

Article

An IEC 61850 GOOSE-Based Methodology for Arc Flash Incident Energy Reduction in Industrial Substations

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Abstract

Arc flash faults in industrial substations can release high levels of incident energy, particularly on the line side of incoming circuit breakers, where opening the local breaker alone does not eliminate the source contribution. This paper proposes and experimentally evaluates an IEC 61850-based methodology to mitigate this protection gap by transferring arc flash trip signals between substations using GOOSE messages. The methodology comprises laboratory validation of the complete GOOSE-based protection chain and communication network, followed by validation in an operating industrial substation. Laboratory tests demonstrated satisfactory performance for both homogeneous and multivendor IED configurations, although longer operating times were observed when the test current approached the overcurrent pickup setting. The communication network achieved a mean transfer time of 5.31 ms and a maximum of 6.00 ms. In the industrial case study, the maximum protection operating time was 90 ms. Considering a conservative total fault-clearing time of 107.5 ms, the incident energy was reduced from 7.34 cal/cm² to 2.04 cal/cm², corresponding to a reduction of approximately 72%. These results demonstrate the feasibility of IEC 61850 GOOSE communication for high-speed trip transfer, reducing fault-clearing time and mitigating incident energy under critical line-side fault conditions.

Keywords: arc flash protection; incident energy; IEC 61850; GOOSE; industrial substations; line side; trip transfer; intelligent electronic devices



Academic Editor: Salvatore Favuzza

Received: 8 June 2026

Revised: 20 July 2026

Accepted: 30 July 2026

Published: 6 August 2026

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1. Introduction

1.1. Background

Electric Power Systems (EPS) are essential for industrial production, operational continuity, and personnel safety. In large industrial facilities, electrical protection systems are responsible for rapidly and selectively detecting, isolating, and clearing faults, thereby minimizing equipment damage while reducing the risks associated with energized installations and maintenance activities [1–4]. The digitalization of industrial substations has significantly transformed these protection systems through the adoption of Intelligent Electronic Devices (IEDs) and the IEC 61850 standard, enabling interoperable, distributed, and flexible protection architectures while reducing dependence on conventional hardwired signaling [5–9].

Among the communication services defined by IEC 61850, Generic Object-Oriented Substation Event (GOOSE) messaging enables the direct exchange of time-critical signals between IEDs over Ethernet networks. Compared with conventional point-to-point wiring, GOOSE communication simplifies system engineering, enhances flexibility, and supports distributed protection, interlocking, and automation schemes while satisfying the performance requirements of protection applications [10–13]. These characteristics make GOOSE particularly attractive for industrial facilities where protection commands must be transferred rapidly between electrically interconnected yet geographically separated substations.

Arc flash is one of the most severe fault types in medium- and low-voltage switchgear because it generates extremely high temperatures, intense light emission, pressure waves, molten metal projections, and toxic gases, posing significant risks to both personnel and electrical equipment [14,15]. Its severity is commonly quantified by incident energy, defined as the thermal energy received per unit area at a specified working distance. Classical and experimental studies have demonstrated that incident energy depends primarily on the fault current, fault-clearing time, working distance, enclosure characteristics, and system configuration, providing the foundation for the empirical models consolidated in IEEE 1584 [16–19]. Among these variables, the total fault-clearing time is the parameter most directly influenced by protection system design. Consequently, minimizing protection operating time is widely recognized as one of the most effective strategies for reducing incident energy and mitigating the thermal and mechanical effects associated with arc flash [20–29].

To reduce the total fault-clearing time, optical detection has become one of the primary technologies used for high-speed arc flash protection. By detecting the intense light emitted during arc initiation, optical relays can operate within only a few milliseconds, with reported detection times typically ranging from 1 to 7 ms and values below 2.5 ms under favorable conditions [30]. Consequently, optical detection directly contributes to reducing fault-clearing time and limiting incident energy [14,24,26]. In industrial substations, it is common to employ protection schemes that combine optical detection with instantaneous overcurrent supervision, such that the trip command is issued only when both light and fault current are detected simultaneously. This approach improves security against undesired operations by reducing the likelihood of false trips caused by external light sources, such as camera flashes, flashlights, or the opening of switchgear doors, without significantly compromising operating speed [21,31,32]. However, the literature also emphasizes that the use of combined light and current supervision should be determined according to the characteristics of the protected zone and the expected fault conditions. Current supervision is effective only when the fault current can be reliably measured by the associated current transformers. Therefore, for line-side faults at the incoming panel of secondary substations, series arcs, high-impedance faults, same-phase arcs, or faults whose current remains below the protection pickup threshold, requiring simultaneous current detection may delay or even prevent protection operation [33]. Under these conditions, several authors indicate that light-only detection is technically more appropriate, provided that appropriate engineering practices are adopted, including proper sensor placement, optical zone segregation, self-supervision, assessment of spurious light sources, and functional validation [29,30,34]. Therefore, light-only detection should not be regarded as a replacement for supervised light-and-current schemes but rather as an appropriate protection philosophy in applications where current cannot be considered a reliable criterion for arc detection.

Several studies have demonstrated that IEC 61850 GOOSE communication provides adequate performance for high-speed protection while reducing conventional wiring and facilitating the implementation of distributed protection functions [11,35,36]. More recent

investigations have also evaluated multivendor interoperability and the application of GOOSE-based schemes in digital substations, highlighting the importance of communication performance, parameterization, and laboratory validation [37–43]. However, these studies have primarily focused on communication performance or protection functions implemented within a single substation. Comparatively few studies have investigated the transfer of arc flash trip commands between physically separated substations or evaluated complete protection methodologies under actual industrial operating conditions.

This work addresses this research gap by proposing and experimentally validating an IEC 61850-based protection methodology specifically designed to mitigate line-side arc flash hazards at the incoming panel of industrial secondary substations. Unlike previous GOOSE-based protection studies, the proposed methodology combines multivendor laboratory validation, evaluation of communication performance throughout the complete protection chain, and deployment in an operating industrial facility, providing a practical assessment of the feasibility of transferring arc flash trip commands to an upstream circuit breaker through GOOSE communication.

1.2. Problem Statement

Large industrial facilities are typically supplied by high-voltage main substations that distribute power to geographically dispersed medium-voltage secondary substations. In these systems, arc flash mitigation depends not only on rapid fault detection but also on the electrical location of the fault relative to the circuit breaker responsible for interrupting the fault current. This distinction is particularly important for faults occurring either on the load side or on the line side of the incoming circuit breaker of a secondary substation.

For load-side faults, opening the local circuit breaker is generally sufficient to interrupt the fault current because the switching device is located between the source and the fault. In contrast, for line-side faults at the incoming panel of a secondary substation, opening the local circuit breaker does not extinguish the arc because the fault remains energized by the upstream main substation. Under these conditions, effective arc extinction depends on the rapid operation of the upstream feeder circuit breaker, which is often installed in a different substation and may be located hundreds of meters or even several kilometers away. Consequently, the protection system must not only detect the arc but also transfer the trip command to a remote circuit breaker with minimal latency.

In conventional industrial installations, the arc flash protection system installed in a secondary substation is generally designed to operate local switching devices. For line-side faults, however, fault clearance requires the operation of the upstream feeder circuit breaker located in the main substation. In many existing installations, no dedicated high-speed communication channel is available to transfer this trip command between substations. Consequently, fault clearance relies on the upstream overcurrent protection, which is typically coordinated to satisfy system selectivity requirements, resulting in longer operating times and greater incident energy exposure. Therefore, a fast and reliable trip transfer mechanism between substations is essential for mitigating line-side arc flash hazards.

The practical relevance of this problem is reinforced by recent accident statistics. Reports published by NFPA and ABRACOPEL indicate that electrical accidents and arc flash incidents continue to result in a significant number of fatalities each year, demonstrating that electrical safety remains a major concern in industrial environments [44,45]. Furthermore, experimental studies have shown that line-side faults in medium-voltage switchgear can produce incident energy levels significantly higher than those predicted under conventional assumptions, further emphasizing the importance of minimizing fault-clearing time in these scenarios [46,47].

Several studies have investigated arc flash protection, optical detection, and the application of IEC 61850 GOOSE messaging in digital substations. However, most published studies have focused on communication performance, interoperability, or protection functions implemented within a single substation. Comparatively few studies have addressed the complete protection chain required to mitigate line-side arc flash hazards at the incoming panel of industrial secondary substations, where the trip command must be transferred to an upstream circuit breaker installed in a physically separated substation. Likewise, there is limited experimental evidence regarding multivendor implementations validated under both laboratory and actual industrial operating conditions.

To address this research gap, this paper proposes and experimentally evaluates an IEC 61850-based protection methodology for mitigating line-side arc flash hazards at the incoming panel of industrial secondary substations. The proposed methodology comprises two complementary stages. The first stage consists of a laboratory evaluation of the complete protection architecture, including multivendor GOOSE communication, interoperability assessment, and analysis of the influence of the communication network on trip transfer time. The second stage validates the proposed methodology in an operating industrial facility by transferring the arc flash trip signal from the local arc flash relay to the upstream feeder circuit breaker through GOOSE communication. Unlike previous GOOSE-based protection studies, which have primarily focused on communication performance or protection functions within individual substations, this work combines multivendor laboratory validation, evaluation of communication performance throughout the complete protection chain, and deployment in an operating industrial facility. This approach provides a practical assessment of the feasibility of reducing the total fault-clearing time and, consequently, mitigating incident energy under critical line-side fault conditions.

2. Methodology

The methodology adopted in this study was structured into two main stages, as illustrated in Figure 1. The first stage consists of laboratory tests, in which two fundamental components of the protection architecture later applied in the industrial case study were evaluated: the transfer of the trip signal from the arc flash relay through GOOSE messages exchanged between IEDs and the influence of the communication network infrastructure on the message transfer time. The second stage consists of an industrial case study, in which the proposed methodology was implemented in an operating substation to transfer the arc flash protection trip signal to the upstream feeder circuit breaker located in a different substation.

To standardize device identification throughout the study, a simplified nomenclature was adopted. The dedicated arc flash protection relay from manufacturer A is identified by the acronym AF1. The identifiers A1 and A2 correspond to IEDs from manufacturer A, configured as GOOSE publishers and/or subscribers. Similarly, B1 and B2 represent the IEDs from manufacturer B used in the experimental evaluations. This nomenclature facilitates the description of the test configurations, preserves manufacturer anonymity, and maintains the functional traceability of the evaluated equipment.

This methodological organization enables a progressive evaluation of the proposed solution. First, laboratory tests assess the performance of the trip signal transfer chain and the influence of the communication network infrastructure on GOOSE message transfer time under controlled conditions. Subsequently, the industrial case study verifies the applicability of the proposed methodology under actual operating conditions, considering the existing network topology, the plant automation infrastructure, and the operation of the upstream feeder circuit breaker.

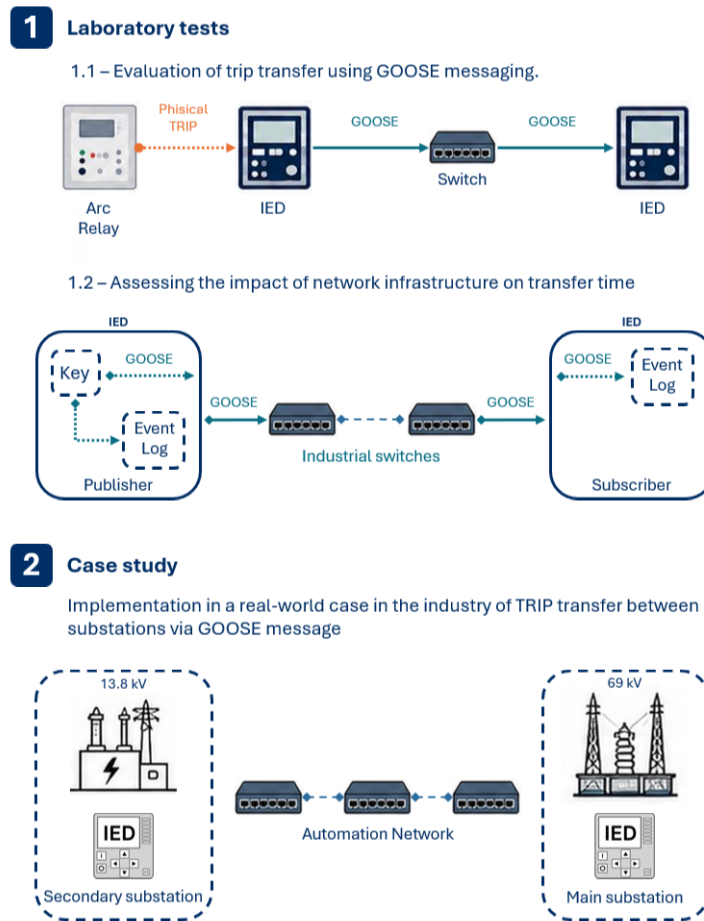


Figure 1. Methodological structure adopted in the study, comprising laboratory tests and the industrial case study.

2.1. Stage 1: Laboratory Tests

The first stage of the methodology was conducted under laboratory conditions and aimed to experimentally evaluate the trip signal transfer subsequently applied in the industrial case study. This stage was divided into two complementary parts: the evaluation of trip signal transfer using GOOSE messaging and the evaluation of the influence of the communication network infrastructure on GOOSE message transfer time.

2.1.1. Evaluation of Trip Transfer Using a GOOSE Message

In the first part of the laboratory tests, the total operating time of the protection chain was evaluated considering the transfer of the trip command through GOOSE messages. In this configuration, the AF1 relay was used to detect the arc flash condition and generate the physical trip signal. This signal was sent to a publisher IED, which detected the state change at its digital input and published a GOOSE message on the communication network. The message was subsequently received by a subscriber IED, which processed the received information and activated its digital trip output.

The GOOSE communication engineering adopted throughout both the laboratory and field tests followed the methodology proposed by Soares [48], which defines the publication and subscription structure, DataSet organization, retransmission strategy, and logical communication configuration for IEC 61850 protection applications. Since the objective of this study is to evaluate the proposed protection methodology and its impact on protection operating time and incident energy reduction, rather than the engineering of GOOSE communication itself, detailed configuration parameters, such as retransmission

intervals, DataSet size, APPID, and VLAN/QoS settings, are beyond the scope of this paper and are therefore not presented.

The time measured in this test corresponded to the complete protection operating chain, including detection, operation, and switching of the physical trip contact by the arc flash relay; recognition of the digital input; processing and transmission of the GOOSE message by the publisher IED; and reception, processing, and activation of the digital output by the subscriber IED. Therefore, the measured value does not represent only the network propagation time of the GOOSE message but rather the total operating time of the protection chain under laboratory conditions.

The arc flash condition was simulated by combining optical sensor activation in the arc flash relay with secondary current injection using a Universal Relay Test Set (URTS). This approach was adopted because no dedicated equipment was available to physically reproduce an electric arc while simultaneously allowing the operating time to be measured in an integrated manner using the URTS. Consequently, the relay optical sensor was manually stimulated during the tests, while the URTS injected the secondary current to reproduce the electrical fault condition and automatically record the operating time.

Three current levels were evaluated: 7.5 A, 10 A, and 12.5 A, corresponding to 1.5, 2.0, and 2.5 times the nominal secondary current of 5 A, which was defined as the pickup setting of the overcurrent function. For each current level, single-phase, phase-to-phase, and three-phase faults were evaluated.

Three experimental scenarios were defined, as illustrated in Figures 2–4, to evaluate configurations involving IEDs from both the same and different manufacturers. In Scenario A, the AF1 arc flash relay transmitted the physical trip signal to IED A1, which published a GOOSE message to IED A2, both manufactured by manufacturer A. In Scenario B, the AF1 relay transmitted the physical trip signal to IED A1, which published a GOOSE message to IED B1, representing an interoperable configuration involving devices from different manufacturers. In Scenario C, the AF1 relay transmitted the physical trip signal to IED B1, which published a GOOSE message to IED B2, both manufactured by manufacturer B.

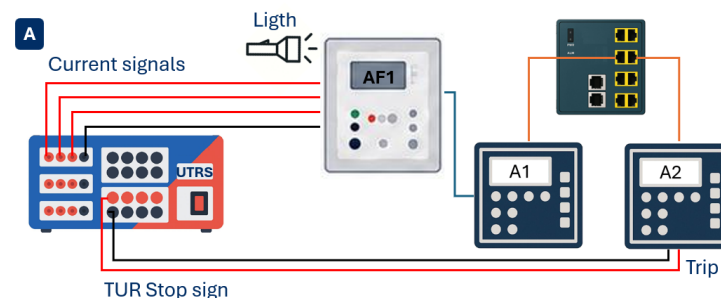


Figure 2. Laboratory test Scenario A for evaluating trip signal transfer using GOOSE messaging: publisher and subscriber IEDs from manufacturer A.

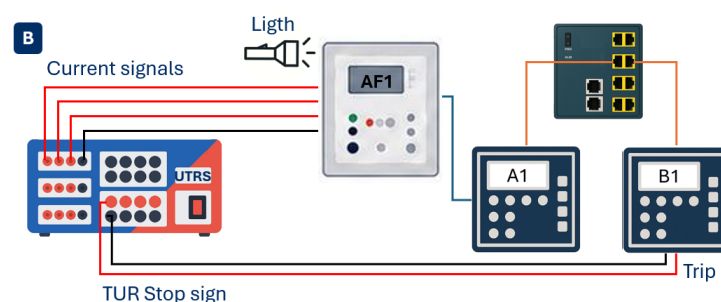


Figure 3. Laboratory test Scenario B for evaluating trip signal transfer using GOOSE messaging: publisher IED from manufacturer A and subscriber IED from manufacturer B.

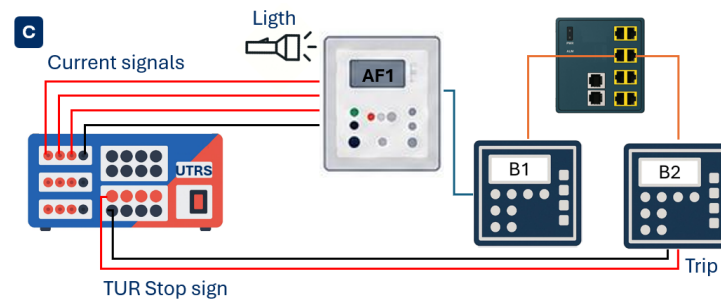


Figure 4. Laboratory test Scenario C for evaluating trip signal transfer using GOOSE messaging: publisher and subscriber IEDs from manufacturer B.

For each combination of current level and fault type, 150 consecutive tests were performed in each scenario. Considering three current levels and three fault types, a total of nine experimental conditions were evaluated for each scenario, resulting in 1350 records for each IED configuration and 4050 samples overall. The results were analyzed using the mean, standard deviation, and maximum recorded operating time. The mean was used to represent the typical performance of the protection chain, the standard deviation to assess the repeatability and variability of the tests, and the maximum value to provide a conservative reference corresponding to the longest operating time observed under each experimental condition.

2.1.2. Evaluation of the Impact of Network Infrastructure on Transfer Time

In the second part of the laboratory tests, the objective was to evaluate the influence of the communication network infrastructure on GOOSE message transfer time. Unlike the previous test, which assessed the complete protection operating chain, this evaluation focused on the time interval between message publication and reception, considering the transmission of the data packet through multiple industrial switches.

The experimental arrangement consisted of a publisher IED, an intermediate communication path comprising four industrial switches, and a subscriber IED, as illustrated in Figure 5. The four-switch topology was defined by the maximum number of industrial switches available in the laboratory. The objective of this test was to evaluate the influence of the communication network infrastructure on GOOSE message transfer time under controlled conditions rather than to investigate the effect of different numbers of network hops. In the publisher IED, an HMI key was configured as a logical command point. When activated, this key changed the state of an internal signal, recorded the corresponding event in the IED event log, and triggered the publication of the updated state as a GOOSE message on the communication network. The message was then transmitted through the intermediate industrial switches to the subscriber IED, where its reception was also recorded in the event log.

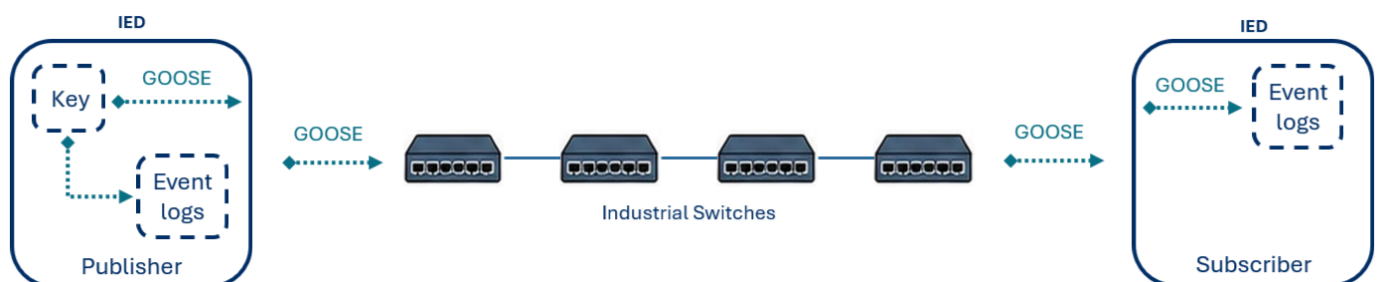


Figure 5. Laboratory arrangement for evaluating the influence of the communication network infrastructure on GOOSE message transfer.

The IEDs were synchronized using the SNTP protocol with a GPS-referenced time server, providing a common time base for comparing the event records. Under the laboratory network conditions, the synchronization accuracy was within the typical range for SNTP-based synchronization in local Industrial Ethernet networks (approximately 0.1 to 1 ms), which is sufficient for the time intervals evaluated in this study. The transfer time was determined from the difference between the event timestamp recorded by the publisher IED and the corresponding event timestamp recorded by the subscriber IED. A total of 100 consecutive message transmission tests were performed.

The results were analyzed using the mean and maximum transfer times. It should be emphasized that the measured time includes publisher IED processing, message transmission through the communication network, and subscriber IED processing, since both the transmission and reception timestamps were obtained from the event logs of the respective devices. Consequently, this test does not isolate the network propagation time of the GOOSE message. The specific transfer times of GOOSE messages under controlled conditions were previously investigated by [48] and are used in this study as a complementary reference for assessing the performance of IEC 61850 communication.

The analysis considers that the communication infrastructure may introduce additional delays in GOOSE message transfer as a function of the number of switch hops, frame forwarding mechanisms, network traffic load, and communication prioritization strategies adopted in the network [49–51]. Accordingly, this stage of the methodology evaluates whether the proposed communication architecture maintains transfer times compatible with the requirements of the intended protection application.

2.2. Stage 2: Industrial Case Study

The second stage of the methodology consisted of implementing the proposed method in an operating industrial substation. The objective was to validate the transfer of the arc flash protection trip signal from the 13.8 kV incoming switchgear of a secondary substation to the corresponding upstream feeder circuit breaker located in a 69 kV main substation.

The implementation was carried out using the actual automation infrastructure of the industrial plant, including the IEDs installed in the secondary and main substations, as well as the industrial switches responsible for communication between the devices, as illustrated in Figure 6. The communication network consisted of a conventional switched Industrial Ethernet architecture without the use of PRP or HSR redundancy protocols. The intermediate switches are part of the existing substation automation network and represent the actual communication path followed by the GOOSE message. Consequently, the validation considered not only the individual performance of the devices but also the actual operating conditions of the communication network, including the existing topology, concurrent network traffic, field parameterization, and integration with the upstream feeder circuit breaker tripping logic.

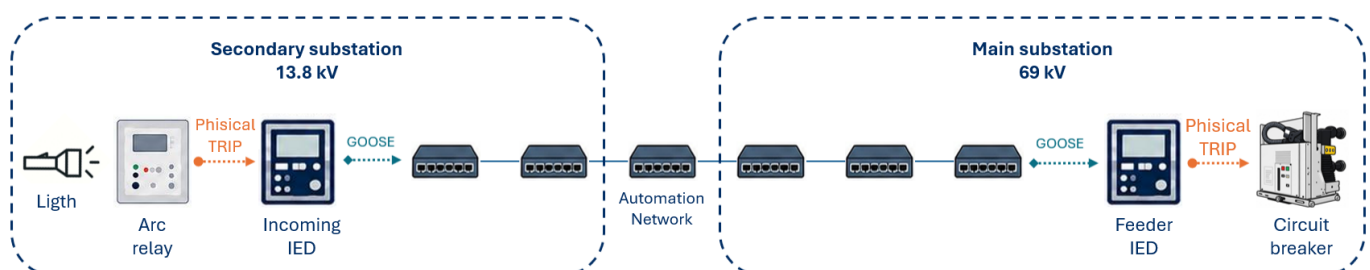


Figure 6. Architecture implemented in the industrial case study for transferring the trip signal between substations using GOOSE messages.

The arc flash relay installed in the secondary substation was configured to operate based solely on light detection, without current supervision. This configuration allowed relay operation to be simulated by applying light to the optical sensor, eliminating the need for current injection into the energized electrical system. It is also consistent with the investigated application, since, for faults located on the line side of the incoming circuit breaker, the fault current may not be reliably measured by the local current transformers of the secondary substation.

The IEDs involved in the case study were synchronized using the SNTP protocol with a GPS-referenced time source, providing a common time base for comparing the event records generated by the devices. The physical trip signal generated by the arc flash relay was received by the secondary substation IED and incorporated into the GOOSE publication logic. The GOOSE message was then transmitted through the existing automation network to the IED installed in the main substation, where it was integrated into the tripping logic of the upstream feeder circuit breaker.

In this stage, the evaluation criterion was the total protection operating time, determined from the time difference between the reception of the trip signal by the secondary substation IED and the effective opening of the upstream feeder circuit breaker in the main substation, as recorded in the event logs of the respective devices. Since the objective of this stage was to evaluate the overall performance of the proposed protection methodology under actual operating conditions, the measured times represent the combined effects of IED processing, GOOSE communication, network transmission, and circuit breaker operation, rather than the isolated propagation time of the GOOSE message. A total of ten tests were performed, a number limited by the operational constraints associated with repeatedly opening a circuit breaker in an operating industrial substation. The analysis focused on the maximum recorded operating time, as it represents the most conservative condition observed during the field validation and is directly relevant to the assessment of incident energy.

3. Results and Discussion

This section presents the results obtained using the proposed methodology. First, the laboratory test results are discussed, including the transfer of the trip signal through GOOSE messaging between IEDs and the evaluation of the influence of the communication network infrastructure on GOOSE message transfer time. Subsequently, the results of the industrial case study are presented, with emphasis on the total protection operating time and the effect of reducing this time on incident energy.

3.1. Laboratory Tests Results

3.1.1. Trip Signal Transfer via GOOSE Message

The first part of the laboratory tests evaluated the total operating time of the protection chain considering the transfer of the trip signal through GOOSE messages. As described in the methodology, the measured time represents the complete response of the laboratory implementation, including the operation of the arc flash relay, switching of the physical trip contact, recognition of the digital input by the publisher IED, internal processing within the devices, publication and reception of the GOOSE message, and activation of the digital output of the subscriber IED.

Tables 1–3 present the mean, standard deviation, and maximum operating times obtained for the three evaluated scenarios.

In all three evaluated scenarios, the tests performed with a current of 7.5 A exhibited the longest operating times. Under this condition, the mean operating times ranged from 24.18 ms to 33.89 ms, while the maximum recorded value reached 36.50 ms. This behavior

indicates that, when the applied current is closer to the pickup setting of the overcurrent function, a longer time is required to confirm the fault condition. This increase is likely associated with input signal filtering, internal validation criteria, and the reliable detection of current levels exceeding the configured pickup threshold. Consequently, in this operating range, small variations in the measured current may require additional processing time before the relay confirms the fault condition and issues the trip command.

Table 1. Descriptive statistics of operating times in Scenario A—Publisher and subscriber from manufacturer A.

Current (A)	Fault	Mean (ms)	Standard Deviation (ms)	Maximum (ms)
7.5	Three-phase	28.30	2.78	32.90
7.5	Two-phase	30.85	0.88	31.90
7.5	Single-phase	30.34	0.70	31.70
10	Three-phase	19.23	1.44	21.90
10	Two-phase	19.68	1.33	21.80
10	Single-phase	20.94	0.70	21.90
12.5	Three-phase	19.18	0.83	21.00
12.5	Two-phase	19.61	0.58	20.70
12.5	Single-phase	21.08	0.80	22.60

Table 2. Descriptive statistics of operating times in Scenario B—Publisher from manufacturer A and subscriber from manufacturer B.

Current (A)	Fault	Mean (ms)	Standard Deviation (ms)	Maximum (ms)
7.5	Three-phase	24.18	1.44	27.00
7.5	Two-phase	29.32	1.30	31.60
7.5	Single-phase	29.37	1.38	31.80
10	Three-phase	18.46	1.38	20.80
10	Two-phase	18.03	1.30	20.60
10	Single-phase	20.11	1.59	22.90
12.5	Three-phase	17.58	1.34	20.20
12.5	Two-phase	17.72	1.32	20.40
12.5	Single-phase	19.45	1.41	21.80

Table 3. Descriptive statistics of operating times in Scenario C—Publisher and subscriber from manufacturer B.

Current (A)	Fault	Mean (ms)	Standard Deviation (ms)	Maximum (ms)
7.5	Three-phase	32.41	2.54	36.20
7.5	Two-phase	33.89	1.38	36.20
7.5	Single-phase	33.82	1.38	36.50
10	Three-phase	23.85	1.19	25.70
10	Two-phase	24.76	1.38	27.00
10	Single-phase	24.58	1.22	27.20
12.5	Three-phase	23.69	1.29	25.60
12.5	Two-phase	23.15	0.90	24.60
12.5	Single-phase	23.80	1.07	25.40

For current levels of 10 A and 12.5 A, the operating times were shorter and exhibited lower variability. Under these conditions, the mean operating times ranged from 17.58 ms to 24.76 ms, indicating that higher fault currents relative to the pickup setting facilitate faster fault confirmation. These results demonstrate that the current level has a significant influence on the total operating time, primarily because it affects the initial operating stage of the arc flash relay.

A comparison of the three scenarios shows that the interoperable configuration involving devices from different manufacturers (Scenario B) did not adversely affect the total operating time. In several test conditions, this configuration produced mean operating times that were comparable to or lower than those observed in the single-manufacturer scenarios. These results demonstrate that GOOSE-based trip signal transfer achieved satisfactory functional performance between multivendor IEDs, confirming the interoperability expected from IEC 61850 [52] when the communication parameters are properly configured.

The results also indicate that a significant portion of the total operating time is associated with the physical interfaces and internal processing of the IEDs. According to the technical specifications of the devices used in this study, conventional digital inputs typically require approximately 5 to 10 ms for signal recognition, while conventional digital outputs may contribute up to 10 ms to the switching process [53,54]. Therefore, the measured operating time should be interpreted as the performance of the complete protection operating chain under laboratory conditions rather than solely as the GOOSE communication time.

Figures 7–9 present the distribution of the total operating times for the three evaluated scenarios. The boxplots confirm that the greatest dispersion occurred in the tests performed with 7.5 A, whereas the results obtained with 10 A and 12.5 A exhibit smaller variability and a greater concentration of operating times.

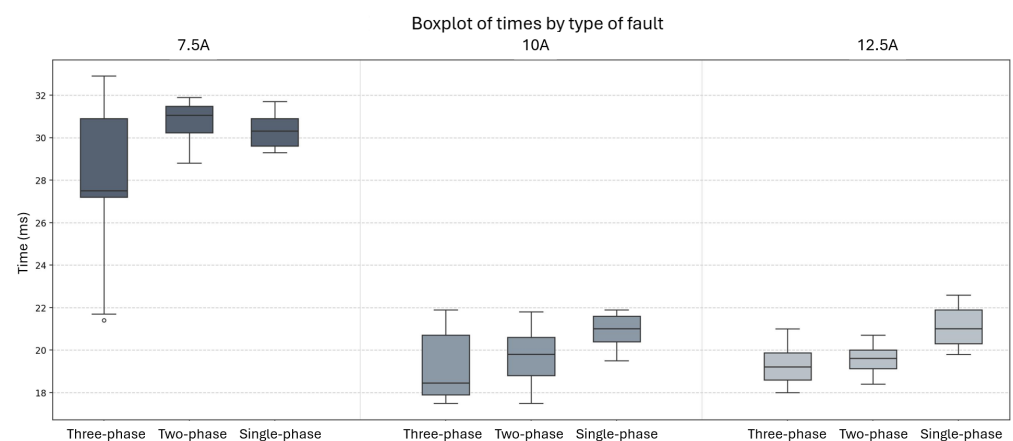


Figure 7. Distribution of the total operating times in Scenario A, with publisher and subscriber from manufacturer A.

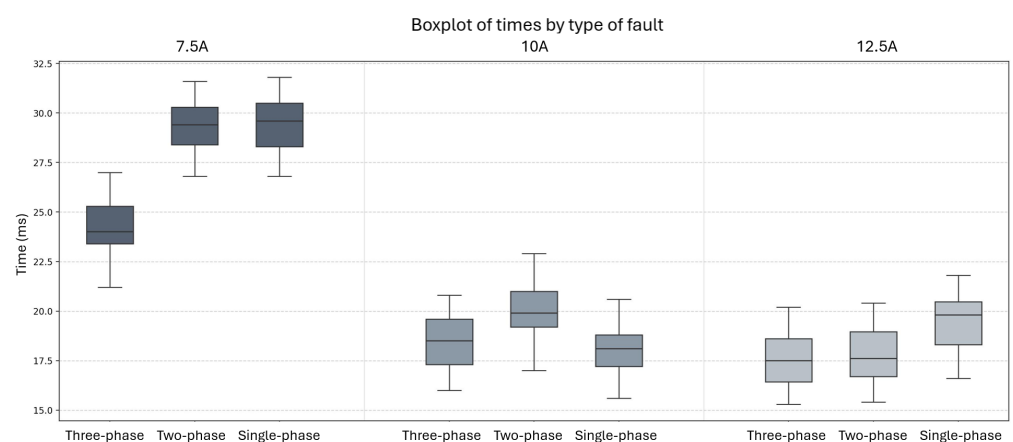


Figure 8. Distribution of the total operating times in Scenario B, with publisher from manufacturer A and subscriber from manufacturer B.

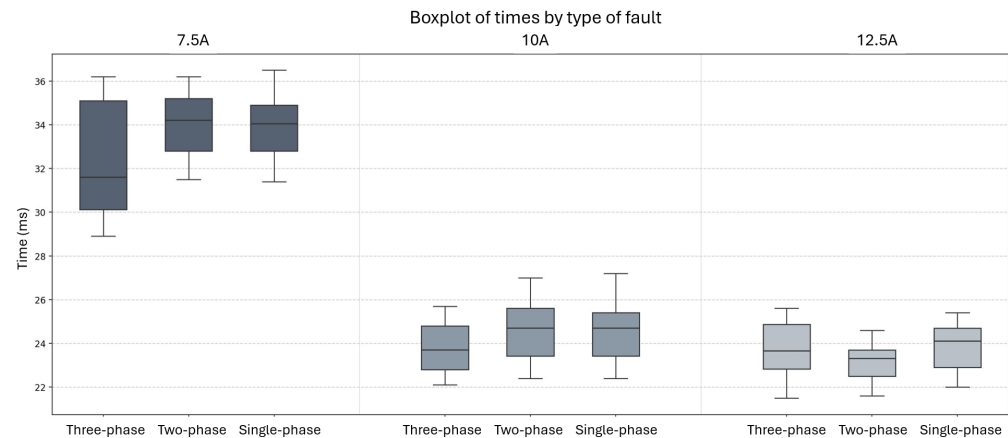


Figure 9. Distribution of the total operating times in Scenario C, with publisher and subscriber from manufacturer B.

3.1.2. Impact of Network Infrastructure

The second part of Stage 1 evaluated the influence of the communication network infrastructure on GOOSE message transfer time. Unlike the previous test, this evaluation focused on the time interval between publication of the message by the publisher IED and its reception by the subscriber IED, considering its transmission through multiple industrial switches.

Figure 10 presents the sequence of transfer times recorded during the 100 consecutive tests.

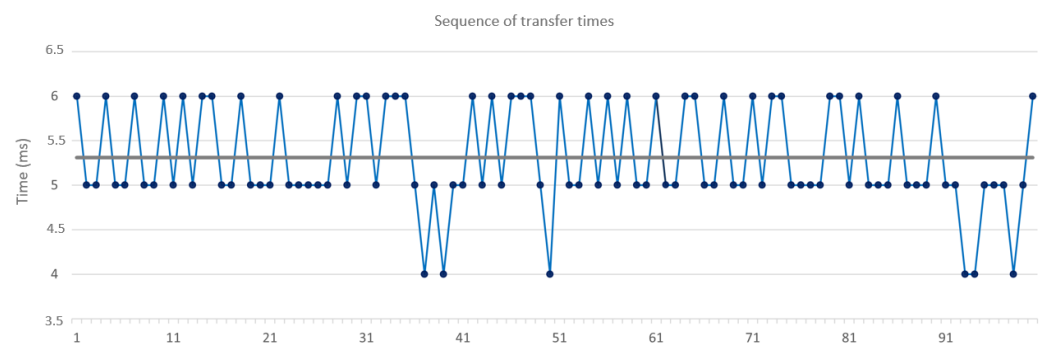


Figure 10. Sequence of GOOSE message transfer times obtained during the network infrastructure test.

The measured transfer times remained concentrated between 4 ms and 6 ms, with a mean value of 5.31 ms and a maximum value of 6.00 ms. The maximum recorded value remained below the 10 ms performance requirement established by IEC 61850-5 for Type 1A messages associated with protection functions [55].

The measured time corresponds to the combined effects of processing in the publisher IED, message transmission through the communication network, and processing in the subscriber IED. Although this measurement does not isolate the network propagation delay, it provides an effective assessment of communication performance in a topology comprising multiple industrial switches. The results indicate that the evaluated network infrastructure did not introduce delays that could compromise the application of GOOSE-based trip signal transfer.

When compared with the results reported by [48] and the typical per-hop delays in managed industrial switches presented by [50], the measured transfer times are consistent with the expected performance of IEC 61850-based protection applications. These laboratory results therefore demonstrate that, in a properly configured communication architecture, GOOSE message transfer can satisfy the timing requirements of the proposed protection application, even when multiple network devices are involved.

3.2. Industrial Case Study Results

The second stage of the methodology consisted of validating the proposed solution under actual industrial operating conditions. The analyzed case corresponds to the incoming switchgear of the SE-1215EE-02 secondary substation, operating at 13.8 kV and supplied by the SE-1815EE-01 main substation, operating at 69 kV and located approximately 2600 m away. Under the original operating condition, a fault occurring on the line side of the incoming circuit breaker in the secondary substation depended on the operation of the upstream feeder overcurrent protection. The existing arc flash study indicated a total fault-clearing time of approximately 525 ms, comprising approximately 450 ms of protection operating time and 75 ms corresponding to the total circuit breaker breaking time, including mechanical opening and arc extinction, according to the manufacturer's reference data for the circuit breaker used in this study [56]. Under these conditions, the calculated incident energy at the incoming cubicle was 7.34 cal/cm².

This operating condition characterizes the protection gap investigated in this study. Although the arc flash protection installed in the secondary substation is capable of detecting the fault, opening only the local circuit breaker does not eliminate the source contribution when the fault is located on the line side of the incoming breaker. Consequently, the proposed solution consists of rapidly transferring the trip command to the upstream feeder circuit breaker through a GOOSE message.

The trip signal generated by the arc flash relay was integrated into the GOOSE publication logic of the secondary substation IED. At the main substation, the signal received by the subscriber IED was incorporated into the tripping logic of the upstream feeder circuit breaker. The total protection operating time was determined from the time difference between the reception of the trip signal by the secondary substation IED and the recording of the circuit breaker open status in the main substation.

Figure 11 presents the operating times obtained during the ten field tests.

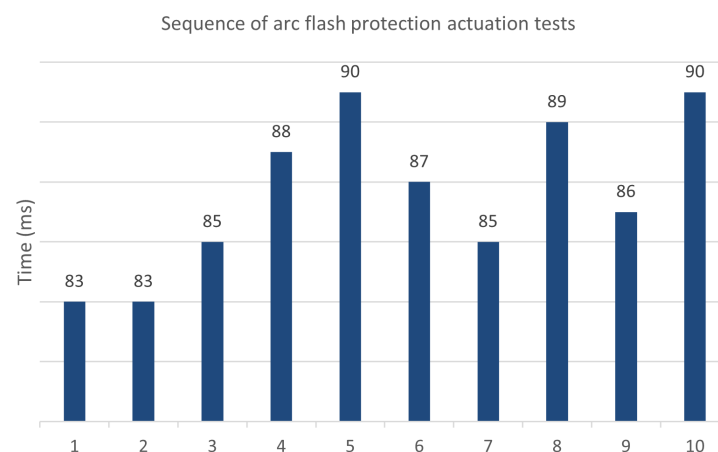


Figure 11. Protection operating times obtained during the ten tests performed in the industrial case study.

In all tests, the time interval between operation of the arc flash relay and opening of the upstream circuit breaker remained below 100 ms. The highest recorded operating time was 90 ms, which was adopted as a conservative experimental reference for evaluating field performance. This result confirms that the proposed methodology is capable of substantially reducing the fault-clearing time compared with the original protection scheme.

For the incident energy recalculation, a conservative total fault-clearing time of 107.5 ms was adopted. This value was established based on manufacturer reference data, applicable standard requirements, and the laboratory and field validations performed in

this study. The adopted value comprises five components: 2.5 ms associated with operation of the arc flash relay, 10 ms corresponding to processing and GOOSE publication by the secondary substation IED, 10 ms allocated to GOOSE message transmission through the communication network, 10 ms corresponding to processing and operation of the subscriber IED, and 75 ms corresponding to the total breaking time of the upstream feeder circuit breaker.

Figure 12 illustrates the operating sequence considered in the conservative composition of the total protection operating time.

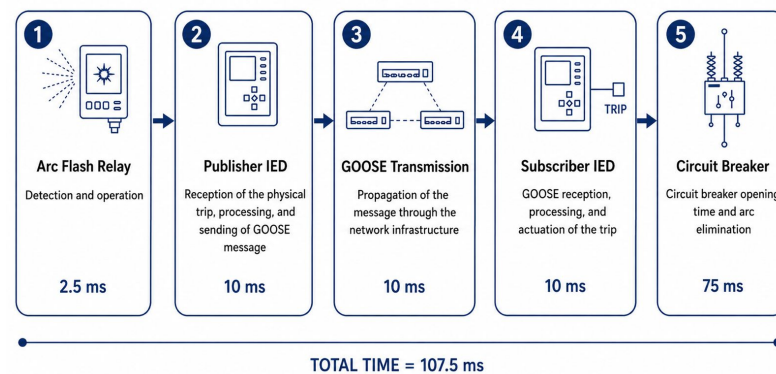


Figure 12. Operating sequence and contribution of each stage to the total protection operating time.

It is important to note that the highest operating time measured during the field tests was 90 ms, which is lower than the conservative value adopted for the incident energy recalculation. Therefore, the use of 107.5 ms introduces an additional safety margin into the analysis, ensuring that the calculated results represent a worst-case operating condition for the evaluated application.

The incident energy recalculation was performed using PTW (SKM Power Tools for Windows), considering the 13.8 kV busbar of the SE-1215EE-02 secondary substation and the fault location on the line side of the incoming switchgear. Figure 13 compares the operating conditions before and after implementation of the GOOSE-based trip signal transfer.

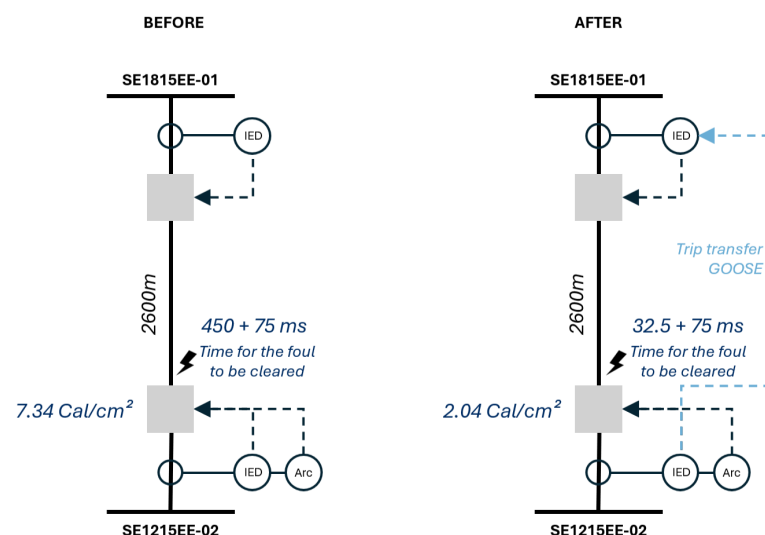


Figure 13. Comparison of the operating conditions before and after implementation of GOOSE-based trip signal transfer.

Following implementation of the proposed methodology, detection of the arc flash condition and initiation of the trip command were performed by the arc flash relay installed

in the 13.8 kV switchgear, while the trip command was transferred to the upstream feeder circuit breaker through a GOOSE message. Based on the adopted conservative operating sequence, the combined detection, processing, and communication time was limited to 32.5 ms. When added to the circuit breaker total breaking time of 75 ms, including mechanical opening and arc extinction, the resulting total fault-clearing time was 107.5 ms.

Under these conditions, the calculated incident energy decreased from 7.34 cal/cm² to 2.04 cal/cm², corresponding to an approximate reduction of 72%. This reduction is a direct consequence of the shorter fault-clearing time, since incident energy is strongly dependent on arc duration.

These results demonstrate that transferring the trip command between industrial substations using IEC 61850 GOOSE communication can significantly reduce the clearing time of faults occurring in regions with limited local protection coverage, such as the line side of medium-voltage switchgear. Consequently, the proposed methodology contributes to reducing workers' exposure to thermal hazards during operation, inspection, and maintenance activities in industrial substations.

4. Conclusions

This paper presented and experimentally evaluated a methodology for mitigating the arc flash protection gap associated with line-side faults in industrial substations by using IEC 61850 GOOSE messages to transfer trip signals between IEDs. The proposed methodology was structured into two stages: laboratory tests to evaluate the trip signal transfer architecture and the influence of the communication network infrastructure, followed by validation through an industrial case study.

The laboratory tests demonstrated that GOOSE-based trip signal transfer provided satisfactory functional performance in all three evaluated configurations, including the arrangement involving devices from different manufacturers. These results reinforce the applicability of the interoperability provided by IEC 61850 for distributed protection schemes, provided that the publication, subscription, DataSet configuration, and IED logic are properly engineered and validated.

The tests performed with a current of 7.5 A exhibited longer operating times than those obtained with currents of 10 A and 12.5 A. This behavior is associated with the proximity of the applied current to the pickup setting of the overcurrent function, under which the relay requires additional time to confirm the fault condition. This finding is particularly relevant for practical applications, as it demonstrates that current settings and supervision criteria should be carefully defined when minimizing operating time is essential for incident energy mitigation.

The evaluation of the communication network infrastructure showed that, even with multiple industrial switches in the communication path, the measured transfer times remained compatible with high-speed protection applications. The maximum recorded value was 6.00 ms, remaining below the 10 ms performance requirement established by IEC 61850-5 for Type 1A protection messages. Since the measured values were obtained from the event records of the IEDs, they include not only the network transmission time but also the processing performed by the publisher and subscriber devices.

The industrial case study demonstrated the feasibility of transferring the trip command from the arc flash relay installed in the incoming switchgear of the secondary substation to the upstream feeder circuit breaker located in the main substation. During the ten field tests, the total protection operating time remained below 100 ms, with a maximum measured value of 90 ms. For the incident energy recalculation, a conservative total fault-clearing time of 107.5 ms was adopted based on manufacturer reference values, applicable standard requirements, and the experimental results obtained in this study.

By implementing GOOSE-based trip signal transfer, the total fault-clearing time was reduced from approximately 525 ms to 107.5 ms. Consequently, the calculated incident energy at the incoming switchgear of the secondary substation decreased from 7.34 cal/cm² to 2.04 cal/cm², corresponding to an approximate reduction of 72%. These results demonstrate that the proposed methodology can significantly reduce the thermal hazard associated with line-side faults in locations where operation of the local arc flash protection alone is insufficient to eliminate the source contribution.

Overall, the results confirm the technical feasibility of using IEC 61850 GOOSE communication to transfer trip signals in arc flash protection schemes between industrial substations. The main contribution of this work lies in the experimental laboratory validation and field implementation of a protection architecture specifically designed to mitigate line-side arc flash hazards. The proposed methodology demonstrates that IEC 61850 GOOSE communication can be effectively employed to reduce fault-clearing time and, consequently, incident energy under actual industrial operating conditions.

The validation of the proposed methodology was strategically focused on a specific industrial architecture, utilizing the exact equipment, protection settings, and communication infrastructure of the evaluated installation. While this approach demonstrates the practical feasibility of the GOOSE-based trip transfer mechanism under standard operating conditions, certain communication robustness aspects—such as message loss, network congestion, hardware failures, and redundancy strategies—were explicitly placed beyond the current scope. These boundaries allowed for a detailed assessment of operating times and functional performance, establishing a solid foundation. Future work will extend this framework to different industrial topologies and rigorously investigate communication anomalies, including the continuous supervision of GOOSE message quality, to evaluate its impact on the dependability of critical protection applications.

Author Contributions: Conceptualization, G.E.J., A.L.M.C. and P.H.V.S.; methodology, G.E.J., A.L.M.C. and P.H.V.S.; validation, G.E.J. and P.H.V.S.; formal analysis, G.E.J. and A.E.A.; investigation, G.E.J.; resources, G.E.J., P.H.V.S. and A.E.A.; data curation, G.E.J.; software, A.E.A.; writing—original draft preparation, G.E.J.; writing—review and editing, A.L.M.C. and P.H.V.S.; visualization, G.E.J.; supervision, A.L.M.C. and P.H.V.S.; project administration, G.E.J. All authors have read and agreed to the published version of the manuscript.

Funding: This work was carried out with the support of the Coordination for the Improvement of Higher Education Personnel—Brazil (CAPES)—Finance Code 001, the National Council for Scientific and Technological Development (CNPq), the Federal University of Ouro Preto, and the Federal University of Itajubá.

Institutional Review Board Statement: Not applicable.

Informed Consent Statement: Not applicable.

Data Availability Statement: The authors declare that all data supporting the findings of this study are available within the article or from the corresponding author upon reasonable request.

Conflicts of Interest: The authors declare no conflicts of interest.

Abbreviations

The following abbreviations are used in this manuscript:

GOOSE	Generic Object Oriented Substation Event
GPS	Global Positioning System
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electronics Engineers

NFPA	National Fire Protection Association
PTW	Power Tools for Windows
SAS	Substation Automation System
SNTP	Simple Network Time Protocol
URTS	Universal Relay Tester Set
VLAN	Virtual Local Area Network

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