Comparing the Cost, Complexity, and Performance of Several In-Service Process Bus Merging Unit Solutions Based on IEC 61850

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COMPARING THE COST, COMPLEXITY, AND PERFORMANCE OF SEVERAL IN-SERVICE PROCESS BUS MERGING UNIT SOLUTIONS BASED ON IEC 61850

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Abstract

In this paper, we make a comparative analysis of the performance, cost, complexity, resiliency, and security of several in-service digital secondary system (DSS) process bus solutions for devices with complete station bus capabilities based on the IEC 61850 communications standard. We summarize the recent work by several technical standards development organizations to further define process bus components. These definitions are consistent with the switchgear controller classes defined by IEC 62271-3:2006. Multiple in-service process bus DSS designs, based on these descriptions, are considered as extensions to the same typical station bus system. Using these definitions, we consider the impact of three unique process bus scenarios for a single relay with a complete station bus implementation. Then, we consider installation, performance, and availability criteria defined in numerous international standards. Finally, using the performance and availability criteria from these standards, we evaluate the process bus merging unit designs and use measured and observed information from in-service systems to compare speed, cost, and reliability.

1 Introduction

This paper is an updated and abbreviated version of [1] and provides a summary of comparative analysis of the various communications, process instrumentation, and control devices. The analysis includes the reliability of various systems in terms of unavailability. The relative cost and complexity of each solution is also evaluated along with the level of expertise required by maintenance teams to detect failures and restore system operation. Performance is evaluated based on the speed of detection and reaction to a power system fault.

Station bus communications are human-to-machine (H2M) connections and protocols that transmit and receive system information and send operator commands to networked intelligent electronic devices (IEDs). These communications include human-initiated and automatic client-server connections for supervisory control and data acquisition (SCADA), monitoring, metering, and engineering access.

Process bus communications are machine-to-machine (M2M) connections and protocols that exchange input/output (I/O) process information between IEDs and process instrumentation and control devices, including data acquisition devices, instrument transformers, and controllers.

M2M information exchange for interlocking, automation, and protection among IEDs is deployed on the station bus, process bus, or both. M2M information exchange for interlocking, automation, and protection between IEDs and process instrumentation and control devices is considered process bus communications. M2M time distribution is deployed on the station bus, process bus, or both.

Numerous protocols are in use in modern energy control system (ECS) networks for process bus communications and copper reduction strategies, including: IEC 61850 Generic Object-Oriented Substation Event (GOOSE) and IEC 61850-9-2 Sampled Values (SV) messaging, IEC 61158 EtherCAT, and IEEE C37.118.2-2011 Synchrophasor Protocol, Precision Time Protocol (PTP), and MIRRORED BITS communications [2]. ECS process bus communications need to be reliable, fast, cost-effective, cybersecure, and designed for a 25-year service life.

When designing an ECS protection system, engineers must devise a solution that is economically feasible and satisfies the performance requirements for protection: speed, safety, reliability, selectivity, and sensitivity appropriate to the criticality and characteristics of each application [3].

2 Internationally Standardized Process I/O Device Definitions

Recent work done by several technical standards development organizations provides standard definitions for process bus components based on their capabilities.

Working Group K15 of the IEEE Power System Relaying Committee on Centralized Substation Protection and Control defines process bus components, without restricting the protocols to be used, in [4]. IEC 61869-9:2016 describes four conformance classes of merging units (MUs). IEC 61869 is a standard for instrument transformers with a digital interface compliant with IEC 61850. It is also backward-compatible with the UCA International Users Group "Implementation Guideline for Digital Interface to Instrument Transformers Using IEC 61850-9-2" [5]. IEC 61869 defines the conformance classes as follows [6]:

- Class a: "The minimal set of services required to transmit MU data using sampled values (M2M SV)."
- Class b: "Class a capabilities plus the minimal set of services required to support GOOSE messages (M2M SV plus M2M GOOSE)."
- Class c: "Class b capabilities plus the implementation of the IEC 61850 series' information model self-descriptive capabilities (M2M SV plus M2M GOOSE plus H2M data models and self-description)."
- Class d: "Class c capabilities plus services for file transfer and either one or more of un-buffered reporting and buffered reporting, or logging (M2M SV plus M2M GOOSE plus H2M data models and self-description plus H2M MMS for monitoring and control)."

IEC 62271-3 describes digital interfaces based on IEC 61850 for switchgear and control gear. IEC 62271-3 defines the classes as follows [7]:

- Class a: "Minimal services to operate switchgear – simple GOOSE only device."
- Class b: "Services to support IEC 61850 information model (logical nodes) with self-description."
- Class c: "All services applicable for a specific LN [logical node]; configuration, file transfer, logging."

3 Signal Exchange, Device, and Local-Area Network (LAN) Acceptance Criteria Based on International Standards

Using the performance and availability criteria from the appropriate international standards [1], we evaluate and then measure and observe the numerous process bus MU designs. We use information from in-service systems to compare speed, cost, and reliability.

In accordance with these standards, the ECS must be designed to perform protection signal exchange that meets the following criteria:

- Have a signal exchange success rate greater than 99.99 percent.
- Achieve an expected signal transfer time between devices of less than three milliseconds.
- Achieve an expected signal transit via LAN of less than one millisecond.
- Have a maximum data delivery time between devices within a substation of less than 0.25 cycles.
- Have a maximum data delivery time between devices external to a substation of less than 8 to 12 milliseconds [8].

The LAN must be designed in accordance with these signal exchange and performance criteria to avoid failure. However, the design must also anticipate failure and have built-in resilience that meets the following criteria:

- Boolean protection logic with fewer than four dropped GOOSE packets and momentary outages shorter than 16 milliseconds.
- Analog protection calculations with fewer than four dropped SV packets and momentary outages shorter than 433 microseconds.
- Failover within each device that occurs within one logic-processing interval.

LAN faults must be detected and isolated, and a dual primary data path must be made available that is fast enough to deliver the protection signal. Therefore, a momentary outage is defined for each signal exchange. Longer sustained outages may prevent the communications-assisted protection from operating.

It must be recognized that communications will eventually fail and the design must have built-in, fault-tolerant resilience to compensate.

4 In-Service Process Bus Application Scenarios

This paper uses analysis methods first illustrated in [3] to compare designs for replacing traditional copper wiring with Ethernet communications. Communications channel design choices include shared-bandwidth switched Ethernet networks and point-to-point links. In this paper, we consider reliability, cost, and ease of diagnostics to evaluate the solutions.

In Section 5, an example application with a one-line diagram is used to aid analysis. The IED types used for this comparison are MU1, MU2, PCM3, PCM4, and PCM5.

MU1 is a process bus publisher device with an I/O interface to the process-level Boolean equipment status, control, and analog signals from current transformers (CTs) and voltage transformers (VTs). It has internal logic processing for protection and automation. This device is an IEEE intelligent merging unit (IMU) and IEC 61869-9 Class d MU with M2M SV, M2M GOOSE, H2M data models and self-description, and H2M Manufacturing Message Specification (MMS) for monitoring and control. The device also supports protocols for process bus publications, including IEEE C37.118.2-2011, PTP, and MIRRORED BITS communications.

MU2 is a process bus publisher device with an I/O interface to the process-level Boolean equipment status, control, and analog signals from CTs and VTs. This device is an IEEE PIU/PID that publishes raw analog values and Boolean equipment status signals and subscribes to control signals for equipment operation based on IEC 61158 EtherCAT.

PCM3 is a process bus subscriber protection, control, and monitoring device with internal logic processing for protection and automation and no I/O interface to the process level. This device receives Boolean equipment status, control, and analog signals from CTs and VTs via digital messaging. This device is an IEEE CPC with M2M SV plus M2M GOOSE. The device also supports protocols for process bus publications, including IEC 61850 GOOSE, IEEE C37.118.2-2011, PTP, and MIRRORED BITS communications. It supports data models and self-description plus H2M station bus protocols, including MMS, Telnet, File Transfer Protocol (FTP), Distributed Network Protocol (DNP3) LAN and wide-area network (WAN), IEEE C37.118.2-2011, PTP, and Simple Network Time Protocol (SNTP).

PCM4 is a process bus subscriber protection, control, and monitoring device with internal logic processing for protection and automation and no I/O interface to the process level. This device is an IEEE CPC that receives Boolean equipment status, control, and analog signals from CTs and VTs via IEC 61158 EtherCAT. It also supports protocols for process bus publications, including IEC 61850 GOOSE, IEEE C37.118.2-2011, PTP, and MIRRORED BITS communications. It supports data models and self-description plus H2M station bus protocols, including MMS, Telnet, FTP, DNP3 LAN/WAN, IEEE C37.118.2-2011, PTP, and SNTP.

PCM5 is a process bus subscriber protection, control, and monitoring device with internal logic processing for protection and automation and also has an I/O interface to the process level and receives Boolean equipment status and control via digital messaging. It is both an IEEE CPC and an IMU with M2M GOOSE. The device also supports protocols for process bus publications, including IEC 61850 GOOSE, IEEE C37.118.2-2011, PTP, and MIRRORED BITS communications. The device supports data models and self-description plus H2M station bus protocols, including MMS, Telnet, FTP, DNP3 LAN/WAN, IEEE C37.118.2-2011, PTP, and SNTP.

Each solution has the same full station bus capability. The three different process bus solutions include:

- Scenario A: MU1 is in the yard sending information to PCM3 in the control house with communications based on networked Ethernet connections. PCM3 has station bus connections in the control house.
- Scenario B: MU2 is in the yard sending information to PCM4 in the control house with communications based on point-to-point Ethernet connections. PCM4 has station bus connections in the control house.
- Scenario C: PCM5 is in the yard without an MU for local protection logic. It also serves as an IEC 61869-9 Class d MU for other station devices. It is communicating process bus and station bus information over networked or point-to-point Ethernet connections to devices in the control house.

5 Comparison of Three Process Bus Scenarios

The unavailability of the protection system is predicted using the mean time between failures (MTBF) and mean time to repair (MTTR) of equipment and devices involved. To simplify the comparative analysis, we disregard common points of failure. For the economic analysis, we consider the cost of equipment involved, such as switches, MUs, cables, and fiber as well as the design costs and level of expertise required to perform diagnostics on the system already in operation. As a summary, we present the comparison between solutions in a table, including unavailability, costs, and level of difficulty for maintenance and diagnostics.

The reliability and performance of the Ethernet network in Scenario A impacts every category of comparison. However, this paper intentionally oversimplifies the Ethernet network to a single switch (and assumes that it is engineered correctly) to relatively compare the other aspects of the process bus designs.

5.1 Reliability Analysis Using Device Rate of Failure and Unavailability

A system consists of several components, for which reliability can be expressed in more than one way. A common measure is the probability that a device will become unavailable to perform functions vital to system operation. If the unavailability of system components is known, a fault tree analysis allows us to predict the unavailability of any system.

The failure rate of a device is the number of failures expected over a period of time. It is common to express these data as the MTBF.

Availability and unavailability are usually expressed as probabilities [9]. For all equipment used in the analysis, the failure rates are based on field data or, where field data are lacking, equipment that has the same level of complexity and is exposed to the same operating conditions.

Given the MTBF and the time needed to detect and repair the problem, unavailability is calculated as shown in Table 1.

Table 1 Approximate availability of system components

Component	Unavailability ($1 \cdot 10^{-6}$)	Availability (percent)	Annual Time Unavailable Equivalent (minutes)
Ethernet switch	96	99.99040	50.46
IED Ethernet interface	2	99.99978	1.15
Electrical cable connection	200	99.98000	105.15
Power cable connection for IEDs and analog signals	1.1	99.99989	0.58
Monitored fiber-optic connection	1.1	99.99989	0.58
MU	18	99.99817	9.60
GPS	96	99.99040	50.46

5.2 *Expected Unavailability of Digitization Solutions*

We use fault tree analysis to compare several solutions, so the focus will be given to the differences between them. That is, everything that is common between the solutions does not influence this analysis and is disregarded in the evaluations.

5.2.1 *Scenario A: MU1 in Ethernet Network*

Fig. 1 shows the block diagram for Scenario A. In the example, MU1 is installed in a junction box in the substation yard and receives digital and analog signals electrically.

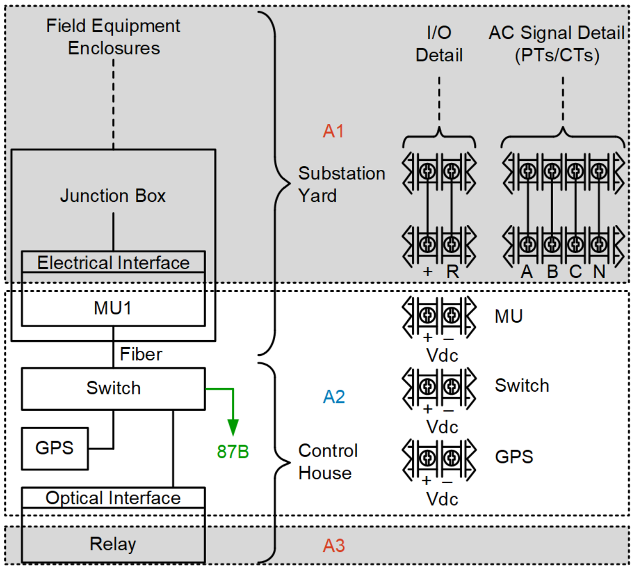

Fig. 1. Block diagram for Scenario A (MU1 in an Ethernet network).

In Fig. 1, the shaded areas (A1 and A3) represent what is common to all solutions and therefore is disregarded in this analysis. The white area (A2) represents the specific characteristics of MU1 in an Ethernet network scenario; they are:

- MU1: hardware and power cable pair with four connections and optical interface for connection to the switch.
- Ethernet switch: switch hardware, MU switch power cables with four connections and optical interfaces for connection to the MU, GPS, and IED. It is considered an optical interface, which is the connection to the IED.
- GPS: GPS hardware, a pair of cables for GPS power with four connections, and an optical interface for connection to the switch.

The fault tree for this solution is shown in Fig. 2. The loss of any analog or digital signal is the primary event, so failures related to MUs, switches, and GPS must be added through an OR logic gate.

The unavailability shown in Fig. 2 is related only to the association of components present in A2.

The digital and analog signals provided for the line protective relay are also available for other applications, such as differential busbar protection.

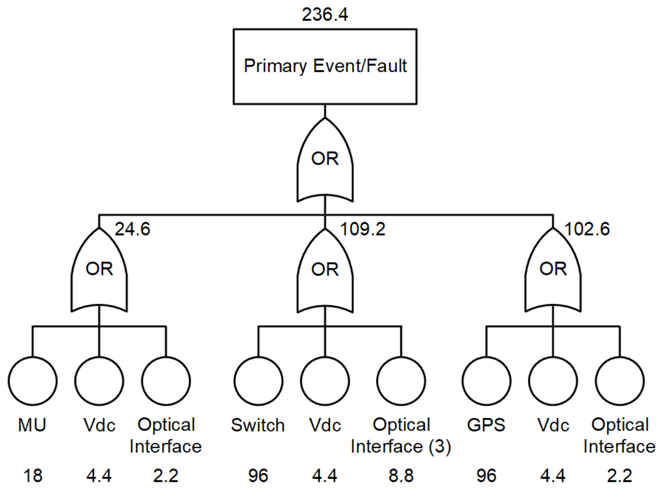

Fig. 2. Fault tree for MU in an Ethernet network (the multiplier for all unavailability is 10^{-6}).

5.2.2 *Scenario B: MU2 With Point-to-Point Link*

Fig. 3 shows the block diagram and Fig. 4 shows the fault tree for using an MU with a point-to-point link. In the example, MU2 is installed in the junction box and receives digital and analog signals.

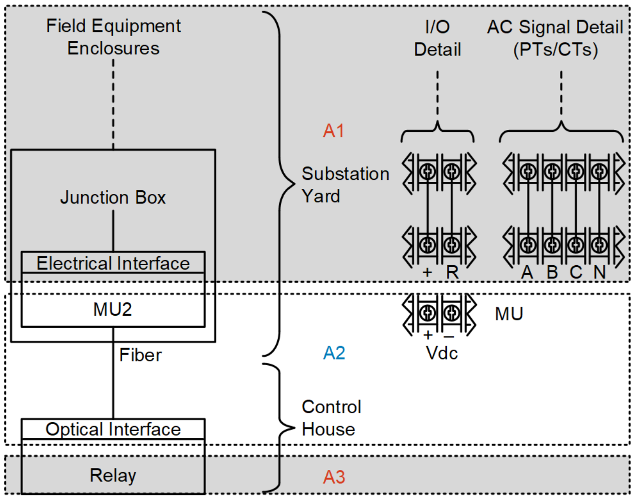

Fig. 3. Block diagram for Scenario B (MU2 with a point-to-point link).

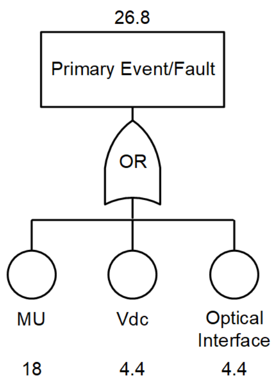

Fig. 4. Fault tree for an MU with a point-to-point link.

5.2.3 *Scenario C: Field-Installed PCM5 Relay/CPC/IMU*

Fig. 5 shows the block diagram and Fig. 6 shows the fault tree for a field-installed PCM5 relay solution. In this case, the protective relay is located in the position occupied by the MU in the previous scenarios.

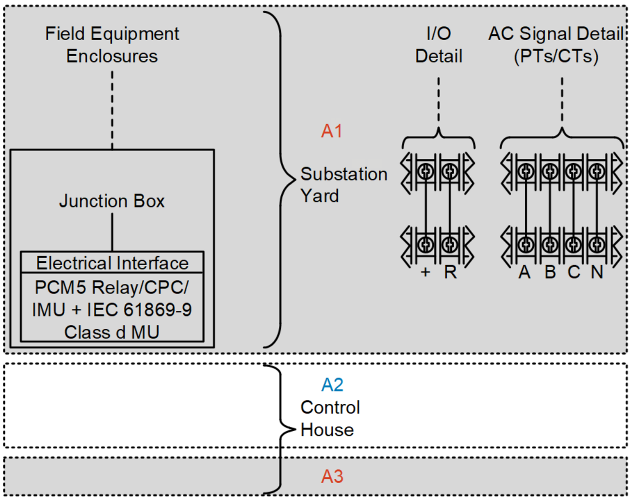

Fig. 5. Block diagram for Scenario C (field-installed PCM5 relay/CPC/IMU).

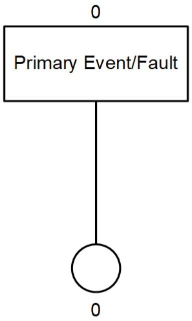

Fig. 6. Fault tree for a field-installed relay.

It should be noted that the result of zero unavailability is not the total unavailability of the system. Because it is a comparative analysis, all non-zero values for unavailability in all solutions can be interpreted as the main differences between those solutions and the field-installed relay solution.

An advantage of the field-installed PCM5 relay/CPC/IMU plus IEC 61869-9 Class d MU capability is that it can also provide process bus signals for other applications besides bay protection. Fig. 7 shows a hardware solution that incorporates protection and control functions in addition to the MU functions. Thus, there is the protection and control of the bay with high availability and also sharing of the signals for other applications.

5.3 *Cost Comparison*

Table 2 shows the hardware and services needed to implement each solution. Because we are doing a comparative analysis, we used the criterion of elimination of common items to determine a ranking of costs. The field-installed relay solution represents the lowest cost, followed by the MU with a point-to-point link, and then the MU in an Ethernet network.

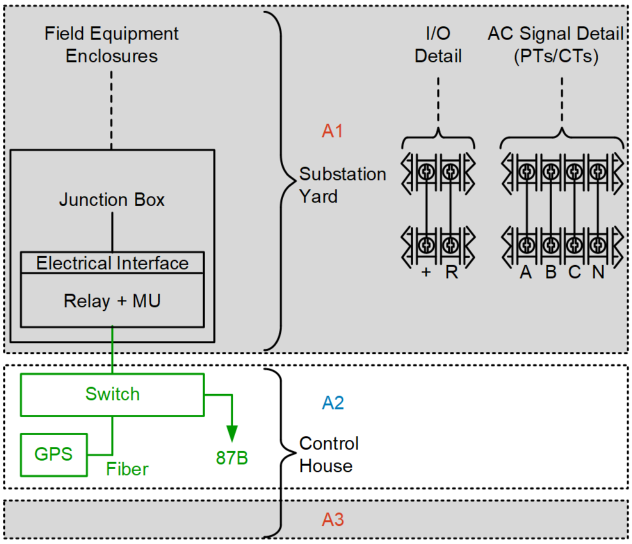

Fig. 7. Block diagram for a field-installed relay with MU functionality.

Table 2 Comparative cost analysis

Item or Solution		MU Ethernet Network	MU Point-to-Point	Field Relay
	Protection and control relay	✓	✓	✓
	MU	✓	✓	
Hardware	Switch	✓		
	GPS	✓	✓	✓
	Ethernet fiber interface	✓	✓	✓
	Relay panel design	✓	✓	✓
	Project panel MU	✓	✓	
	Automation panel design	✓		
Services	Fiber launch	✓	✓	✓
	Relay configuration	✓	✓	✓
	MU configuration	✓	✓	
	Network configuration	✓		
Cost rank		Highest	Between	Lowest

5.4 *Ease of Maintenance and Fault Diagnostics Comparison*

Table 3 shows the tools and knowledge that the maintenance team needs to diagnose failures in each solution. As in the cost analysis, the criterion of elimination of common items was used to determine a ranking of ease of maintenance diagnoses. The field-installed relay solution represents the greatest ease of use, followed by the MU with a point-to-point link and then the MU in an Ethernet network.

Table 3 Comparative diagnosis and maintenance analysis

Item		MU Ethernet Network	MU Point-to-Point	Field Relay
Tools	Relay software	✓	✓	✓
	MU software	✓	✓	
	Switch	✓		
	GPS software	✓	✓	✓
	Conventional test enclosure	✓	✓	✓
	SV test enclosure	✓	✓	
	Network analyzer	✓		
Knowledge	Protection engineering	✓	✓	✓
	SV network engineering	✓		
Maintenance rank		Most complex	Between	Simplest

5.5 *Speed of Protection Trip*

Measurements of the elapsed time between the presence of a fault measurement and the resulting trip confirm that the field-installed relay solution is fastest, followed by the MU with a point-to-point link and then the MU in an Ethernet network. These results are predictable based on the quantity of devices and types of communications in each system. Like the other comparisons in the paper summarized in Table 4, this relative speed comparison, confirmed by actual measurements, represents what is possible regardless of manufacturer.

Table 4 Comparative Analysis of Cost, Reliability, Complexity, and Speed

Aspect	Scenario A (IEC 61850 SV IMU to CPC)	Scenario B (IEC 61158 MU to CPC)	Scenario C (IMU in Field Does Protection)
Cost	Highest	Between	Lowest
Reliability based on future analysis	Least	Between	Highest
Maintenance complexity	Most complex	Between	Simplest
Tripping time	Slowest	Between	Fastest

6 Conclusion

Working Group K15 of the IEEE Power System Relaying Committee on Centralized Substation Protection and Control describes CPCs, MUs, RIOs, PIU/PIDs, and IMUs for digital secondary systems. IEC 61869-9:2016 describes four conformance classes of MUs compatible with IEC 61850-9-2 for SV and IEC 62271-3. These classes roughly match up with the IEEE PIU/PID, RIO, MU, and IMU devices.

This work, summarized in Table 4, shows that the allocation of protection and control IEDs in the substation yard presents the best index regarding reliability, costs, and ease of maintenance and fault diagnosis. The point-to-point MU solution presents the second best performance. The MU in an Ethernet network solution ranks last. The field-installed relay with built-in MU functions has the advantage of making analog and digital values available for other applications and is the most reliable scheme.

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