Centralized Protection and Control – Enhancing reliability, availability, flexibility and improving operating cost efficiency of Distribution Substations

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Abstract *The first Electromechanical relay for power system protection appeared during early 1900s. Protection & Control 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. The launch of global standard for Power System applications in the year 2004, viz., IEC 61850 has been a game changer enabling Power System industry to explore more efficient ways of utilizing the 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. The Centralized Protection and Control (CPC) system is based on a flexible distribution or even a replication of protection and control functions between devices at feeder and substation levels via a highly-available and fast Ethernet network based on the IEC 61850 standard.*

The system configuration comprises 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. Besides 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 that makes it very exceptional. This paper compares the pros and cons of CPC architecture with traditional microprocessor relay protection and control architecture with respect to design, engineering, testing, operation and maintenance of power system protection and control.

Key words- Architecture, availability, centralized protection and control, ethernet, flexibility, GOOSE, IEC 61850 standard, intelligent merging units, merging units, microprocessor relay, networks, redundancy, redundant communication, reliability, sampled values, time synchronization

I. INTRODUCTION

Protection in power systems has been subject to several technological advancements. From electromechanical mechanisms to the microprocessor 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 protection and control schemes [2]. Furthermore, these advances have opened space for the implementation of the centralized protection and control (CPC) system [3].

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.

This paper consists of seven sections. The first section is an introduction. The second section describes a traditional protection and control (P&C) architecture. The third section defines a CPC system, components, and design considerations. The fourth section compares a traditional P&C system with a CPC system. The fifth section summarizes some of the application examples for a CPC system. The sixth section mentions the lesson learned from a real example using a CPC system in Finland. And finally, the seventh section includes the conclusion.

II. TRADITIONAL MICROPROCESSOR RELAY PROTECTION & CONTROL ARCHITECTURE

The first generation of microprocessor relays were designed to replace the protection capabilities of its predecessors namely, static and electromechanical relays. However, microprocessor-based design enabled relay manufacturers to deliver multifunction capability. Multiple protection elements were integrated into one device. While protection was the primary focus, microprocessor relays also provided analog measurements and limited amount of logic building capability. 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, like transformer, feeder, motor, bus, etc. A traditional microprocessor relay protection and control communication architecture is shown in Fig 1.

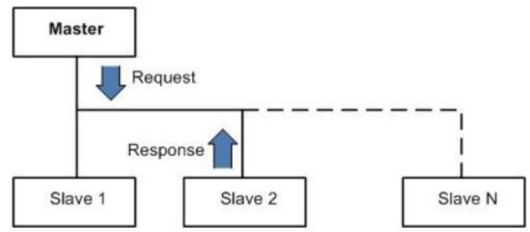

Fig 1 – Typical communication architecture with Modbus/DNP protocol

With addition of communication capability in the microprocessor relays, the industry desired the capability to design and implement intelligent protection and control schemes like zone selective interlocking, fast bus protection, CB failure protection scheme, etc. Such a requirement 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 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 below.

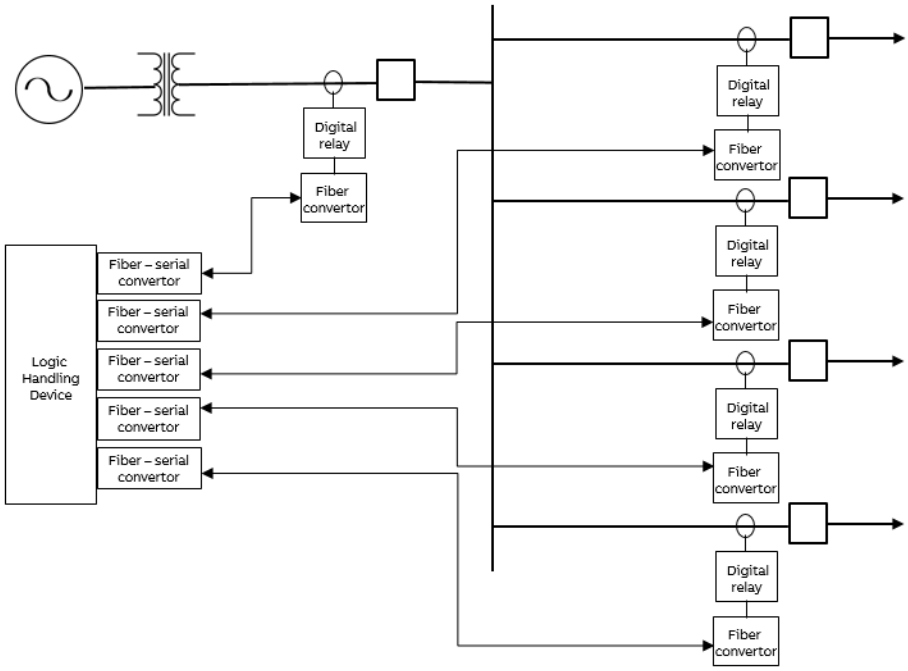

Fig 2 – Typical architecture to implement a fast bus protection scheme using proprietary protocol

As we observe from the above architecture, the relays had limited communication capability which necessitated use of additional hardware in order to complete the scheme. First the native serial communication electrical port is converted to 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 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 are 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. As stated before, the proprietary nature of the protocol 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. Introduction of first edition of IEC 61850 standard in year 2004 opened tremendous opportunities for power system engineers to create and implement intelligent and efficient protection and control schemes.

A fast bus protection architecture using native IEC 61850 relays is shown below.

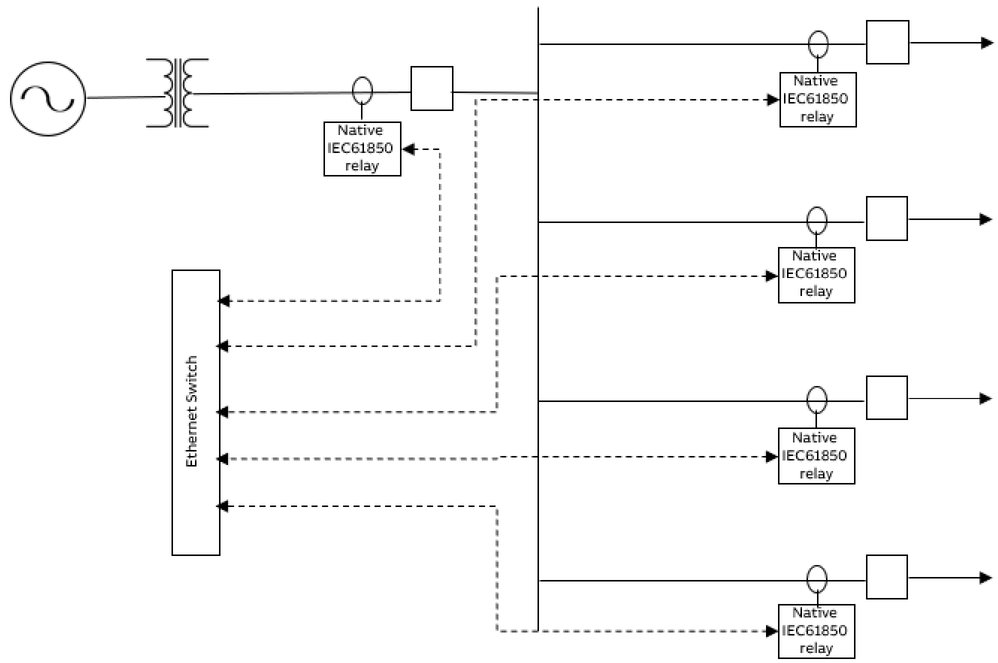

Fig 3 – Typical architecture to implement a fast bus protection scheme using IEC 61850

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 the Fig. 2.

The addition of process bus standard into IEC61850 further enhanced the opportunity to improve the efficiency of protection and control scheme implementation. The process bus communicates digitized analog values from traditional CTs/PTs or Current/Voltage sensors. The digitization is done by a device called Merging Unit. Merging Unit at each feeder converts the respective currents and voltages and feeds the Sampled Values into the process bus. The protection relays subscribe to the required Sampled value and perform protection and measurements based of the Sampled Value it received. This further improved the design and implementation efficiency as CT and PT copper wiring is drastically reduced. Instead all the signals, both GOOSE and Sampled Values are communicated via the same fiber cable ethernet network. A typical IEC 61850 Protection and Control architecture is illustrated below.

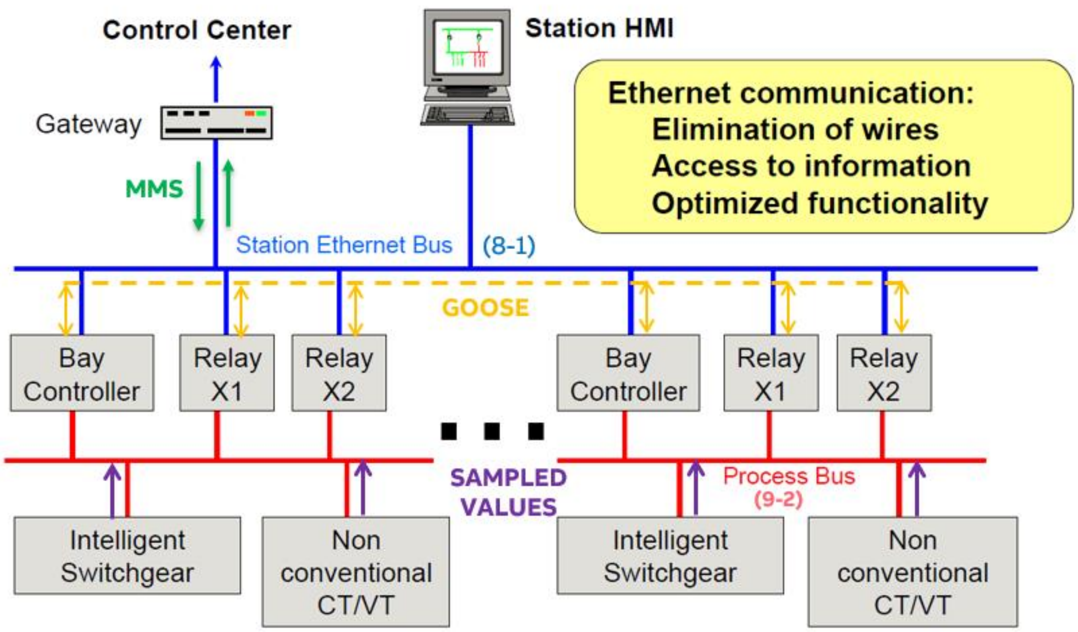

Fig 4 – Typical IEC 61850 protection and control architecture using GOOSE messages and Sampled values

III. Centralized Protection and Control

A. *Concept*

Main idea of centralized protection 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.

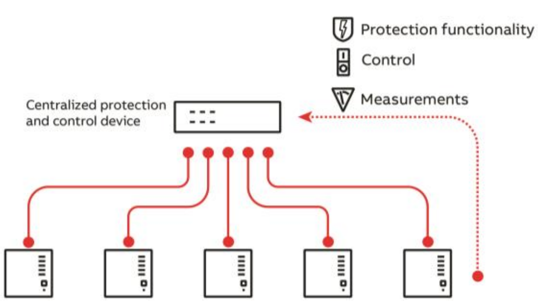

Fig 5 – Centralized protection and control system

Centralized protection and control concept itself is not new but only the advancements in CPU technology and international standards makes it possible to replace a modern protection and control system with centralized protection [3] [4]. Complexity of modern protection algorithms requires extensive processing power and capability to ensure the real-time requirements of protection. Standards like IEC 61850 and IEEE 1588 enables highly compatible centralized protection systems but also demands quite much from communication networks and again processing capabilities. Because of the new technologies and high performance needs, it is essential to compare traditional protection and control to a new centralized solution. Simulation based viability assessment for the centralized concept can be found in [5].

B. *System Components*

Traditionally the protection has been distributed in multiple different devices (Figure 4) but in centralized protection and control 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 bigger applications than traditional P&C relays. Other difference is that the physical interfaces can be simplified as all the inputs/outputs can be managed with standard Ethernet interfaces.

Other components in 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 Merging Unit (MU). MU is defined in IEC 61850-9-1 as 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 interface unit between primary equipment and CPC, MU can also host I/Os (input/output) to handle feeder based digital signals. It can communicate the digital status of primary equipment, like the circuit breaker, isolator, grounding 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 MU includes additional functionality like protection functions, it is called Intelligent Merging Unit (IMU). In practice IMUs are normal microprocessor-based relays that also includes process bus sending capabilities. Main benefits of IMUs are in reliability as a local backup protection is still available even if the communication network is not fully working. 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 existing.

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 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. 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, IEC 61850 standard mandates the use of 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.

C. *System design considerations*

For risk mitigation it is extremely important to consider possibilities for redundancy. Also, in centralized protection the modifications 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 a 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 seems to be the optimal solution.

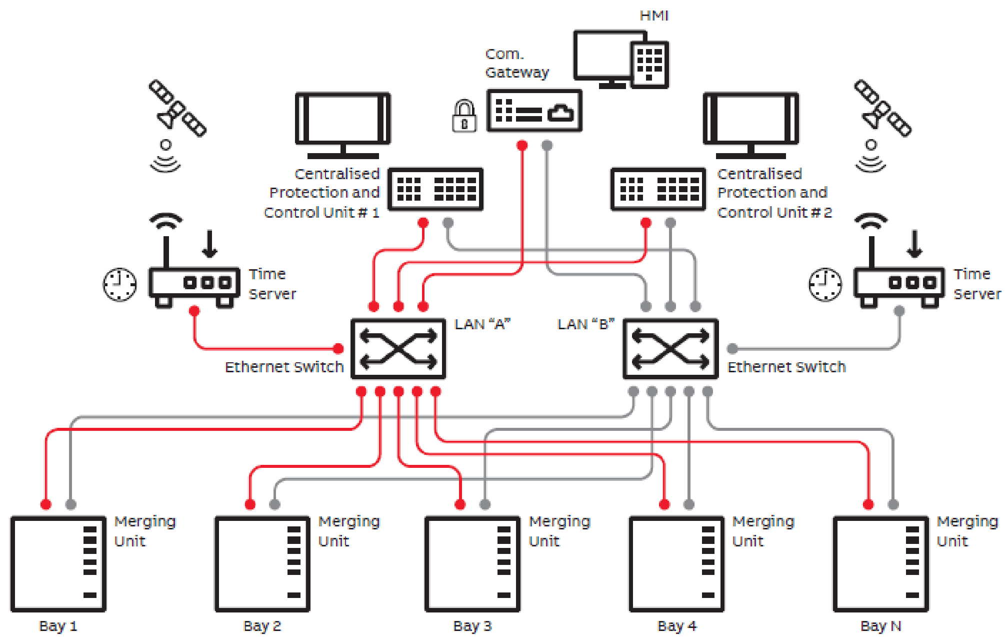

Fig 6 – Centralized protection and control system with redundant CPC unit (System #1)

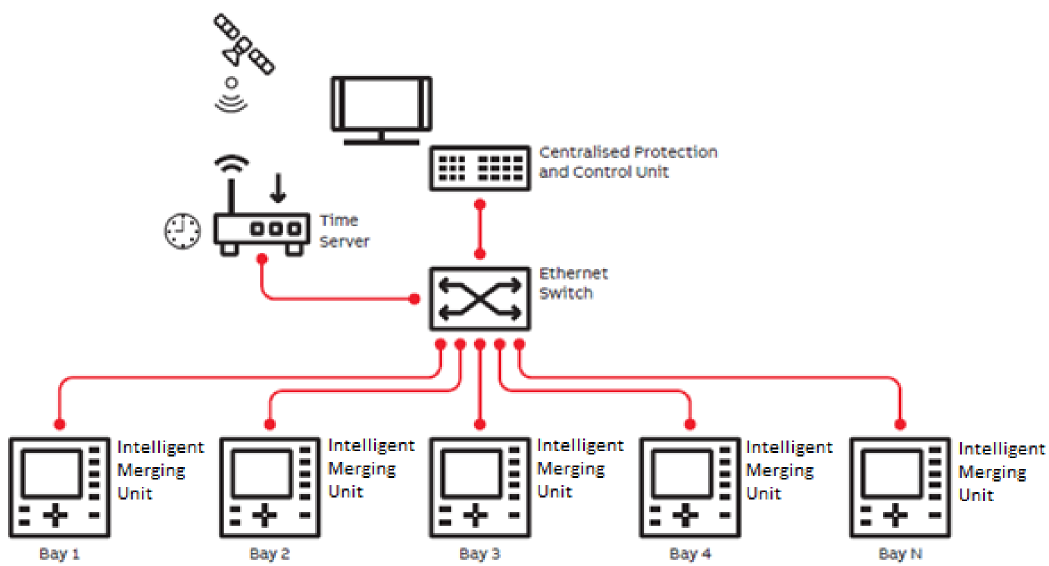

Fig 7 – Centralized protection and control system with Intelligent Merging Units (System #2)

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

D. *Cybersecurity*

Cybersecurity for centralized protection and control is as important as it is to any part of the critical infrastructure. In modern protection and control system it's not enough to just isolate the OT from IT and hope there are no attacks or human errors exposing the system to cyber threats. The best way to enforce secure system is to follow international standards and guidelines like IEEE 1686, IEC 62351 or NERC CIP.

Cybersecurity of a protection and control system can only be ensured by securing the complete system, not only single devices. Devices themselves needs to include capabilities and functionalities to enable secure system building. These functionalities include role-based access control, secured communication protocols, audit trails, signed software packages and remote asset management capabilities. CPC has the same cybersecurity requirements as traditional relays, but centralization enables certain benefits:

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

IV. COMPARISON OF TRADITIONAL P&C SYSTEM VS. CPC APPROACH

A. *Relay selection*

As explained in section II above, in the traditional approach a multifunction microprocessor relay is dedicated to a feeder. The relays are selected based on the main application it covers. Transformer is protected by a dedicated transformer protection relay, feeder by feeder protection relay, motor by motor protection relay, busbar by dedicated bus protection relay and so on. The relay selection is an important piece of P&C design and implementation. Selection of wrong order code results in ending up with wrong relay. Reordering or modification of the wrongly selected relay has significant cost impact and cause project commissioning delays affecting the overall cost efficiency of the project. Further, from the maintenance standpoint, for each relay type the user carries a spare relay. This factor also adds up to the overall life cycle cost of the project.

The centralized protection approach drastically minimizes the overall life cycle cost. First, it eliminates the need of one relay per application per feeder. Every feeder will have the same type of Merging Unit. The protection application is no longer dependent on the hardware. CPC system allows configuring several different protection applications within the same device. CPC can be reconfigured anytime without having to modify the hardware. This provides great flexibility in selection and ordering of the devices. Having only two type of devices for the whole system, i.e., CPC and MU bring down the cost of ordering and maintaining spares. CPC approach thus provides great benefit to the designer and the user.

B. *System engineering*

When comparing a traditional Protection and Control scheme versus a Centralized Protection and Control system, the CPC solution provides unmatched flexibility in terms of engineering, commissioning, maintenance, and modifications as new protection requirements are needed.

It can take from thirty to sixty minutes to program and configure a dedicated protective relay for each application by an experienced protection engineer, this considering that the protection engineer is familiar with the dedicated multifunctional microprocessor relay, if not it could take 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 protective relays, in the best of the cases. With a Centralized Protection and Control System since everything is contained within one device this time could be reduced by at least thirty percent to approximately 7 hours.

The primary driver to the reduction in the engineering time is due to one device containing all the required protection elements, settings, and control elements for the whole substation. Furthermore, configuration of GOOSE messages is simplified as 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.

The CPC system benefits from the fact that communication need to be established with only device during commissioning rather than establishing communication with several discrete relays in the traditional approach. With the CPC system you get access to the whole substation protection. The CPC solution also provide 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.

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) at a point of user interface in a substation. A CPC unit can offer web-based dedicated user interface, which offers 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 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 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 centralized protection and control solution, it would be very easy to add new protective functions to a complete substation without having to touch every single protective relay.

C. *Redundancy and Reliability*

Probably one of the biggest concerns with a CPC system compared to traditional approach using dedicated multifunctional protective relays is with respect to the redundancy and the reliability of the system. Today many electrical utilities in North America use primary and backup protection even when using dedicated multifunctional relays, and the thought of migrating to a CPC system brings memories of the challenges faced when transitioning from electromechanical/solid state relays to microprocessor relays.

The table below shows some of the different redundant systems that could be developed when implementing a CPC system. Please notice that for simplicity purposes 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 customers using a single multifunctional relay per circuit in the traditional approach.

An alternative is to use one CPC unit and one IMU or multifunctional protective 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 protective functions which they can do at 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 20 circuits by being able to connect to 20 Sampled Values (20 MUs), the same CPC unit can only protect 10 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 the highest cost of any other system 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 unit failing and one CPC unit and either the MU or IMU failing and there will not be a circuit that is left unprotected. This system is recommended for those customers 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.

Finally, the last system covered in this section is System #5. 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 customers that already have microprocessor relays capable of act as merging units and want to add additional protective functions at the centralized protection and control level, or want 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.

Redundant system	**# CPC Units**	**Merging units**	**Intelligent Merging Units***	**Comments**
#1	Two	One per circuit	Zero	With this scheme the system is never unprotected in case 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 in case 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. Please notice that with this scheme the number of protection circuits by 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. Please notice that with this scheme the number of protection circuits by 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. Please notice that with this scheme the number of protection circuits by CPC unit is reduced by half.

*Protective relay capable of act 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 more reliable a system is, the more costly it becomes. The decision of what system architecture shall be used is solely the responsibility of the user. Our aim is to educate the customer on some of the considerations when applying CPC systems.

D. *Testing*

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

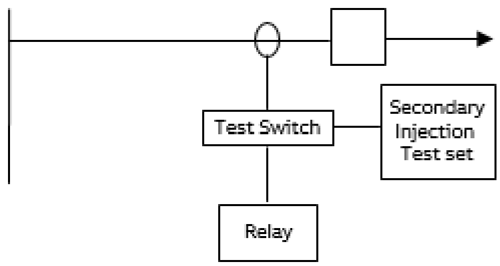

Fig 8 - Traditional P&C test set up

Testing of a traditional P&C sytem and a CPC system is the same throughout the comissioning stage, being the only differnce that secondary injection may need to be done closer to the breakers at the susbtation yard if the MU/IMU are loacted there to reduce hardwired connections going to the control room.

As described in previous sections a CPC system operate based on the Sampled Values received from the Merging Units. 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 protective functions a 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 till all the feeders configured in the CPC are tested. CPC approach provides tremendous time saving from the wiring and connection of the test set as the test set up remains unchanged irrespective of which application or feeder is tested on CPC. Periodic and maintenance testing could be done this way if allowed 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].

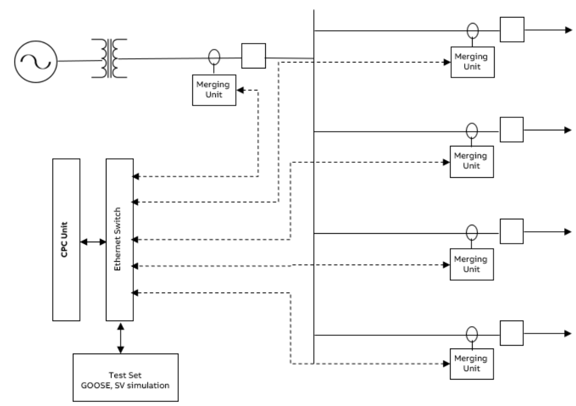

Fig 9 – CPC test set up

Alternately, each feeder can be tested by putting both the MU and the CPC in the test mode. In this case the secondary injection of analog quantities is done at the MU. When the CPC is in the 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 the traditional P&C system.

E. *Operation*

Once the P&C system is 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 is the case with 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. Fault identification process involves checking the reason for trip, evaluating fault data and analyzing 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 traditional approach, when multiple relays are involved in a fault situation, the operator need to access relays one at a time to download 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. SCADA system provided centralized data acquisition and control capability and are typically implemented to improve the operational efficiency.

Whereas in a CPC system all relevant information for fault detection and analysis are available at single point with inherent time synchronization. The trip information of multiple feeders can be viewed at 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 at the CPC system giving the operator a clear picture of how and when each event occurred. CPC system provide these benefits without the additional cost of SCADA system.

F. *Maintenance*

According to PRC-005-2 standard, maintenance of a P&C system involves periodical testing to ensure that the relay settings are as specified, operation of the relay inputs and outputs that are essential to proper functioning of the protective system and the measurements reflect power system values 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. Traditional microprocessor relays with draw out design is particularly helpful to drastically reduce mean-time-to-repair (MTTR).

Traditional P&C systems need 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.

As explained in Section III, CPC system has very minimum hardware variants. Testing a CPC system is much more efficient as explained in Section IV – D. Firmware upgrade, if necessary, is to be done only on a single device in a substation as compared to multiple relays within the substation. This is a much simpler process as compared to traditional approach. Further, CPC system need to have only a CPC 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 new software application and reconfiguring the system.

G. *Safety*

Safety continues to be paramount in the design of electrical systems: remote operation, used 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 to minimize 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 MU/IMU capable to be connected to arc sensors, provides additional protection to personnel and equipment in case of an arc fault.

V. APPLICATION EXAMPLES

There are multiple applications and functions, that either benefit from 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 through legislation or from the business environment, the function would benefit from centralized architecture, where updating is faster and more economical to do [7].

A proposed list of the CPC system functionality:

- Protection and analysis functionality utilizing measurements from multiple bays:
    - Differential protection e.g. for bus bar
    - Sensitive directional ground fault protection e.g. for intermittent faults
    - Protection against faults with low fault current magnitude: e.g. high impedance ground 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 the CPC system could be installed: Control room, medium voltage switchgear, and outdoor equipment.

1. The CPC unit(s) at the control room, together with the managed ethernet switches, and time synchronization sources with the merging units at the substation yard closed to the instrument transformers. This would be the ideal installation for greenfield (new construction) applications, where the benefits of not having to run all the control wire from the substation to the control room is achieved.
2. The CPC unit(s) at 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) at the control room, together with the managed ethernet switches, and time synchronization sources including the MU/IMU. This would be the ideal installation for brownfield (existing construction) applications, where customers are looking at avoiding to having to remove the existing control wiring, and an additional degree of safety is desired by having the MU/IMU inside the control room.

VI. 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 actually the primary driver for the first installation of CPC system in Finland. Caruna, the largest electricity distribution system operator in Finland, piloted a concept where the protection system in Noormarkku substation was upgraded with a new centralized protection and control solution. Caruna was looking for a flexible and future-proof solution for their network. As they invested more heavily in weatherproofing, underground cabling was added. Caruna needed additional protection and a more flexible solution. They chose to pilot the CPC system to meet new protection requirements and to benefit from the latest developments in relay technology [12].

Commissioning was done in May 2017. The commissioning and testing had to be done in a live substation without 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.

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

This CPC pilot has now been operational for 2.8 years. In short, the results show that the CPC system has been reliable and efficient. During the piloting period there has been 99 overcurrent faults and 69 ground faults, which all have been successfully handled by the new solution. Operation is comparable to conventional relays, and the communication performance of IEC 61850-9-2 LE and IEC 61850-8-1 GOOSE fulfilled the protection needs.

The pilot was also a showcase of a modern retrofit project because the existing relay-based protection was preserved, and new ground fault protection functionality was introduced to the substation within one new CPC unit. Existing relays were left as back-up protection, it was not required to remove or replace them since they already supported IEC 61850-9-2LE process bus. This means that upgrade of substations can be cost-efficiently managed with centralized protection and control devices.

VII. CONCLUSION

A centralized protection and control 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 as a 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 centralized protection and control system unlock benefits that could not be achieved before using multifunctional protective relays. Awareness of your overall system in a convenient location, being able to update/upgrade your system with minimum disruption, and having a more reliable and cost effective electrical system are few of the benefits why every customer should consider the deployment of a CPC system in critical areas.

New technology brings new opportunities and new challenges and that is why is very important to understand the limitations and considerations when implementing a CPC system. In this paper we have described, the possible applications, redundancy considerations, testing and maintenance requirements that a centralized protection and control system would need.

VIII. References

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