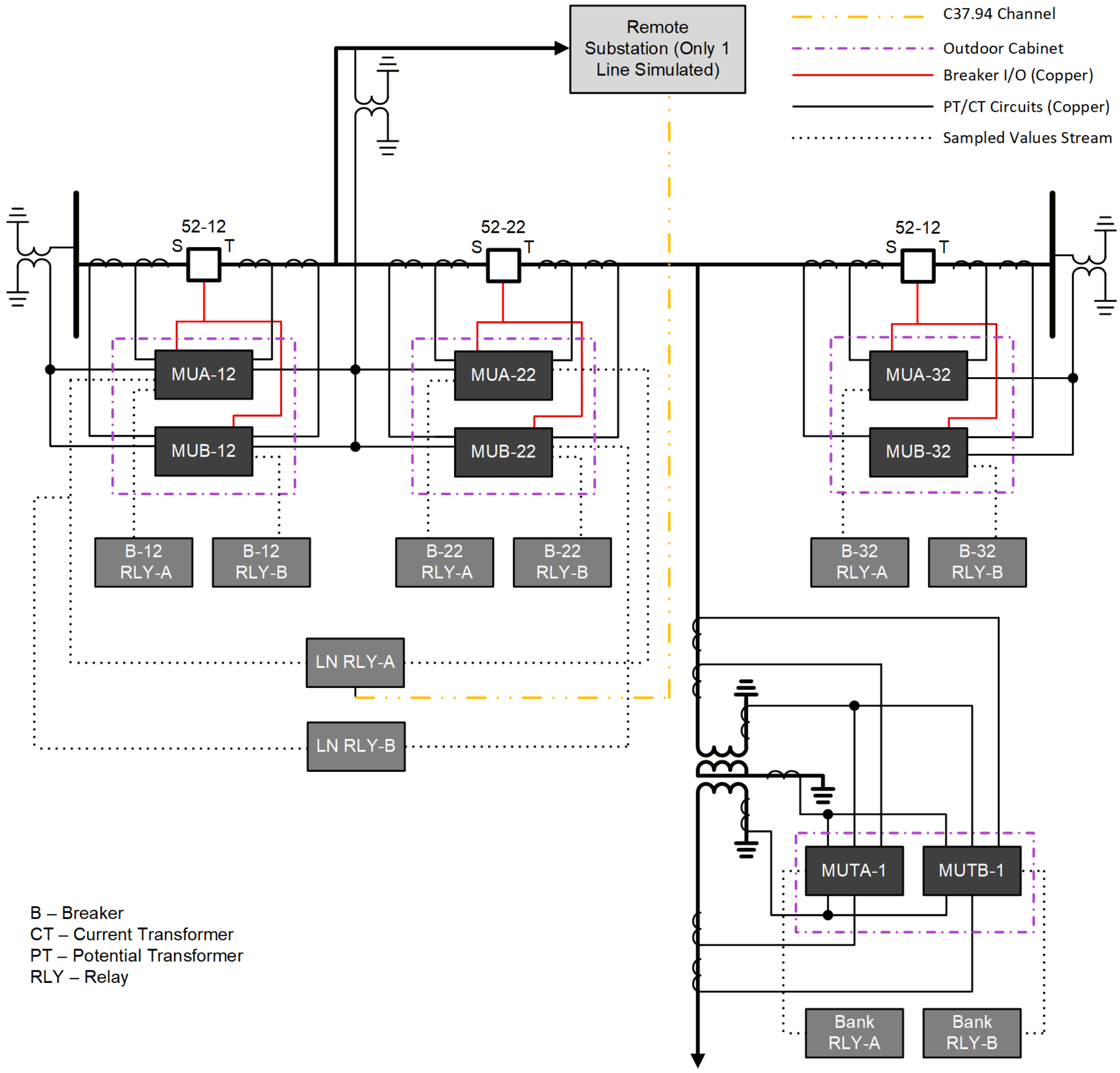


Fig. 1 System Single-Line Diagram

The communications network is illustrated in Fig. 2. The station bus is implemented using a ring-based failover topology, enabling support for devices that do not natively implement Parallel Redundancy Protocol (PRP). For the PB, PRP was chosen as the network redundancy strategy to allow for zero failover time and high availability. With two independent PAC systems (System A and System B) operating in parallel, the PRP design results in four fully redundant PB networks.

Time synchronization is provided by two PTP clocks per system, for a total of four overall. The clocks are connected to the PB in PRP mode. The PB network will consist only of Layer 2 data supporting SV, PTP, and Protection Critical GOOSE protocols. The station bus network will be using Layer 3 Protocols MMS, Modbus, DNP3, and FTP.

The PB will consist of protective relays and PIUs. The PIUs will not be connected to the station bus. This philosophy was used to limit External Routable Connectivity by only allowing the PIUs to connect to a Layer 2 network and have all engineering access and report collection done out-of-band via local access in the field. The PB network switches and the PTP clocks will be continuously monitored using Simple Network Management Protocol (SNMP) and the firmware management will undergo processes as laid down for protective relays.

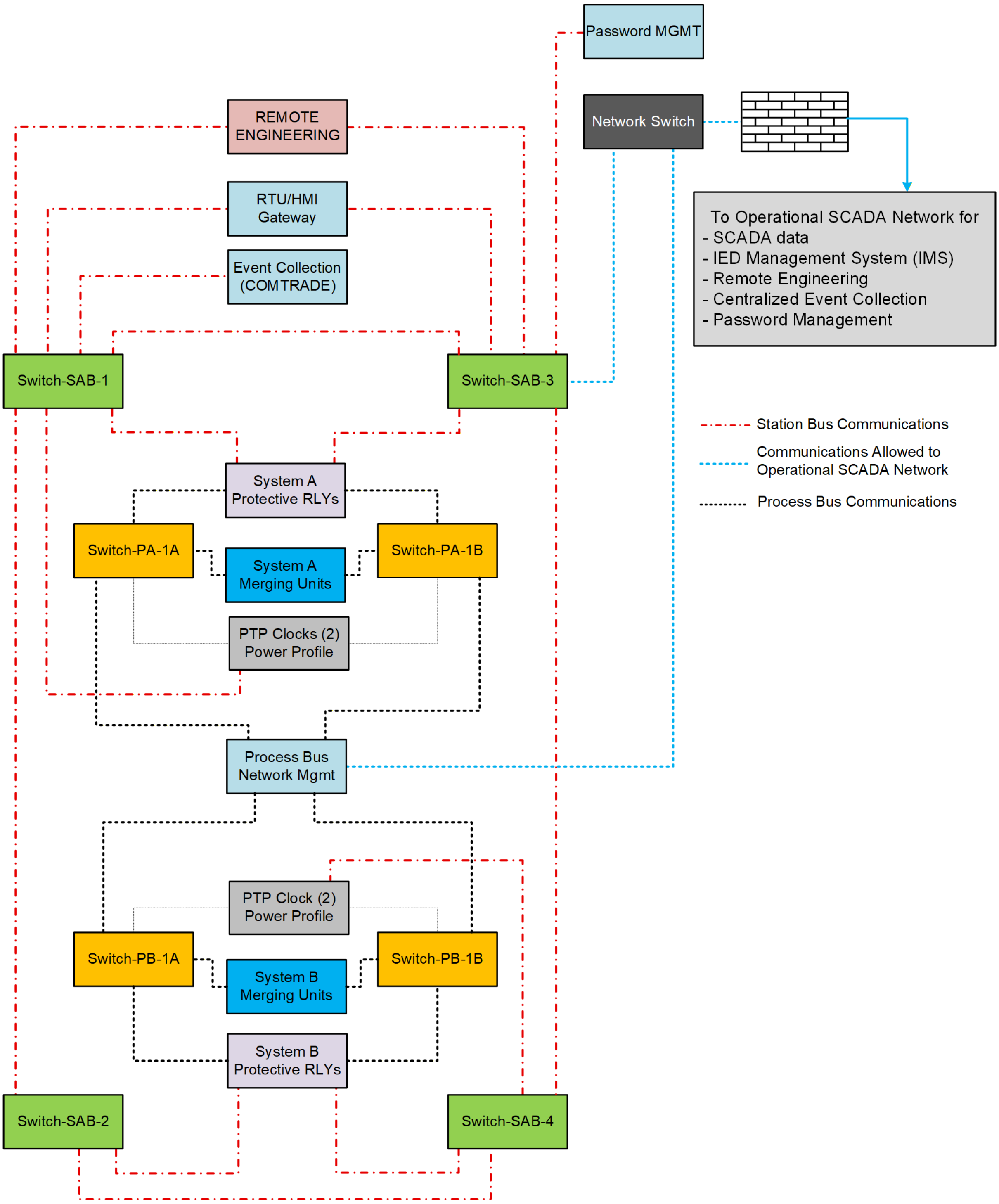


Fig. 2 Overall System Communications Drawing

2. Traditional Line Protection

A typical comprehensive line protection includes line current differential/protection differential (87L/PDIF), ground and phase distance protection (21/PDIS), ground and phase directional overcurrent (67-51/PDIR+PTOC), overvoltage (59/PTOV), and pilot protection scheme. Additionally, control functions considered are synchronism check (25/RSYN), switch onto fault (SOTF), autoreclosing (79/RREC), and breaker failure (RBRF).

In the traditional protection architecture of the utility, these responsibilities are divided between two independent microprocessor-based relays [4]. One relay, referred to as the breaker failure relay (BFR), provides breaker failure protection, reclosing, and synchronism check functions. Because these functions are breaker-centric, the BFR relay is associated with a specific breaker and also provides supervisory control and data acquisition (SCADA) control. In the DSS implementation, the circuit breaker (i.e., XCBR) logical node is modeled within the BFR relay.

The second relay, referred to as the LINE relay, performs line-oriented protection functions, including line current differential (PDIF), distance protection (PDIS), and overcurrent protection (PTOC). This functional separation—BFR for breaker-centric logic and LINE for line-centric protection—was a deliberate design choice by the utility and remains preserved in the IEC 61850-based DSS architecture.

The 87L protection compares the currents entering and leaving a transmission line protection zone. There are two identical relays at either end of the protected line, with a current transformer (CT) located on the bus side of the substations. These relays share their individual current samples using the communications link (see Fig. 3).

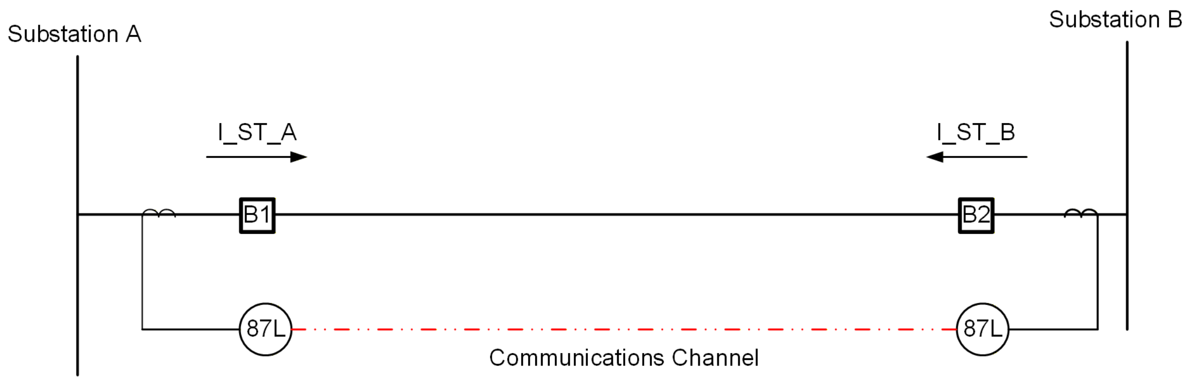


Fig. 3 Two-Terminal Line Differential

The percentage-restrained differential is also applied for transformers and motor and generator protection. The relays calculate the ratio of operating to restraining current and compare it to a user-settable percentage threshold. The operating and restraining currents are defined as:

$$IOP = |\overline{I\_ST\_A} + \overline{I\_ST\_B}|$$

$$IRT = \frac{(|\overline{I\_ST\_A} - \overline{I\_ST\_B}|)}{2}$$

Fig. 4 shows a dual-slope percentage-restraint differential with operating and restraint regions. The plot also shows a minimum operating current to allow for any CT imbalances. The dual-slope has a breakpoint set where any CT saturation is anticipated. Slope 1 is set based on steady-state CT errors and Slope 2 is based on expected measurement errors resulting from CT saturation after the breakpoint.

Transmission line protection schemes, particularly line current differential, distance, and directional overcurrent elements, depend on accurate measurement of line current. At single-breaker terminals, the line current is directly measured by a single set of CTs. However, at dual-breaker terminals, such as BAAH or ring-bus configurations, the line current is not directly measured; instead, it is derived by summing the currents from the CTs installed on two breakers. This indirect measurement creates fundamental challenges for protection security under certain fault conditions.

Two common approaches are used to obtain line current at dual-breaker terminals:

1. Paralleling breaker CTs externally and feeding a single current input relay,
2. Wiring each breaker CT to separate current inputs of a dual-input relay and summing the currents internally.

Under ideal CT performance, both approaches provide an accurate representation of line current in both magnitude and phase. However, during faults that lead to CT saturation particularly asymmetrical saturation driven by dc offset, the derived line current can deviate significantly from the true line current, potentially affecting protection security and dependability. A comprehensive discussion of these phenomena is provided in [5].

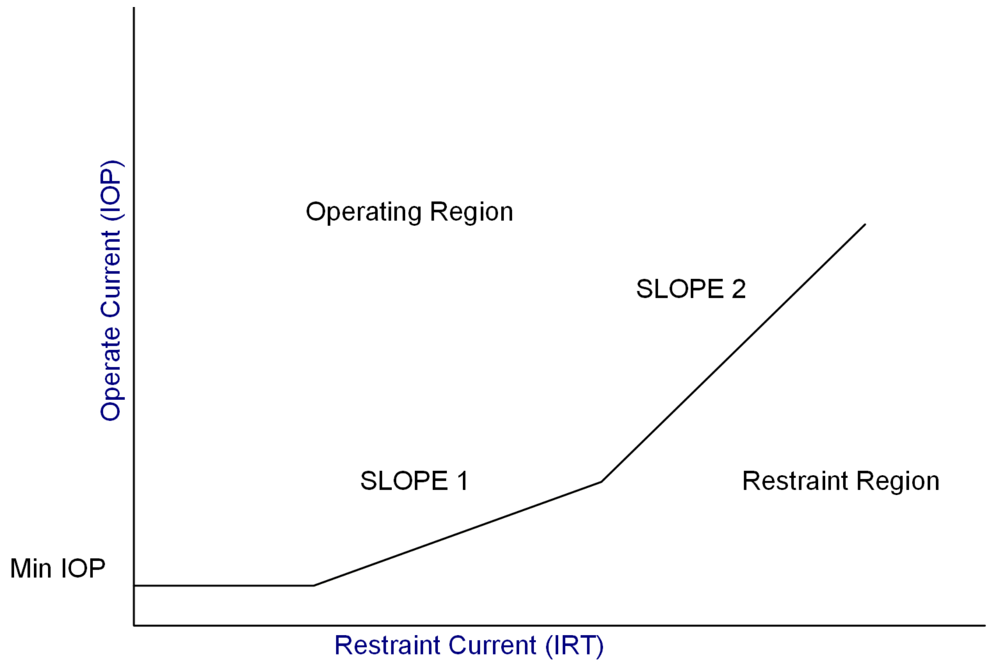


Fig. 4 Dual-Slope Percentage-Restraint Differential

3. Transition to DSS

For DSS line protection schemes, the underlying element operating characteristics and scheme functionality remain unchanged; the primary difference lies in the data acquisition mechanism. Due to the subscription flexibility of SV and fault detection delays inherently introduced by the additional devices and processing steps of merging unit designs, setting engineers have additional considerations when setting line protection relays.

Furthermore, because there now exists dependency on the network for the transfer of SV, statuses, and trip/close signals between merging unit and protection relays, there exists conditions in which receiving and sending the data may be compromised (e.g., a broken fiber cable, network bandwidth congestion, or loss of time synchronization). Having a well-designed PB network will help mitigate many of these concerns but does not fully eliminate all possible failures.

Monitoring these conditions enables true evidence-based high availability. When a messaging failure does occur, such as the loss of a hardwired analog signal, the relay may deem the SV stream(s) unusable and issue appropriate warning and alarm indications. These indications can be used to disable applicable protection functions, either automatically through built-in security logic or through user-defined torque-control equations using the specific bits that have indicated a failure.

Supervision for security or for consistency and dependability [6] is suggested to be added not just for element protection, but also for protection schemes like POTT, DCB, and SOTF. For the 87L element, if the relay manufacturer does not provide built-in DSS-specific security logic, utilities must implement supplemental logic that meets operational requirements. This includes accounting for any additional timers needed to maintain proper alignment of local and remote currents, given the inherent delays introduced by the DSS architecture. See Section 3.2 for a further setting delay to consider for 87L implementation.

The sections below provide some insights into key design considerations around delays, time synchronization, and network design.

3.1. Channel Delay

A delay always exists between the moment when the MU takes an analog sample to when the SV relay receives it. IEC 61869-9 specifies that the MU processing delay should not exceed 2 ms for a protection application [7]. This processing time adds to the latency created by network topology and the signal transmission through fiber-optic cables. When an SV relay subscribes to multiple MUs, and those MUs are from different manufacturers, this latency may vary. The delay may be increased further by increased load on the PB. Thus, the latency for one application may not be the same as another application, and it is extremely important for network engineers to design the PB with [8] latency in mind.

The IEC 61850-5 provides the performance guidance of P7 with TT6 transfer type, i.e., ≤3 ms for the raw data, with an additional note that the delay should be so small that no negative impact on application function is experienced.

To account for these nondeterministic delays, SV relays provide a channel delay (CH_DLY) or sampled measured value delay settings (SMV) that buffers incoming SV for a configured period. Because SV streams may arrive out of order, experience jitter, or contain missing samples, the relay waits for the full channel-delay interval before resampling. This ensures that the quantities delivered to protection algorithms are based on correctly ordered, chronologically aligned samples. The relay may reorder samples using the sample count (smpCnt), interpolate missing samples, or apply other manufacturer-specific methods to maintain data integrity.

When an SV relay subscribes to multiple MUs, it holds the samples from each MU for the configured delay, aligns them by smpCnt, and then forwards them to the protection algorithms. This alignment is essential when MUs from different manufacturers introduce different processing delays or when network loading causes variable latency.

To see the impact of the SV channel delay, COMTRADE (DAT) and filtered event files initiated on a common preset trigger were downloaded from both an MU and SV relay, and then aligned in an event analysis software. In Fig. 5, the yellow line represents the COMTRADE file from the SV relay, and the red line represents the COMTRADE file from the MU relay. The blue line represents the filtered file from the SV relay, and the green line represents the filtered file from the MU relay. COMTRADE files represent what the system did, whereas relay filtered event files represent what the relay acted on. A COMTRADE file downloaded by an SV relay uses the channel delay in its skew parameter to align with the true time the event occurred [9] [10]. The skew parameter also accounted for adjusting the filtered event downloaded from the MU, as there is also a shift between the MU COMTRADE (red) and MU filtered (green) lines to account for the MU processing delays. Lining up the two vertical timing lines on the zero crossing of the two filtered events, the time between the SV signal (blue) and the MU signal (green) is 2.086 ms. This is within one hundred microseconds of the set channel delay (2 ms), showing that there are other delays in play. Thus, the time difference between a filtered MU event and a filtered SV relay event may not be exactly to the time to which the channel delay is set. The MU filtered event report is created after various processing of the analog voltage and current signals including, but not limited to, low-pass filtering, analog to digital (A/D) converter, and bypass and cosine filters. Whereas an SV relay filtered event report is created by first decoding the received MU SV streams, then passing them through additional filtering before finally creating the filtered event. Thus, the time difference seen in Fig. 5 is a combination of the additional cosine and anti-alias filters the MU goes through to create its filtered event, dependent on relay processing times, and that of the additional decoding and resampling the SV relay goes through where accounting for the channel delay is included, but not the only processing the relay goes through. In conclusion, the delay a filtered MU and SV event may show is a rough indication of the configured channel delay; however, engineers need to consider the additional processing time included in this time difference per application [11].

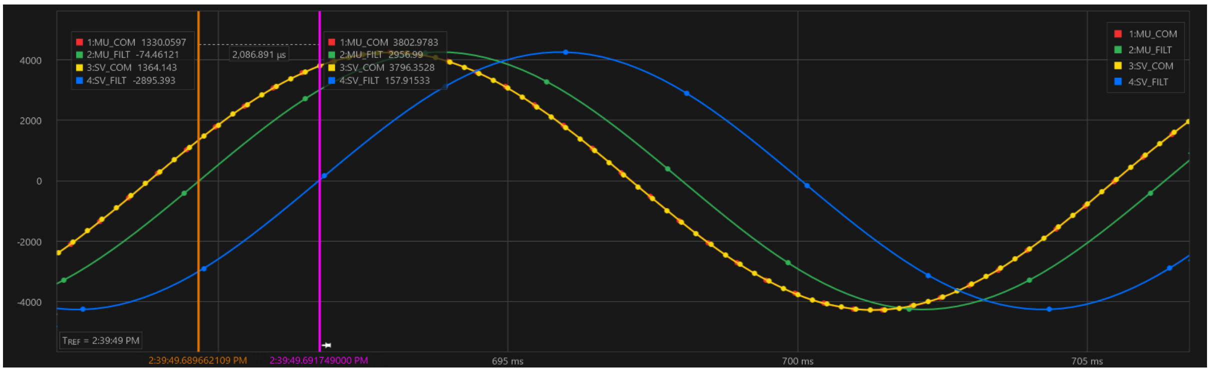


Fig. 5 COMTRADE and Filtered Event Overlay from MU and SV Relay

The SV delay setting must be configured according to the device manufacturer recommended calculation or by analyzing substation system performance during commissioning. The value is typically expressed in milliseconds. The typical concept is to set this delay to the maximum observed network delay across all subscribed streams plus additional time the relay is expected to tolerate missing SV messages through interpolation. Relays determine the delay by comparing the smpCnt of received samples with their arrival timestamps and make available the maximum observed delay for each SV subscription within the device monitoring and diagnostic means. See (1).

$$CH\_DLY = MAX\ (SVNDmm) + Ridethrough\ time \tag{1}$$

where:

MAX (SVNDmm) is the maximum network delay out of all received streams.

Ridethrough time is the additional time the relay is expected to tolerate missing SV messages by interpolating data.

If the bandwidth of the network reaches its maximum, thus overloading the network and increasing the network delay, the channel delay may be exceeded. Depending on relay type and settings programming, an exceeded channel delay may disable protection.

To demonstrate this concept, a network testing device was wired in network series with an MU and SV relay (see Fig. 6). The test device was able to simulate additional network delays at different amounts. A channel delay setting of 2 ms was determined relevant to the test setup. This value was based on the approach described above, allowing the relay to be able to interpolate up to three missing samples.

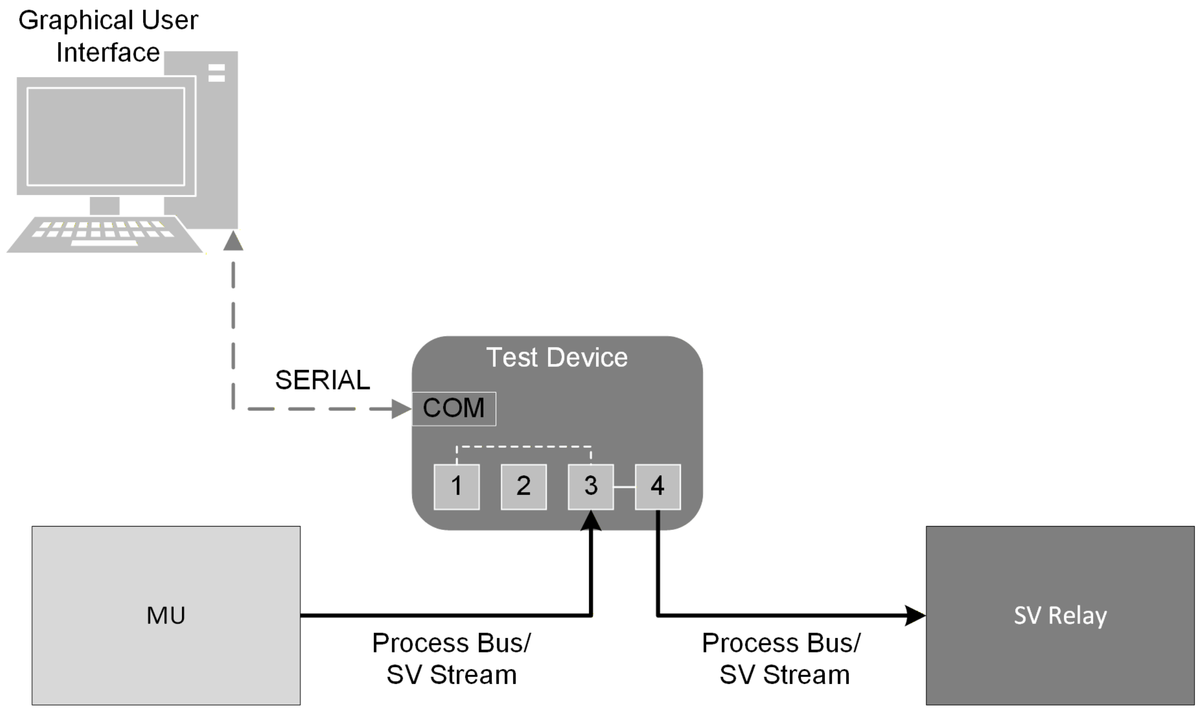


Fig. 6 Channel Delay Exceeded Test Setup

Fig. 7 shows the normal expected network delay for a selected system with no SV block bits asserted nor error code. In Fig. 8, the test device was adding a small additional network delay, not large enough to cause the channel delay of 2 ms to be exceeded, but enough to increase the calculated network delay of the relay due to increased PB load. Fig. 9 shows the SV block bits asserting, which will disable protection in this specific relay application because the test device increased the network load such that the channel delay has been exceeded. This highlights the importance of appropriately setting the channel delay and designing a network that minimizes the network delay as it has an impact on the protection.

Before commissioning new systems—or when integrating MUs from different vendors—it is recommended to reassess the appropriate SV delay value, as variations in MU processing and network behavior can significantly affect end-to-end latency.

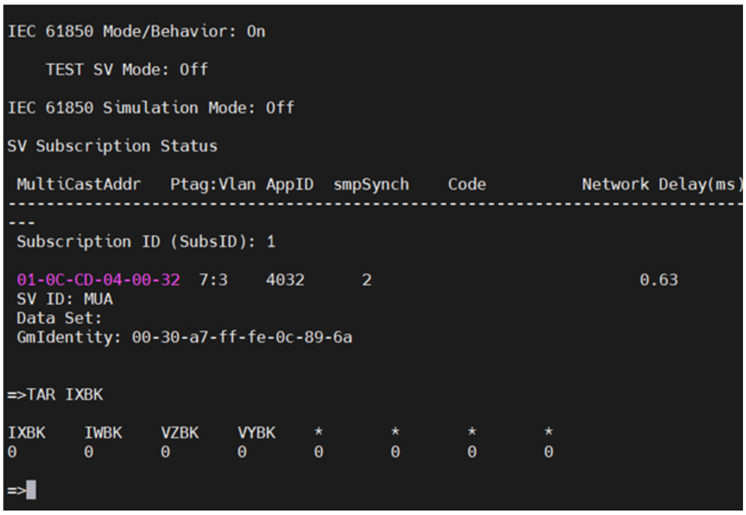


Fig. 7 Expected Network Delay

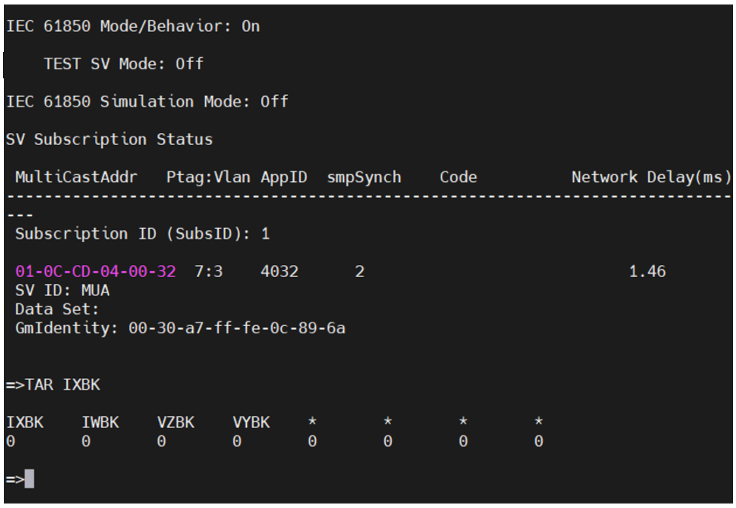


Fig. 8 Increased Network Delay

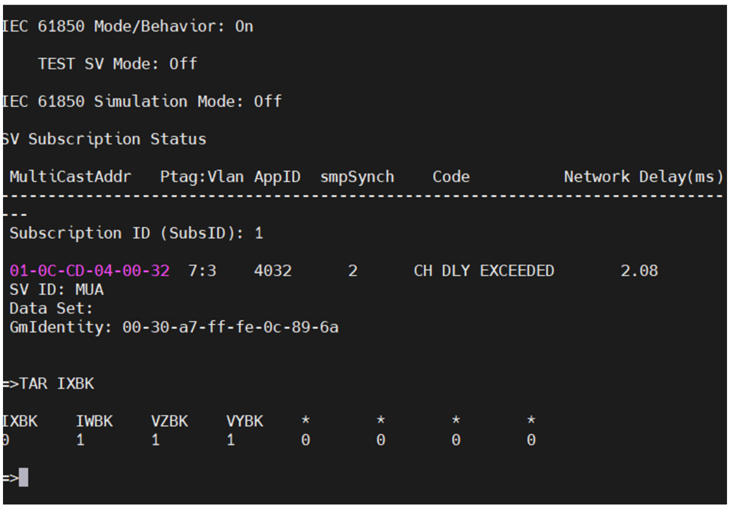


Fig. 9 Channel Delay Exceeded

For line protection relays operating on an 87L scheme, data from the remote and local ends need to be properly aligned to calculate the operate and restraint values. Data alignment can be channel-based or external time-based, where external time-based methods require an external time source such as a GPS clock. For line protection 87L schemes incorporating an SV relay, which has a channel delay setting as discussed in the previous section to address the CT signal latency and a traditional relay, an additional setting may be required for interoperability to be possible. This channel delay should be extended to the remote-end 87L channel settings as well. In any case, when a DSS relay is used in the scheme, it must be able to locally align the current samples if subscribing to packets from multiple MUs before transmitting the combined current samples over the 87L channel to the remote end. It must also know the elapsed time from when the analog current readings were first taken at any given point in time on the remote end to when the remote relay transmitted that current samples over the 87L channel.

3.2. Time Synchronization Considerations

Accurate time synchronization is essential in DSS applications to ensure that MUs and protective relays operate on a common, precise time reference. The standard-approved synchronization methods are PTP (IEEE 1588-2018, *IEEE Standard for a Precision Clock Synchronization Protocol for Networked Measurement and Control Systems*/IEC 61588) and 1PPS. PTP is used more widely because it provides submicrosecond accuracy (<1 μs) and leverages the existing Ethernet network infrastructure. For this project, the selected PTP profile was the IEC 61850-9-3 Power Utility Automation Profile. Additionally, the clocks for these systems must be equipped with at least Oven-Controlled Crystal Oscillators (OCXO) to allow better holdover performance.

A critical aspect of PB design is ensuring that network switches support PTP transparent clock operation. Transparent clocks apply hardware-based timestamping and correct for residence time, enabling accurate propagation of timing information from the grandmaster clock. The chosen implementation used a two-step peer-to-peer (P2P) mechanism.

Initially, each PTP clock in the system was configured with a different Priority 1 value. Under the Best Master Clock Algorithm, this caused a clock with Priority 1 to become the grandmaster even when it was in holdover mode and had lost its GPS reference. To prevent this and allow clocks with best overall source be the grandmaster, all clocks were assigned the same Priority 1 value, while Priority 2 was set uniquely for each device. This ensured stable and predictable grandmaster selection. All clocks also operated in PRP mode, distributing PTP time over redundant networks. This configuration provided high availability and ensured that both relays and MUs remained synchronized to an accurate time source, even under network or device failure conditions.

SV messages have a sample synchronized field, denoted as smpSynch, which is an indication of the synchronization status of the MU. The format for the smpSynch field is assigned a INT8U as per IEC 61850-9-2 and is expected to have a value of 0, 1, or 2. The rest of the values are reserved and should not be used. When an MU is synchronized to a high-quality global time source, the smpSynch value will be 2. When synched locally, for example if the GPS clock lost its antenna and is in holdover mode, the smpSynch value will be 1. A clock holdover time depends on the quality of the crystal oscillator it is configured with. When an SV relay is subscribed to an MU with smpSynch 1, protection will still be enabled, thus design engineers should also consider the holdover capability within the clocks. However, when sympSync drops to 0, indicating no synchronization, protection may be disabled depending on the programming and subscribing relay used [12].

When subscribing to current from multiple MUs, time synchronization is important because, for 87L line protection, all local current is summed before transmission. For DSS applications, with no direct analog connection and thus an additional channel delay, this local addition relies on commonly synched MU and SV relays. Once that local current is aligned, it is then transmitted to align with the remote relay's current for differential calculations. When using the ping-pong method, it is ok if the remote line relay and MU are synched to a different time source than that of the local relay and MU if, within that system, the SV relay and MU are synched to the same source so its local current can be aligned if from different MUs. For the SV relay to align the transmitted local and remote currents, it needs to know the additional delay the remote SV relay waited to transmit its current, DSS channel delay, to add to the communications channel delay as calculated by the clock offset ping-pong method [13]. The second DSS setting delay introduced for line relays, remote end data acquisition delay (87RDLY), is set to the remote-end DSS delay of that channel, CH_DLY, if an SV relay or if a traditional relay, set to OFF. For example, in the test case shown in Fig. 10, an 87L scheme involves one DSS relay and one traditional line relay.

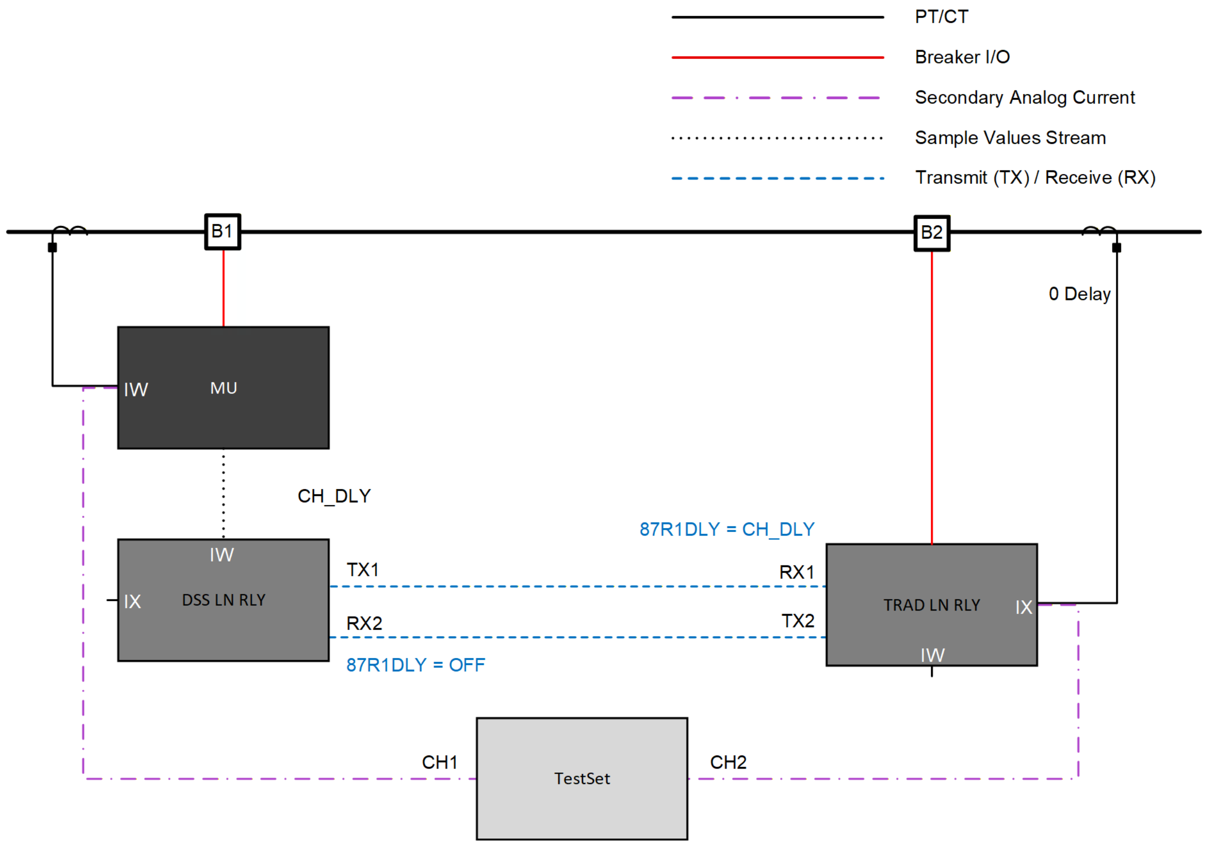


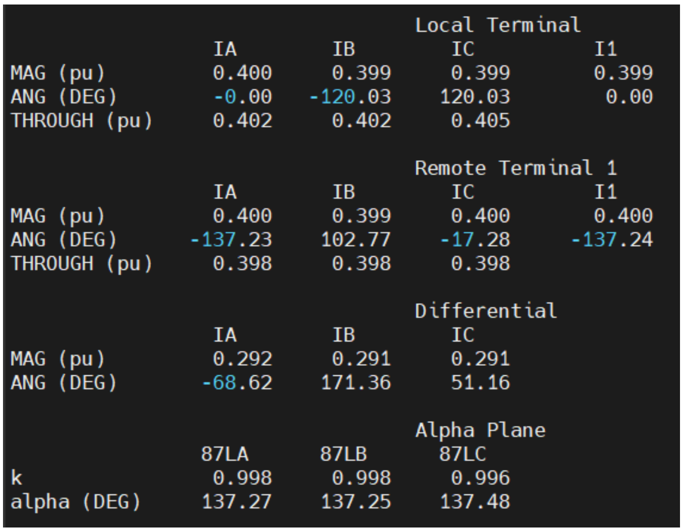
Fig. 10 87L Scheme Setup With DSS Line Relay and Traditional Line Relay

To see the impact of incorrectly set data acquisition delays in a mixed relay type 87L scheme on the differential calculations, the 87RDLY in the DSS relay for the Fig. 10 setup was set correctly and then incorrectly. In both cases, the test set injects the same current magnitudes at the same angles. Because the remote end is a traditional relay, the 87RDLY within the DSS relay should be set to OFF, as there is no delay from the time the remote line relay receives and processes the analog current. Current was injected into both relays, simulating load conditions. On the other hand, the 87RDLY for the traditional relay should be set exactly to the remote DSS end, CH_DLY, to allow compensation for the channel delay for the digital SV relay. Fig. 11 shows the resulting alpha plane calculations, where the current magnitude ratio comes out to exactly 1 and the angle to exactly 180 degrees.

			Local Terminal	
	IA	IB	IC	I1
MAG (pu)	0.400	0.399	0.399	0.399
ANG (DEG)	-0.03	-120.03	120.05	0.00
THROUGH (pu)	0.406	0.401	0.403	
			Remote Terminal 1	
	IA	IB	IC	I1
MAG (pu)	0.400	0.400	0.400	0.400
ANG (DEG)	-177.27	62.81	-57.17	-177.21
THROUGH (pu)	0.398	0.398	0.399	
			Differential	
	IA	IB	IC	
MAG (pu)	0.019	0.020	0.019	
ANG (DEG)	-89.75	149.07	27.85	
			Alpha Plane	
	87LA	87LB	87LC	
k	1.000*	1.000*	1.000*	
alpha (DEG)	180.00*	180.00*	180.00*	

Fig. 11 Correct 87RDLY in DSS Relay (OFF)

In the next scenario, the 87RDLY in the DSS relay for that of the remote-end traditional relay was incorrectly set to 2 ms. Fig. 12 shows the impact on the alpha plane calculations. For the same injected values, the line relay shows the local and remote current of only 137 degrees. With a 2 ms difference in the correct 87RDLY setting, where 1 ms misalignment corresponds to a 21.6-degree shift in current, 137 degrees nearly equals the theoretical value of 43.2 degrees (180 – 137 = 43) [14].



Local Terminal

	IA	IB	IC	I1
MAG (pu)	0.400	0.399	0.399	0.399
ANG (DEG)	-0.00	-120.03	120.03	0.00
THROUGH (pu)	0.402	0.402	0.405	

Remote Terminal 1

	IA	IB	IC	I1
MAG (pu)	0.400	0.399	0.400	0.400
ANG (DEG)	-137.23	102.77	-17.28	-137.24
THROUGH (pu)	0.398	0.398	0.398	

Differential

	IA	IB	IC
MAG (pu)	0.292	0.291	0.291
ANG (DEG)	-68.62	171.36	51.16

Alpha Plane

	87LA	87LB	87LC
k	0.998	0.998	0.996
alpha (DEG)	137.27	137.25	137.48

Fig. 12 Incorrect 87RDLY in DSS Relay (2 ms)

In summary, the channel delay, CH_DLY, within the SV relay buffers the incoming SV streams so they are not sent to the protection algorithms until the CH_DLY has elapsed. The 87RnDLY is an additional line relay-specific setting that allows the local end to know how long the remote relay has waited to send its local current, which must be set to the correct remote-end CH_DLY or to OFF if a traditional relay is used; otherwise, the alpha plan calculation will incorrectly align the local and remote current and thus cause a misoperation. Therefore, it is critical to accurately determine the network delay, set the channel delay accordingly, and ensure that the channel delay is extended to the remote end and coordinated with the relay types used in the 87L protection scheme.

3.3. Networking

The communications network is an important aspect in DSS, where critical protection functions are tightly coupled with high-speed data exchange. With the transition from a traditional hardwired scheme to a network-based DSS, both the reliability and performance of the network directly impact the protection system. In a traditional system, the only network within the substation was intended for SCADA and engineering access data collection and equates to the station bus (SB), as mentioned in the IEC 61850 standards. This network system design and management have historically been considered the responsibility of a business system network engineer action and have fallen under the purview of information technology staff. The IEC 61850 SB data flow is accomplished by identifying communications links and parameters between computers, controllers, and relays in the Substation Configuration Description (SCD) file. Data flow is not supported in the SCD file for all non-IEC 61850 protocols, such as DNP3, Telnet, FTP, HTTPS, and private configuration protocols used by some suppliers. There is no standards-based method to design, manage, or maintain these communications.

The introduction of a PB that replaces the hardwire signals with a network needed a different approach to maintenance and management. As designed at the utility, the PB and SB are two physically separate networks, with different ownership responsibilities. The PB only included Layer 2 SV messages, Protection-related GOOSE messages, and PTP time synchronization protocols. These critical actions on the PB require that it be designed by an operational technology specialist. In DSS applications, the protection engineer is defining the data flow by establishing communications links and parameters between different relays and MUs in the SCD file. Reference [15] describes different use cases and use of static- and autorouting based on the SCD file. Among some the technologies mentioned, software-defined networking (SDN) is one. Along with a robust network, accurate monitoring of the system is required.

SDN technology offers a deterministic approach where the traffic in the network is preplanned and failure scenarios are precomputed. The flow rules are defined to ensure low latency, minimize jitter, and provide high-speed reliable communication. SDN also offers a standardized way to create data flow rules for the communications not supported in the SCD, including the previously mentioned non-IEC 61850 protocols, such as DNP3, Telnet, FTP, HTTPS, and private configuration protocols used by some suppliers.

SDN also offers zero-touch deployment [16] where the flows/circuits are created based on the communications architecture and data flow diagram using network management system.. The implementation also offers a simplistic approach where the GOOSE, SV-based network flows are built directly by parsing through the SCD file created. The utility leveraged the SDN methodology for programming and configuring the flows for the PB based on the data flow identified in the SCD file.

For line protection application, the PB network must be robust and resilient to withstand failures without compromising protection. Resiliency is achieved by implementing redundancy through the supervision of PRP duplication and the alarming of detected PRP faults. PRP works by sending duplicated frames over two independent networks (local-area network [LAN] A and LAN B). Every frame is transmitted simultaneously on both networks, with corresponding PRP trailers. The receiving device accepts the first arriving frame and discards the duplicate. This discard without supervision masks a fault that creates an undetectable n-0 condition.

For the laboratory system setup, there is one SDN switch per each LAN network making a total of four SDN switches in the PB (System A – PRP LAN A and LAN B, System B – PRP LAN A and LAN B). The SDN controller configures all four PB networks independently, ensuring isolation and eliminating traffic interference. SDN provides automated flow provisioning and precise traffic engineering, enabling seamless scalability while maintaining strong protection performance.

In DSSs, network disturbances such as increased network path delay, packet loss, corrupted messages, link/switch failures, and broadcast storms can directly impact protection. Thus, continuous monitoring and proactive maintenance is essential to track any abnormalities that would lead to network issues and for reliable line protection.

For a PRP-based redundant network, in the event of failure of one of the networks, the protection remains in service as the other network is active and forwarding traffic. But when both the process networks are lost, the relay loses protection. Without monitoring, a faulted data path in a redundant system will remain a hidden failure until manual testing or failure of the duplicate data path. PRP does not alarm N-1 and does not survive N-2 failure scenarios [17]. To increase the availability of the PB system, constant supervision is required. IEC 61850 Logical Nodes (LNs) such as physical communication channel supervision (LCCH) are used to validate primary and redundant channel health and error counters over MMS. LN extensions, including counter of frames missing on the redundant channel for internet protocol, GOOSE messaging, and SV, provide detection and alarming of PRP faults.

SNMP is used to monitor network health by collecting information like link status, number of packets received/transmitted, and bandwidth usage from the network switches. This enables real-time alerting in case of any network disturbance and also supports preventative maintenance.

Testing devices, like network analyzers, can be used to troubleshoot both the PRP networks and identify any discrepancies in communications. The collected information can be displayed on the HMI screens and it is suggested to be sent as actionable alarms for operator’s attention.

Fig. 13 shows an example HMI screen with the information received from the PB LCCH logical node.

The IEC 61850 standard also supports GOOSE and SV supervision based on the services tag “SupSubscription” and provides the LNs for GOOSE subscription (LGOS), SV subscription (LSVS), and time master supervision (LTMS) for monitoring GOOSE, SV, and PTP messages. The information from these LNs is collected over MMS for monitoring and alerting in case of unexpected conditions.

The GOOSE messages subscribed by the line relay/MU for all critical protection GOOSE messages can be monitored via logical node LGOS over MMS. This monitoring enables the collection of information such as GOOSE subscription status, total downtime, maximum downtime, GOOSE errors, and corresponding error counters. The LGOS was extended as defined in IEC 61850, and additional data attributes were added to allow further granular monitoring. Fig. 14 shows an example HMI screen displaying GOOSE diagnostics.

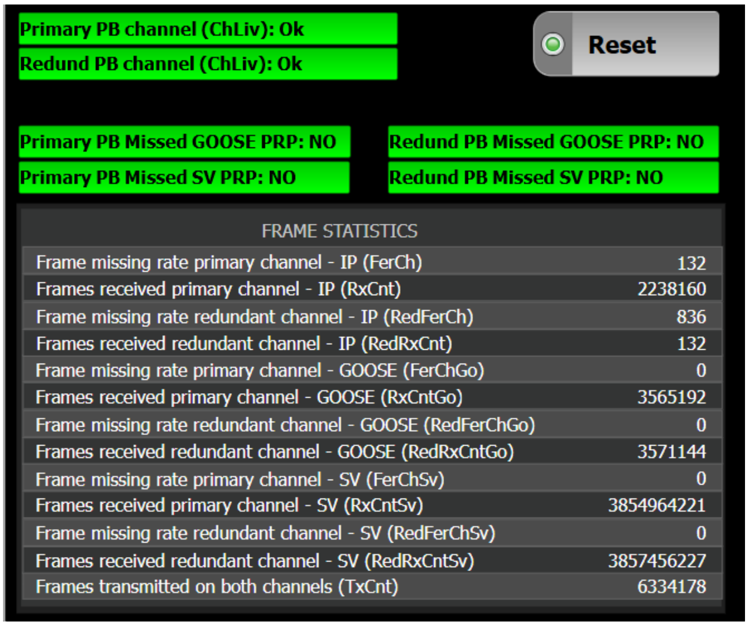


Fig. 13 LCCH Statistics

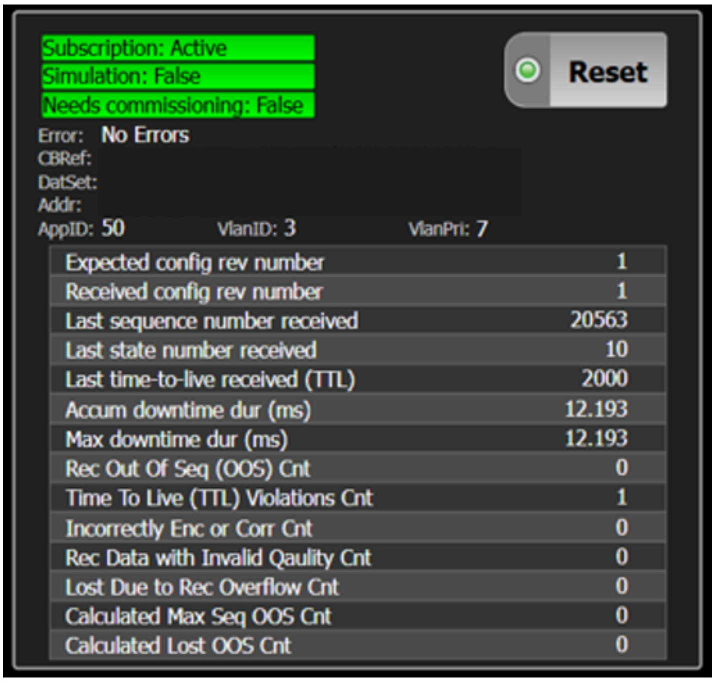


Fig. 14 GOOSE Statistics

The SV streams subscribed by the line relay from the merging unit can be monitored via the LSVS logical node over MMS. This monitoring enables the collection of information such as SV stream subscription status, time synchronization state, network delay, total downtime, maximum downtime, SV errors, and the number of SV streams that are interpolated or discarded. Fig. 15 depicts an example HMI screen displaying SV diagnostics.

In addition to network traffic monitoring, high-accuracy time synchronization is very important in the PB to correctly align the SV streams published by the MUs (see Fig. 16). The LTMS logical node is used to gather time synchronization-related information, such as time source identity, clock source identity, and accuracy. Any drift in the accuracy of the synchronization can be captured and alerted to take corrective actions.

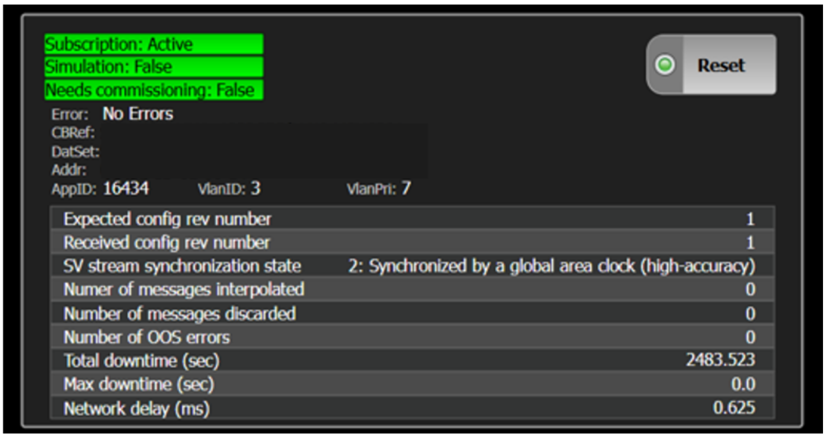


Fig. 15 SV Stream Statistics

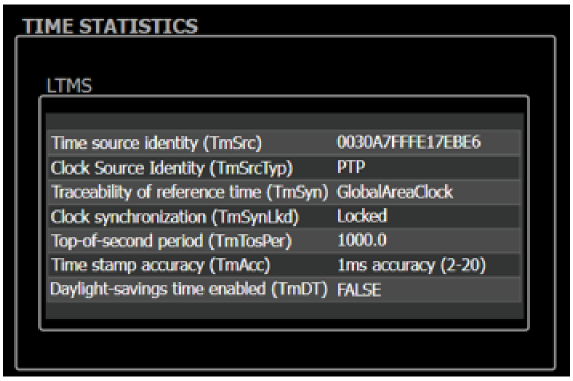


Fig. 16 Time Statistics

This information collected from the relays can be very helpful in doing routine maintenance to ensure network stability and for troubleshooting network failures or disturbances. These can be visualized in the HMI or forwarded to a central management system for monitoring.

In addition to monitoring the network, it is essential to accurately estimate the network bandwidth and select appropriate network speeds to avoid congestion and potential data loss. In a PB network, SV traffic produces a continuous high data rate, while GOOSE messages create transient traffic bursts during state changes. In addition, PTP communications further contributes to the overall network load.

Considering the system to be based on the IEC 61869-9 standard, the SV transmission variants are described using the following notation:

F f S s I i U u

where:

- f denotes the digital output sampling rate, expressed in samples per second;
- s represents the number of ASDUs (samples) contained within a single sampled value message;
- i is the number of current quantities included in each Application Service Data Unit (ASDU);
- u is the number of voltage quantities included in each ASDU.

An equivalent configuration to IEC 61850-9-2LE for a 60 Hz power system is expressed as F4800S1I4U4, where it always needs four current and four voltage channels per stream.

Table I presents bandwidth estimations for several commonly used SV variants.

Table I
NETWORK BANDWIDTH CALCULATION

		F4800S1I4U4	F4800S1I6U6	F4800S2I6U6	F4800S1I18U6	F4800S2I18U6
System Freq (Hz)	**f**	60	60	60	60	60
Sampling Rate	**F**	80	80	80	80	80
Bytes/Channel	**B**	8	8	8	8	8
Number of Channels	**C**	8	12	12	24	24
Number of ASDU	**S**	1	1	2	1	2
ETH Overhead (in Bytes)	**H**	42	42	42	42	42
SV Header (in Bytes)	**sh**	8	8	8	8	8
Typical ASDU Header (in Bytes)	**ah**	30	30	30	30	30
Bandwidth (Mbps)		5.6	6.8	4	10.5	5.8

These bandwidth figures are approximate and may vary. The variation is primarily influenced by differences in ASDU header content—such as the length of the svID—as well as the use of network redundancy protocols like PRP or High-Availability Seamless Redundancy (HSR). To accurately determine the required network bandwidth, the following components must be considered:

- Ethernet overhead, including preamble, media access control and virtual local-area network (VLAN) headers, frame check sequence (CRC), and optional PRP trailers;
- SV PDU headers, including fields such as AppID and length;
- ASDU header elements for each ASDU, such as svID, smpCnt, confRev, smpSynch, and related fields;
- ASDU payload data, calculated as the number of channels multiplied by 8 bytes per channel.

A critical aspect of ASDU header calculation is the inclusion of not only the nominal size of each information element (i.e., svID), but also the associated ASN.1 Basic Encoding Rules overhead, which consists of Tag, Length, and Value fields. Details of this encoding structure are defined in IEC 61850-9-2, Annex A.

In practical substation implementations, the predominant configurations are F4800S1I6U6 for circuit breaker applications and F4800S1I18U6 for transformer protection and measurement functions. The maximum calculated data bandwidth from the MU to the network switch is approximately 11 Mbps.

IEC 61869-9 also defines both minimum and maximum limits on the number of current and voltage quantities supported per SV stream on a 100 Mbit/s Ethernet network. At a minimum, the standard allows the transmission of one current and one voltage quantity. For a 100 Mbit/s network, the maximum supported quantities are defined as follows: up to 24 quantities for general measurement and protection applications, up to 8 quantities for quality metering applications, and up to 24 quantities for dc control applications.

These bandwidth calculations are essential for determining the required network speeds on switch ports and end devices. For example, a line relay subscribing to two MUs using the F4800S1I6U6 variant must support approximately 13–14 Mbps of SV traffic. In contrast, a low-impedance bus differential application can easily reach 60–70 Mbps—representing 60–70 percent of the capacity of a 100 Mbps link. To maintain adequate performance margins, it is recommended that network designs limit steady-state utilization to no more than 50–60 percent of rated bandwidth.

With this safety margin in mind, appropriate port speeds must be selected for both trunk links between switches and access ports connected to hosts. Practical testing showed that trunk ports should use at least 1 Gbit/s connections to ensure sufficient headroom for SV traffic, GOOSE messaging, and PTP synchronization.

4. Testing of DSS Line Protection

Transparency is a key consideration for stakeholders evaluating the migration from conventional protection schemes to DSSs. In addition to understanding the anticipated benefits, it is essential to identify performance differences and potential limitations so that protection engineers can assess risk and implement mitigation measures where required.

End-to-end testing was conducted to evaluate and compare the tripping performance of a DSS-based protective relay with that of a conventional relay. The testing program also included monitoring the startup time of a DSS relay. To come to a quantitative value that could be later compared to similar tests, the time between the relay enabling and the relay declaring a trip was noted. Fault current was injected into the MU to determine the time required for a sampled-value (SV) relay to detect the fault condition after turn on and for the associated merging unit to assert its output.

Additional testing was performed to assess DSS relay behavior when concurrently receiving process-bus messages representing real system conditions and simulated messages that did not include a simulation flag. Only a single representative test case is presented in this paper. However, it is recommended that standard line-protection performance testing be conducted over a full range of fault locations, including close-in and end-of-line faults. Furthermore, collection of multiple datasets is recommended to allow statistical evaluation of operating times and to support meaningful performance comparison between DSS-based and conventional protection systems.

The test setup for all the following tests is shown in Fig. 10.

4.1. Time From Fault Injection to Trip Output Operation

To compare the time from when a fault occurs on a system to when a relay issues its output contact to trip the breaker, the following test was performed:

- Inject fault current via test set into MU and Traditional line relay at the same time. For consistency, the same fault type was injected into both relays to rule out different element processing times assuming negligible firmware timing differences.
- Record the time from fault injection to:
  - The MU asserting its trip output contact. Fig. 17 below shows the Sequential Events Recorder (SER) for both the MU and SV relays for additional timing details.
  - The traditional relay asserting its output contact.

Fig. 18 below shows the recorded starting time of the test set from the time the same fault type was injected into the MU and the traditional relay to the time the MU output and traditional relay output operated. In the limited testing that was done, it was observed that the time (Tact) is longer for that of a DSS system than a traditional relay. Based on the preliminary test results, it was determined to conduct additional testing in accordance with standard line-protection test procedures to obtain a larger sample of data for timing measurements and to enable a more comprehensive round-trip operating time analysis, including processing time across each device, PIU, switches, user-defined relay logic. The tripping times and other information on the GOOSE performance is made available in the manufacturer's protocol implementation extra information for testing (PIXIT) documentation. Running these tests, help understand the protection the accuracy of the performance parameters and timing performance. When comparing end-to-end trip timing differences, engineers shall keep the channel delay and GOOSE messaging delays in mind.

```
                                          Date: 03/25/2026  Time: 12:48:06.74
9
EVOLUTION SUB                             Serial Number:
FID=
#     DATE        TIME           ELEMENT             STATE
12    03/25/2026  12:45:33.8437  TRIP                ASSERTED
11    03/25/2026  12:45:33.8437  87OP                ASSERTED
10    03/25/2026  12:45:33.8457  PSV23               ASSERTED
9     03/25/2026  12:45:33.8457  PSV29               ASSERTED
8     03/25/2026  12:45:33.8457  OUT205: COGEN KEY   ASSERTED
7     03/25/2026  12:45:33.8457  OUT206: COGEN FUTURE ASSERTED
6     03/25/2026  12:45:35.8102  TRIP                DEASSERTED
5     03/25/2026  12:45:35.8102  87OP                DEASSERTED
4     03/25/2026  12:45:35.8122  PSV23               DEASSERTED
3     03/25/2026  12:45:35.8122  PSV29               DEASSERTED
2     03/25/2026  12:45:35.8122  OUT205: COGEN KEY   DEASSERTED
1     03/25/2026  12:45:35.8122  OUT206: COGEN FUTURE DEASSERTED

=>
Exclude "111LA" from MultiExec mode
1     03/25/2026  12:45:36.0158  OUT204: S TRIP 2    DEASSERTED
=>SER
                                          Date: 03/25/2026  Time: 12:48:06.72
7
Evolution Sub                             Serial Number:
FID=
#     DATE        TIME           ELEMENT             STATE
8     03/25/2026  12:45:33.8493  PSV04               ASSERTED
7     03/25/2026  12:45:33.8493  OUT202: S TRIP 1    ASSERTED
6     03/25/2026  12:45:33.8493  OUT204: S TRIP 2    ASSERTED
5     03/25/2026  12:45:33.8493  VB042               ASSERTED
4     03/25/2026  12:45:35.8158  PSV04               DEASSERTED
3     03/25/2026  12:45:35.8158  VB042               DEASSERTED
2     03/25/2026  12:45:36.0158  OUT202: S TRIP 1    DEASSERTED
1     03/25/2026  12:45:36.0158  OUT204: S TRIP 2    DEASSERTED
=>
Exclude "Serial (COM)" from MultiExec mode
```

Fig. 17 SER of SV Relay (Top) and of MU Relay (Bottom)

Time Assessments: State Sequencer in MU-1022.occ

					Time Assessment			
	Name	Ignore before	Start	Stop	Tnom	Tdev-	Tdev+	Tact
1	DSS		State 2	Bin. in 1 0>1				163.7 ms
2	TRAD		State 2	Bin. in 2 0>1				158.2 ms

Fig. 18 Test Set Recorded Trip Times for DSS Relay vs. Traditional Relay

Given that DSS-based relays inherently introduce tripping latency, utilities should collect a detailed testing data set for their applicable systems to allow evaluation of appropriate mitigation strategies. Such strategies may include the use of high-speed output contacts to offset the cumulative delays introduced by DSS architecture. In addition, relay engineers should ensure that relay logic implemented in SV-based relays and MUs is optimized for efficiency and does not introduce unnecessary logic processing delays.

4.2. Turn-On Test

When typical traditional relays turn on, protection is available in less than 10 s. Due to the changes in data acquisition, the relays and PIUs have different startup times to ensure reliable SV data are available. These test steps were performed to note how long it takes a DSS line protective relay to trip a breaker upon turning on into a fault condition. The fault condition is selected to benchmark against a quantifiable startup event of the test, to a quantifiable end event (i.e., TRIP). The startup times for the test sequence will vary depending on whether the PIU or the relay is restarted.

The test steps are:

- Turn off the relay.
- Inject the fault current (87L for consistency).
- Turn on the relay.
- Calculate the difference between the relay turn-on in the SER vs. when the protective relay issues the trip under the same fault conditions.

The time it takes for a DSS relay to trip its breaker is considerably longer than that of a traditional relay. It is going through more processing, as shown from the SER in Fig. 19, Fig. 20, and Fig. 21 below. Before a trip can be issued, all the DSS block bits must de-assert, which is also dependent on the PTP being established. Due to the type of fault being injected, additional processing time was needed for the combined 87L block bit to de-assert before the trip was first issued, as seen in Fig. 20.

```
=>SER 150

Line RLY A                                      Date: 03/25/2026  Time: 14:28:05
                                                Serial Number:

FID=

#     DATE        TIME            ELEMENT              STATE
133  03/25/2026  14:25:14.8742   Power-up             Group 1
132  03/25/2026  14:25:15.0747   Relay                Enabled
131  03/25/2026  14:25:15.0747   87CH1OK              ASSERTED
130  03/25/2026  14:25:15.0747   87CH1AL              ASSERTED
129  03/25/2026  14:25:15.0747   IN209: CB1 NOT BYPS  ASSERTED
128  03/25/2026  14:25:15.0747   IN210: CB2 NOT BYPS  ASSERTED
127  03/25/2026  14:25:15.0747   PSV16                ASSERTED
126  03/25/2026  14:25:15.0747   PSV50: PBUS A FAIL   ASSERTED
125  03/25/2026  14:25:15.0747   PSV50: PBUS B FAIL   ASSERTED
124  03/25/2026  14:25:15.0747   PLT01                ASSERTED
123  03/25/2026  14:25:15.0747   PLT07                ASSERTED
122  03/25/2026  14:25:15.0747   ALT01:BF-VCB1 DC01   ASSERTED
121  03/25/2026  14:25:15.0747   ALT02:BF-VCB2 DC02   ASSERTED
120  03/25/2026  14:25:15.0747   ALT03:LINE PROT DC03 ASSERTED
119  03/25/2026  14:25:15.0747   SALARM               ASSERTED
118  03/25/2026  14:25:15.0747   OUT203:PILOT CUT-IN  ASSERTED
117  03/25/2026  14:25:15.0747   IXIS                 ASSERTED
116  03/25/2026  14:25:15.0747   IWIS                 ASSERTED
115  03/25/2026  14:25:15.0747   LINK5D               ASSERTED
114  03/25/2026  14:25:15.0747   LINK5C               ASSERTED
113  03/25/2026  14:25:15.0747   LINK5B               ASSERTED
112  03/25/2026  14:25:15.0747   LINK5A               ASSERTED
111  03/25/2026  14:25:15.0747   TQUAL1               Asserted
110  03/25/2026  14:25:15.0747   TQUAL2               Asserted
109  03/25/2026  14:25:15.0747   TQUAL4               Asserted
108  03/25/2026  14:25:15.0747   TQUAL8               Asserted
107  03/25/2026  14:25:15.0747   87BLK                ASSERTED
106  03/25/2026  14:25:15.0747   PTP_RST              Asserted
105  03/25/2026  14:25:15.0747   SVS01OK              ASSERTED
104  03/25/2026  14:25:15.0747   SVS02OK              ASSERTED
103  03/25/2026  14:25:15.0747   IAWBK                ASSERTED
102  03/25/2026  14:25:15.0747   IBWBK                ASSERTED
101  03/25/2026  14:25:15.0747   ICWBK                ASSERTED
100  03/25/2026  14:25:15.0747   IAXBK                ASSERTED
99   03/25/2026  14:25:15.0747   IBXBK                ASSERTED
98   03/25/2026  14:25:15.0747   ICXBK                ASSERTED
```

Fig. 19 DSS Line Relay SER

```
15   03/25/2026   14:25:42.0308   VCZBK                DEASSERTED
14   03/25/2026   14:25:42.0308   87SVTBK              DEASSERTED
13   03/25/2026   14:25:42.2808   87BLK                DEASSERTED
12   03/25/2026   14:25:42.4203   TRIP                 ASSERTED
11   03/25/2026   14:25:42.4203   87OP                 ASSERTED
10   03/25/2026   14:25:42.4228   PSV23                ASSERTED
9    03/25/2026   14:25:42.4228   PSV29                ASSERTED
8    03/25/2026   14:25:42.4228   OUT205: COGEN KEY    ASSERTED
7    03/25/2026   14:25:42.4228   OUT206: COGEN FUTURE ASSERTED
6    03/25/2026   14:26:42.3183   TRIP                 DEASSERTED
5    03/25/2026   14:26:42.3183   87OP                 DEASSERTED
4    03/25/2026   14:26:42.3203   PSV23                DEASSERTED
3    03/25/2026   14:26:42.3203   PSV29                DEASSERTED
2    03/25/2026   14:26:42.3203   OUT205: COGEN KEY    DEASSERTED
1    03/25/2026   14:26:42.3203   OUT206: COGEN FUTURE DEASSERTED

=>
```

Fig. 20 DSS Line Relay SER (Cont.)

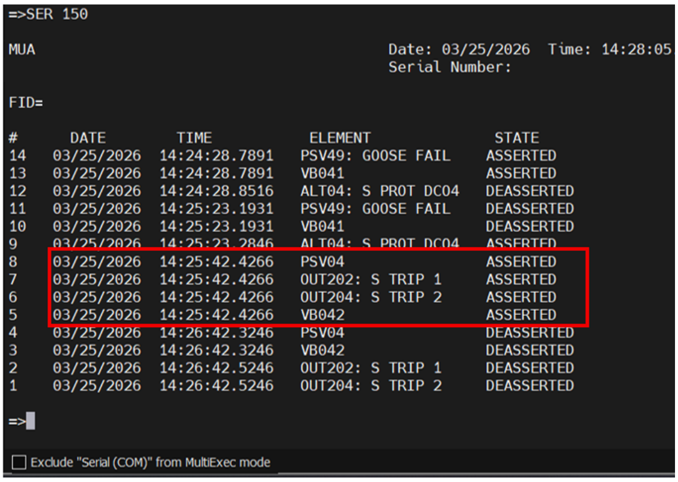


Fig. 21 DSS MU Relay SER

4.3. Impact of Spoofed SV Stream With Simulation Flag Set to FALSE

With the introduction of DSS, testing tools have also been updated. IEC61850 Edition 2.1 test and simulation modes give utilities flexibility in how they test their systems. IEC61850 SV, GOOSE, and PTP are designed to function on private networks isolated from bad actors like the hardwired systems they replace. Communications assisted systems are subject to the same vulnerability as the scenario where a hardwired input is intentionally or accidentally replaced by a test, simulation, or malicious signal, The same intentional design to support testing and commissioning via test and simulation messages can result in unwanted operations when done incorrectly. This is not a flaw, but rather an essential tool that must be managed and the care and attention that it deserves.

IEC 61850 Test Sets can inject sampled value streams or GOOSE messages into the PB network and can simulating a merging unit by using the SCD file. An SV relay determines what signals to process and act upon, the real ones or the test set simulated ones, by checking for a simulation flag in the GOOSE or SV header. Normally, the test set will be configured to publish samples values or GOOSE messages with the simulation flag set to TRUE. An SV relay put into simulation mode, LPHD.Sim.stVal is true, will still act upon and process the real messages with simulation flag set to false until it receives its first simulated message and then it switches over to acting upon those simulated messages even while real messages are still being published. The relay will then only switch over to using real messages when it is taken out of simulation mode, LPHD.Sim.stVal is false. However, because test software have the option to publish SV or GOOSE messages with the simulation flag set to false, it is important to know how a relay will respond when it receives both real messages from the real merging unit and real messages from a test set mimicking a real merging unit to mitigate any risks [18] [19]. Testing has been performed to determine relay behavior in such a case.

For this test, the test set was set up to inject analogs into MUA-12 IW terminal and to mimic MUA-12 by publishing SV from its IW terminal but with the simulation flag set to FALSE as seen in Fig. 22 and Fig. 24. To determine what current an SV relay operates on, different magnitudes were published. With a CT ratio of 600, an analog secondary injection of 1 A corresponds to 600 A primary, while SV streams were published as 1.2 kA primary.

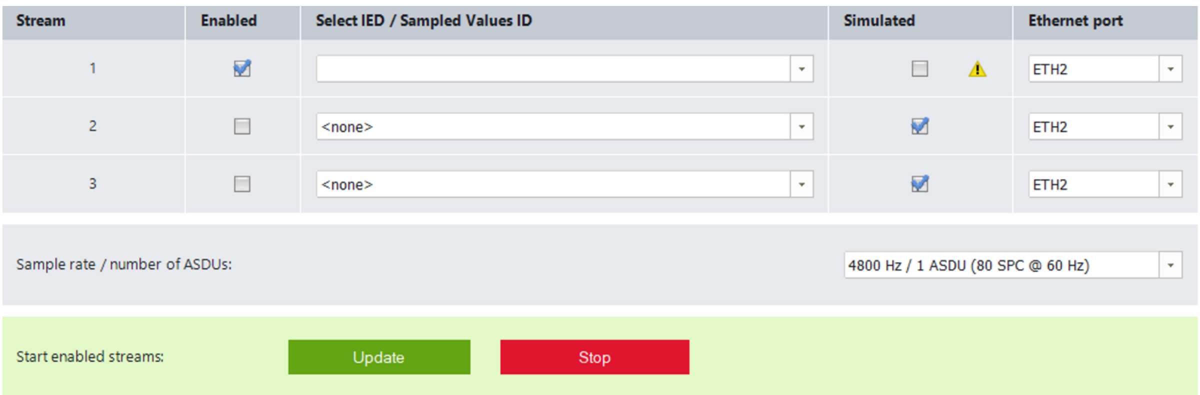


Fig. 22 Test Set Setup for Publishing SV Streams With Simulation Flag Set to FALSE

Analog Outputs			
Set Mode	Direct		
IAW	1.200 kA	-52.00 °	60.000 Hz
IBW	1.200 kA	128.00 °	60.000 Hz
ICW	1.200 kA	120.00 °	60.000 Hz
IAW REAL	1.000 A	0.00 °	60.000 Hz
IBW REAL	1.000 A	-120.00 °	60.000 Hz
ICW REAL	1.000 A	120.00 °	60.000 Hz

Fig. 23 SV Streams Injected in Primary Values; Analogs Injected in Secondary Values

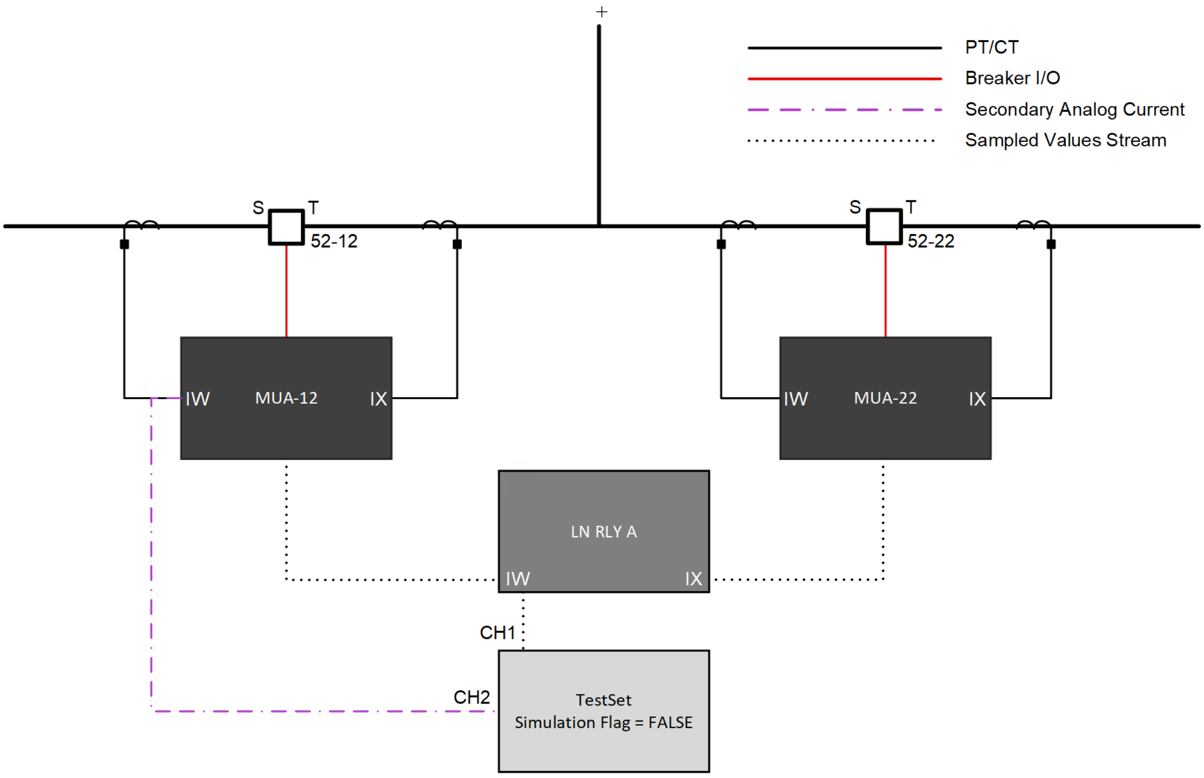


Fig. 24 Setup for MUA-12 Analog and SV Injections From the Test Set

From the perspective of the line relay, a COMM SV response issues a warning code of "out of sequence." This warning code is displayed for an out-of-sequence condition, identified when the smpCnt value between the received SV messages is not sequential [11]. The test set SV stream is published directly into the PB network, whereas the analogs injected into the MU need to first be processed by the MU and are then published into the PB network. Thus, with the current setup, the test set streams are received by the SV relay before the real streams. Issuing a metering command on the relay showed that the relay is using the streams that arrive later; in this case, the real MU streams. When the real MU is removed from the PB, the SV relay switches over to using the simulated real messages. Despite this warning code, no block bits are asserted, thus protection remains enabled. This is a concern because, without protection disabled, the relay can operate on the spoofed simulated messages if those messages are delayed long enough to be received after the real messages. See Fig. 25.

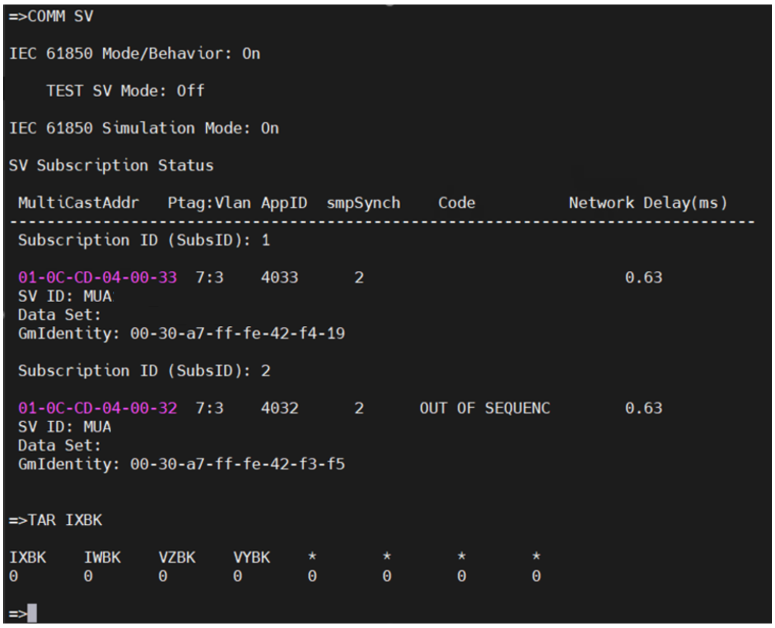


Fig. 25 Diagnostic View of Real and Simulated Real Messages

Based on these findings, this paper encourages protection engineers to consult with relay vendors and network engineers as to how the relay will respond when there is no time delay between receiving spoofed real messages and real MU messages. It is also recommend that diagnostics be in place to create and monitor alerts to detect duplicate messages coming in.

5. Optimal Placement of MUs

For the BAAH scheme in Fig. 1, each MU is wired to the CTs and potential transformers (PTs) on both the S and T sides of each breaker. This allows for subscription flexibility. For example, the line SV relay needs both line current and line voltage. If the bus is reconfigured, the line is fed from only 52-22; due to 52-12 and MUA-12 being out of service, protection needs to remain enabled. If the line relay subscribes to voltage from both MU-12 and MU-22, it may use an alternate line voltage setting to switch from its primary voltage source, MU-12, to MU-22 to keep protection enabled. This is only possible if both MUs are hardwired to the line PT. For a DSS solution, one of the main goals is to reduce the amount of copper wiring involved in the scheme; however, depending on the substation layout and distance from the MU cabinets in relation to the CTs and PTs, tapping two MUs into the line PT may reintroduce long lengths of copper wiring. CTs are not always located close to the PTs. Thus, utilities must also consider the optimal placement of the MU cabinets in relation to their protection needs and adaptability requirements. Wiring multiple MUs to the same CTs and PTs allows for more subscription flexibility by SV relays, but a balance must be found between the additional copper wiring required, the location of where the MU is placed, and the number of MUs. Utilities may consider adding multiple smaller form factor MUs close to each necessary CT and PT, thus reducing the copper wiring to each instrument transformer. However, this introduces additional dependency of the PB network, as SV relays will need to subscribe to more MUs, and increases the bandwidth on the PB network.

Utilities should also consider what happens when all communications are lost to the MU. In a DSS solution, the MU is the only relay with hardwired controls to trip and close the breaker; thus, if it cannot receive a trip command from a relay due to lost comms, the breaker will not trip under faulted conditions. Therefore, utilities should consider enabling backup protection within the MU directly. The utility discussed in this paper has enabled backup definite time ground and phase overcurrent that enabled when communications is both between both S and T side protection relays, not one or the other but both.

In summary, utilities must determine the quantity of MUs, the location of each MU, and the instrument transformer each MU taps into to strike a balance between limiting copper runs and protection requirements. They must also consider what backup protection is in place if the PB were to fail, since the MUs are the last line of defense against interrupting faults.

6. Conclusion

Migrating utility standards to a DSS framework introduces challenges and uncertainty, but understanding these obstacles and their mitigations helps reduce skepticism and build confidence in the transition. This paper addressed those concerns by sharing practical experience and lessons learned from implementing a DSS line differential protection application. This included considerations for designing an efficient PB to limit delays yet ensure security, adapting protection elements to be secure for DSS SV block conditions or loss of time synchronization, and how the location of MUs in the substation yard bring additional considerations.

7. References

[1] S. Bricker, C. Dryer, and S. Bodhankar, "Road Mapping an Electric Power Utility's Digital Substation Journey," proceedings of the 52nd Annual Western Protective Relay Conference, Spokane, WA, October 2025.

[2] R. E. Mackiewicz, "Overview of IEC 61850 and Benefits," proceedings of the IEEE PES Power Systems Conference and Exposition, Atlanta, GA, USA, 2006, pp. 623–630, doi: 10.1109/PSCE.2006.296392.

[3] G. Huon, P. Myrda, and P. Lindbad, "IEC 61850 Based Substation Automation Systems – Users Expectations and Stakeholders Interactions," Protection and automation (B5), Reference 819, CIGRE, 2020. Available: e-cigre.org/publications/detail/819-iec-61850-based-substation-automation-systems-users-expectations-and-stakeholders-interactions.html.

[4] D. Erwin, R. Pineda, M. Anderson, E. Udren, J. Bell, and N. Jones, "PG&E 500 kV Protection Standard Design and Development," proceedings of the 41st Annual Western Protective Relay Conference, Spokane, WA, October 2014.

[5] H. Miller, J. Burger, N. Fischer, and B. Kasztenny, "Modern Line Current Differential Protection Solutions," proceedings of the 36th Annual Western Protective Relay Conference, Spokane, WA, October 2009.

[6] G. Meyer, "Securing Protection in the SEL-400 Series Sampled Values Subscriber and TiDL Relays," SEL Application Guide (AG2023-07), 2025.

[7] IEC 61869-9, *Instrument Transformers* – Part 9: Digital Interface for Instrument Transformers, 2016.

[8] S. Chase, E. Jessup, M. Silveira, J. Dong, and Q. Yang, "Protection and Testing Considerations for IEC 61850 Sampled Values-Based Distance and Line Current Differential Schemes," proceedings of the 72nd Annual Conference for Protective Relay Engineers, College Station, TX, March 2019.

[9] B. M. Cockerham and J. C. Town, "Understanding the Limitations of Replaying Relay-Created COMTRADE Event Files Through Microprocessor-Based Relays," proceedings of the 20th Annual Georgia Tech Fault and Disturbance Analysis Conference, Atlanta, GA, May 2017.

[10] IEEE Standard C37.111-2013, *Measuring Relays and Protection Equipment* – Part 24: Common Format for Transient Data Exchange (COMTRADE) for Power Systems, 2013.

[11] *SEL-411L-2 Advanced Line Differential Protection, Automation, and Control System With Sampled Values or TiDL Technology*.

[12] J. Bettler, R. McDaniel, and D. Bowen, "Performance of IEC 61850 Sampled Values Relays for a Real-World Fault," proceedings of the 49th Annual Western Protective Relay Conference, Spokane, WA, October 2022.

[13] A. Ravi, V. Skendzic, V. Yedidi, C. Clark, and B. Janarthanan, "Channel Asymmetry Compensation for Line Current Differential Relays Without External Time Sources," proceedings of the 78th Annual Conference for Protective Relay Engineers at Texas A&M, College Station, TX, March 2025.

[14] E. Chen, B. Smyth, M. Van Rensburg, and M. Rajasekaran "It's About Time—Considerations and Requirements for DSS and Line Current Differential Applications," proceedings of the 76th Annual Georgia Tech Protective Relaying Conference, Atlanta, GA, May 2023.

[15] IEC TR 61850-90-22, *Communication Networks and Systems for Power Utility Automation* – Part 90-22: SCD Based Substation Network Automated Management With Visualization and Supervision Support, 2024.

[16] D. Bordon, R. Meine, S. Dayabhai, and J. Dearien, "Case Study: Implementing a Zero-Touch Deployment Methodology Using SDN to Improve the Security, Reliability, and Engineering of Substation Automation Systems in Slovenia," proceedings of the PAC World Conference 2023, Glasgow, UK, June 2023.

[17] M. Silveira, A. Rash, D. Dolezilek, and A. Shrestha, "Understanding the Impacts of Networks and Parallel Redundancy Protocol for Process Bus Applications," proceedings of the 17th International Conference on Developments in Power System Protection (DPSP 2024), Manchester, UK, March 2024.

[18] IEC 61850-7-1, *Communication Networks and Systems for Power Utility Automation* – Part 7-1: Basic Communication Structure – Principles and Models, 2020.

[19] IEC 61850-7-2, *Communication Networks and Systems for Power Utility Automation* – Part 7-2: Basic Information and Communication Structure – Abstract Communication Service Interface (ACSI), 2010.

8. Biographies

Shashank Bodhankar (Member, IEEE) his MS degree in electrical engineering from North Carolina State University, USA, and his BE degree in electrical engineering from the College of Engineering, Pune, India. He has over 15 years of experience in electrical power systems and automation, with a specialization in IEC 61850. He is currently a digital secondary system engineer expert with Pacific Gas and Electric Company (PG&E), San Francisco, CA, USA, where he focuses on IEC 61850-based system design, SCADA integration, and communications networks. In previous roles, he led the development of protection and control schemes for microgrids and industrial systems using MMS and GOOSE protocols. Mr. Bodhankar is a licensed professional engineer in the State of California. He is a member of IEEE.

Ashish Sharma (Member, IEEE) received his MS degree in power systems and electronics from the NYU Tandon School of Engineering (NYU), USA, and his BE degree in electrical engineering from Rajasthan Technical University, India. He has more than 14 years of experience in power system protection and control. He is currently an engineering manager at Schweitzer Engineering Laboratories, Inc. (SEL), Vacaville, CA, USA. He is a member of IEEE.

Rachel Oelsner received her BS degree in mechanical engineering, specializing in renewable energies, from UCSD and a Power Engineering Certificate from UCSD Extension (UC San Diego). She has nearly five years of experience in power system protection and control and various data concentration projects. She is currently a protection engineer at Schweitzer Engineering Laboratories, Inc. (SEL), in Vacaville, CA, USA.

Priyadharshini Guruprasad received her MS degree in electric power systems engineering from North Carolina State University, USA and BE degree in electrical and electronics engineering from SSN College of Engineering, Chennai, India. She has six years of experience in network automation and controls. She is currently an automation engineer at Schweitzer Engineering Laboratories, Inc. (SEL), in Vacaville, CA, USA.

Abstract—The transition to digital secondary systems marks a critical step in modernizing the U.S. electric power grid. By adopting IEC 61850 standards, utilities can achieve standardized, repeatable engineering designs that enhance operational efficiency, reduce life cycle costs, and improve system reliability. As part of its strategic roadmap for DSS implementation, the utility conducted a laboratory demonstration to validate concepts and approaches before field deployment.

This paper presents lessons learned from migrating an established utility line protection philosophy to an IEC 61850-based digital secondary system architecture. It details the design considerations and methodologies employed during implementation, focusing on practical aspects that influence protection system performance. Key topics include optimal placement of merging units relative to instrument transformers (current transformers and potential transformers) and breaker input/output interfaces within a representative 115 kV substation layout. The paper also addresses network topology

development and strategies for mitigating risks associated with reliability, routine maintenance, and comprehensive testing under network disruptions.

A significant portion of the discussion explores the impact of network performance and time synchronization on Sampled Values-based protection functions. These factors are critical to ensuring operational integrity and accurate responses for different failure modes. The paper highlights how latency, redundancy, and synchronization accuracy affect protection schemes and provides insights into engineering practices that enhance resilience.

Success criteria for the implementation included system availability, device redundancy, and process bus traffic performance. Comparative testing was conducted to evaluate the IEC 61850-based protection scheme against traditional hardwired protection, offering a clear perspective on performance differences and operational benefits. The findings underscore the importance of robust network design, precise time synchronization, and thorough validation testing in achieving reliable digital protection systems.

By sharing these experiences, the paper aims to provide actionable guidance for protection engineers tasked with deploying IEC 61850-compliant line protection schemes. The lessons learned serve as a foundation for developing resilient architectures that support future grid modernization initiatives while maintaining high standards of reliability and operational excellence.

20260617 • TP7258