# Evolution of Digital Protection and Control Systems at EPCOR

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## SUMMARY

This paper discusses the evolution of digital protection and control systems at EPCOR. It covers the steps taken while deploying digital solutions for over the last 18 years starting from DNP3 alternatives, progressing to station bus and ultimately process-bus based applications. Experiences and lessons learned that led to development and modification of standards and common practices as well as formulation of digital protection and control philosophy are highlighted.

## KEYWORDS

digital protection and control systems, station bus, process bus.

## 1. Introduction

EPCOR Distribution and Transmission Inc. (EDTI) is a regulated electrical subsidiary of EPCOR corporation which owns, plans and operates the electrical infrastructure in Edmonton and nearby area in the province of Alberta, Canada. EPCOR has been renowned for positioning themselves in the front line of technological advances in substation protection and control (P&C) as an early practitioner of IEC 61850-based digital technologies. EPCOR applications of IEC 61850 date back to 2009 with the implementation of client-server communication in parallel with DNP3 for SCADA monitoring tasks. Generic Object-Oriented Substation Event (GOOSE) messages were first successfully implemented in a novel feeder protection upgrade project to trigger disturbance fault recorder (DFR) functions in neighbouring feeder protection relays.

After numerous other small-scale GOOSE applications, a full-scale implementation of GOOSE for inter-device signalling was realized in 2020 in a green field substation project. In addition to standardizing on IEC 61850 station bus applications, EPCOR completed and energized its first process bus installation at Woodcroft Substation in 2016 based on the UCA IEC 61850-9-2 Light Edition (LE) implementation guideline, followed by a Strathcona Substation deployment in 2022-2023. The initial process bus project scope allowed for breaker fail, sync check and trip coil monitoring and was expanded to include transformer protection for Woodcroft Substation. For Strathcona Substation design includes high voltage protection for line, transformer, and breaker fail protection schemes.

This paper discusses the evolution of process bus-based applications at EPCOR. By comparing designs from the first process bus installation at Woodcroft Substation to the new design at Strathcona Substation, it extrapolates lessons learned to what would be done for a future process bus installations. In this process, EPCOR standards and engineering process were reviewed and simplified as new tools and products became available.

## 2. Digital Protection and Control Systems

To assist with interpretations of design differences, basics of digital substation technologies are briefly covered in this section.

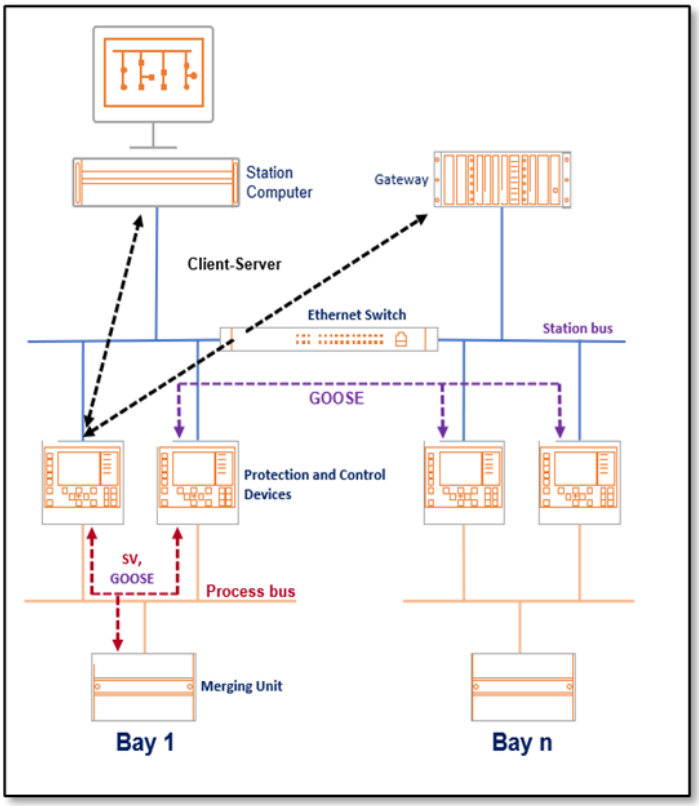


Figure 1. Digital Substation Communication Overview

Digital substations are commonly built using IEC 61850 technology, which does not only define information exchange but also provides standardized and complete object modelling techniques and description language [1]. In place of traditional copper connections for analog and binary signals, digital substations rely on signals shared as data values sent over Ethernet connections. For analog values, IEC 61850 sampled values (SVs) are used. For binary signals GOOSE messages are applied. These communication-based analog and binary signal exchanges are shown on Figure 1, borrowed from [2].

EPCOR defines "digital substations" as the implementation of protection and control applications through microprocessor-based devices communicating with each other through digital communication methods. This contrasts with what is considered a "conventional substation" for protection and control applications, which utilize electromechanical relays and copper wiring to achieve application goals, refer to [4].

It is EPCOR Transmission's vision to utilize and implement digital substation solutions in pursuit of the following goals:

1. Improving safety
2. Improving system reliability
3. Decreasing maintenance requirements
4. Simplifying and reducing electrical wiring
5. Reducing costs
6. Maintaining or improving EPCOR's reputation
7. Enabling advanced technology.

## 2.1 Woodcroft Substation Design

The Woodcroft Substation P&C upgrade was considered a major achievement at the time in the Utility industry. It was the first protection system upgrade project to adopt UCA IEC 61850-9-2LE process bus implementation guideline in Canada [3]. Woodcroft is a 72kV, brown field station, adding additional complexities in testing and commissioning aspects to the project. Protection upgrades are executed in phases for brown field stations so it is extra critical to minimize disruptions to protection schemes not included in the upgrade work. Two phases have been successfully completed in Woodcroft to date. The initial phase involved upgrades to breaker management units utilized for breaker failure, sync-check and breaker health monitoring applications. Transformer protections were added during phase two of the project, but only Main B protection was designed to subscribe and process sampled values to limit risks. Vendor and product evaluation of the process bus technology commenced in 2014, detailed design of phase one occurred in 2015, and was fully commissioned in 2016. Phase two of the upgrade was completed in 2018. Station bus applications are fairly similar to those implemented in another EPCOR substation called Riverview with the exception that transmission line protections were not included for GOOSE exchanges as dictated by the phased upgrade schedule for this brown field substation. Phase three of the protection upgrade, which includes line protection is scheduled for execution in 2025. The ultimate phase would have all HV P&C assets upgraded to IEC61850 communication by the late-2020's. Figure 2 illustrates the ultimate layout in Woodcroft.

Process bus technology based on UCA IEC 61850-9-2LE, entails digitizing analog signals from the current and voltage transformers close to the source by hardware located at the switchyard. Commonly known as a merging unit (MU) or process interface unit (PIU), this hardware has similar analog terminals for CT and VT connections and in most commercial design today also comprises digital I/Os in the same enclosure to support binary signalling to/from the field. The Ethernet frames carrying digital samples of analog measurements, known as Sampled Values (SV), are processed by protection IEDs similar to analog current and voltage inputs. The process network is an Ethernet network, often employing parallel redundancy protocol (PRP) to address any single point of network component failure, a critical requirement for sampled value transmission to ensure the same measure of dependability as conventional protection systems.

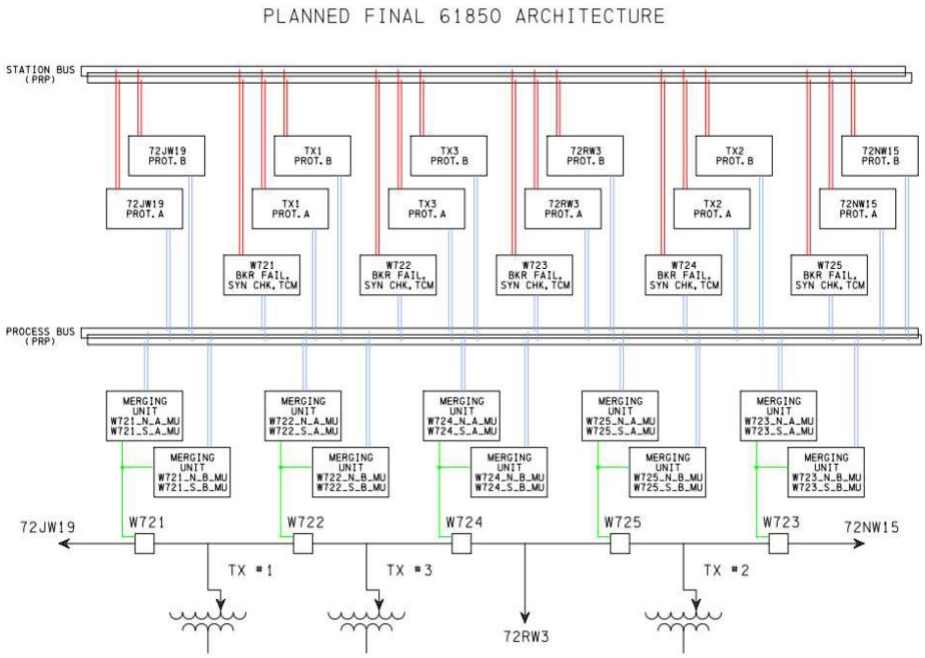


Figure 2. Woodcroft Ultimate IEC 61850 Configuration

The key functionality of the process bus network is to

- Publish sampled values from merging units located in the switch yard onto the process network. The SV streams are subscribed and processed by different protection IEDs through vendor specific engineering procedures.
- Transfer binary values via GOOSE messages. This includes both publishing signals such as circuit breaker (CB) positions, disconnect switch positions, and trip coil health collected via the digital inputs and subscribing to critical trip, re-trip, and close signals from protection IEDs from the different P&C schemes. Figure 3 below displays an example of IEC 61850 network architecture.

Throughout 2014, product evaluations were conducted in EDTI's protection laboratory and two viable process bus solutions were found. By the end of 2014, the Woodcroft Substation 72kV breaker fail upgrade project was selected to implement IEC61850-8-2LE process bus as part of its scope, utilizing the selected vendor for all IEDs. Detailed design for the breaker fail upgrade including a portion of the ultimate process bus configuration for the station commenced in 2015.

The ultimate Process Bus design for Woodcroft included the following features:

- a dedicated process bus switch network (separate from the station bus)
- one Pulse Per Second (1 PPS) time synchronization
- Stand Alone Merging Units (SAMUs) to supply Sampled Values (SV) analogs, yard equipment statuses via GOOSE message and execute breaker trips
- IEC 61850-8-1-Ed2 Station Bus GOOSE messaging for protection signals in the relay room, including breaker failure initiate (BFI), block close, DFR triggers, and auto-restoration signals
- Signal blocking for individual GOOSE signals via conventional FT test switches wired to relay binary inputs
- Individual Virtual Local Area Networks (VLANs) for each GOOSE message and SV

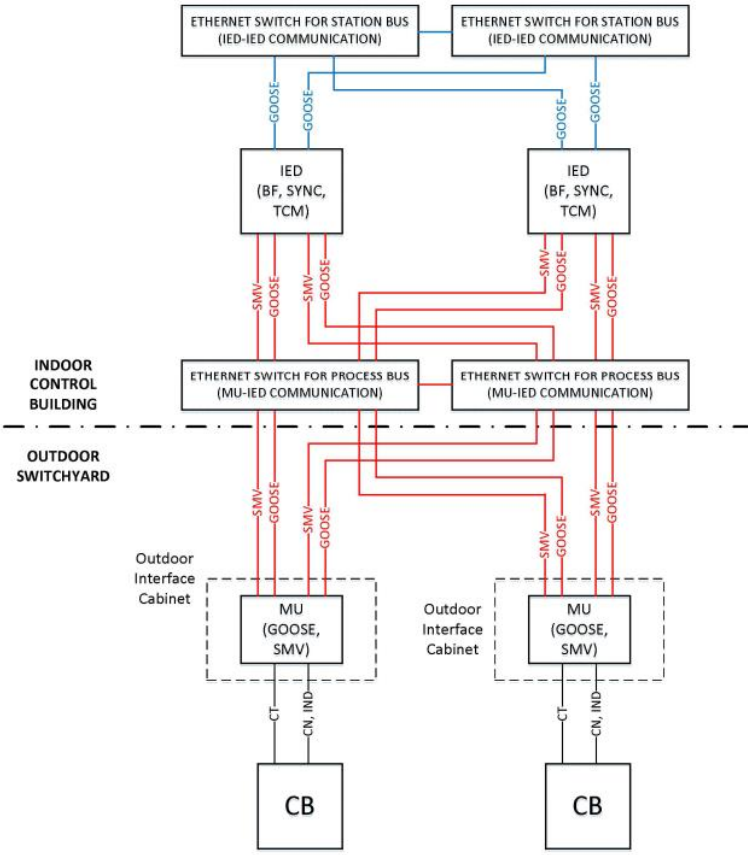


Figure 3. Example IEC61850 Network Architecture

Only the "B" scheme at Woodcroft utilizes Sampled Values (SVs) and GOOSE tripping through merging units. The "A" scheme at Woodcroft utilizes GOOSE messaging within the relay room (station bus), but does not utilize any SVs or GOOSE tripping. This approach (one conventional scheme and one process bus scheme) was taken to mitigate any unforeseen risks with implementing the new process bus technology. The full process bus network was thoroughly tested in EDTI's protection laboratory before the materials were released to the field.

The construction of the Woodcroft 72kV breaker fail upgrade project began in late 2015/early 2016. As expected, some difficulties associated with using a new technology caused minor delays early on. However, all items were placed in service after thorough field testing and commissioning in Q2/Q3 2016.

In 2017, design of transformer protection upgrades at Woodcroft commenced. This design continued to put in place merging units and protection aligned with the ultimate Process Bus design that was planned for Woodcroft. The transformer protection was put into service in 2018. The TX3 "B" protection system misoperated three times between 2018 and 2022, but the nature of the misoperations was attributed to merging unit analog card performance and improper relay parameters rather than the process bus technology itself. However, the process bus would be considered a contributing factor to the repeated misoperations since the use of the new technology made the analysis of these misoperation events more challenging.

### 2.2 Strathcona Substation Design

In 2022, construction of the Strathcona 72kV protection upgrade started. For this protection upgrade the "A" schemes were selected to utilize IEC 61850-9-2LE process bus technology from a different vendor from the Woodcroft project. Both the "A" and "B" schemes utilized IEC 61850 station bus for

GOOSE messages. This mirrored the approach taken at Woodcroft in 2016, but allowed the exploration of an alternate vendor.

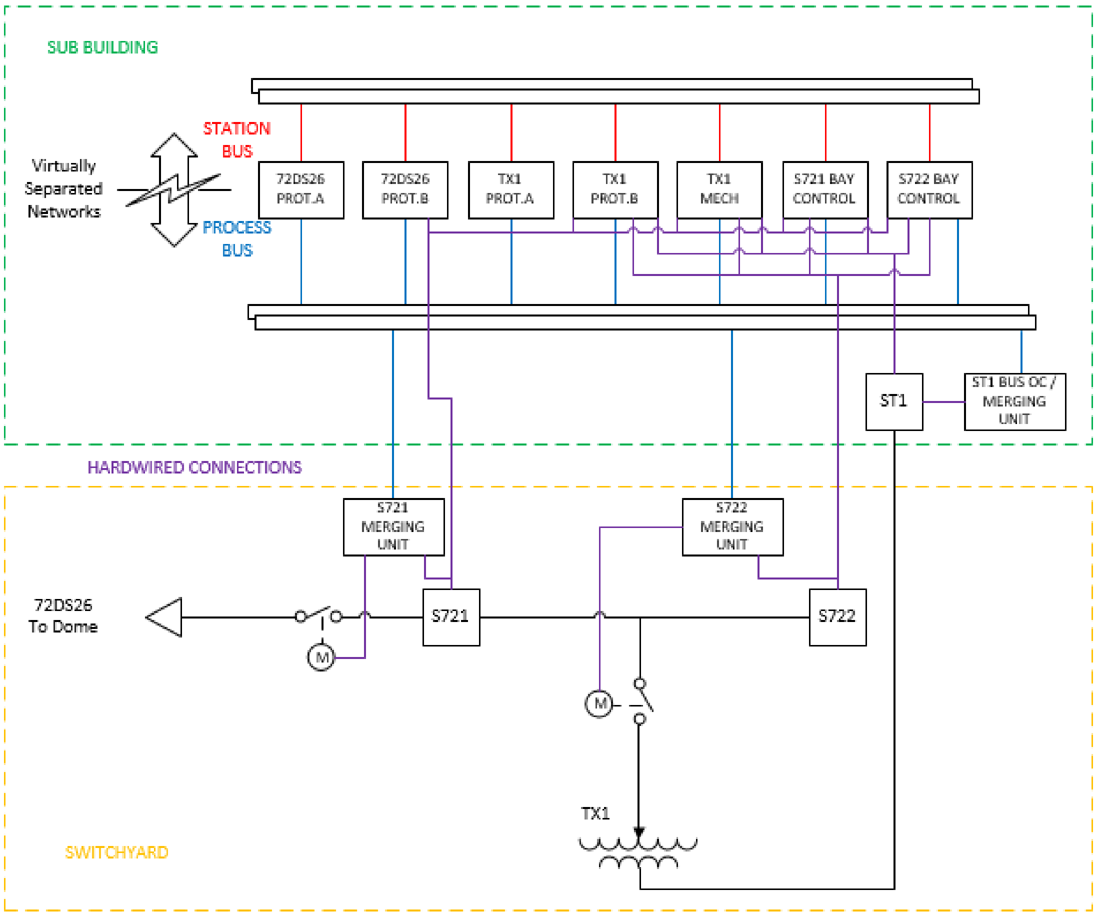


Figure 4. Strathcona Substation Protection Topology (Partial Station)

The ultimate Process Bus design for Strathcona included the following features:

- A combined station bus and process bus switch network (one physical network using VLANs to separate station bus and process bus);
- Two different vendors for Ethernet switches for "A" and "B" PRP network;
- IEEE 1588 Precision Time Protocol (PTP) time synchronization;
- Stand Alone Merging Units (SAMUs) to supply Sampled Values (SV) analogs, yard equipment statuses via GOOSE message and execute breaker trips;
- IEC 61850-8-1-Ed2 Station Bus GOOSE messaging for protection signals in the relay room, including BFI, block close, DFR triggers, and auto-restoration signals.
- IEC 61850-8-1-Ed2 Test and Simulation Mode integration for blocking and maintenance tasks, activated via binary input at each relay.
- Individual VLANs for each SV, and two common VLANs for all GOOSE messages, separating station and process busses.

Only the "A" scheme at Strathcona utilizes Sampled Values (SVs) and GOOSE tripping through merging units. The "B" scheme at Strathcona utilizes GOOSE messaging within the relay room (station bus), but does not utilize any SVs or GOOSE tripping.

Strathcona Substation protection topology is shown on Figure 4.

## 3. Digital Substation Philosophy developed based on Lessons Learned

Through deployment of digital protection and control systems at EPCOR various lessons were learned, and digital substation philosophy was developed. Experience collected from Woodcroft heavily affected strategy and decisions deployed at Strathcona. Lessons learned from both of these sites heavily influence the present philosophy for digital substations at EPCOR.

### 3.1 Time Synchronization Methods

When designing and implementing UCA IEC 61850-9-2LE in 2014 through 2016, one Pulse Per Second (1 PPS) analog timing was the vendor prescribed method for providing time synchronization to devices supplying SV signals, this is the only synchronization method defined by IEC 61850-9-2LE. As such, this method of time synchronization was utilized for Woodcroft Substation. After working with this method of synchronization, EPCOR deemed this solution as non-preferable due to the need for dedicated 1 PPS timing infrastructure, challenges related to setting and troubleshooting the 1 PPS time signal waveform, and preventing nuisance alarms related to end device interpretation of 1 PPS signals.

When designing and implementing IEC 61850-9-2 process bus-based designs in 2020 through 2022, IEEE 1588 PTP timing had emerged as a method for providing time synchronization and was compatible with IEDs providing SV signals. For Strathcona substation, EPCOR pursued this PTP method of time synchronization in the interest of avoiding the challenges associated with 1 PPS found at Woodcroft in 2016. Even though the implementation of PTP wasn't seamless (many challenges were encountered with fine tuning clock configurations and working through specific hardware related misalignments with the IEEE1588 standard), it was still seen as an improvement, especially in the reduction of dedicated timing infrastructure.

EPCOR has adopted IEEE 1588 PTP as its default protocol for supplying time synchronization as a result of the lessons learned at Woodcroft and Strathcona substations.

### 3.2 Physical Network Architecture

A positive lesson learned from the implementation of process bus infrastructure at Woodcroft substation was regarding the effectiveness of PRP infrastructure. This network architecture performed as expected and informed the decision to continue deploying networks using PRP going forward, including at Strathcona. At Woodcroft a dedicated process bus network was deployed, physically separate and independent of the station bus network. Separate network architecture was seen as a method to guarantee containment of SVs and avoid unintentional interaction with a network carrying GOOSE trip signals. It was observed that this infrastructure implementation roughly doubled the number of network switches required and forced requirements for additional network ports on relays. It was noted, that with monitoring of the effectiveness of other tools, such as VLANs, it could be possible to relax requirement for a physically separate process bus.

After several years of successful operation of the infrastructure at Woodcroft, EDTI elected to evolve its process bus network design by moving to a virtual process bus network (existing as VLANs only) on the same physical infrastructure as the station bus network at Strathcona substation. As of this time, EPCOR has not experienced any drawbacks related to this style of process bus architecture.

EPCOR has adopted PRP and a unified physical network for process bus and station bus on separate VLANs as its default physical network configuration when deploying process bus going forward.

### 3.3 Virtual Network Architecture

EPCOR protection engineers had limited experience with Virtual Local Area Networks (VLANs) when design began for Woodcroft's process bus installation. In the interest of minimizing bandwidth saturation on network switch ports and restricting visibility of signals for both network cyber security and protection system security of operation, for the new GOOSE and SV applications, unique VLANs were applied for each GOOSE message and SV streams. This design choice did prove effective in accomplishing its goals, however managing relay and switch configurations with respect to so many

VLANs was felt to be more challenging than necessary. As a result, EPCOR was interested in simplifying VLAN design for Strathcona.

At Strathcona, a single VLAN was deployed for GOOSE messaging on the station bus and other VLANs were deployed for process bus. Individual VLAN IDs were maintained for each SV streams. This strategy proved successful for Strathcona and EPCOR has adopted this VLAN strategy as its default for any future process bus installations.

### 3.4 Merging Unit Enclosure Design

Standalone merging unit designs seen from vendors in the 2010's typically took on a surface mount form factor. As a result, merging unit cabinet designs from EDTI in this time period were based on a shallow but wide junction box style. This design style was deployed at both Woodcroft and Strathcona sites. During the early 2020's it is being observed that the next generation of merging units are more often using a rack mount form factor. This form factor that will be challenging to retro fit into the existing enclosures at Woodcroft and Strathcona when replacements are needed. EPCOR is exploring alternative designs that better accommodate rack mount IEDs for future cabinets as a result of this lesson learned.

### 3.5 IEC 61850 Test and Simulation Modes

When implementing process bus at Woodcroft substation, products utilizing IEC 61850 test modes were available, but simulation modes were not yet established. As a result, much of the hardware deployed at Woodcroft substation is not capable of correctly interpreting simulation mode signals. Testing performed at this site often involves hardware level blocking and powering down SV and GOOSE sources in order to inject signals on their behalf. EPCOR testing and maintenance procedures accommodate the lack of simulation mode at this site, but this missing feature was sought after during development at Strathcona.

Vendor IED solutions that were selected for Strathcona include support for IEC 61850 simulation mode. EPCOR testing and maintenance procedures at Strathcona substation incorporate this feature, refer to [5] for more details.

EPCOR has adopted 61850 Test and Simulation modes as technical requirements for IEDs going forward as a result of the lessons learned from Woodcroft and Strathcona process bus implementations. Using test and simulation modes has led to simplified and more efficient testing compared to applying conventional means for isolation, i.e. FT switches , to digital substations.

Descriptions and Figures below cover test scenario examples from [6], utilizing test and simulation modes.

Function test for Relay 1 is illustrated on Figure 5. Relay 1 is isolated by placing it in Test mode. Behaviour is now Test and published GOOSE will have a Test flag set to High. Relay 1 is also placed into Simulation mode to subscribe to simulated GOOSE and SV. FT switches must be opened to block operation of binary outputs of Relay 1. Any required binary signals are wired to the test set. The test set publishes SV and GOOSE as required with Simulation flag set to High. Because these signals are ignored by all other IEDs that are not in Simulation mode, the Test flag is not applied. The test set subscribes to GOOSE published by Relay 1.

Operation check for Merging Unit 1 is depicted on Figure 6. The same setup as for the Function test for Relay 1 is applied. In addition, FT switches must be opened to block operation of binary outputs of Merging Unit 1. Merging Unit 1 is placed into Test mode. Merging Unit 1 will now operate based on GOOSE received from Relay 1 with Test flag set to High. Note that Relay 2 (not being tested) is not placed in Simulation mode, since it is not using any simulated data. Selectively close Merging Unit 1 FT switches to allow desired operation checks.

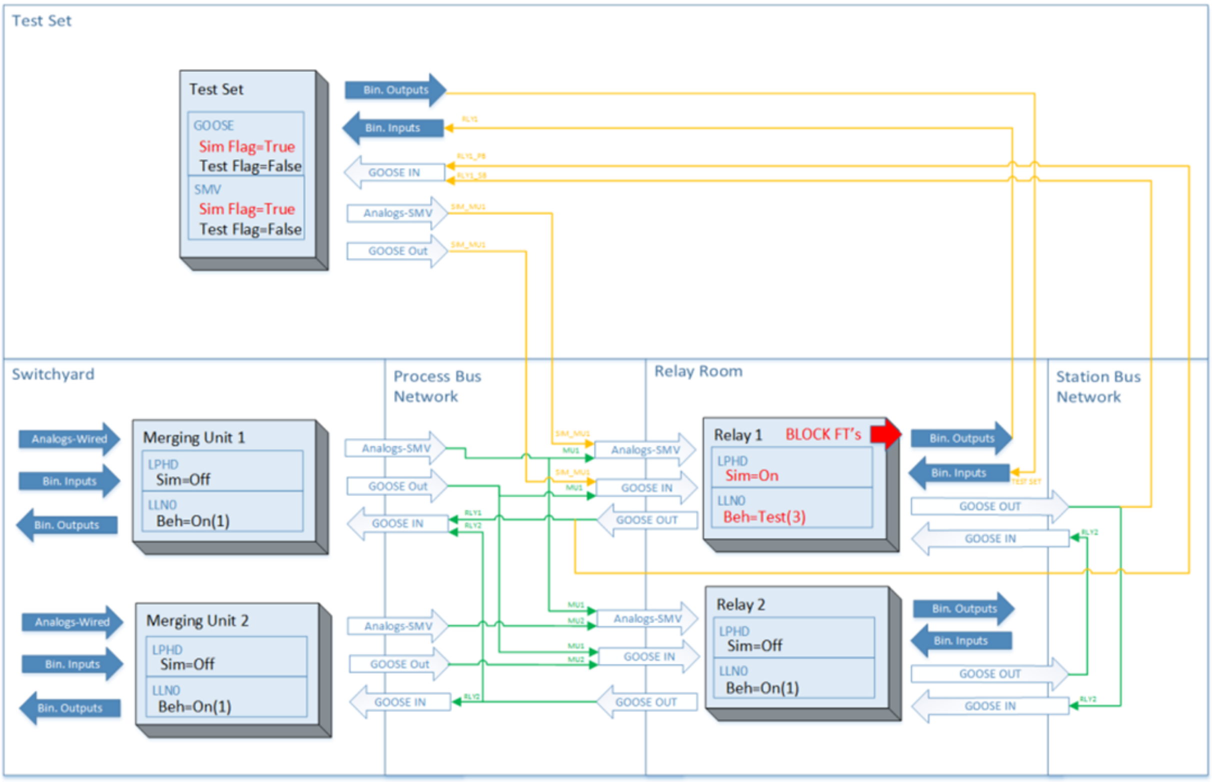


Figure 5. Function test for Relay 1

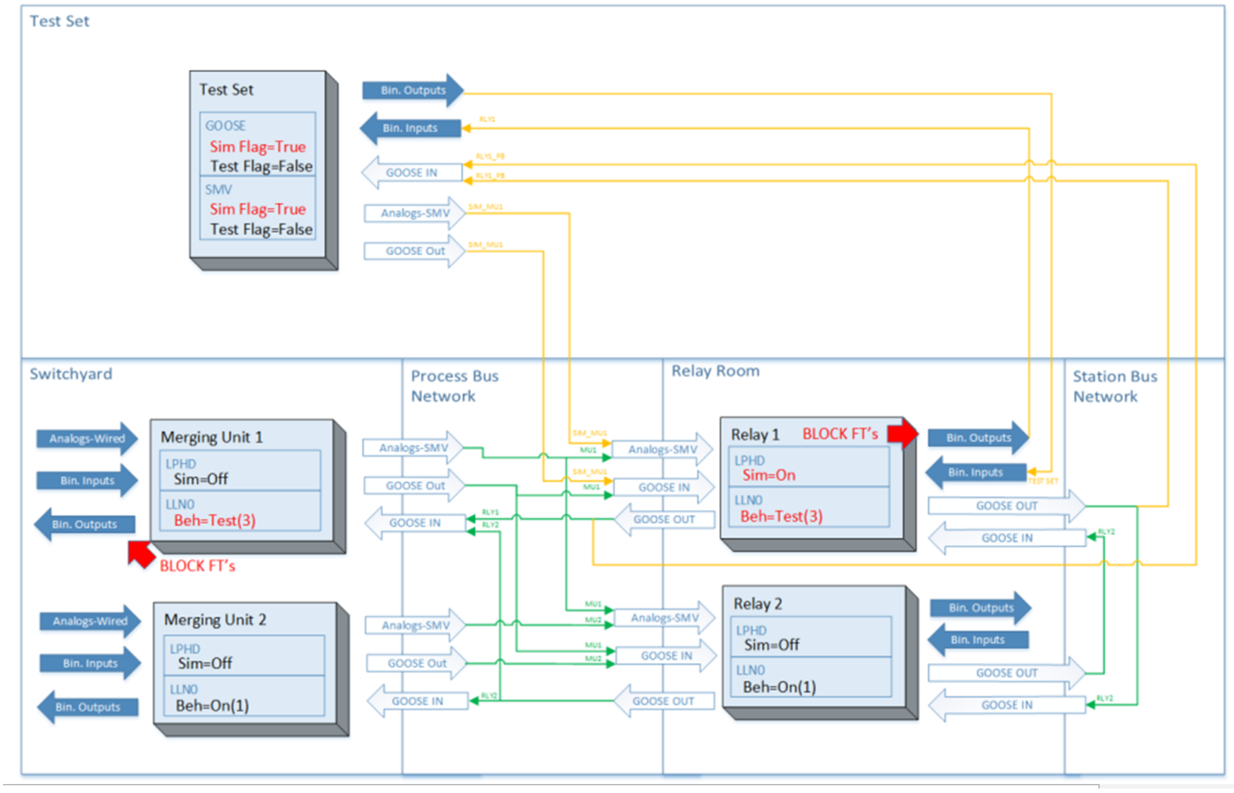


Figure 6. Operation check for Merging Unit 1

### 3.6 Utilizing protection IEDs to Publish Sampled Values

At Strathcona substation the medium voltage bus overcurrent relays were used as merging units, publishing current and voltage SVs to the transformer differential protection relay. EPCOR made this design choice in the interest of reducing overall IED counts for the substation and in the pursuit of cost savings by combining backup protection and MU functionality. However, this functionality combination leaves opportunity for a miss-operation when the MV bus overcurrent relay has its CT shorted for maintenance or isolation. It is imperative to place the MV bus overcurrent relay in test mode before shorting the CT, as this will correctly block operation of the transformer differential relay. This is the only such application in EPCOR, thus increasing the potential for error. Although there are advantages to applying protection functions in merging units, going forward EPCOR will keep protection functions separate from merging units. This decision will be revisited once process bus applications are more common.

## 4. Conclusions

EPCOR has evolved its digital substation philosophy based largely on lessons learned from deployment of digital substation technology in Woodcroft and Strathcona substations. These lessons learned greatly affected decisions and future directions. EPCOR's Digital Substation Timeline, shown on Table 1, provides a summary and gives a prospective for timing, lessons learned and evolutionary directions pursued over the last 18 years.

Table 1. Digital Substation Timeline

DIGITAL SUBSTATIONS TIMELINE

| | Pre-2006 | 2006-2010 | 2010-2012 | 2012-2014 | 2014-2016 | 2016-2018 | 2018-2020 | 2020-2023 |
|---|---|---|---|---|---|---|---|---|
| DNP3 | DNP3 is the dominant communication protocol in substations | | DNP3 use begins to decline as MMS becomes the preferred comm. protocol | | | | | DNP3 only used where MMS is unavailable |
| IEC61850 MMS | | MMS is introduced at EPCOR and begins seeing use to provide some alarms to the EDTI control room | MMS begins to be used for SCADA alarms and analogs with any relays it is available for | | MMS controls are piloted for use with HLT remote enable/disable schemes and for Rossdale VRR | | MMS protocol is now the standard protocol for statuses, analogs, and controls between IEDs and the Substation Gateway | |
| IEC61850 GOOSE | | GOOSE relay-to-relay communication is attempted and fails at East Industrial Substation | GOOSE is implemented at Summerside POD. It isn't documented well, but it does go in-service | GOOSE is implemented for various small applications | GOOSE is implemented for Process/Station bus at Woodcroft breaker fail protection upgrade | Woodcroft Process/ Station Bus is expanded to include transformer protection B schemes. | GOOSE Station Bus is fully implemented for Riverview greenfield project, now considered standard for greenfield | GOOSE is implemented for Process/Station bus for Strathcona 72kV Protection |
| IEC61850 SMV | | | | SMV technology is researched at EDTI for its potential use with upcoming upgrades | IEC61850-9-2-LE Process Bus technology is installed and goes in service for Woodcroft breaker failure protection upgrade | Woodcroft Process Bus is expanded to include transformer protection B schemes. | | IEC61850-9-2-LE Process Bus technology is installed and goes in service for Strathcona 72kV Protection A |
| Time Sync | IRIG-B is used to supply high accuracy time signals as needed. Many relays are not time-synced. | | SNTP is utilized by IEDs at some sites where the signal happens to be available on the local network. | | | | IEEE 1588 PTP is piloted at Riverview Substation | IEEE 1588 PTP is installed at Strathcona Substation for use with IEC61850 Process Bus. Now considered standard. |
| Network Redundancy | | | Switchgear purchased for Summerside Substation utilizes HSR loops for relay SCADA connections | PRP network architecture is piloted at EDTI substations | PRP network architecture deployment continues | PRP is considered the standard network architecture where relays are involved | | All major EDTI substations have a PRP network architecture established |
| Substation HMI | | Substation HMI PCs are piloted but they are not granted in-service status for usage by operations | | | | | Substation HMI is re-piloted at Riverview Substation and goes in service | Substation HMIs are upgraded and commissioned in service at all major EDTI substations |

This paper summarized digital design details for both Woodcroft and Strathcona substations. Among important learnings are time distribution methods synchronization (1 PPS vs IEEE 15488 PTP), network architectures (separate networks for station and process bus vs a single physical network with VLAN separation for station and process bus), use of IEC 61850 test and simulation modes, and merging unit enclosure designs. Informed decisions based on these learnings will be applied to future digital substation designs at EPCOR.

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Adam Rudd joined EPCOR Distribution and Transmission Inc. in 2010 as a Power System Electrician in the Substation Operations team. Adam transitioned to EPCOR's Transmission Protection and Control Engineering team in 2014, where he holds his current role as Electrical Technologist, Substation Integration. Adam has implemented and tested several digital substation projects over the past 10 years, utilizing IEC 61850 MMS, GOOSE, and sampled values.

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Galina S. Antonova serves as a Technical Sales Engineer at Hitachi Energy in North America. She has 20+ years of experience in electrical engineering, data communications and time synchronization, applied to the electrical power industry. Galina received M. Sc. with Honors (1993) and Ph.D. (1997) from the State University of Telecommunications, St. Petersburg, Russia, and spent one year at University of British Columbia on a scholarship from Russian President. She is actively involved with IEEE PSRC, PSCCC and is a Canadian member of the IEC TC57 WG10. In her spare time Galina enjoys ice dancing, playing piano and growing lavender.