Power Research - A Journal of CPRI, Vol 22(1), 2026 | pp. 57-65

Interoperable Line Differential Protection using IEC61850

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Keywords: GOOSE, Interoperable, Line Differential, MPLS-TP, Sampled Value

Article Received: 25-01-2026
Article Revised: 11-02-2026
Article Accepted: 22-02-2026

DOI: 10.33686/pwj.22.1.2026.57-65

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Abstract

This paper provides a comprehensive overview of the state-of-the-art interoperable digital line differential protection technology with the help of IEC61850, particularly Sampled Values (SV) and Generic Object-Oriented Substation Event (GOOSE) services, offering a highly flexible, interoperable, and robust communication infrastructure that can overcome challenges of interoperability limitations within C37.94. The challenges in transferring the sample values between substations are now addressed, which opens the gate to exchanging data in GOOSE and SV between substations. This paper describes the test setup and performance of two-terminal differential relays from the same vendor which is communicating in IEC61850 for transferring analog and digital signals via a Multiprotocol Label Switching – Transport Profile (MPLS-TP) network to perform line differential protection. It also proposes the modelling of multi-vendor line differential protection.

1. INTRODUCTION

The reliable operation of power systems is predicated on the effective protection of transmission lines, which form the arteries of electrical energy delivery. The prevalence of faults on transmission lines, estimated at approximately 80% of all system faults, necessitates protection strategies that are both highly selective and sensitive, ensuring prompt isolation of faulty segments while maintaining service continuity elsewhere in the grid. Line current differential protection, leveraging Kirchhoff's Current Law (KCL), has been widely adopted for its inherent selectivity and ability to detect low-magnitude fault currents.

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Traditional implementations of line differential protection require accurate measurement of line currents at both the local and remote ends of the protected section. While local Current Transformer (CT) outputs can be directly fed into protection relays, remote measurements must be transmitted reliably across considerable distances, typically via communication protocols such as C37.94[1]. Although C37.94 has served as a mainstay for such applications, the increasing digitalisation of substations and the proliferation of Intelligent Electronic Devices (IEDs) from diverse vendors have exposed certain interoperability challenges. The considerations and limitations of communication channels are explained in the study[2].

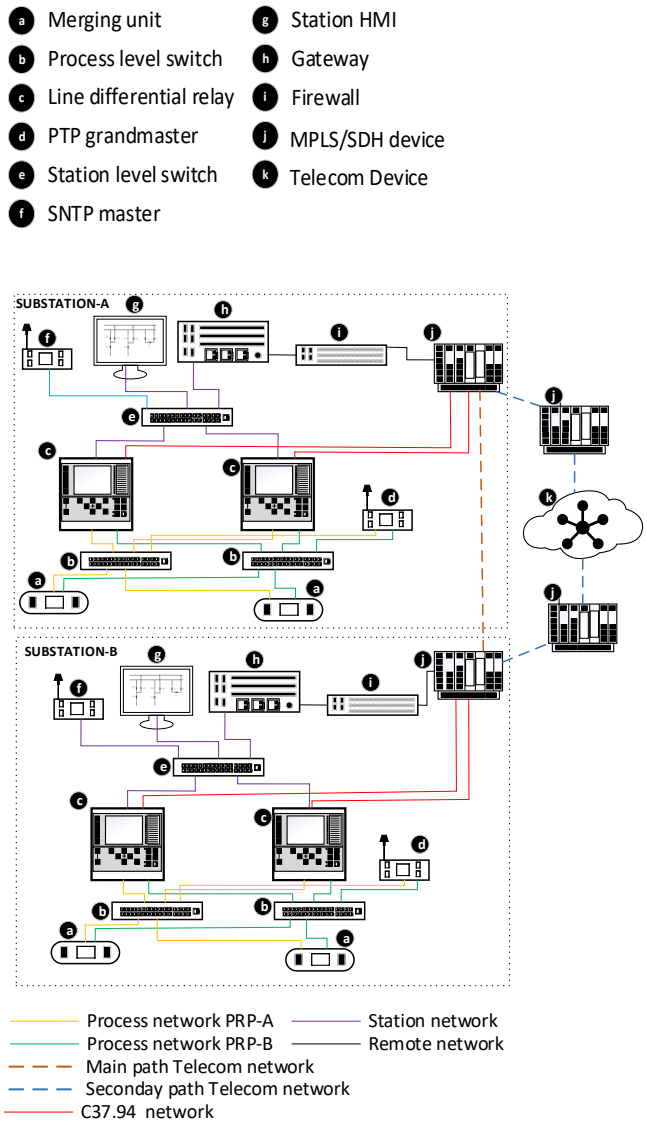


Figure 1. Architecture of a digital substation with C37.94-based line differential.

Guidance for differential protection is provided in the study 3, which describes the modelling for utilisation of IEC 61850 for line differential protection.

The advent of the IEC61850 standard, particularly its process bus (SV) and station bus (GOOSE) protocols, has revolutionised the communication paradigm in substations. IEC61850 provides a stringent yet flexible framework for ensuring interoperability, time synchronisation, and extensibility, enabling seamless integration across multi-vendor environments. IEC 61850 is a family of protocols that comprises Manufacturing Message Specification (MMS), GOOSE, SV and Precision Time Protocol (PTP).

Generic Object-Oriented Substation Event (GOOSE) messages leverage a publisher-subscriber paradigm; this allows multiple IEDs to simultaneously receive event notifications with deterministic latency, essential for protection and control functions that demand response times within milliseconds. The protocol's use of Ethernet Layer 2 frames ensures minimal overhead and rapid delivery, while sequence numbers and time-to-live fields enhance reliability and facilitate message supervision. The configuration of GOOSE messages is facilitated through standardised System Configuration Description Language (SCL) files, enabling system engineers to define the data sets, communication parameters, and subscription relationships among IEDs, which is described in the study[4].

IEC 61850-9-2[5] defines the mapping of SV services onto Ethernet frames, employing a publisher-subscriber model like GOOSE. SV messages encapsulate time-synchronised samples of analog signals, enabling multiple IEDs to receive and process the same measurement data for protection, metering, and control purposes. High sampling rates (*e.g.*, 4000 at 50 Hz and 4800 at 60 Hz samples per second for protection applications) generate substantial network

traffic, necessitating robust network infrastructure and quality-of-service mechanisms to guarantee timely delivery.

IEC 61850-9-3[7] was introduced specifying the use of the Precision Time Protocol (PTP). PTP enables sub-microsecond synchronisation accuracy across Ethernet networks, providing a deterministic temporal framework for substation operations.

A typical communication architecture of two adjacent digital substations with C37.94-based line differential via MPLS-TP is shown in Figure 1.

In the power system telecom network, Multi-Protocol Label Switching - Transport Profile (MPLS-TP) solution delivers a fully open standard, flexible and powerful technology. It meets the most stringent performance and availability requirements of traditional SDH/SONET transport while providing new and advanced packet capabilities for future network evolution. As a highly scalable and protocol-agnostic mechanism, MPLS-TP provides connection-oriented transport for packet networks in a truly multi-service approach. It leverages the pseudo-wire technology to transmit packet and TDM traffic over virtual circuits with high efficiency and operational simplicity.

Recent research and industrial practice have demonstrated the feasibility of achieving true digital line differential protection, wherein sampled values from one substation can be reliably transferred and processed at another. The authors[7] have implemented multi-vendor differential protection using Hitachi Energy's TEGO1 device.

2. FUNDAMENTALS AND EVOLUTION OF TRANSMISSION LINE DIFFERENTIAL PROTECTION

2.1 Principle of Operation

Line current differential protection operates on the fundamental principle of Kirchhoff's Current Law, which states that the algebraic sum of currents entering and leaving a node (or zone) must be zero. In a protected transmission line, this translates to a comparison of the vector sum of currents measured at both terminals. Under normal and external fault conditions, the sum is nominally zero; any significant deviation indicates an internal fault, prompting a trip command.

Classical architecture comprises CTs at both ends, with analog or digitised outputs relayed to protection devices. Accurate time alignment and synchronisation of these measurements are paramount, as even minor discrepancies can result in erroneous differential calculations.

2.2 Communication Requirements and Legacy Protocols

A defining feature of line differential protection is its reliance on communication channels to transmit remote current measurements. Legacy implementations have predominantly utilised the C37.94 protocol, designed for robust point-to-point optical communications as shown in Figure 2, offering fixed bandwidth and deterministic performance. While C37.94 has been effective in homogeneous environments, its limitations become apparent in the context of modern, multi-vendor digital substations:

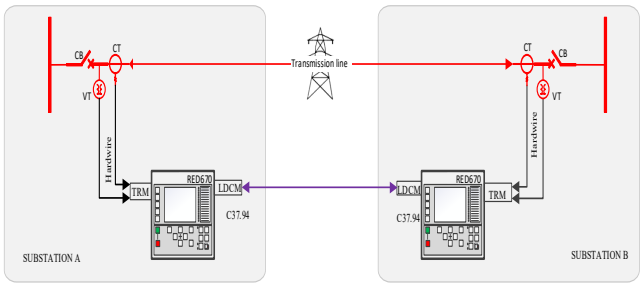


Figure 2. C37.94 Direct communication.

2.3 Synchronised measurement

Accurate time alignment of current samples from both end lines is typically achieved via echo communication between both end-line differential relays; one will act as time master and the other as slave.

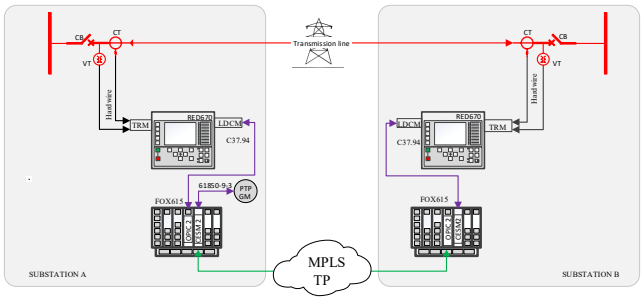


Figure 3. C37.94 Communication via telecom device.

2.4 Inflexibility

C37.94 is optimised for fixed-function, point-to-point links, making adaptation to evolving network topologies or integration with newer devices challenging.

In the later stage, with the help of improvements in the communication channels, point-to-point communication has been routed via communication devices such as SDH and MPLS, as shown in Figure 3.

2.5 Long Distance Communication

With the help of telecom devices, the communication distance for line differential protection has increased.

2.6 Synchronised Measurement

Accurate time alignment of current samples from both line ends is typically achieved via echo communication between the line differential relay and the telecom device (the telecom device will act as master).

2.7 Lack of Interoperability

Current standards such as IEEE C37.94 provide structure for the frame format and have not standardised the content of the frames used for line differential. This situation results in using the same vendor for line differential protection relays, and at times even the same firmware, due to discrepancies in the differential protection algorithms within vendors. This challenge impacts customers' operational flexibility and efficiency.

3. DIGITAL LINE DIFFERENTIAL WITH IEC61850 APPROACH

To address the bottleneck associated with the single vendor approach in line differential, it is crucial that we implement a standardised interoperable communication strategy.

In pursuit of this goal, the existing standard protocol, IEC 61850-9-2, is used to facilitate fast and reliable exchange of analog data. The potential variations in algorithms between different vendors necessitate the exchange of inter-trip signals between relays to ensure performance of protection. Utilisation of the IEC 61850-8-1 protocol will address the exchange of binary signals for inter-trips and status exchange.

There has been a shortage of telecom devices in the market capable of exchanging both SV and GOOSE between substations. This issue has been effectively addressed by the introduction of the TEGO1 Module within the Hitachi Energy FOX615 device.

The TEGO1 telecom module utilises an innovative methodology for IEC 61850-based line differential protection, successfully replacing the traditional C37.94 link. This advancement is illustrated in Figure 4.

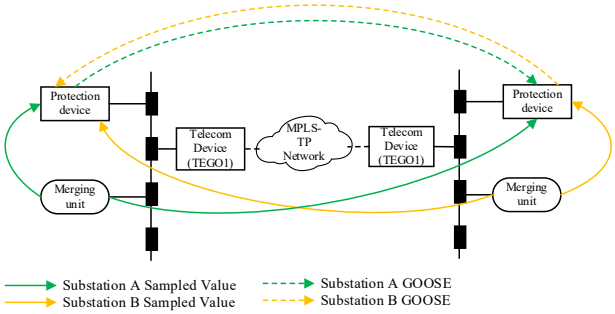


Figure 4. Logical diagram for IEC 61850-based line differential.

Both the relays and merging units at the local and remote ends are synchronised in PTP so that both the sampling and processing will be performed precisely at both ends.

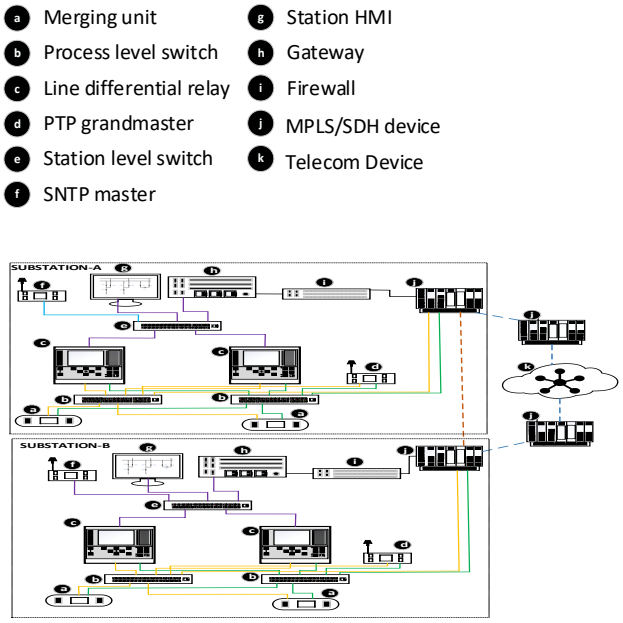


Figure 5. Architecture of digital substation with IEC 61850-based line differential.

A typical communication architecture of the digital substation with line differential via IEC61850 is shown in Figure 5.

On comparison with Figures 1 and 5, the hardware and communication architecture are the same. The only point of differentiation is eliminating the C37.94 protocol by introducing a telecom module. This new module, TEGO1, will facilitate the exchange of SV and GOOSE messages via the existing MPLS-TP infrastructure.

4. TEST SETUP

The test setup includes the equipment below at both substations and is connected via a 50 km link between the two FOX615s.

- RED670 – Line differential relay.
- Merging Unit (MU) - Standalone SAM600
- PTP GM - Grandmaster clock.
- FOX615 with TEGO1 module.

The typical architecture for the setup is shown in Figure 6.

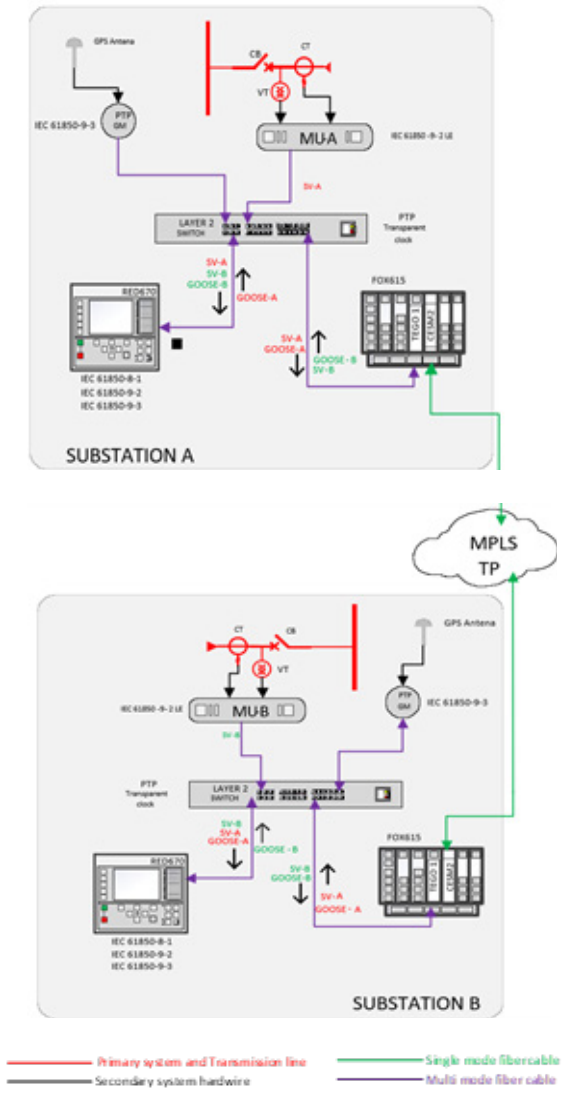


Figure 6. Architecture of the test setup.

The communication interface module used for the exchange of analog and digital data is called TEGO1 of FOX615[8]. The SV and GOOSE messages from the local substation are not sent directly to the remote substation. Instead, the local TEGO1 device subscribes to the local SV and GOOSE messages and then republishes them at the remote substation using a

completely different frame through the remote TEGO1 device. The SV ID and its properties can be configured within the TEGO1 module based on the substation's engineering requirements.

For the test setup SV ID of local and remote end devices are configured as shown in Table 1.

Table 1. SV ID configuration

Substation-A		Substation-B	
MU SV ID	TEGO1 SV ID	MU SV ID	TEGO1 SV ID
SSA_SV	**TEGO1_SSB_SV**	**SSB_SV**	**TEGO1_SSA_SV**

The results and observations from our recent testing are shared in Section 5. We used a secondary injection kit for current injections. The current sources were wired to standalone merging units at both substations.

5. TEST RESULT

Case 1: Stable/Through Fault Condition

We injected a rated current of 1000A at both ends with a phase shift of 180 degrees. The disturbance recorders (Figure 7) were triggered simultaneously at both substations (RED670), and the recorded data were merged by matching the timestamps of the samples.

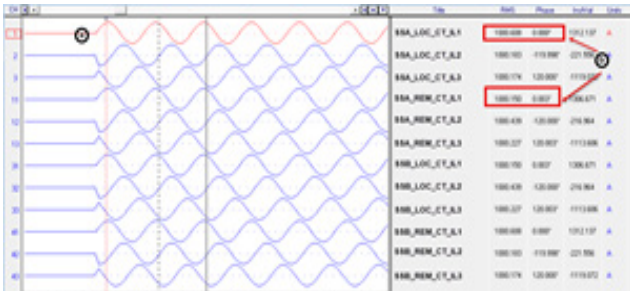


Figure 7. Merged DR of the local and remote ends during stable conditions.



Figure 8. Differential and bias current of the local and remote end relays during stable conditions.



Figure 9. SV Monitoring at Substation A.

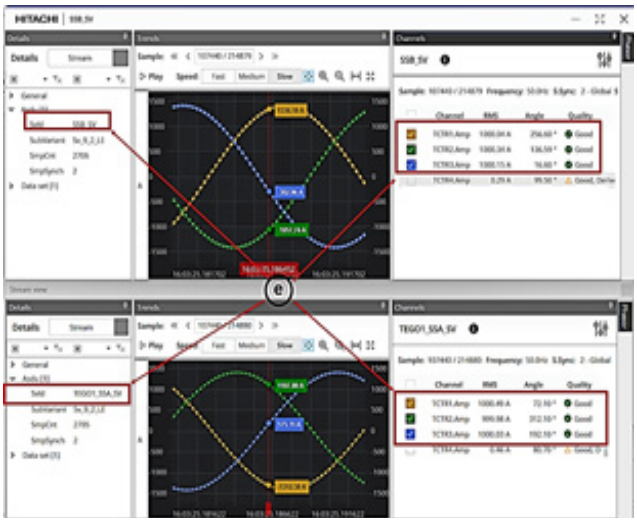


Figure 10. SV Monitoring at Substation B.

Table 2. Stable condition observation

Ref	Stable condition observation
a	From Figure 7, it is observed that both local end and remote end currents are sampled precisely at the same time due to PTP time sync.
b	From Figure 7, it is observed that both local end and remote end currents have an exact 180-degree phase shift as we injected.
c	From Figure 8, it is observed that there is no deviation between local end and remote end currents (a) and differential current is measured as zero.
d	From Figure 9, it is observed, SV frames captured through ITT software show that the SVs are published as SSA_SV and TEGO1_SSB_SV, as configured in Table 1, and the injected current of 1000 A is reflected correctly in the SV frame.
e	From Figure 10, it is observed that SV frames captured through ITT software show that the SVs are published as SSB_SV and TEGO1_SSA_SV, as configured in Table 1, and the injected current of 1000 A is reflected correctly in the SV frame.

Case 2: In Zone Fault Condition

We injected a rated current of 1000A at both ends with a phase shift of 0 degrees. The disturbance recorders were triggered simultaneously at both substations (RED670), and the recorded data were merged by matching the timestamps of the samples.

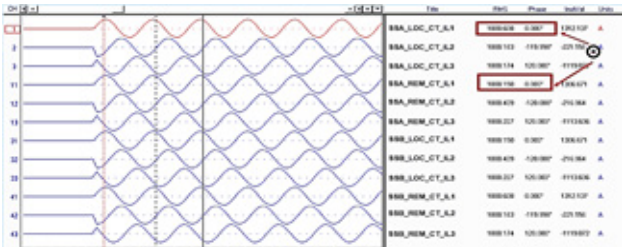


Figure 11. Merged DR of local and remote end during an in-zone fault.



Figure 12. Differential and bias current of local- and remote-end relays during an in-zone fault.

Table 3. In-zone fault condition observation

Ref	In-zone fault Observation
a	From Figure 11, it is observed that both local end and remote end currents are exactly 1000A and 0-degree phase shift, as we injected.
b	From Figure 12, it is observed that, since we injected both substation currents in phase with each other, the differential current adds up and is reflected as 2000A.

Case 3: Trip Time Validation at Rated Current

To evaluate overall timing for the protection trip, full load current is injected as fault current only at Substation-B, and the feedback is measured at Substation A. It was observed that the trip time is approximately 21 ms, as shown in Figure 13.

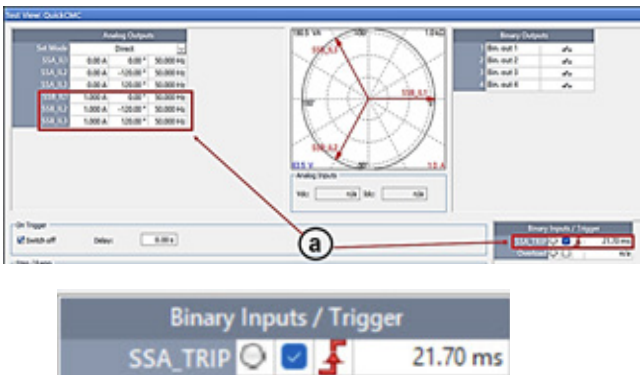


Figure 13. Trip time of line differential relay via IEC61850 approach.

Inter-trip time was measured by mapping both local end trip and remote end trip received via GOOSE to the disturbance recorder and events.

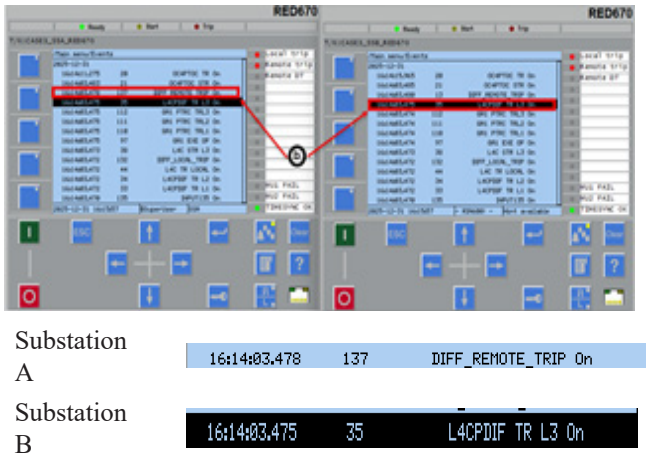


Figure 14. nter-trip transmission time measurement.

We prepared the same setup as shown in Figure 3 for C37.94-based line differential protection via a telecom device as referred to in the study[9] and tested the trip time. Full load current was injected only at Substation-B, and the feedback was measured at Substation-A. It was observed that the trip time is approx. 26 ms, as shown in Figure 15.

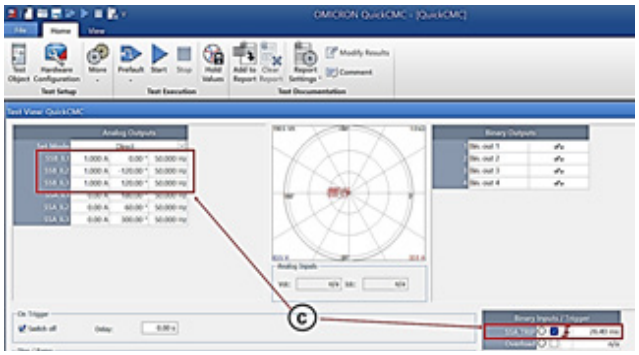


Figure 15. Trip time of line differential relay via C37.94 protocol.

Table 4. Trip time observation

Ref	Trip time Observation
a	From Figure 13, it is observed that, for IEC 61850-based line differential, the injected rated current at Substation B was transmitted to Substation A, and the Substation A line differential processed and issued a trip command. The overall time for SV publication, subscription, processing and tripping was observed to be approximately 21 ms.
b	From Figure 14, it is observed that the time difference between the local end relay trip command and subscription at the remote end relay was observed to be approximately 3-5 ms.
c	From Figure 15, it is observed that, for C37.94-based line differential, the injected rated current at Substation B was transmitted to Substation A and the Substation A line differential processed it and issued a trip command. The overall time for transmitting analog data via C37.94 and tripping was observed to be approximately 26 ms.

Points to remember:

- Having digital substations at both ends will improve cost optimisation.
- The bandwidth requirement of one SV for a 50 Hz system is 1048 X 4000 = 4.2 Mbps. Attention needs to be given to calculating and designing the bandwidth for IEC61850 (SV and GOOSE) based line differential.

6. CONCLUSION

At present, C37.94-based line differential solutions have challenges, including troubleshooting communication issues and dependency on the same manufacturer at both ends.

Recent developments facilitated by IEC standards, such as SV and GOOSE, along with advancements in telecom modules, have led to the successful establishment of interoperability between line differential relays.

Our test results demonstrate that the performance and operating time of the line differential relay are within acceptable limits for power system requirements, and in fact, we observed improvements in trip times.

In our Test case, we utilised the same vendor make (Hitachi Energy, RED670) at both ends, which has proven successful. However, we believe that we can also achieve interoperability between devices that support SV and GOOSE protocols for line differential protection.

7. ACKNOWLEDGEMENT

The authors would like to thank Mr. Praveen AN, Customer Service Centre Manager, Hitachi Energy, Dubai, United Arab Emirates, Ms. Aby Hanna Varghese, Technical Support Manager, Hitachi Energy, Bangalore, India, for their valuable support and guidance.

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