WHITE PAPER

# Centralized protection and control – Enhancing reliability, availability, flexibility and improving operating cost-efficiency of distribution substations

**Conventional protection and control solutions may be costing your business more than you think. With a Centralized Protection and Control (CPC) solution, you can manage your substation more effectively and gain cost savings of up to 15 percent in substation life cycle costs.**

**With CPC the flexibility and performance of the whole automation system increases substantially, allowing for new ways to manage substation automation. It offers convenient station-wide visibility, minimal engineering, and cost-efficient system management.**

**In this white paper, we address the key points when implementing a CPC system: the possible applications, redundancy considerations, as well as the testing and maintenance requirements.**

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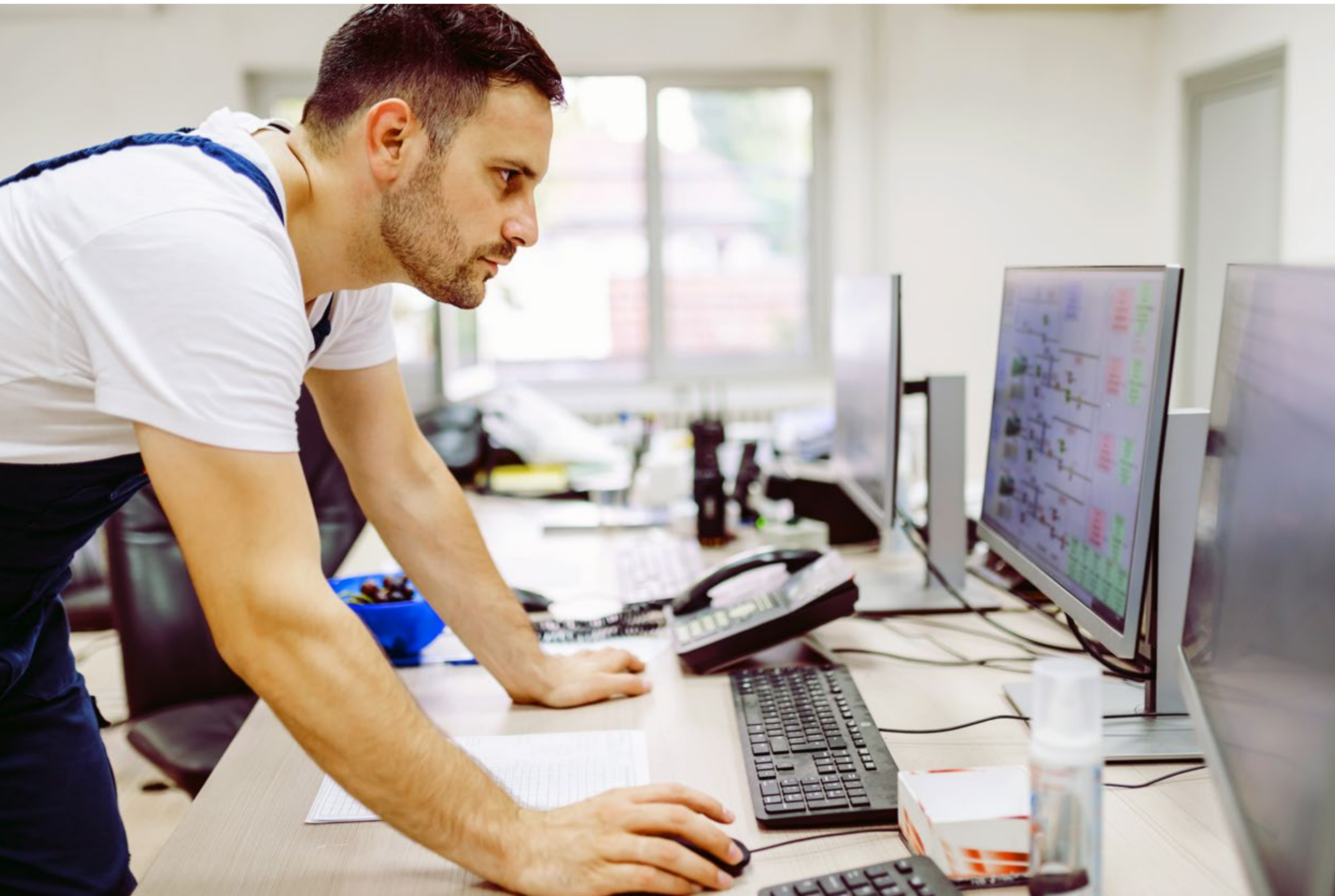
# Making the switch to centralized protection and control

To ensure reliability of power supply, there is a need to monitor, control and protect different elements in distribution networks. In the last decades, since the first introduction in the 1980s, protection and control of electricity distribution networks has been done with microprocessor-based protection and control relays. This paradigm has now been challenged by the introduction of a digital and software-oriented solution – centralized protection and control (CPC).

Climate reports, such as the Intergovernmental Panel on Climate Change (IPCC), emphasize that to fight climate change also our energy system needs to adapt rapidly – as new renewable and intermittent energy resources are to an increasing amount are connected to the energy system, consumption becomes managed with demand response, and new storage devices are deployed and used. All this must happen without risking the security of the power supply. This means that the P&C functionality in our power networks must be enabled to manage continuous changes during the lifetime of the devices. This is a tremendous challenge for the P&C system as it needs to become more flexible and be able to reconfigure faster.

CPC units can be deployed in several different architectures, depending on the other solution components used and overall solution requirements. The main expected benefits from a CPC solution are related to increased flexibility and performance and reduced overall life cycle costs.

In this paper, the pros and cons of CPC architecture versus conventional microprocessor relay protection and control architecture is compared with respect to design, engineering, testing, operation and maintenance of power system protection and control.



## What is a CPC system?

A CPC system configuration is made up of dedicated merging units (MU) and/or numerical protection relays (PR) with merging unit capabilities for every feeder and a CPC unit. The desired levels of functional or physical redundancies can be selected depending on the relative criticality of the feeders connected to the load centers or equipment in the network. The system solution integrates the substation secondary system and CPC unit(s), over a redundant IEC 61850 network.

On top of running feeder level functions for all feeders, the CPC unit also hosts advanced and complex intra or inter substation-wide functions and applications. This approach increases system flexibility, reliability, and availability in distribution systems, which makes it truly exceptional.

The CPC concept is based on the concentration of substation protection and control in a single device and the utilization of communication networks to converse between different components, bays, substations, and the related operators [3]. The most substantial protection philosophy change in this system is the total or partial shift of functions from the bay level, i.e., from the relays to the station level in the substation.

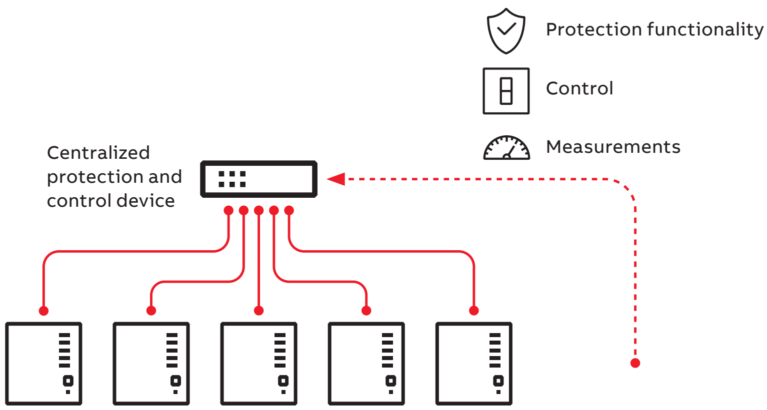



**Fig 1. Simplified diagram of a CPC system**

## Why is now the right time for CPC?

The first electromechanical relay for power system protection appeared during the early 1900s and P&C technologies have come a long way over the last 100+ years. Power system protection, engineering, operation and maintenance have gone through dramatic changes over the years, especially in the last 30 years. With the drastic advancement of microprocessor technologies in the recent years more could be done with less. Further, the launch of global standard for power system applications in the year 2004, viz., IEC 61850 has been a game changer enabling the power system industry to explore more efficient ways of utilizing assets while reducing cost.

With the advanced computing capabilities of modern microprocessors and the matured IEC 61580 standard, the concept of centralized protection is now a reality.

Centralized protection and control systems are based on flexible distribution or even a replication of P&C functions between devices at feeder and substation levels via a highly available and fast Ethernet network based on the IEC 61850 standard.

From electromechanical mechanisms to the microprocessor-based intelligent electronic device (IED) [1], relaying has been primordial to the continuing development of a more flexible, interconnected and smart power system. Recently, advances in communication systems, including time synchronization, their integration to substation applications and the standardization of protocols have facilitated the operation and the diagnosis of failures in complex grids and have enabled new possibilities for P&C schemes [2]. These advances have also opened the space for the implementation of CPC systems [3].

# Conventional microprocessor relay protection & control architecture

The first generation of microprocessor relays were designed to replace the protection capabilities of its predecessors, i.e., static and electromechanical relays. With microprocessor-based design, relay manufacturers became able to deliver multifunction capability, where multiple protection elements were integrated into one device.  Protection was the primary focus, nevertheless, microprocessor relays also provided analog measurements and a limited amount of logic building capability.

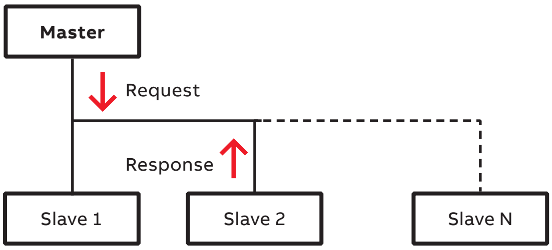


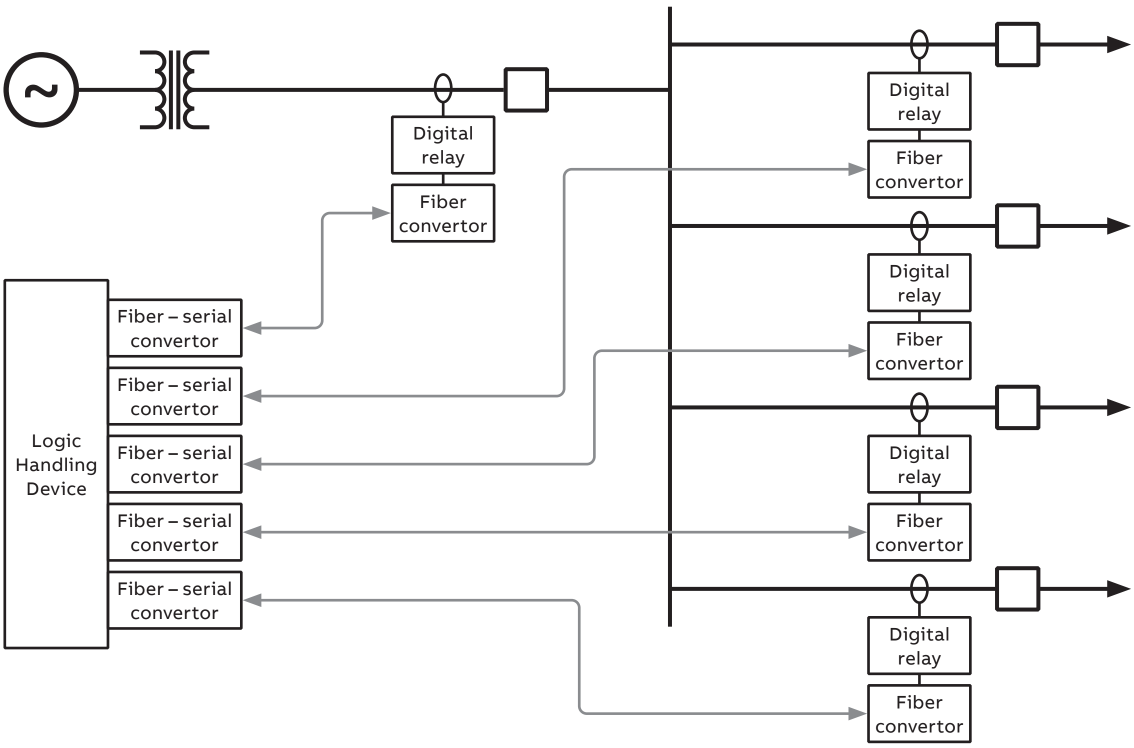

**Fig 2. Typical communication architecture with Modbus/DNP protocol**

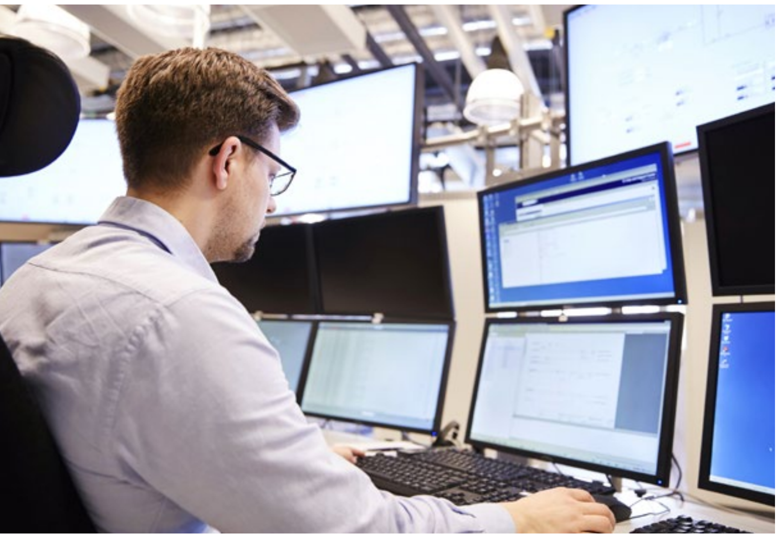
The second generation of microprocessor relays brought in added capability of communicating analog and digital signals over traditional protocols like Modbus and DNP to Substation Automation and Data Acquisition (SCADA) systems. Typically, one relay was applied on each feeder. The relay was selected based on the application i.e., based on the primary object to be protected, such as a transformer, feeder, motor, bus, etc. A conventional microprocessor relay P&C communication architecture is shown in Fig 2.

With the addition of communication capability in the microprocessor relays, the industry desired the capability to design and implement intelligent protection and control schemes, such as zone selective interlocking, fast bus protection, circuit breaker (CB) failure protection scheme. These requirements called for bidirectional signal transfer between multiple relays. These schemes could also be achieved by hard-wiring multiple I/Os from multiple relays for signal transfer. However, such an implementation was not very efficient, since a large amount of copper wiring was required between the relays. In order to make the design efficient, different vendors implemented proprietary methods of peer-to-peer communication techniques. A widely used architecture in North America to implement fast bus protection scheme is shown in Fig 3.

As can be seen from the architecture outlined in Fig 3, the relays had limited communication capability, which necessitated the use of

**Fig 3. Typical architecture to implement a fast bus protection scheme using proprietary protocol**





additional hardware in order to complete the scheme. First, the native serial communication electrical port is converted to an optical signal using an optical convertor. Optical communication is the most secured way of communicating signals in power system applications, as it is immune to electromagnetic interference. Next, the data is converted back to an electrical signal before connecting to a logic handling device. The logic handling device is required as the proprietary peer-to-peer communication protocol could only communicate from relay A to relay B. However, in almost all the protection schemes multiple relays were involved. The logic handling device was therefore essential to build the scheme. This device is then programmed to build monitoring and interlocking logics to achieve the scheme. A great disadvantage here was the proprietary nature of the protocol, which hindered the use of multiple vendors in a protection scheme.

The industry's desire to have peer-to-peer communication with multiple relays and between different relay vendors led to the development of IEC 61850 standard. The introduction of the first edition of the IEC 61850 standard, in year 2004, opened up tremendous opportunities for power system engineers to create and implement intelligent and efficient P&C schemes.

A fast bus protection architecture using native IEC 61850 relays is shown in Fig 4.

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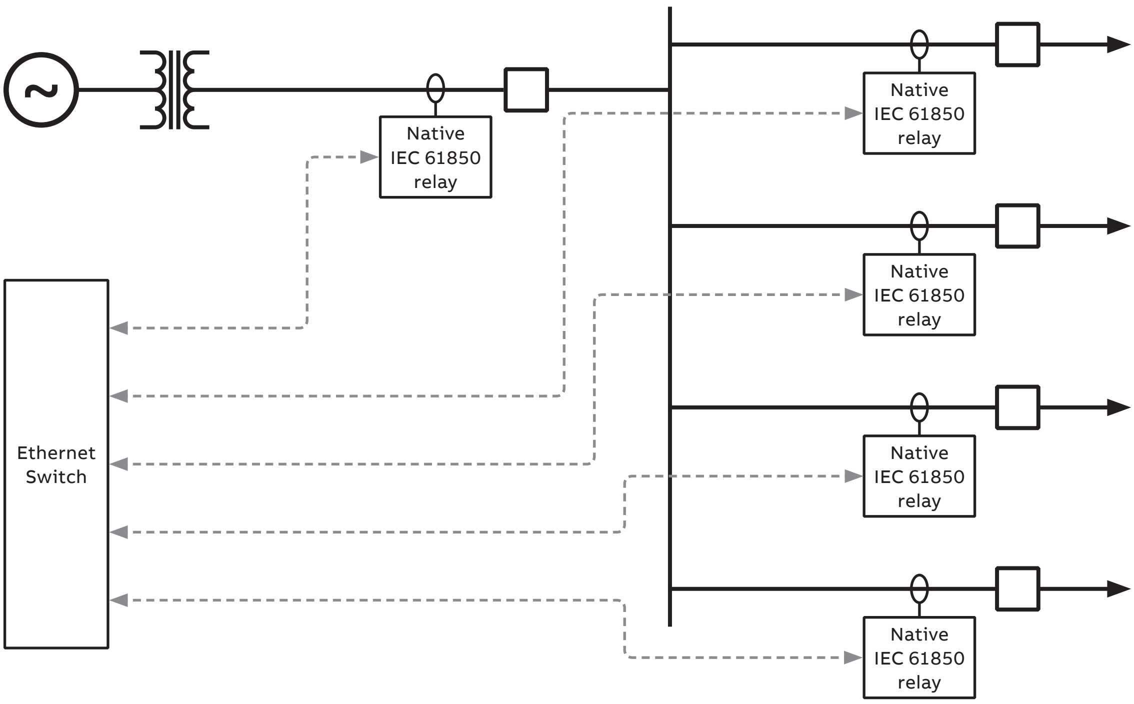
**Fig 4. Typical architecture to implement a fast bus protection scheme using IEC 61850**



This scheme utilizes advanced intelligent microprocessor relays with native IEC 61850, fully delivering IEC 61850 station bus capability. The relays have direct fiber optic output on the device. The fiber ports are networked through an Ethernet switch. These relays were designed with built-in capability of handling the logics. The overcurrent protection pickup and trip signals are communicated between all the relays involved in the scheme without the need of any additional logic handling devices as seen in Fig 4.

The addition of the process bus standard into IEC 61850 further made it possible to further improve the efficiency of implementing the P&C scheme. The process bus communicates digitized analog values from conventional instrument transformers or current/voltage sensors. The digitization is done by the merging unit (MU) device. The MU at each feeder converts the respective currents and voltages and feeds the sampled values (SV) into the process bus. The protection relays subscribe to the required SV and perform protection and measurements based of the SV received. This further improved the design and implementation efficiency as instrument transformer wiring is drastically reduced. Instead, all signals, both GOOSE and SV, are communicated via the same fiber cable Ethernet network. A typical IEC 61850 P&C architecture is illustrated in Fig 5.

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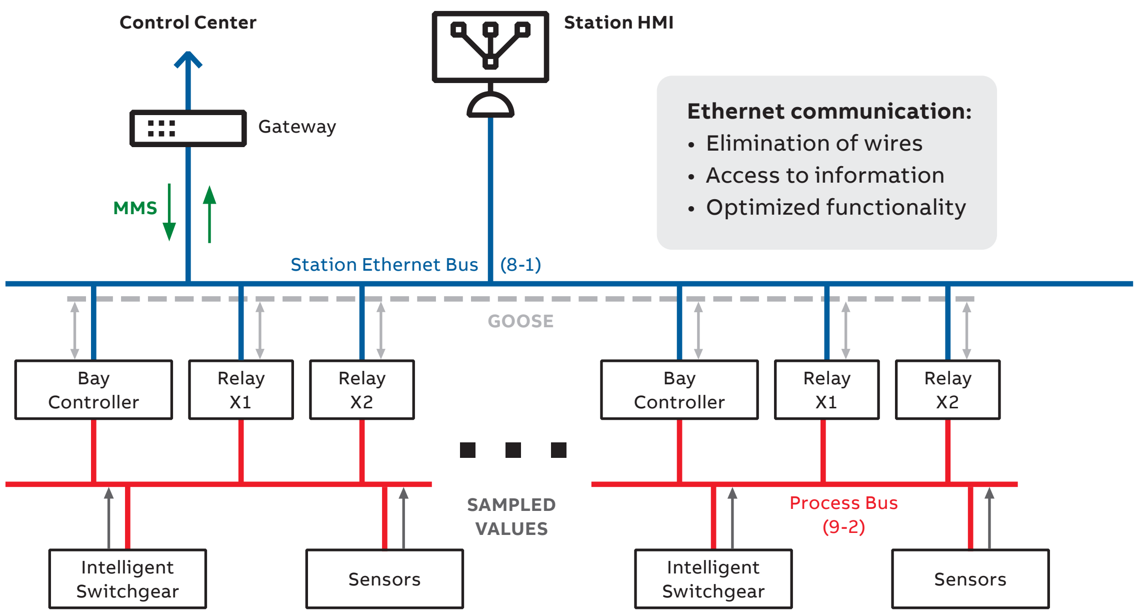
**Fig 5. Typical IEC 61850 P&C architecture using GOOSE messages and sampled values**



# Centralized protection and control

## CPC concept

The main idea of the CPC concept is to move protection and control from multiple bay level devices to a single central processing unit. As the protection and control relays are executing similar tasks, it is logical to centralize the functionality in one single location.

As such the concept itself is not new, but only the advancements in CPU technology and international standards have made it possible to replace a modern protection and control system with centralized protection [3] [4]. The complexity of modern protection algorithms requires the capability to ensure the real-time requirements of protection. Standards such as IEC 61850 and IEEE 1588 enable highly compatible centralized protection systems, but also demand quite much from communication networks and processing capabilities. Because of the new technologies and high-performance needs, it is essential to compare conventional P&C to a new centralized solution. Simulation-based viability assessment for the CPC concept can be found in [5].

## System components

Traditionally, protection has been distributed in multiple different devices but with a CPC approach, all the safety critical intelligence is in one place [6]. Most obvious component for CPC is the centralized protection and control unit. In practice the unit is functionality-wise just like a modern protection and control relay. Main difference is that the device must have high performance to handle protection needs for much big bigger applications than conventional P&C relays. Another difference is that the physical interfaces can be simplified as all the inputs/outputs can be managed with standard Ethernet interfaces.

Other components in a CPC system are:

**Merging Unit:** The interface of the instrument transformers (both conventional and non-conventional) with the CPC unit is through a device called the merging unit (MU). MU is defined in IEC 61850-9-1 as an interface unit that accepts current transformer (CT)/voltage transformer (VT) and binary inputs (BI) and produces multiple time synchronized digital outputs to provide data communication via the logical interfaces. IEC 61850-9-2LE or IEC 61869-9 defines a sampling frequency of 4 kHz (in 50 Hz networks) and 4.8 kHz (in 60 Hz networks) for raw measurement values to be sent to subscribers. Apart from acting as an interface unit between the primary equipment and the CPC, the MU can also host I/Os (input/output) to handle feeder-based digital signals. The MU can communicate the digital status of primary equipment, such as the circuit breaker, isolator, earthin switches, to network devices, as well as receive trip and open or close signals from an external unit.

**Intelligent Merging Unit**: In some applications it is beneficial that the MU also includes additional protection close to the protected equipment. When the MU includes additional functionality like protection functions, it is called an intelligent merging unit (IMU). In practice IMUs are normal microprocessor-based relays that also include process bus sending capabilities. The main benefits of IMUs are in reliability as a local backup protection is still available, even if the communication network is not fully operational. A CPC system with IMUs still enables the main benefits of centralized protection, as the central unit still holds the information for the whole system and the flexibility to add/modify protection and control is still available.

**Substation Time Synchronization:**
With Ethernet-based technology it is possible to achieve software-based time synchronization with an accuracy of 1 ms quite easily, and without any help from hardware (HW). This is also what the IEC 61850 standard refers to as the basic time synchronization accuracy class (T1). An older and more common protocol is the SNTP (Simple Network Time Protocol), which is suitable for local substation synchronization in relatively small systems.

However, if the SNTP server is behind multiple Ethernet nodes, the latency increases, which reduces the accuracy of the time synchronization. Therefore, SNTP is not an ideal solution for system-wide implementation. Normally a GPS or equivalent time synchronization resource is required in every substation. IEEE 1588v2 and IEC 61850-9-3 deal with these issues and makes it possible to achieve a time synchronization accuracy of 1 µs. This is required if an IEC 61850-9-2 process bus is used.

**Redundant communication equipment:** High availability and high reliability of a communication network are two very important parameters for architectures utilizing a CPC system. The IEC 61850 standard recognizes this need, and specifically defines in IEC 61850-5 the tolerated delay for application recovery and the required communication recovery times for different applications and services. The tolerated application recovery time ranges from 800 ms for SCADA, to 40 µsec for sampled values. The required communication recovery time ranges from 400 ms for SCADA, to 0 for sampled values. To address such time critical need for zero recovery time networks, the IEC 61850 standard mandates the use of the IEC 62439-3 standard, wherein clause 4 of the standard defines Parallel Redundancy Protocol (PRP) and Clause 5 defines High-Availability Seamless Redundancy (HSR). Both methods of network recovery provide “zero recovery time” with no packet loss in case of single network failure.

## System design considerations

For risk mitigation it is crucial to consider possibilities for redundancy. Also, in CPC modifications done to the protection device might cause downtime for the complete substation, if the device needs to be taken out of use.

Most obvious redundancy possibility is to duplicate the central device (Figure 6). This ensures that in case of CPC unit failure, there is still fully functional protection available. As the central protection devices can have identical configurations, the engineering and maintenance is still efficient. Also, during update procedures and testing, the redundant unit can handle protection, while the other unit is out of service. For completely new installations this kind of duplicated central protection is often the optimal solution.

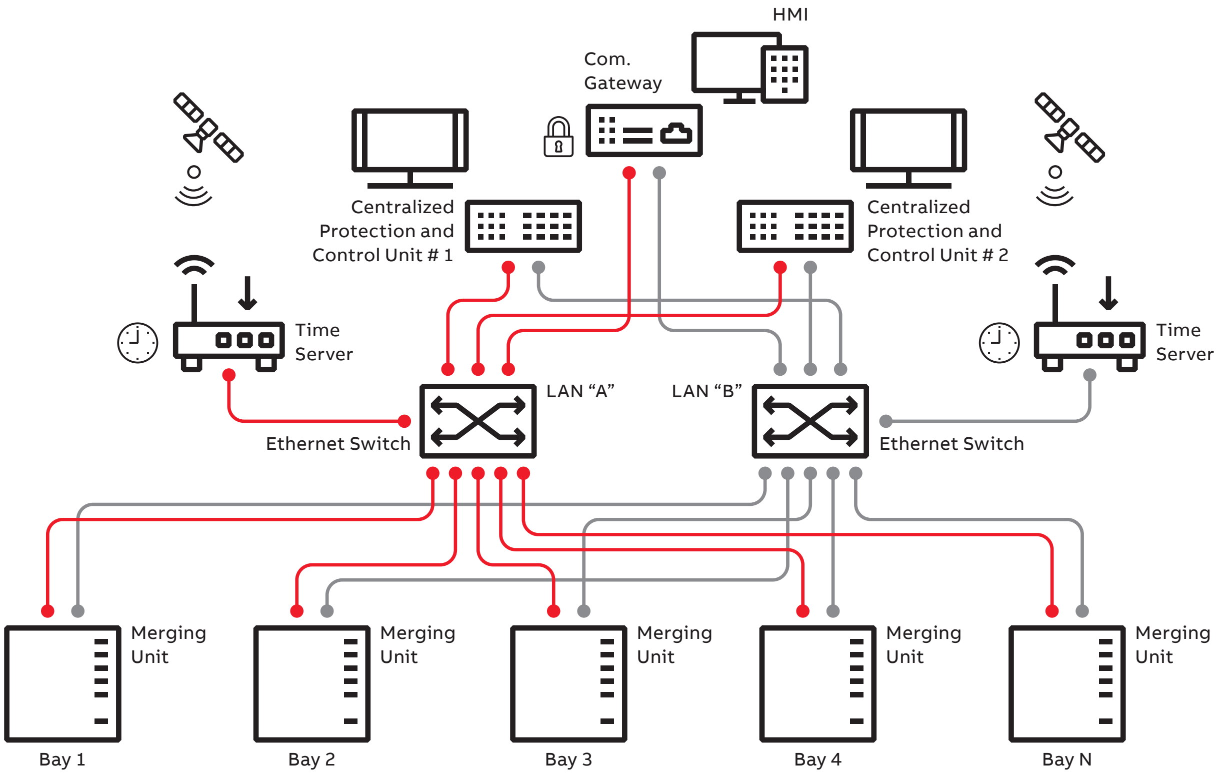



**Fig 6. Centralized protection and control system with redundant CPC unit (System #1)**

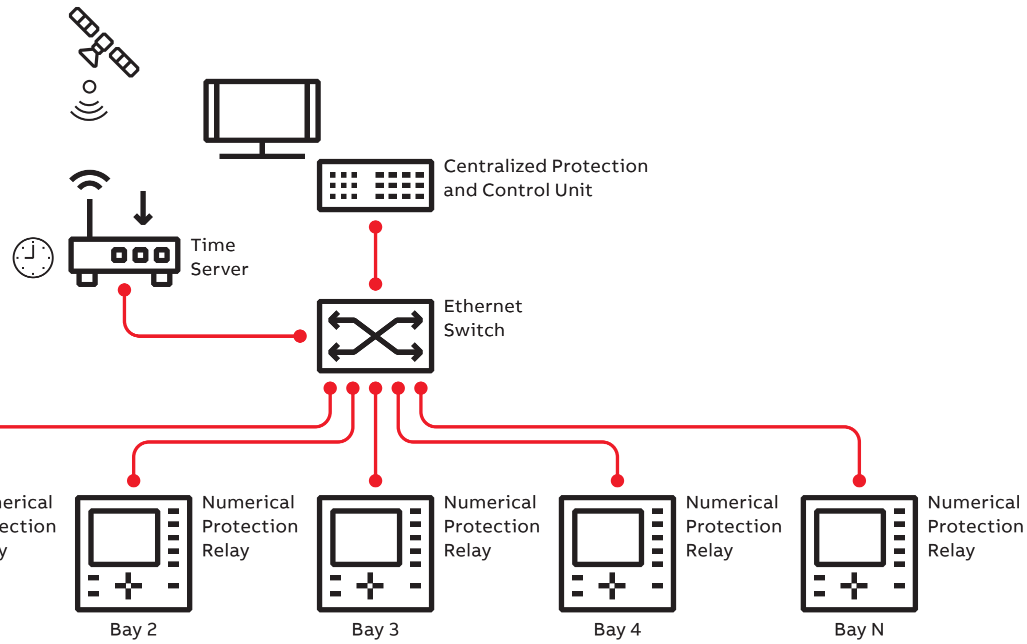



**Fig 7. Centralized protection and control system with Intelligent Merging Units (System #2)**

Another redundancy possibility is to combine the good parts of both approaches via using bay level backup protection with the centralized protection. This approach is shown in Fig 7. The idea of a combined solution is to use simplified protection on the bay level and all the substation-wide and advanced protection in the CPC device. The protection system will still have the flexibility of a centralized protection and control concept, as new functionalities and extensions can be updated in a single location. A combined solution is also a good possibility for existing installations, as just adding the CPC device can introduce new functionalities for the complete substation.

## Cyber security

Cyber security for centralized protection and control is as important as it is to any part of critical infrastructure. In modern protection and control systems it's not enough to just isolate the OT from IT and simply hope that there will be no attacks or human errors that would expose the system to cyber threats. The best way to enforce a secure system is to follow international standards and guidelines such as IEEE 1686, IEC 62351 or NERC CIP.

Cyber security of a protection and control system can only be ensured by securing the complete system, not only single devices. The devices themselves need to include capabilities and functionalities that enable you to build a secure system. These functionalities include role-based access control, secured communication protocols, audit trails, signed software packages and remote asset management capabilities.

CPC has the same cyber security requirements as conventional relays, but centralization enables certain benefits:

- Access points to the devices is easier to manage. The CPC device can be the only entry point to external OT systems, like gateways or SCADA, instead of accessing multiple relays. The CPC device can also have dedicated physical ports to enable only relevant services exposed to upper layer communication and segregate the process bus to its own network.
- Security critical information is centralized. The CPC device has the audit trails and security events in one location where it is easy to manage.
- Fleet management is simplified. As the P&C intelligence is centralized the need for security relevant firmware updates lessens. Instead of updating multiple devices, only the centralized unit might need actions.

# Comparison of a conventional P&C system vs. CPC approach

## Relay selection

With a conventional approach, a multifunction microprocessor relay is dedicated to a feeder and the relays are selected based on the main application they cover. For example, the transformer is protected by a dedicated transformer protection relay, the feeder by a feeder protection relay, the motor by a motor protection relay, the busbar by a dedicated bus protection relay, etc. The relay selection is an important piece of P&C design and implementation. Selecting the wrong order code results in ending up with the wrong relay. Reordering or modification of the incorrectly selected relay has significant cost impact and cause project commissioning delays, which in turn affect the overall cost efficiency of the project. Further, from the maintenance standpoint, for each relay type the user needs to have a separate spare relay. This factor also adds up to the overall life cycle cost of the project.

CPC drastically minimizes the overall life cycle cost. Firstly, it eliminates the need for one relay per application per feeder. Every feeder will have the same type of merging unit. Secondly, the protection application is no longer dependent on the hardware. The CPC system allows you to configure several different protection applications within the same device. CPC can also be reconfigured at any time, without having to modify the hardware. This provides great flexibility in selection and ordering of the devices. Having only two types of devices for the whole system, i.e., CPC and MU, reduces the cost of ordering and maintaining spares.

A CPC approach thus provides great benefits for design and operation.

## System engineering

When comparing a conventional P&C scheme versus a CPC system, the CPC solution provides unmatched flexibility in terms of engineering, commissioning, maintenance, and the possibility to do modifications as new protection requirements are needed.

For an experienced protection engineer, it takes 30-60 minutes to program and configure a dedicated protection relay for each application. This is considering that the protection engineer is already familiar with the dedicated multifunctional microprocessor relay, if not, it would require significantly more time. If, for example, we are protecting a substation with 20 different electrical objects/breakers (feeders, transformers, buses, etc.) – we are talking about 10 hours to only configure the protection relays, in the best of cases. With a CPC system, where everything is contained within one device, this time could be reduced by at least 30 percent to approximately 7 hours.

The primary driver for the reduction in engineering time needed is thanks to having only one device containing all the required protection elements, settings, and control elements for the whole substation.

Furthermore, configuration of GOOSE messages is simplified as the whole substation protection is contained in one device. And being able to copy and paste existing templates saves a lot of time while configuring the CPC unit.

In a CPC system we can benefit from the fact that communication needs to be established with only one device during commissioning – rather than establishing communication with several dedicated relays, which you would have in a conventional approach. The CPC solution also provides significant benefits when commissioning complex interlocking schemes, automatic transfer schemes, or bus protection schemes, when more than one dedicated relay is involved, since all the monitoring information is readily accessible via the CPC system.

The availability of a CPC unit makes it possible to concentrate all substation data (real time data of protection and control scheme, various primary equipment status, various measurements from protection CTs or sensors) to one user interface in a substation. A CPC unit offers a web-based dedicated user interface, which has multiple HMI options throughout the substation over secured LAN or even remote access through secured VPN and internet. Since all substation data is available at a central location, this allows for an improved user experience with e.g. centralized alarms, events, and disturbance recording for all the bays, more efficient and safe control and operation of primary equipment, centralized engineering, the handling of protection settings and configuration storage of substation devices [7].

Finally, the integration of distributed resources at the distribution level has created additional challenges for electrical utilities requiring them to add new protective functions to their existing installations to be able to cope with bidirectional power in areas where the power used to flow in only one direction. With a CPC solution, it is very easy to add new protection functionality to a complete substation without having to modify every single protection relay.

## Redundancy and reliability

One of the most often raised concerns when comparing a CPC system to a conventional approach is with respect to the redundancy and the reliability of the system. Today many utilities use primary and backup protection even when using dedicated multifunctional relays and changing to new technologies like CPC is met with hesitancy, similarly, as was the case when moving from electromechanical to numerical relays.

In Table 1 some of the different redundant systems that could be developed when implementing a CPC system are shown. Note that for simplicity, the managed Ethernet switches are not shown, but redundant communications need to be used, preferably PRP to handle sampled value traffic in every system.

The system #1 relies on having two CPC units to eliminate the loss of protection in case one of the CPC units were to fail. However, it only relies on having one merging unit per electrical circuit being protected, so in case the MU were to fail, the specific electrical circuit would be unprotected. This system is recommended for those users using a single multifunctional relay per circuit in the conventional approach.

One alternative is to use one CPC unit and one IMU or multifunctional protection relay that can act as a merging unit per circuit, as described in system #2. The advantage of system #2 is that you can use only one CPC unit, and in case of failure of the CPC unit the IMU would still provide protection for the system. However, if the IMU were to fail, the circuit where the IMU was used would be unprotected. This is an ideal solution for users having multifunctional relays capable of acting as merging units already in the system, and they are either looking to add new protection functions which they can add to the CPC unit, or they are looking for backup protection.

System #1 can be improved by having two merging units for every electrical circuit being protected and eliminating a single point of failure (System #3). In the case of System #3 not one failure in the system would jeopardize the protection. However, it is important to point out that when the MUs are doubled per circuit, the number of protected circuits by the CPC unit is reduced by half. This is because while the CPC units can protect several circuits at once, there is a maximum number of circuits that can be protected by a CPC unit. For example, if a CPC unit is capable of protecting 30 circuits by being able to connect to 30 sampled values (30 MUs), the same CPC unit can only protect 15 circuits when the number of merging units per circuit are doubled. This system is ideal for customers that want to avoid a single point of failure in their system and want to provide all protection and control functionality at the CPC level.

System #4 provides the highest reliability levels and also has the highest cost of any of the systems described in this section. In System #4, there are two CPC units for the whole system, and one MU and one IMU per electrical circuit being protected. In this scheme you can have either both CPC units failing, and one CPC unit, and either the MU or the IMU failing, and there will not be a circuit that is left unprotected. This system is recommended for those who want to achieve the highest levels of reliability. However, just like System #3, if the MU/IMU are doubled per electrical circuit being protected, the number of protected objects by the CPC unit is reduced by half. Please refer to the description of system #3 to understand why the number of circuits protected by the CPC units are reduced by half.

In System #5 we have one CPC unit for the whole system, and one merging unit and one intelligent merging unit per electrical circuit being protected. System #5 is similar to System #2 with the difference being that you are avoiding a single point of failure by adding an IMU. In this system you can have the CPC unit, MU, or IMU failing and the system is still protected.
This system is ideal for those that already have microprocessor relays capable of acting as merging units and want to add additional protection functions at the centralized protection and control level, or who wish to add additional backup protection without having a single point of failure. This system just like System #3 and #4, reduces the number of circuits that the CPC unit can protect by half. Please refer to the description of system #3 to understand why the number of circuits protected by the CPC units are reduced.

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**Table 1: Redundancy systems**

| Redundant system | # CPC Units | Merging units | Intelligent merging units *) | Comments |
|---|---|---|---|---|
| #1 | Two | One per circuit | Zero | With this scheme the system is never unprotected even if one of the CPC units were to fail. However, failure of the merging unit would cause loss of protection in the affected circuit. |
| #2 | One | Zero | One per circuit | With this scheme the system is never unprotected even if the CPC unit were to fail. However, if the intelligent merging unit were to fail, the protection would be lost in the affected circuit. |
| #3 | Two | Two per circuit | Zero | With this scheme a single point of failure is eliminated completely if either a CPC unit or a MU were to fail. Note that with this scheme the number of protection circuits by the CPC unit is reduced by half. |
| #4 | Two | One per circuit | One per circuit | With this scheme a single point of failure is eliminated completely if either a CPC unit, a MU, or an IMU were to fail. This scheme provides double point of failure for the CPC units, and for one CPC unit and one MU/IMU. Note that with this scheme the number of protection circuits by the CPC unit is reduced by half. |
| #5 | One | One per circuit | One per circuit | With this scheme a single point of failure is eliminated completely if either a CPC unit, a MU, or an IMU were to fail. Note that with this scheme the number of protection circuits by the CPC unit is reduced by half. |

*) Protection relay capable of acting as a merging unit

More information about reliability and ratings can be found in [5] and [3]. In general, it can be seen from the information provided that the higher the requirements for system reliability are, the more costly the system becomes.

## Testing

P&C systems are tested during different times over the life cycle. Pre-shipment test at the factory, commisioning test at site, periodical maintenance testing, are the common type of tests performed at various stages. [8]. In the conventional approach every relay is repeatedly tested individually at every phase of their lifetime [9].

Currents and voltages are injected to the relay using a seconday injection test set for metering test, protection pickup and protection trip verification. A typical test set up is as shown below.

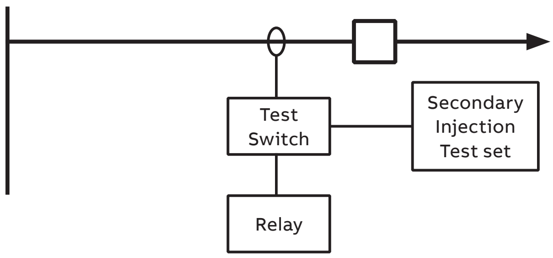


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**Fig 8. Conventional P&C test set up**

Testing a conventional P&C sytem and a CPC system is the same throughout the comissioning stage. The only difference is that secondary injection is done to the merging units, instead of to the protection relays.

A CPC system operates based on the sampled values received from the MUs. The circuit breaker (CB) status information (52a, 52b contacts) and the CB trip and close signals are transmitted as GOOSE messages. During the periodical maintenance testing stage, or when changes are made to the system that do not affect the control wire and communications of the system, simulation of the sampled values and GOOSE messages could be performed. For example, when adding new protection functions a result of system changes.

Most of the relay test set manufacturers have introduced test sets with GOOSE and sampled value simulation capability. The test set is connected to the network switch from where all the protection applications for each feeder configured in the CPC can be tested. The test process allows CPC to be put in test and simulation mode. The test set injects the operating quantities in the simulation mode for each feeder, one at a time. Under this condition the CPC ignores the real MU values. Once a feeder is tested, the SV ID address of the test set is changed to that of the next MU for testing its corresponding feeder. This process is continued until all the feeders configured in the CPC system are tested.

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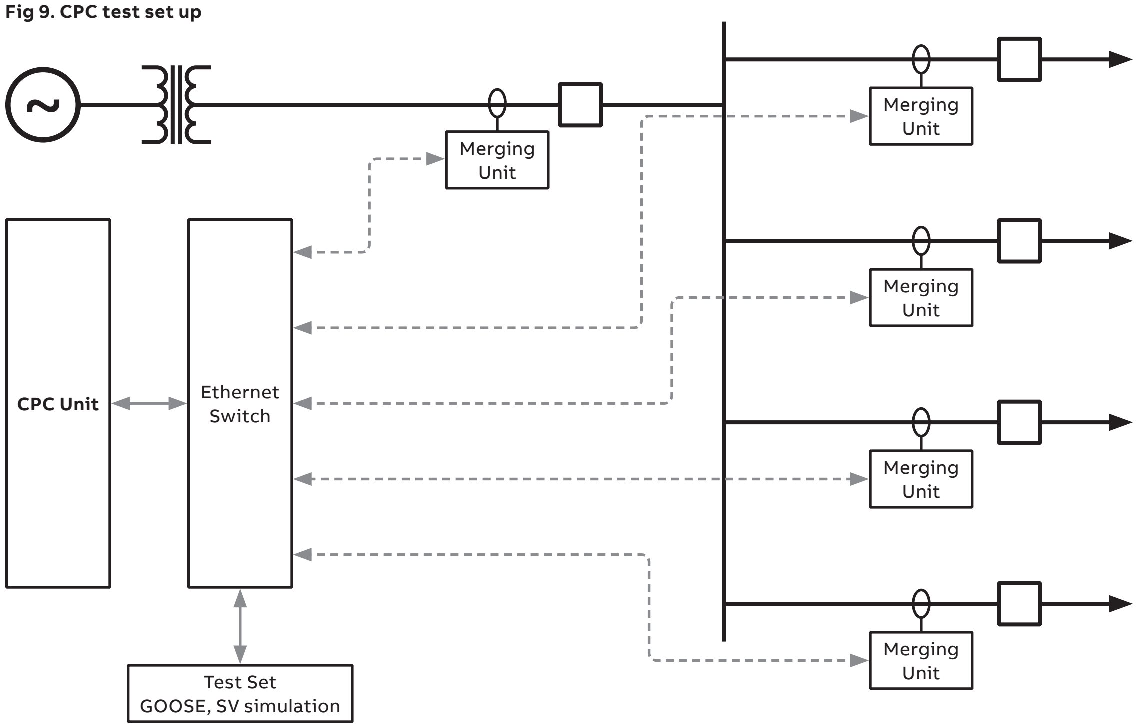
**Fig 9. CPC test set up**



A CPC approach provides tremendous time savings in wiring and connecting the test set, as the test set up remains unchanged irrespective of which application or feeder is tested. Periodic and maintenance testing could be done this way,if permitted by the regulating authority. Further, the test process can be automated taking advantage of IEC 61850 standard and test set capabilities, which allow uploading and linking of parameter settings, GOOSE and sampled values into the test plan [10] [11].

Alternately, each feeder can be tested by putting both the MU and the CPC in test mode. In this case the secondary injection of analog quantities is done at the MU. When the CPC is in test mode, it ignores the real sampled values from other MUs. This method allows the entire path to be tested – the MU, communication channel, and the CPC operation. This method is similar to testing conventional P&C systems.

## Operation

Once the P&C system has been tested and commissioned, it is energized and is expected to provide stable protection during normal modes of operation. The operation and switching requirements vary between utility companies. Same goes for commercial and industrial systems. In the event of an abnormal system condition, the relays are expected to detect the fault and clear it based on the set parameters. In some cases, a single fault may lead to multiple feeders tripping. The operator is expected to identify and clear the fault before the system is turned back into operation. The fault identification process involves checking the reason for the trip, evaluating fault data, and analyzing the waveform captured by the relays to locate the actual point of fault and to take corrective actions – if any, before turning the system back on.

In the conventional approach, when multiple relays are involved in a fault situation, the operator needs to access the relays one at a time to download the necessary information for fault identification and analysis purposes. If these different relays are not synchronized from a common time source, the information gathered is found useless in many cases. In substations without a SCADA system, gathering substation-wide information from several different relays is a time-consuming process.

In a CPC system, however, all relevant information for fault detection and analysis is available at a single point with inherent time synchronization. The trip information of multiple feeders can be viewed on the same alarm notification page. Further, the waveforms are captured by the same disturbance recorder function for all the feeders in the substation, which makes it very convenient to compare the waveforms from multiple feeders. Also, the sequence of events from multiple feeders are listed in a chronological order in the CPC system, which gives the operator a clear picture of how and when each event occurred. The CPC system provides these benefits without the additional cost of a SCADA system.

## Maintenance

According to the PRC-005-2 standard, maintenance of a P&C system involves periodical testing to ensure that the relay settings are as specified, and that the operation of the relay inputs and outputs that are essential to proper functioning of the protective system and its measurements reflect that the power system's values are within the tolerance level. Another major aspect of maintenance is to keep the relay firmware up-to-date. Typically, relay vendors release firmware upgrades periodically to enhance protection functions and to take care of software bugs. Some vendors tend to release firmware upgrades more frequently than others. Additionally, if a relay fails it must be replaced as quickly as possible to ensure continuity of protection. Conventional microprocessor-based relays with draw out design is particularly helpful to drastically reduce mean-time-to-repair (MTTR).

Conventional P&C systems require more time to test and verify each individual relay. In case of firmware upgrades hundreds of relays are updated individually and then tested to verify accurate operation. This is a very time consuming and laborious process. Also, the user needs to carry spares for different type of relays and order codes used for various applications. This adds up to the cost of maintenance over the life cycle of the project.

A CPC system on the other hand has minimum hardware variants and testing a CPC system is much more efficient. A firmware upgrade, if necessary, is to be done only on a single device in a substation, and not to multiple relays within the substation.

This is a much simpler process as compared to the traditional approach. Further, CPC system need to have only a CPC device and a MU to be carried as spares for the whole substation. Additionally, if the P&C system needs to be updated, for example, adding a feeder or change in protection and interlocking schemes, no hardware changes are needed. This can easily be accomplished by updating and adding a new software application and reconfiguring the system.

## Safety

Safety is paramount in the design of electrical systems: remote operation, use of non-traditional instrument transformers, and the use of arc sensors are all possibilities with a centralized protection and control system.

The CPC system allows very easily to consolidate all the information in a single location away from the electrical equipment. This minimizes the risk of being in close proximity of the arc flash areas when operating circuit breakers, or in case of an electrical fault.

Furthermore, if the MUs/IMUs are able to support nontraditional instrument transformers (current sensors/Rogowski sensors and voltage sensors), then additional benefits could be achieved by eliminating concerns with the secondary side of CTs being left open, and potentially developing high voltages, and ferro-resonance problems that could happen with traditional voltage transformers.

Finally, the utilization of a MU/IMU capable of being connected to arc sensors, provides additional protection to personnel and equipment in case of an arc fault.

# Application examples

There are multiple applications and functions, that either benefit from a centralized architecture or even require it. The most obvious indication of station-level functionality is the communication requirement. If the functionality requires horizontal and/or vertical communication, in other words, if information needs to be exchanged between several units, it is beneficial to implement the functionality at the station level.

Also, one indicator is the function maturity and the expected 'functional life cycle' of the application. If there are changes expected in the requirements for the function, either coming from legislation or from the business environment, the function would benefit from a centralized architecture, as updating is faster and more economical to do [7].

**A proposed list of CPC system functionality:**

- Protection and analysis functionality utilizing measurements from multiple bays:
  - Differential protection e.g. for bus bar
  - Sensitive directional earth fault protection e.g. for intermittent faults
  - Protection against faults with low fault current magnitude: e.g. high impedance earth faults
  - Islanding operation and Loss-of-Mains protection when islanding is not allowed
  - Fault locator
- Control functionality requiring a substation level view:
  - Interlocking
  - Post-fault power restoration and self-healing control applications
  - Load shedding
- Other supporting substation functionality:
  - Station-wide disturbance recorder
  - Automatic recalculation of protection parameters based on topology and DER changes, adaptation of protection application
  - Advanced condition monitoring and asset management support
  - Cyber security monitoring and protection
  - Station-level self-supervision

**There are three typical applications where a CPC system could be installed:**

1. The CPC unit(s) in the control room, together with the managed Ethernet switches, and time synchronization sources with the MUs at the substation yard close to the instrument transformers. This is often the ideal installation for greenfield (new construction) applications, where the benefit of not having to run all the control wire from the substation to the control room is achieved.
2. The CPC unit(s) in the medium-voltage switchgear, together with the managed Ethernet switches, time synchronization clocks, and MU/IMU. This type of installation can be used for any substation with medium-voltage switchgear.
3. The CPC unit(s) in the control room, together with the managed Ethernet switches, and time synchronization sources including the MU/IMU. This is often the ideal installation for brownfield (existing construction) applications, where you wish to avoid having to remove existing control wiring, and wish to have an additional degree of safety via having the MU/IMU inside the control room.

# Lessons learned from field installations

As discussed in this paper, two of the primary drivers for a CPC system were the environmental and regulatory conditions that have caused either the integration of distributed resources or the increase in availability requirements of electrical power.

Availability of power was the primary driver for the first installation of a CPC system in Finland. Caruna, the largest electricity distribution system operator (DSO) in Finland, piloted a concept where the protection system in the Noormarkku substation was upgraded with a new centralized protection and control solution.

The DSO was investing more heavily in weatherproofing, increasing underground cabling and was looking for a flexible and future-proof solution for their network. Caruna chose to pilot the CPC systemto meet additional and new protection requirements and to benefit from the latest developments in relay technology [12].

Commissioning of the CPC system was done in May 2017. The commissioning and testing had to be done in a live substation, which meant it was crucial that there were no interruptions. The network status at Caruna was such, that it was not possible to completely replace the substation with backup connections. Instead two feeders at a time were disconnected and commission tested. Both CPC system and the relays were tested similarly based on standard commission testing procedures.

Dedicated test equipment was connected to the analog inputs of the feeder level relay. When fault current was injected to the relay inputs, the relay was simultaneously publishing the measurements, according to IEC 61850- 9-2 LE, and executing its own internal protection functions. The acceptance criteria for each case were that the trip events both from the bay level relays and the CPC unit were correctly received by the SCADA system, and that the CPC unit would not be slower than the bay level protection.

The outcome and results of the pilot are positive. They indicate that the CPC system has been reliable and efficient. During the piloting period's first 3 years there were 99 overcurrent faults and 69 earth faults, which were all successfully handled by the new solution. The operation is comparable to using conventional relays, and the communication performance of IEC 61850-9-2 LE and IEC 61850-8-1 GOOSE fulfilled the protection needs. The installation has now been in use since 2017.

The pilot was also a showcase of a modern retrofit project, as the existing relay-based protection was preserved, and new earth fault protection functionality was introduced to the substation within one new CPC unit. Existing relays were kept as back-up protection. It was not required to remove or replace them, as they already supported IEC 61850-9-2LE process bus. In other words, upgrading existing substations can be cost-efficiently managed with centralized protection and control.

# Conclusion

A CPC system is now possible, thanks to the advancements on microprocessors technology and the development and adoption of the IEC 61850 standard.

The components of a CPC system at minimum are: a centralized protection unit capable of providing substation-level protection for multiple objects, managed Ethernet switches, a time synchronization clock, and merging units to digitalize the analog information from instrument transformers/sensors and interact with each breaker/contactor being protected.

A CPC system unlocks benefits that could not be achieved earlier using multifunctional protection relays.

## Key benefits of CPC systems:

- **Increased awareness of your overall protection and control system**
- **Ability to update/upgrade your system with minimum disruption**
- **Improved reliability**
- **Cost-effective electrical system**

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## List of abbreviations

| | |
|---|---|
| CPC | Centralized Protection and Control |
| CT | Current Transformer |
| GOOSE | Generic Object Oriented Substation Event |
| GPS | Global Positioning System |
| HSR | High-Availability Seamless Redundancy |
| HW | Hardware |
| IED | Intelligent Electronic Device |
| IT | Information Technology |
| OT | Operational Technology |
| P&C | Protection and Control |
| PRP | Parallel Redundancy Protocol |
| SCADA | Substation Automation and Data Acquisition |
| SNTP | Simple Network Time Protocol |
| SV | Sampled Values |
| VT | Voltage Transformer |

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