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A PRACTICAL APPROACH TO THE REQUIREMENTS AND STRATEGIES FOR MONITORING THE IEC 61850 PROCESS BUS IN A MULTIVENDOR TEST PLATFORM

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SUMMARY

The application of the IEC 61850 Process Bus is today a reality in many new projects in Brazil. This brings new challenges, including the availability of Protection, Automation and Control systems - PAC. One of the technological advantages is the possibility of monitoring infrastructure and functionalities. Different strategies can be applied to monitor the PAC system. The first is to use the resources provided in IEC 61850 standard in Logical Nodes, taking advantage of the information that the devices themselves can diagnose, involving physical conditions, quality, and absence of digital, analog and time synchronization signals. A second strategy is monitoring the signals on the network, comparing with the project described in the SCD (Substation Configuration Description) file. When adopting both strategies, it is possible to monitor, audit and report failures on the process bus network during operation and disturbances of the electrical system. This issue increased in importance with the review of grid code by the National System Operator (ONS), which included requirements for the implementation of digital substations. Monitoring in the process bus was considered mandatory. To deepen this discussion and evaluate the possibilities to meet these requirements, the B5 Protection and Automation Study Committee of CIGRE Brazil promoted a workshop in August 2023 with a test platform with the participation of several manufacturers. A test roadmap was created and applied to this platform. The results evaluated the effectiveness of the monitoring strategy proposed by each supplier. This paper will address in detail the characteristics of the implemented platform, the proposed monitoring options, the tests results, and the conclusions from the discussions held during the workshop.

KEYWORDS

IEC 61850, Process Bus, PAC System Tests

1. INTRODUCTION

The implementation of Digital Substation of IEC 61850 began in Brazil in 2006 with the application of Station Bus deployments. It has been consolidated over the years and has become a standard for transmission utilities. The next step in this process would be the implementation of Process Bus. The initial strategy of utilities was to conduct pilot projects, to evaluate the impact and specially the performance of the protection functions. The successful outcomes of these pilot projects led to the implementation of first projects. Currently there are several digital substations (Process Bus) in service, from various manufacturers.

The application of redundancy concepts is crucial to ensure the availability of protection and control functions in projects. However, for redundant systems to truly increase reliability, it is critical to monitor the devices, network infrastructure, services, protection, and control functionalities. Different strategies can be applied for this monitoring.

The first strategy is to use the resources provided in the IEC 61850 standard in Logical Nodes. This involves taking advantage of the information that the devices themselves can diagnose, including physical conditions, quality, and absence of GOOSE (Generic Object-Oriented Substation Event), SV (Sampled Values), and PTP (Precision Time Protocol) signals.

The second strategy is to monitor the signals on the network, comparing them with the project described in the SCD (Substation Configuration Description) file. In this case, an independent network DFR (digital fault record) will be necessary to monitor, audit, and report failures on the process bus network during operation and disturbances of the electrical system and the associated process bus network. This includes monitoring signals (GOOSE, SV, and PTP) for protection systems.

2. REVIEW OF GRID CODE

The National Electric System Operator (ONS – *Operador Nacional do Sistema Elétrico*) is responsible for coordinating and controlling the generation and transmission of electrical energy in the national interconnected system. All ONS activities are based on technical criteria and rules, which are organized in grid code documents. These ones determine the premises, criteria, and procedures for operation the system, as well as the responsibilities of those involved in each function. The protection, disturbance recording, and teleprotection systems must meet minimum requirements to ensure that each transmission installation performs to the established technical and functional criteria. These systems play a crucial role in ensuring the electrical safety of the national interconnected system.

In recent years, substations have undergone a significant process of technological evolution involving the use of data communication networks between these devices an increase in the processing power of Intelligent Electronic Devices - IED. Over the years, the standard has undergone various revisions that have facilitated the dissemination of its application in substations. IEC 61850 standardized and defined the object-oriented data model for substation equipment, including protection, measurement, and control functionalities. It has also defined network protocols for transmitting different types of data (commands, supervision, and communication between IEDs), and standardized the interface for conventional and Low-Power Instrumentation Transformers (LPIT). These technologies have revolutionized conventional solutions, both in technical aspects and in the development of projects.

Therefore, the ONS began a process of updating the grid code Submodule 2.11 - Minimum requirements for protection, disturbance recording and teleprotection systems, to adapt them to the needs of digital substation implementations.

The main aspects reviewed in the grid code related to monitoring are:

2.1 Communication networks used by protection system

As substation PAC systems become increasingly digitalized, the communication network used for protection becomes an integral part of these systems. Therefore, specific requirements were created to guarantee reliability and security in this application, involving the LAN (Local Area Network), as well as the WAN (Wide Area Network) used for teleprotection.

- **Independent and redundant networks:** For the protection systems to be secure and reliable, it is important that the communication (local and external networks) used to connect the protection devices must be independent and redundant for the main 1 and main 2 protection systems. To achieve this network with redundancy protocols with zero switching time should be used. This involves duplicating the network elements of the main and alternate protection systems into the redundant equipment. Each protection system needs to be connected to two different, independent paths, and simultaneously active.

- **Network Monitoring System:** To guarantee the operational condition of the PAC system, it is necessary to implement monitoring functions. The local network monitoring functions and external networks used by routing/teleprotection must be capable of detecting and signaling anomalies or absences of messages planned for each segment or connection between substations, following the requirements specified by the corresponding standard. At least the following conditions must be monitored:

a) Be able to monitor, detect and flag anomalies or absences of predicted messages on the network.

b) Continuously monitor and flag the following failure modes:

I Loss of message integrity.
II. Absence of planned messages.
III. Absence of time synchronization messages.
IV. Presence of unforeseen messages.
V. Abnormal intervals between predicted messages.
VI. Abnormal propagation time (latency) for predicted messages with fixed publication period.

c) Have a resource for storing event records.
d) Be synchronized via the substation's communication network.
e) Can use, in addition to the messages available on the network, the monitoring and diagnostic information of the end devices (IEDs, PIUs, switches, GNSS, etc.).
f) It shall make available to SCADA, through a protocol with time stamping, configurable alarm points of the detected abnormalities.

2.2 Use of digital signals for measurements

The use of LPIT and Stand-Alone Merging Units (SAMU) can be applied to obtain voltage and current signals for protection systems. The sensors and sampled values (currents and voltages) for each main and alternating protection system must be obtained from independent optical ports of each LPIT. The same applies to SAMU.

2.3 Role of time synchronization

With the increasing use of digital protection systems, time synchronization becomes essential. To ensure this, a requirement has been introduced that the main 1 protection system, which relies on time synchronization signals must use a time signal source (GNSS- Global Navigation Satellite System) that independent of the main 2 protection time signal source Additionally, an automatic mechanism must be implemented to select and maintain a specific time signal generator for the main 1 protection and another for main 2 protection between the available IEDs or clocks, in case of loss of the external time signal source (GNSS). These selected generators will serve as a reference signal (master or grandmaster clock) to maintain accurate time synchronization.

Changes in grid code are important for managing technological disruption. By defining criteria, energy utilities, suppliers and designers can safely implement the Process Bus safely and meet the power system's requirements. The main new question is related to the monitoring system. It requires new engineering solutions, that can be implemented in different ways. Additionally, specific and new tests on PAC systems will be required.

3. MONITORING STRATEGIES

The Process Bus is a new technology that replaces the traditional infrastructure used for transmitting status signals, commands and measurements of electrical cables for data communication. Although the cabled infrastructure is known for its high availability and is independent of electronic devices it is not always possible to detect the absence of signals caused by cut cables, faulty terminal connections, or open isolator switches. In contrast, data communication infrastructure with electronic devices (Switches, GNSS, MU) have high availability but are less reliable than an electrical cable. To ensure that the level of availability is maintained, two strategies are applied: device redundancy and system monitoring.

The protective systems must maintain their major objectives even in the event of device failure associated with a protective system. This requirement usually demands the implementation of two independent protection schemes for every protected equipment on bulk power systems [7].

Redundancy is an important factor in ensuring high availability levels like those of cabled infrastructure, according to various publications [6]. Redundancy is necessary to prevent the failure of any single protection component, such as a relay, control circuit, or communication channel from resulting in a loss of capacity to detect and isolate faults. The protective systems must maintain their major objectives even in the event of device failure associated with a protective system. This requirement usually demands the implementation of two independent protection schemes for each protected equipment on bulk power systems [7].

Figure 1 shows the reliability of a doubly redundant, one-out-of two (1oo2) system. The MTBF (mean time between failures) of the one-out-of-two (1oo2) system without repair is only one-and-a-half that of a non-redundant, one-out-of-one (1oo1) system. A double redundancy system without repair is of little help in a grid automation system that operates for years [8]. To ensure proper repair, monitoring is necessary to act before system failure. In practice, a redundant system without monitoring over time becomes a simple system that does not respond to an N-1 failure.

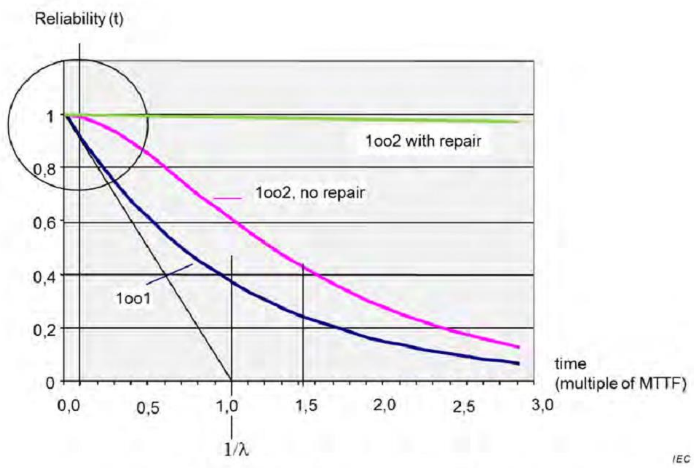

Figure 1 - Redundancy of redundant systems - IEC TR 61850-90-12 [8]

The basic monitoring to be carried out includes typical features of communication networks, based on SNMP - Simple Network Management Protocol, applied to Ethernet network devices for a long time. But in addition, the IEC 61850 standard itself establishes the System logical nodes LN of group L, in IEC 61850-7-4 Ed.2 [5] and application aspects in IEC TR 61850-90-4:2020 [8] related to the health of devices and communication of data. The main ones are highlighted below:

- LPHD (Physical Device Information).
- LCCH (Physical Communication Channel Supervision).
- LGOS (GOOSE Subscription).
- LSVS (Sampled Values Subscription).
- LTIM (Configurations regarding the local time at IED).
- LTMS (Configuration and supervision of the time synchronization function at IED).
- LTPC (Ordinary Clock model).
- LTTC (Transparent Clock model).

For each Logical Node, the standard establishes the attributes. Table 1 highlights some of the most important ones:

Table 1 – Logical Nodes and attributes

LGOS	LSVS	LTPC
• St • SimSt • NdsCom	• St • SimSt • NdsCom	• GmClkClass • GmClkAcc • MePathDlTmns • OfsMaster • TmSrcVal • ClkVar • ClkIdcan

Monitoring is done by consulting the devices' physical conditions, their communication conditions and the quality of the digital signals and measurements received.

Another approach is to spy the network with a sniffer, comparing the network's behavior with the communication and functionality details outlined in the substation's SCD - Substation Configuration Description file. Additionally, it is possible to compare this information with the communication requirements and timing specifications defined in the IEC 61850 standard (Figure 2).

In this case, we need to sniff each network segment of the system. There are several tools currently capable of carrying out this task, from different suppliers. It has some impact on the processing of the switches, which need to mirror the traffic to the monitoring system. This approach is in line with the principle that system conditions must be audited by an independent system, and not by the devices themselves.

This approach is also in the direction that as well as all records of the conditions of the power system, equipment and protection functions using DR - Disturbance recorders are made, it is necessary to have an independent recorder that stores network conditions and signal communication to assist in the performance analysis of the protection system.

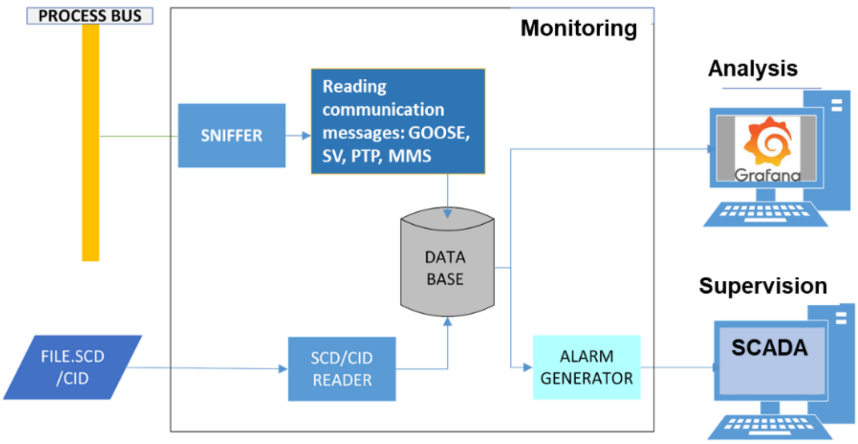

Figure 2 - Typical Monitoring System

The two monitoring strategies, which involve reading the conditions of the devices and using a sniffer on the network, can provide excellent diagnoses. However, the implementation of a solution will depend on the company's criteria regarding the level of monitoring and cost investment it wishes to make. In Brazil, the requirements of the ONS grid code will be crucial for transmission utilities to define a solution since they will be mandatory from 2024. To contribute to this discussion, the Brazilian Study Committee B5 - Protection and Automation organized a Workshop in August 2023 to discuss the topic and apply a real test platform with different approaches involving the participation of several IED manufacturers.

4. TESTING PLATFORM ARCHITECTURE

To set up the test platform, it was decided to configure the protection and control system by simulating a transmission line input in a circuit breaker and a half arrangement. Each manufacturer, (A, B, and C) configured the system using their equipment. Two PIUs were used for digitization of the bay (1 circuit breaker, 1 current transformer and 2 switch disconnectors each). Voltage measurement was done in one of the PIUs, while an IED was used for protection and control functions (Figure 3).

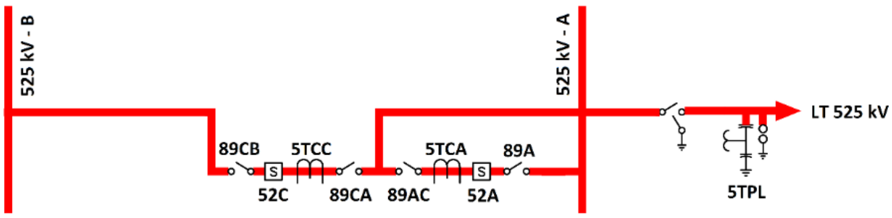

Figure 3 - Test Bay

The defining signals for testing on the platform were:

- GOOSE message exchange: IED -> PIU and PIU -> IED
- Sending SV flows: PIU -> IED
- Sending alarms via MMS: IED -> SCADA
- Sending PTP synchronization signals: GNSS -> Devices

The tests were defined to analyze the monitoring systems capabilities in identifying and signaling the following failure modes. This way, the requirements defined in the previously presented item on the review of grid code will be verified:

I. Loss of message integrity.
II. Absence of planned messages.
III. Absence of time synchronization messages.
IV. Presence of unforeseen messages.
V. Abnormal intervals between predicted messages.
VI. Abnormal propagation time (latency) for predicted messages with fixed publication period.

The following conditions were defined for the tests:

- Devices must be in their default configuration for the testing framework.
- All network interfaces provided for the testing structure must be connected and active.
- No device should have active alarms regarding the receipt of GOOSE, SV and PTP messages.
- All devices must be synchronized with the respective GNSS.
- The monitoring system must identify the presence of configured GOOSE, SV and PTP messages.

All devices were integrated into the station bus and process bus. The process bus was connected in PRP and using VLANs. A SCADA System was also installed to supervise the system. Each IED manufacturer monitors all platform devices (Figure 4).

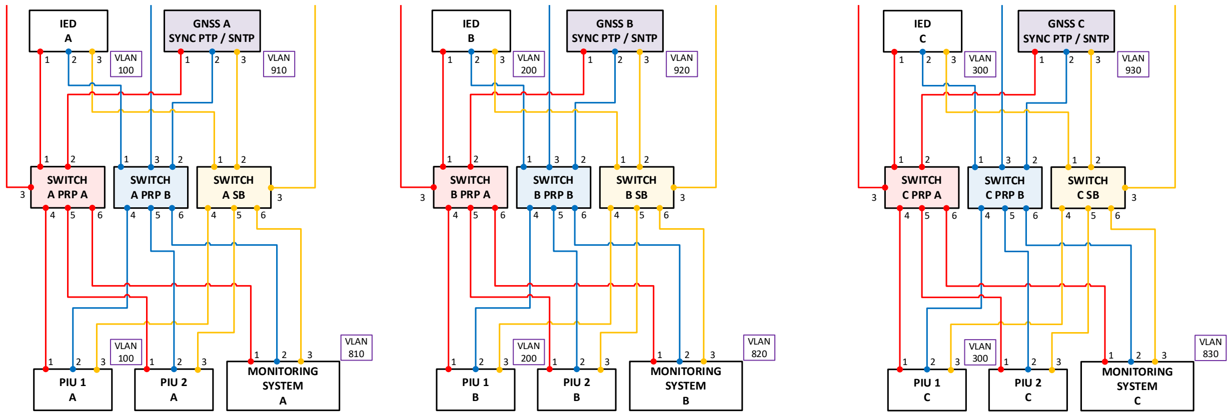

Figure 4 - IED platform communication architecture

In addition to the three platforms with IED/PIU, three network monitoring systems were set up (Figure 5).

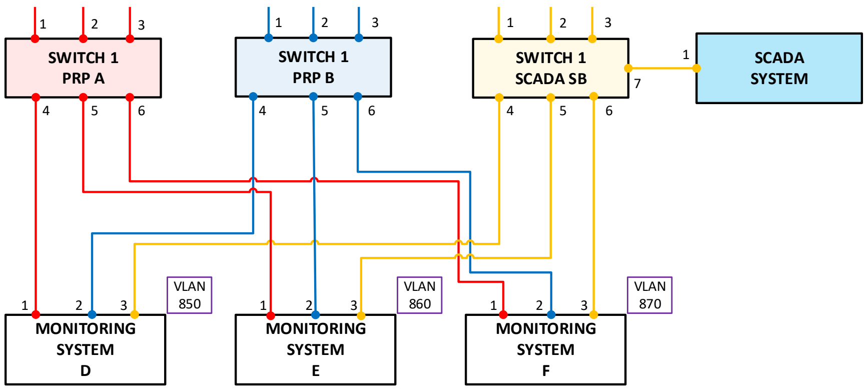

Figure 5 - Monitoring platform architect

5. ROADMAP OF APPLIED TESTS AND RESULTS

The tests were applied to the three implemented PAC systems, with monitoring from these manufacturers: A, B and C, basically based on the health monitoring of the devices themselves. In addition, three network monitoring systems: D, E and F. More than forty tests planned for execution on each monitoring system <=> IED/PIU pair. The tests were separated into groups associated with the communication protocols: GOOSE, SV and PTP. The main aspects of each are presented in table 2:

Table 2 – Overview of the tests applied

Testing Roadmap – GOOSE / SV:	• Detection of absence of expected messages (publisher disconnection; subscriber disconnection; network configuration failures) • Detection of unexpected messages on the network • Detection of lost, delayed, duplicated, out-of-sequence or corrupted messages • Fault detection in one of the PRP networks • Detection of messages with altered quality bits • Detection of configuration errors (modifications to various parameters: APPID, Dataset, ControlBlock, SVId, confRev, Dataset content) • Unsynchronized SV Stream Detection
Test Roadmap - PTP	• Detection of absence of synchronization signals and unexpected PTP messages • Monitoring redundancy of synchronization signals and changes in accuracy (lack of precision) • Monitoring of switching of synchronism signal sources and presence of two masters on the network

The results were classified as satisfactory or partially satisfactory. The main ones will be presented below.

5.1. Results – GOOSE / SV

5.1.1. Satisfactory results:

- Detection of missing expected messages.
- Configuration error detection:
  - ✓ APPID
  - ✓ Dataset Name
  - ✓ ControlBlock
  - ✓ SVID
  - ✓ confRev
  - ✓ Dataset Content
- Detection of messages with active quality bits (test/simulation)
- GOOSE redundancy monitoring in PRP networks (disconnecting only one of the physical connections).
- Performance evaluation of GOOSE messages (transmission time – minimum, average, and maximum).
- Message loss or delay detection.
- Out-of-sequence message detection.
- Detection of unsynchronized SV streams.

5.1.2. Partially Satisfactory:

- Detection of absence of an expected message at the subscriber, due to removal of physical connection at Process Bus can be detected indirectly through a failure to receive messages from the device removed from the network (streaming based on network capture). It is possible to detect the failure through the device's internal signal collected by Station Bus.
- Detection of expected message absence at subscriber without link failure (change in VLAN/SDN configuration): When the change also affects the streaming connection via capture, absence is detected. Possible to observe the failure through the device's internal signal collected by Station Bus.
- Detection of the presence of unexpected messages (GOOSE injection not configured in the SCD): Monitoring systems based on packet capture identify. IED/PIU do not directly identify. Filtering configured on the switches assists in this monitoring.
- Duplicate GOOSE message reception detection: Monitoring systems based on packet capture identify. IED/PIU may not alarm duplicity directly (indication of increased packet discard on the communication interface).

5.2. Results – PTP

5.2.1. Satisfactory results:

- Detection of absence of synchronism signals.
- Redundancy monitoring of synchronism signals (failure to receive the PTP signal on one of the PRP interfaces).
- Global reference monitoring and “clock class” (alarm for lack of global synchronization reference).
- Timing accuracy monitoring.
- PTP Message Latency Monitoring.
- PTP timing source switching.

5.2.2. Partially Satisfactory:

- Detection of the presence of unpredicted PTP messages: PTP signals were not described in the SCD, which makes it difficult to define which signals are predicted and which are spurious. Filtering techniques on switches can assist in detection.
- Detection of the presence of more than one Master on the network: IED/PIU select the GNSS with better precision (they do not generate an alarm when receiving two different PTP signals). Monitoring the devices GMID indicates which synchronization source is used. Monitoring System with network capture can identify the presence of distinct PTP signals.

The conducted tests have indicated the effectiveness of the monitoring systems in detecting the anomalies analysed. It is imperative to apply technology to monitor alarms from the devices themselves, and capture messages on the network to ensure proper identification of the different fault conditions tested.

The SCADA must receive more clearly defined alarms from monitoring systems to enable power system operators to take appropriate action.

It is important to advance in the construction of a single SCD file for each substation, especially when multiple manufacturers and tools are used in the same Protection, Control, and Supervision System

6. CONCLUSIONS

The paper presented reasons for monitoring the Process Bus and the results of a test on a multi-vendor platform. It demonstrated compliance with the review of ONS grid code.

The Brazilian Study Committee B5 - Protection and Automation formed a national Working Group to compile and document all the necessary details of the tests conducted. The intention is to create a technical reference guide that would serve as a helpful resource for the entire PAC systems community to facilitate their application of monitoring systems.

It also revealed that the solutions have different suppliers and are interoperable. This points to the philosophy of the IEC 61850 standard.

It will be important to verify real applications in future projects that will have to comply with the new grid code. This experience will serve to consolidate best practices.

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