A centralized protection and control system using a well proven transmission class protection relay

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1. Introduction

The growing adoption of process bus and the desire for a digital substation is leading to a new interest in the concept of centralized protection and control, where all protection functions for a substation are combined into a single device. When considering implementations of this solution, it is important to remember that this device will be installed in a substation and must meet all the expected environmental and performance requirements for protective devices in substations. Importantly, a centralized protection device must be a technologically mature solution, robust and self-supervised platform, using proven protection algorithms, scalable for any substation size, on hardware capable of the expected 20-year service life.

This article describes one specific actual implementation of such a system for distribution substations, based on an existing transmission class protection relay. This centralized distribution system takes advantages of features already developed for the transmission protection platform, including:

- Proven protection algorithms for feeder, bus, and transformer protection
- A robust cyber security implementation
- Support for multiple SCADA protocols
- Support for IEC 61850, including sampled values subscription
- Numerous communications ports to support separate connections to station bus, process bus, and engineering networks simultaneously

A growing requirement for distribution substations is the ability to integrate into wide area monitoring, protection and control schemes. As the device is based on a transmission-based relay platform, this ability is quickly met by including multiple Phasor Measurement Units, and the use of Routable GOOSE to provide inter-station events and control indications.

2. Centralized Protection and Control System (CPC)

Centralized Protection and Control System (CPC) is a concept to combines the function of several IEDs into one single hardware. This allows more efficient use of the processing power and achieves cost saving by reducing the number of hardware used. While achieving the cost saving is important, CPC shall not compromise the stability and neglect the reliability offered by the conventional solution. Therefore, it is important to find a balance of saving without overlooking the criticality of power system operation.

Centralized Protection and Control System is not just about a single centralized protection device, because this device alone will not bring benefit to the user. CPC is a system involving process level digitization and a substation HMI, along with interfaces to wide area monitoring and control as in Figure 1. Having all functions running in one centralized hardware opens up some new requirement too, such as the need of robust cyber security in a CPC unit as discussed in section 5.3, redundant system to prevent maloperation due to device faulty which discussed in section 7, time synchronization as in section 8.

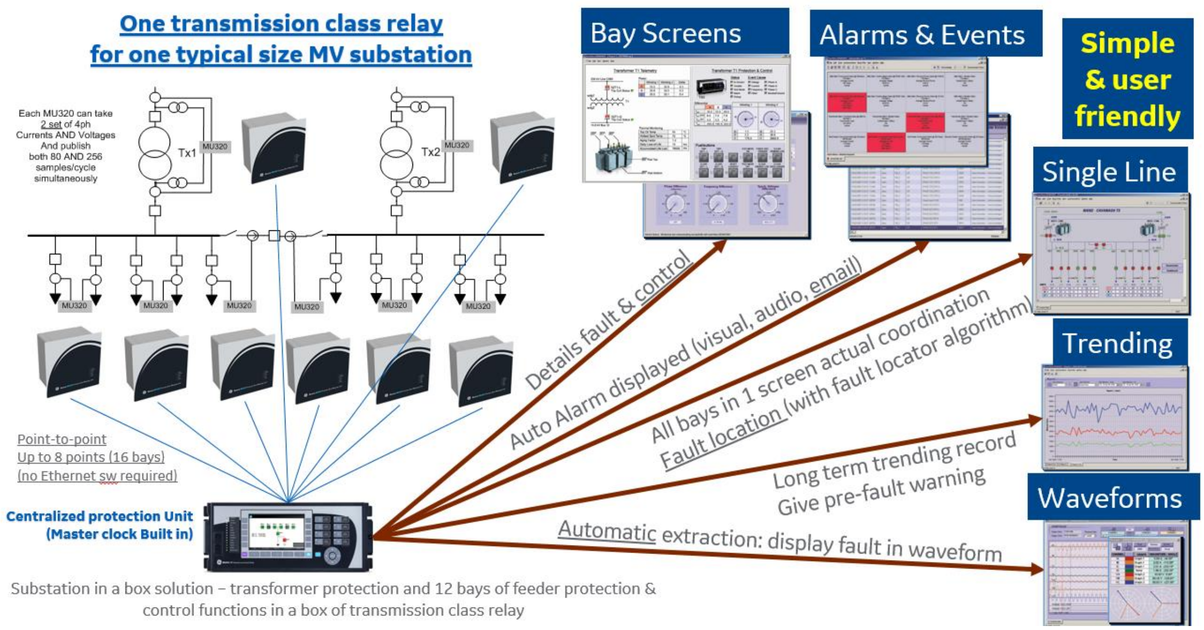


Figure 1: CPC system is process level digitization, station level centralized protection unit, centralized substation HMI

3. Process level digitization

The process level is the input and output interface for the primary equipment. Digitization takes place in rugged I/O devices to convert the analogue measurements and statuses into digital messages using the data models and message formats of the IEC 61850 Standard. In 2004 the UCA Users Group released an Implementation Guideline for a digital interface standard using IEC 61850-9-2LE process bus for the transmission of current/voltage samples. IEC 61850-9-2LE defines two distinct sampling rates for the SV-based process bus:

- 80 samples per nominal system frequency cycle
- 256 samples per nominal system frequency cycle

80 samples per cycle is sufficient to satisfy most of the common protection functions, whereas 256 samples per cycle is used for high-speed functions such as power quality monitoring and digital fault recorder.

Process bus should facilitate flexibility and adaptability by providing all basic data for state, status, and control of the substation to the station level for protection, automation and control application integration. This digitization and process bus turn field wiring of primary equipment into a one-time exercise to interface to input/output devices and eliminates the need for a wiring interface to control devices, protective relays, and especially the centralized protection device.

3.1. Merging Unit (MU)

To digitalize process bus, Merging Unit (MU) is used to convert the analogue measurement to IEC 61850-9-2 Digital sampled values (SV). IEC 61850-9-2 SV represents primary current and voltage measurements as instantaneous digital samples.

3.2. Remote Input Output unit (RIO)

As for status and control function, the Remote Input Output unit (RIO) is equipped with a high number of contact inputs and outputs to monitor the status and control of circuit breakers and switches and to respond to control and tripping indications from other devices. The communications between RIOs and other devices uses IEC 61850 GOOSE messaging. A RIO can be equipped with High Speed High Break (HSHB) contact outputs for protection tripping purpose, to compensate for the delay of publishing and subscribing to GOOSE traffic.

3.3. Process interface unit (PIU)

Process interface unit is a term this paper refers as a multi-functional merging unit. A PIU is a single device that combines both MU and RIO functions, extending to cover all functions required at the bay level.

The limits to PIU functionality are defined by suppliers. A well-defined PIU will multiple sets of CT and VT inputs to connect to both protection class current transformers (CT), and measurement class CTs. A PIU should also support multiple SV streams with different data rates. A PIU can also have HSHB contacts for tripping and control purposes.

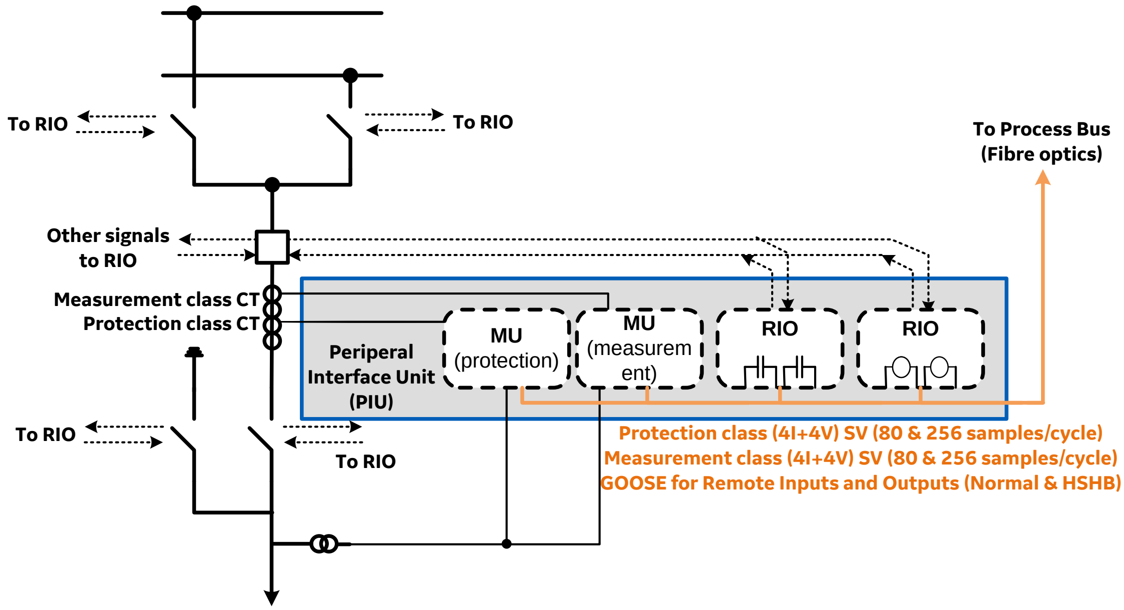
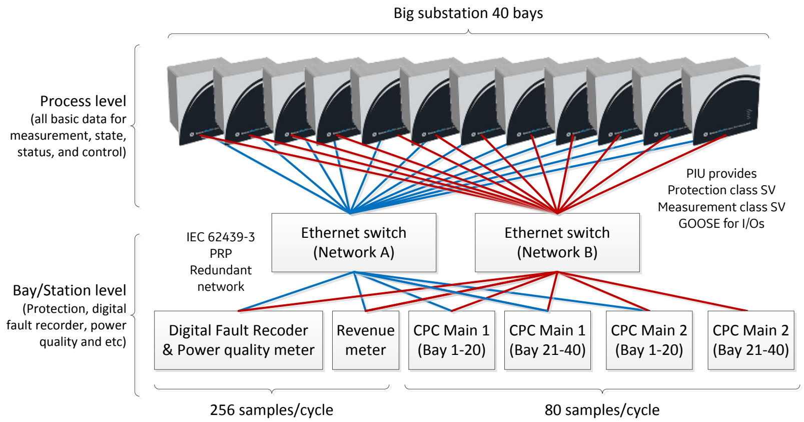


Figure 2: PIU provides all raw data on a bay eg. protection class CT and measurement class CT

The goal for a well-defined PIU should be to optimize the device such that one PIU can accept all the inputs and outputs for a single bay, as in Figure 2. The process bus digitization should stay simple and rugged and focus on getting maximum raw data in a digital IEC 61850 format, to provide the ability to quickly and efficiently design, build, commission, and operate the substation, even if that process involves the refurbishment of existing primary equipment. Once the bay and PIU is commissioned, it should be future proof because any device or application supporting IEC 61850 when connected to this process bus network can subscribe to the data and interoperate without impacting process bus devices or applications.

The goal of the PIU is illustrated in Figure 3: the SV and GOOSE messages from the PIU interface to any device in the substation, supplying the appropriate data at the appropriate data rates for the application. CPC Main 1 (bay 1-20) & CPC Main 1 (bay 21-40) and CPC Main 2 (bay 1-20) & CPC Main 2 (bay 21-40) are the centralized protection and control scheme. Details of redundant main 1 main 2 is covered in section 7.2 and the scalable CPC solution is covered in section 5.7 which will not be explained here. The revenue meter normally is an independent approved meter device used by the utility for the consumer revenue purpose. The Digital Fault Recorder and Power Quality Meter is assumed as an independent device because when the substation is being digitalize, it is important to have a dedicated device only to monitor the fault and events in the substation, independent of the protection and control applications.



*CPC = Centralized Protection and Control unit

Figure 3: Process bus is interoperable with all devices

4. Centralized protection solution today

There are many permutations of how centralized protection and control can be implemented. Proof of concept CPC devices have been based on industrial computers, due to the needs of software development, and not the true requirements of substation protection device.

Industrial computers are commonly used in utility substations to run more software-based applications such as SCADA services, control functions, HMIs, DER management, wide area fault detection and isolation, and microgrid integration and control. However, protection functions require a real time consistent and deterministic fast 10ms-40ms operating time.

The challenge to implementing protection functions in an industrial computer is to have a real-time operating system to run protection applications. The concern is in part due to technical considerations about running real-time and non-real-time operating systems in the same device for 24 hours a day, 365 days a year for a 20 year service life.

Also the CPC system needs to protect a high number of bays, for example 24 bays for a typical size substation. This will require the computer to process large numbers of SV, including filtering, re-sampling, and handling missing samples deterministically. The conventional relay relies on Field Programmable Gate Arrays (FPGA) to manage values data, but FPGAs are not typically available in a standard industrial computer.

It is also important to remember that centralized protection devices will be installed in substations and must meet all the expected requirements in substations. The device must pass all the environmental tests specified in IEEE 1613 and IEC 61850-3, including electromagnetic interference, surge immunity, and fast transients.

For a CPC to be a successful solution, a utility must have confidence in the computing platform, both the hardware and the software or firmware.

5. Centralized protection solution with proven transmission relay

A realistic approach to CPC is to base the design on well proven transmission class relay. Once relays become optimized for process bus, the only limitation to the number of protection zones is the number of SV streams, and the capabilities of the processor to handle the data and the functionality. Busbar protection relays are coming on to the market that accept up to 24 SV data streams, so the complete protection of small substations in a single relaying platform is possible.

A good concept to further prove CPC is to start with protection of a complete distribution substation. This involves a limited number of protection functions to use, lower risk in case of performance issues, and easier integration into the power system. The CPC device therefore uses protection algorithms already developed for the relay platform, simply implementing more instances of these proven functions.

5.1. Proven protection algorithms for feeder, bus, and transformer protection

By utilizing the spare processing power in an existing transmission-class protective relay hardware, this is relatively simple concept to develop off of existing hardware platforms. Because it is based on an existing relay platform with a proven operating history in substations, this solution offers a more secure, mature, and stable solution. This type of device can run multiple instances of an entire zone of protection, using existing, proven algorithms, running on the same proven operating system and hardware.

5.2. Proven hardware platform

A transmission class protection relay is a custom hardware specifically designed and type tested to the highest requirement of the substation harsh environment. The relay has comprehensive device health diagnostic tests at startup and continuously during run-time to test its own major functions and critical hardware. These diagnostic tests monitor for conditions that could impact security and availability of protection, and present device status via SCADA communications and the front panel display. Providing continuous monitoring and early detection of possible issues help improve system uptime and prevent any failure to cause malfunction to the grid system. Transmission class protection relay also has full portfolio of hardware options such as below.

- Redundant power supply option which can take in power supply from two different sources and DC voltage
- The use of conformal coasting on the relay's internal printed circuit boards to reduce part failure and extend the device availability in substation harsh environment
- Inter-substation C37.94 fiber optic communication option provides an interface for remote communications and teleprotection when required.
- RTDs option allows the user to monitor the temperature of the transformer or motor.
- Contact Inputs/Outputs option offers the user flexibility if a minimum amount of contact inputs is required for panel opening detection, or some contact outputs for alarming purpose.

The hardware cost for a transmission class protection relay is comparable to an industrial computer. However, the relay platform is designed to operate in the harsh environment of a utility substation for more than 20 years, with a proven history of reliability. This far exceeds the shorter design life of an industrial computer.

5.3. A robust cyber security implementation

The relay platform is already implementing cybersecurity that meets utility requirements. As the platform is upgraded for new requirements and capabilities, this is automatically done for the CPC as well. The relay platform meets NERC CIP, NIST, ISO, provides remote authentication, authentication without passwords, RBAC, syslog, encryption.

5.4. Support for multiple SCADA protocols (IEC 61850 and legacy protocols)

Transmission class relay supports the most popular industry standard protocols enabling easy, direct integration into monitoring and SCADA systems such as IEC 61850 Ed. 1 and Ed. 2 Station Bus, IEC 61850-2-2LE / IEC 61869 Process Bus, and IEC 61850-90-5 PMU over GOOSE. Also on the legacy protocols such as DNP 3.0 (serial & TCP/IP), Ethernet Global Data (EGD), IEC 60870-5-103 and IEC 60870-5-104, Modbus RTU, Modbus TCP/IP

5.5. Numerous communications ports to support separate connections to station bus, process bus, and engineering networks simultaneously

A transmission class relay is designed to support different communication network architectures, including independent SCADA/station bus, engineering access, and process bus networks. This includes enough ports for each network to support industry standard communications redundancy methods such as PRP (parallel redundancy protocol) and HSR (high-availability seamless redundancy). For small distribution substations, it is convenient to have up to 8 process bus ports to allow simple point-to-point communications, without a network or switch, as in Figure 4.

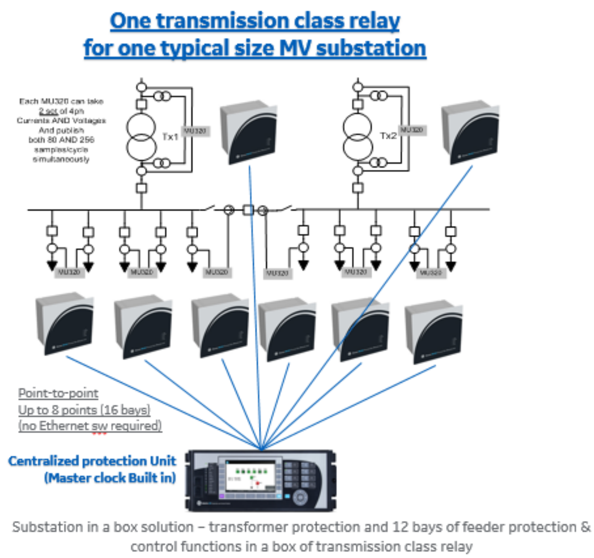


Figure 4: CPC relay can do up to 8 point-to-point connections

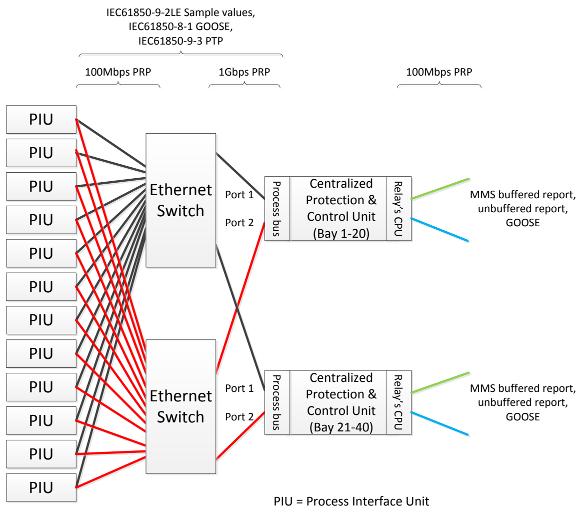
5.6. Wide area monitoring and control

Using a transmission class protection relay as a CPC automatically brings in other transmission features such as synchrophasors. The device can act as phasor measurement unit (PMU), streaming data as per EEE C37.118 or using R-GOOSE and R-SV as defined in IEC 91850-90-5. This means the CPC can easily integrate into wide area monitoring and protection and control schemes, as well as provide inter-substation signaling.

5.7. Scalable solution

As the power network becomes complex, the number of bays in the substation is getting higher. Therefore, the CPC solution must be scalable, down to small few bays substation and up to many bays in huge substation. CPC unit can extend easily as it uses only two pair of fiber optic cables, independent of how many bays there are in the substation. Each CPC unit connects to the process bus network and subscribes to only the SV and GOOSE messages from the necessary PIUs. Therefore, there is no complex field wiring to connect, only straightforward device configuration, and practically have no limit on number of bays. However, a CPC is only as scalable as the number of SV streams the device can subscribe to. Once this limit is reached, multiple CPC devices are required. For example, for a smaller substation with 20 bays, a single CPC unit box will do; whereas for a larger substation of 40 bays, two CPC units could provide adequate protection.

Fig. 5 illustrates two CPC units connect to the process bus network, but they only subscribe to data from the PIUs associated with a specific part of the bus. Fig. 6 shows the same concept using an HSR ring for the process bus communications. Once again, each CPC unit only subscribes to data from some of the PIUs.



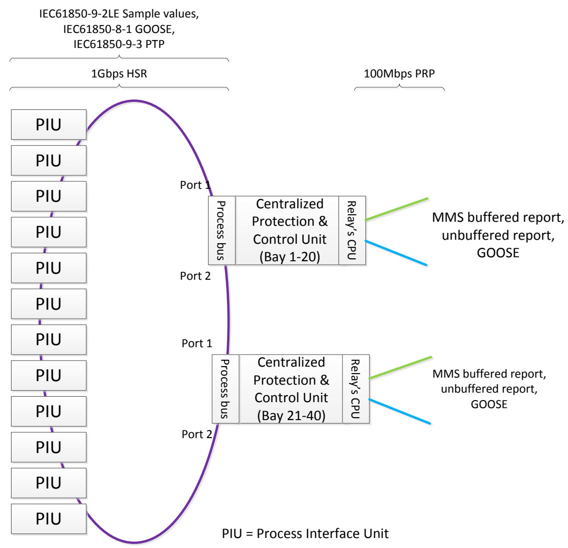


Figure 5: two CPC units connect to the process bus network, but they only subscribe to data from the PIUs associated with a specific part of the process bus in a PRP connection.

Figure 6: shows the same concept using an HSR ring for the process bus communications.

6. Substation Human Machine Interface (HMI)

CPC solution today uses industrial computer as the hardware platform. The industrial computer can then connect to a monitor to display the status and information. This is a perfect feature as Human Machine Interface but monitor typically is not rugged built for substation environment and therefore limited to be used in the airconditioned control room. This could be a problem because MV Substation may not have control room.

6.1. Built in graphical LCD & virtual annunciator windows

Numerical protection relay today is advance and user friendly. Some even offer large seven inches graphical LCD display ordering option which can display the live status of single line diagram (SLD) diagram on the protection relay itself. As the LCD is built in the relay, it has been designed to work in a substation. As in Figure 7, The same LCD can also be programmed to display as a virtual annunciator windows to indicator any alarm in the substation, replacing the need of physical bulky annunciator window. These features especially come in handy when protection relay is used as a CPC. Conventionally, the user needs to check on multiple relays and probably need a laptop or monitor connect to multiple relays to read the status of the substation, but now the user has all the live status and information displayed in a graphical way in a single box of protection.

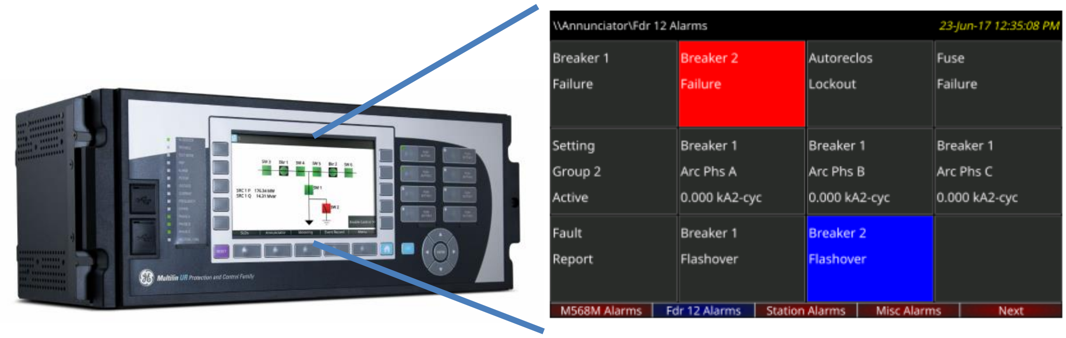


Figure 7: Large display on protection relay showing SLD and virtual annunciator windows

6.2. User friendly multi-functional centralized HMI toolsuite

If substation HMI is a preferred solution over the relay LCD, the relay toolsuite software can offer similar HMI display with a series of pre-configured display for analyzing the health and status display or the user can design a custom display in the toolsuite too. The relay toolsuite software is not a new application, but it is again a proven and mature feature used by many customers as a monitoring and control HMI today. Compared to a monitor display in an industrial PC, the relay toolsuite probably offers stronger function and complete feature such as Open Platform Communication (OPC) server integration for database management, remote monitoring, third party device monitoring. While the relay toolsuite requires to be hosted on a windows-based PC, but this typically can be hosted on the gateway computer. If the substation is unmanned, the HMI will only be required when the user visit the substation, which the user can connect directly with a laptop. Figure 8 below shows an example of toolsuite single line diagram (SLD), displaying the live status of breaker, isolator status and current, voltage measurement of all bays.

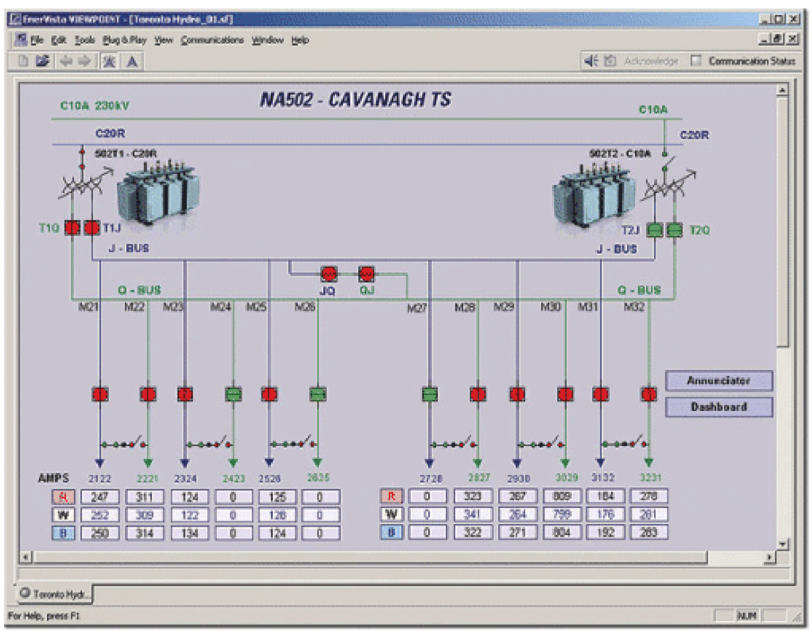


Figure 8: SLD displays the live status of breaker, isolator status and current, voltage measurement of all bays

6.3. Centralized and Systemwide HMI toolsuite

As discussed in section 5.7, CPC is a scalable solution, where a big substation with many bays will require more hardware. The relay toolsuite can communicate to multiple CPC relays and act as a centralized HMI and data repository. The toolsuite displays SLD with the breaker, isolator status and current, voltage measurement of all bays in the substation collected from two CPC relays on polling basis.

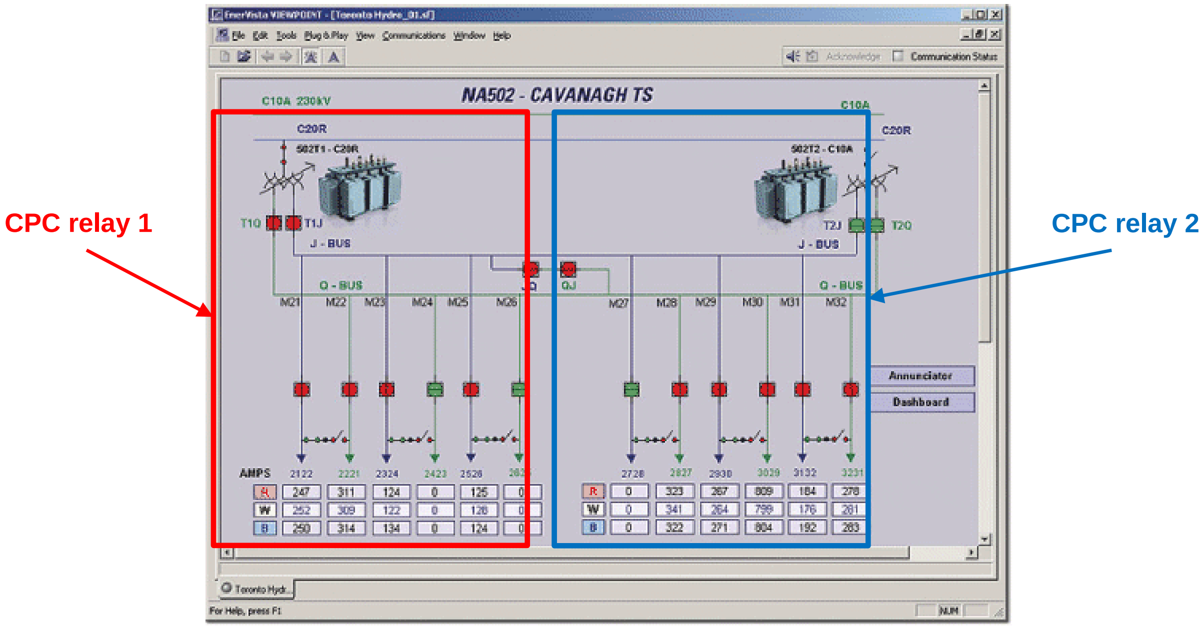


Figure 9: SLD displays the live status of breaker, isolator status and current, voltage measurement of all bays from two CPC relays

Each CPC unit has its own oscillography recorder and sequence of events record built in. However, a well thought CPC solution should offer a system wide solution regardless of how many CPC units are used in the substation. In this case, the HMI toolsuite can act as the integrator, which it automatically download from each CPC unit and stored in a centralized, system-wide, sequence of event record. The HMI toolsuite will continually poll each CPC relays to see if any new events have been added to that device's event record. Once a new event has been detected, the event record will be downloaded and the new events will be time aligned and stored in the system-wide sequence of events record as shown in Figure 10.

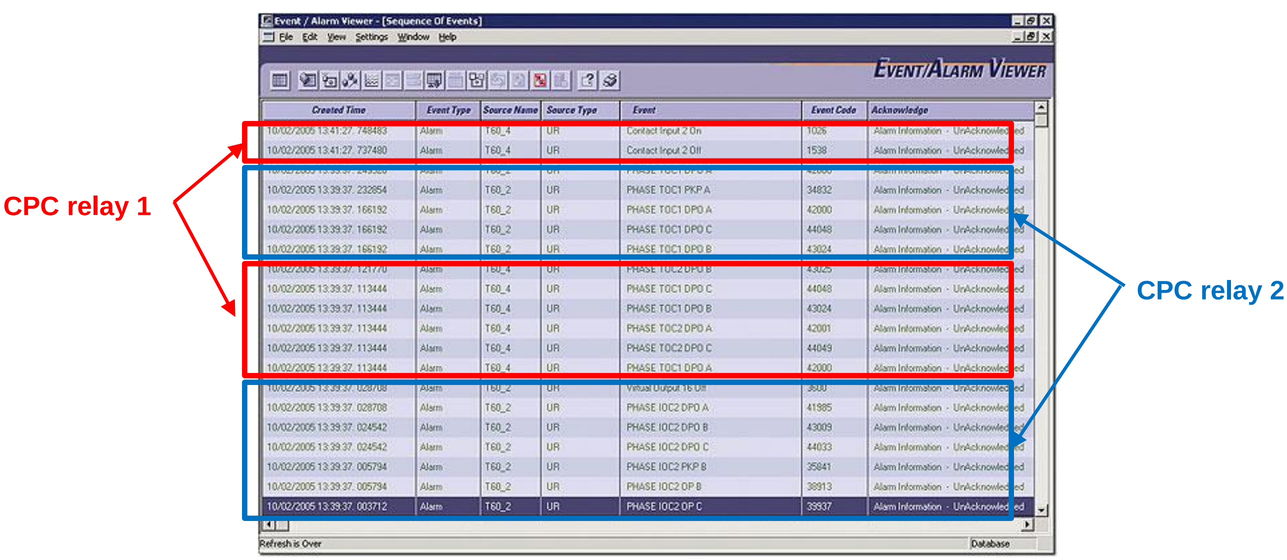


Figure 10: Toolsuite is a centralized, system-wide, sequence of event record

6.4. Remote monitoring

An established HMI toolsuite shall allow remote monitoring by several devices too.

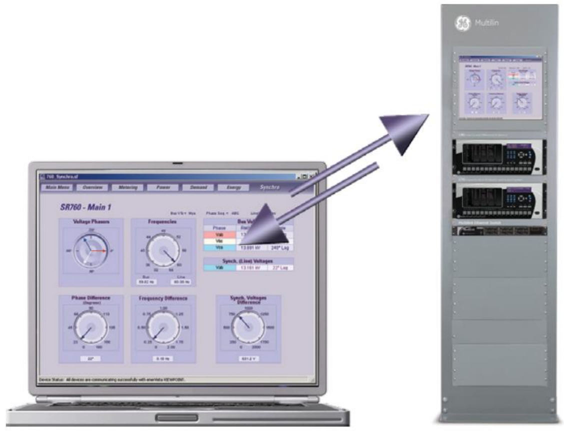
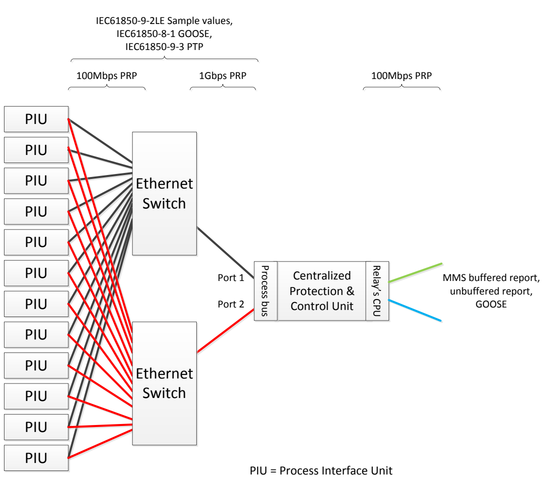


Figure 11: Remote monitoring on the HMI toolsuite

7. Fail safe & redundancy

7.1. Redundant network architecture

This network-based solution has the advantage of easily allowing redundant communications paths without requiring significant additional cabling. High availability network protocols such as PRP and HSR are defined in IEC 62439-3. Both PRP and HSR connections require only 2 pairs of fibre optic cables connecting to the relay for redundant communications, and it is not dependent on how many bays or merging units are in the protection relay. Figure 12 and Figure 13 show how CPC unit could operate with PRP and HSR technology. Both protocols are appropriate to use for CPC solution, and have advantages and disadvantages based on application requirements. Simplifying connection to only 2 pairs of fibre optic cables save on the wiring labour cost and limits human wiring mistakes.



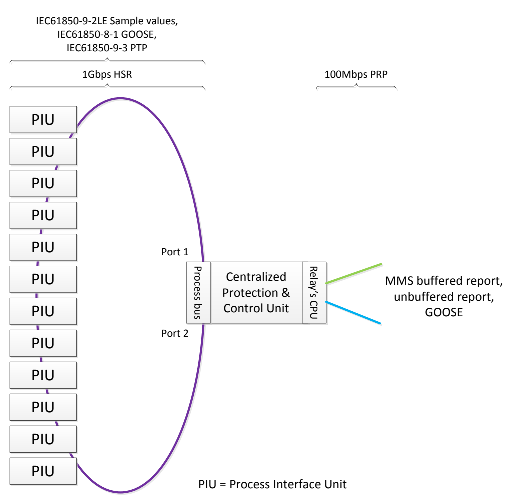
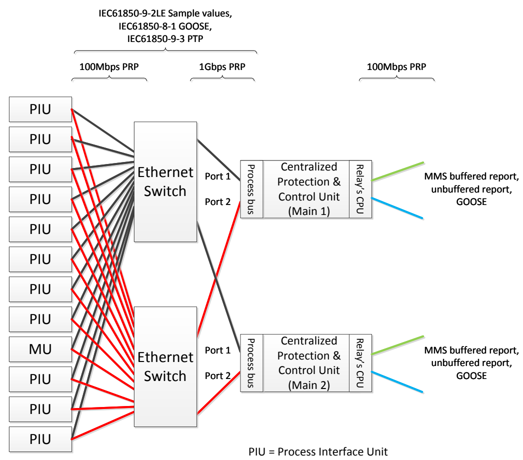


Figure 12: CPC unit works in PRP star redundant network

Figure 13: CPC unit works in HSR ring redundant network

7.2. Main 1 Main 2 redundant CPC protection

When come to centralized protection, redundant protection may be required for reliability purposes. This can take the form of Main 1 / Main 2 protection. The two Main 1 / Main 2 CPC unit connect with 2 pairs of fiber optic cables, communicate to the same merging units, and use the same data. This is true for any network connection, both the PRP networks of Figure 14 and the HSR ring of Figure 15.



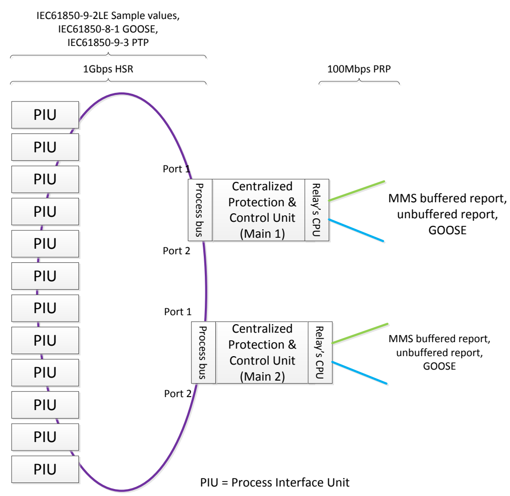


Figure 14: CPC Main 1 / Main 2 in PRP star redundant network

Figure 15: CPC Main 1 / Main 2 in HSR ring redundant network

7.3. Redundant SV sources

Since PIU can have multiple analogue inputs, cross connecting two bays' CTs and PIUs as shown in Figure 16 is possible. Having this connection can offer redundant SVs publishing.

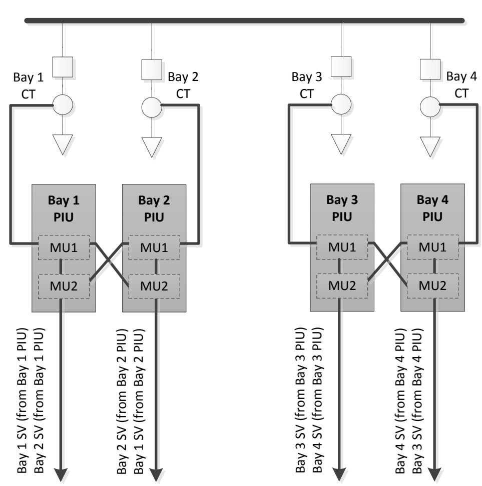


Figure 16: Cross connecting two bays' CTs and PIUs for redundant SVs publishing

As an example, in the event of Bay 1 PIU failure, the Bay 2 PIU continue to publish the SVs for Bay 1 CT. The CPC unit shall be the intelligent to detect the loss of SV publishing on the faulty Bay 1 PIU and automatically switch to the SV subscription to Bay 1 SV from PIU2. Streamless switching will allow protection and control function to operate correctly as shown in Figure 17. This redundant protection scheme was not possible in the conventional protection without significant additional cost and complicated wiring. However, with the multiple analogue inputs PIU, this can offer additional security and reliability at the small cost of connecting of adding another analogue input at the PIU.

There is one practical concern using redundant SV sources is the CPC unit has a fixed number of subscriptions to SV streams. Every redundant SV source reduces the number of bays that can be protected by one. So a fully redundant SV source can protect half the number of bays. However, thanks to the scalable relay solution as discussed above, another pair of relays could be added to cover all bays.

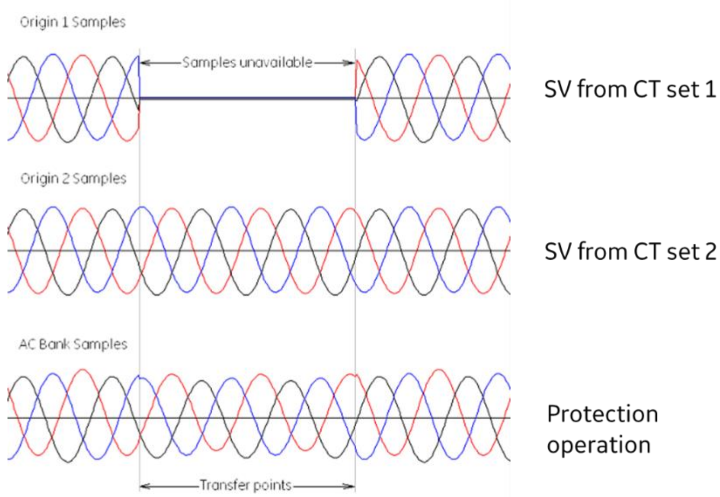


Figure 17: CPC can subscribe to two set of SVs and automatically switch over if the prefered SV stream is unavailable

7.4. Total redundant scheme

The same principal above can be extended to have total redundant scheme where dual HSR network with redundant current transformers, PIUs and redundant CPCs are used. CPC unit can operate as Main 1 / Main 2 protection, with each CPC subscribing to SV data from different PIUs. With redundant PIUs for Main 1 / Main 2 CPC protection, measuring the same currents, the CPC unit can have fully redundant protection and fully redundant measurement. For example, Figure 18 shows two set of CTs and merging units connected to two independent HSR 1 Gbit/s rings. The 2 independent HSR rings offer a true redundant scheme. This scheme requires each central unit to connect to both HSR rings independently, and therefore requires the units to have 4 fibre optic ports and connections. These are independent connections for redundancy and are not a QuadBox segmentation or linkage as defined in IEC 62439-3 Clause 5.

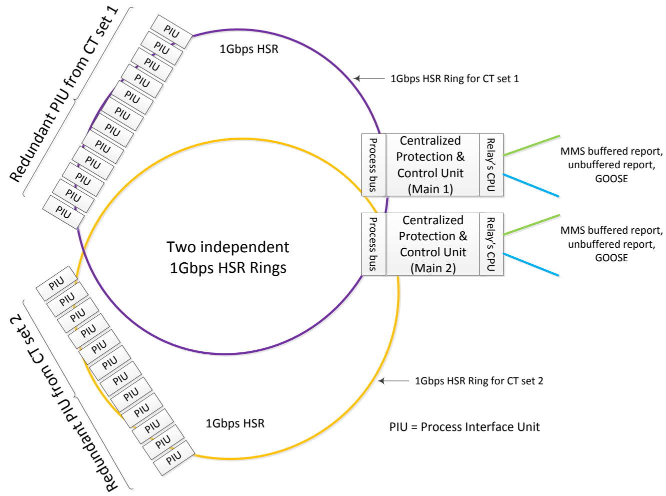


Figure 18: Total redundant scheme with two independent 1Gbps HSR, redundant CTs and PIUs and redundant CPC unit

This scheme offers total redundant scheme which each component in the system is redundant built to prevent any mal operation due to device failure. The CPC unit can have consistency check to monitor the consistency of both SVs from two PIUs as shown in Figure 19.

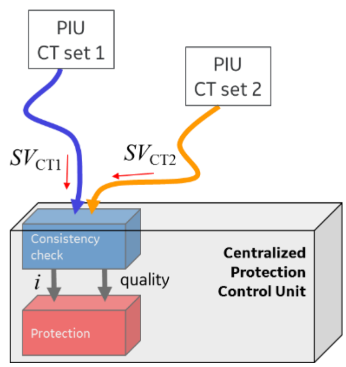


Figure 19: CPC can subscribe and do consistency check on SV CT set 1 and SV CT set 2 for total redundant scheme

7.5. System A system B independent scheme

A conventional system A system B independent scheme can be built too. The process bus has the additional benefit which discussed in section 7.3 and section 7.4. CPC can be configured so that if the system A merging unit down, the system A protection will detect the failure and give the alarm as shown in Figure 20. By using dependability biased preferred configuration, the System A can switch the measurement input to system B measurement input automatically and continue providing the protection as shown in Figure 21. This provides additional benefit compared to a conventional system A system B independent scheme.

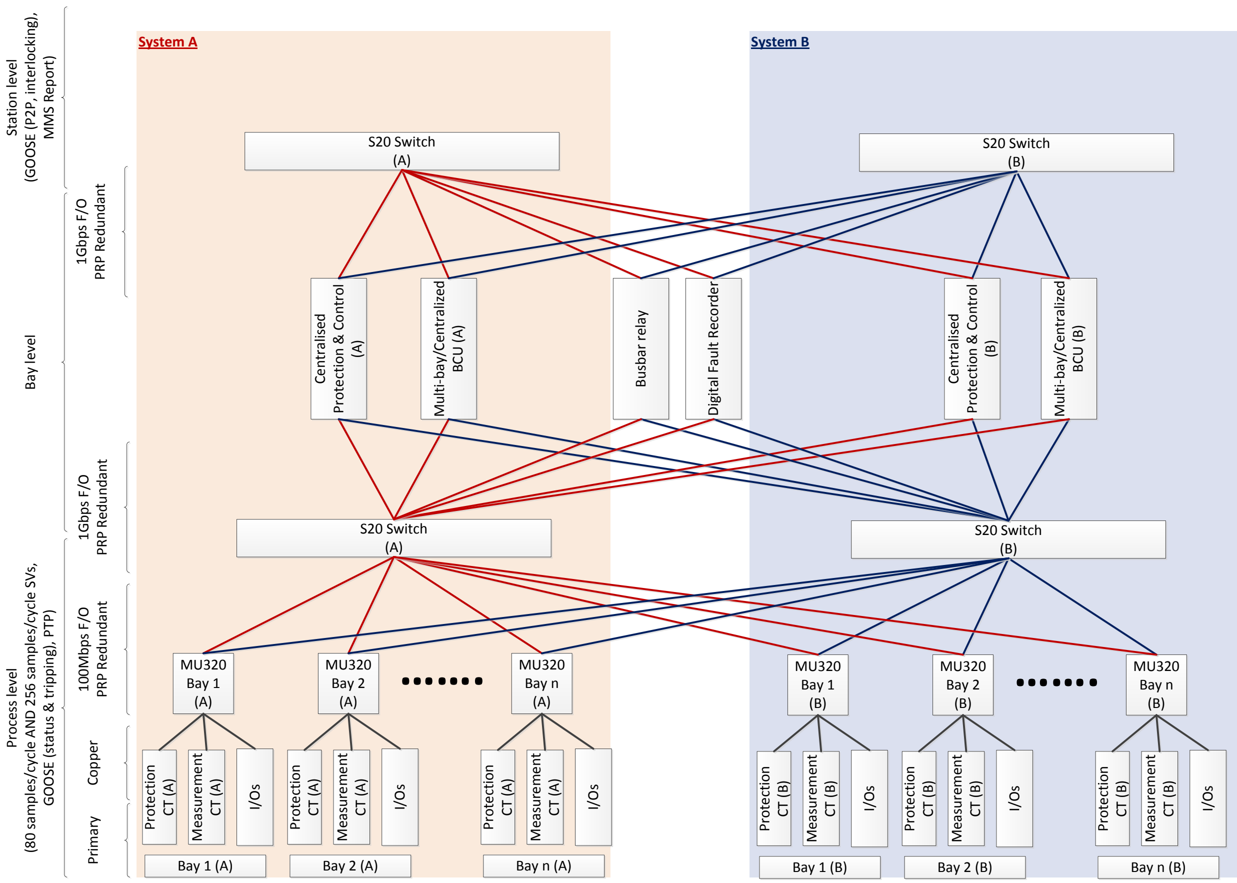


Figure 20: Independent System A System B

Reliability Setting	System-A MU	System-B MU	Protection Elements
Dependability Biased	OK	OK	Normal
	OK	N/A	Normal
	N/A	OK	Normal
	N/A	N/A	Blocked
	Discrepant		Blocked
Security Biased	OK	OK	Normal
	OK	N/A	Blocked
	N/A	OK	Blocked
	N/A	N/A	Blocked
	Discrepant		Blocked
None	OK	OK	Normal
	OK	N/A	Normal
	N/A	OK	Normal
	N/A	N/A	Normal
	Discrepant		Normal

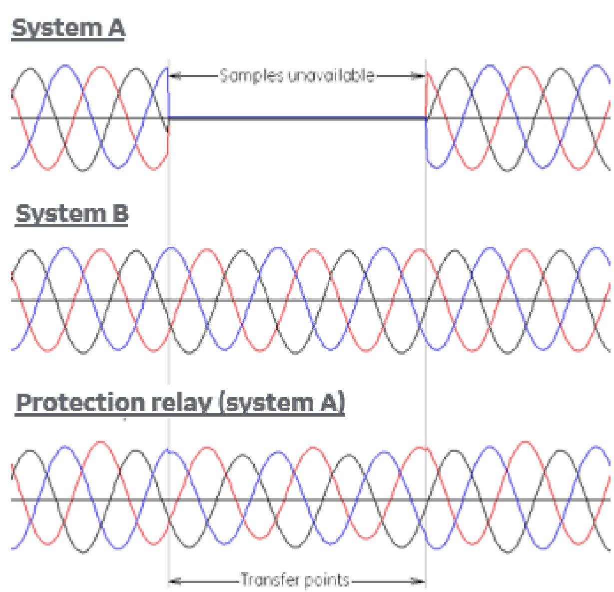


Figure 21: With dependability biased setting, System A System B are capable to switch over on failure

8. Time synchronization

For proper operation of a CPC system, it is necessary that merging units be time synchronized to each other to ensure protection functions to operate properly. It is desirable for the CPC to be time synchronized as well. The proper method for time synchronization for process bus is to use one of the industry-specific application profiles of IEEE 1588 (or PTP, “precision time protocol”) as the protocol, over the communications network. CPC devices and merging units therefore have slave clocks synchronized to IEEE 1588 master clocks connected to the communications network. One technical advantage of IEEE 1588 is that it permits the use of multiple master clocks on the same network, so the failure of one clock doesn’t result in a synchronization failure.

In a digital substation, with good architecture design including duplicated master clocks, it is unlikely to lose all the time masters. But if this rare situation occurs, the merging units will lose time synchronization, and protection functions must be blocked under this situation. However, the CPC can be designed to act as an IEEE 1588 master clock to the process bus network. In normal operations, the master clock in the CPC device is synchronized to the substation master clocks.

However, if the substation master clocks are no longer available, all merging units communicating to the protection will be synchronized with the same relative time to the CPC device, allowing protection functions to remain in service. Since the protection will interface to most of the merging units in the substation, most protection in the substation will still operate in this unlikely scenario.

8.1. CPC without GPS clock (in a conventional substation)

CPC does not require absolute time synchronization, but only relative synchronization between the merging units and CPC. The IEEE 1588 master clock capability as discussed allows the CPC to synchronize all the merging units in the system. As long as all the merging units are synchronized to the same source, the CPC relay, the SV streams can be aligned and used for protection, including the low impedance differential for transformer and busbar. This therefore allows the application of the same CPC protection in a conventional substation without the need of a satellite clock or absolute time synchronization.

9. Conclusion

Transmission class protection relay not only offers a good alternative to the industrial computer-based CPC solution, but it is a much more mature and proven solution having been used in transmission. For example, a transmission class protection was designed for harsh environment, type tested for IEEE 1613 and IEC 61850-3. Using transmission class relay as a CPC offers many other benefits such as IEC 61850-90-5 PMU & R-goose functions, teleprotection, IEEE 1588 master clock built in, legacy communication protocols which is currently lacking on the industrial computer-based CPC. A transmission class relay was designed to operate for 20 years life in the substation, offer peace of mind after installation. Process bus MUs and PIUs are future proof and should have facilitated flexibility and adaptability by providing all basic data for state, status, and control of the substation to the station level from the beginning.

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