Advancements in Centralized Protection and Control Within a Substation

Working Group on Centralized Substation Protection and Control, IEEE Power System Relaying Committee

***Abstract*—Smart-grid development focusing on renewable energy sources is changing power system characteristics at a time when utilities are also focusing on improving customer service and resiliency of the grid. All of these activities require renewed attention to safety, protection, and control strategies that take advantage of available technologies while promoting newer ones. To explore better utilization of present technologies and chart the development of next generation protection and control technologies, the IEEE Power System Relaying Committee formed a working group to prepare a report describing and analyzing state-of-the-art and emerging technologies for centralized protection and control within a substation. When appropriately applied, these novel practical technologies may significantly improve the reliability of protection and control systems and the power grid. This paper reviews the key advancements in centralized protection and control systems.**

***Index Terms*—Centralized protection and control (CPC), distributed control, intelligent merging unit (IMU), merging unit (MU), process interface unit/device (PIU/PID), protection & control (P&C), remote input/output (RIO) module, sensors, smart grid.**

I. Introduction

THE power grid is being transformed into a smarter grid to better integrate renewable energy sources, and improve customer service and resiliency of the grid. Considering the new characteristics of the grid, it is necessary to take advantage of available technologies in protection and control and promote newer ones in order to ensure grid safety and reliability. The end-of-useful-life issue of protection equipment has an impact on protection system architecture requirement for easy upgrade and replacement. The IEEE Power System Relaying Committee has formed a working group to investigate state-of-the-art and emerging technologies for centralized protection and control (CPC) within a substation and chart the development of next generation protection and control technologies. This paper highlights the findings of this working group [1].

While the protection system is associated with protecting the power system from occasional abnormal operation, the control system is concerned with supporting the operation of the equipment at all times. Over the years, protection and control functions have been developed and implemented in relays. The introduction of the numerical relay in the mid-1980s and its evolution since then has created the technology for sharing information among relays and integrating relays into a substation automation and communications scheme [2], [3].

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There are two basic types of control operation: manual and automatic control. Both can be performed locally, at a control house, remotely from a centralized location, or with any combination of the three.

A reliable communications system has become more and more critical when designing protection and control systems. Utilities are investing increasingly in their dedicated telecommunications infrastructure. Secure and reliable communications are at the core of CPC systems [4].

This paper reviews the key advancements in CPC systems within a substation and also compares CPC systems with traditional systems.

II. Centralized Substation Protection & Control

There is no formal definition of centralized protection and control (CPC) in IEEE based upon the working group's survey of IEEE publications. The working group report defines a CPC system as a system comprised of a high-performance computing platform capable of providing protection, control, monitoring, communication and asset management functions by collecting the data those functions require using high-speed, time synchronized measurements within a substation [1].

The concept of centralized protection and control within a substation dates back almost to the beginning of the wide adoption of computers for business, starting with a proposal published in 1969 [5], and a pilot field installation as a proof of concept in 1972 [6], [7]. The early experimental systems focused on computer relaying in general and were limited by the technology available at the time.

A. History

Westinghouse Electric Corporation prepared a system requirements specification for a "Substation Control and Protection System" for the EPRI research project RP-1359-1 in April 1980. This specification is considered one of the earliest attempts to provide protection and control in an integrated system. The report includes line, transformer, bus, shunt reactor, out-of-step, and breaker failure protections. The specification also includes control features such as local control of voltage, VAR flow, load shedding, and automated switching sequence. Sequence of events records and oscillography along with system restoration aids such as fault location estimation are also included in the specification. Revenue metering and supervisory control and data acquisition (SCADA) interfaces were also considered. Based on this specification, the WESPAC system was developed and deployed in several substations starting in early 1980s. American Electric Power (AEP) developed an integrated modular protection and control system (IMPACS) during this period while ASEA had developed a hybrid system in conjunction with the Swedish State Power Board [8].

The 'Integrated Protection System for Rural Substations' or 'Sistema Integrado de Protección para Subestaciones Rurales' (SIPSUR) system was developed by GE and the North West Utility in Spain, Union Electrica Fenosa, in 1990 [9]. SIPSUR was a project to integrate the entire protection system for a distribution medium voltage substation in a single hardware package. The system was comprised of two incoming lines, one transformer and five distribution feeders. The highlight of this system was the concept of "CPU backup."

Ontario Hydro developed the integrated protection and control system (IPACS), which was first installed in 1992. IPACS was a computer system designed in one box panel by Ontario Hydro to do all the protection, control, monitoring, and recording for a Dual Element Spot Network (DESN) station. A DESN station is a transformer station that steps voltage down from transmission to distribution levels. Ontario Hydro (now Hydro One) has about 300 DESN stations, and an IPACS was a cost-effective method to refurbish these stations. Fifty-six IPACS systems were built and installed before the project was abandoned in 1998.

Vattenfalls Eldistribution developed a centralized protection and control system for the island of Gotland in 2000 [10]. The system was developed in collaboration with ABB, with all protection and control algorithms operating on a standard industrial computer. The system was developed starting with technology used for protection and control of HVDC substations, with AC protection algorithms added to the existing control system. Each protection and control system uses an industrial computer and I/O devices connected to the primary processor. The I/O signals are connected to the computers via a separate cabinet with terminal blocks for each computer. The first of these systems was installed in 2000, and five different systems are now in service.

B. Existing Technologies Supporting CPC

The idea of relays sharing information opens up many possibilities with the clear potential of better detection of fault conditions and improvements in protection system reliability. These possibilities can be implemented in a variety of architectures that may include a central computing unit in a substation to concentrate the information and perform protection using centralized data. A CPC system within a substation may be comprised of a (high-performance) computing platform capable of providing protection, control, monitoring, and communication - including asset management functions. Fig. 1 illustrates the evolution of the protection, control, monitoring, and communication system leading to a CPC [11].

Block 1 shows electromechanical and solid state relays. Block 2 provides data communication through a remote terminal unit (RTU) or a data concentrator. This was the beginning of a substation automation system. Block 3 shows a communication system using protocols such as distributed network protocol (DNP) and Modbus. More recently, Block 3 also represents peer-to-peer communications using generic object-oriented substation events (GOOSE) as per IEC 61850. Block 4 shows the transfer of

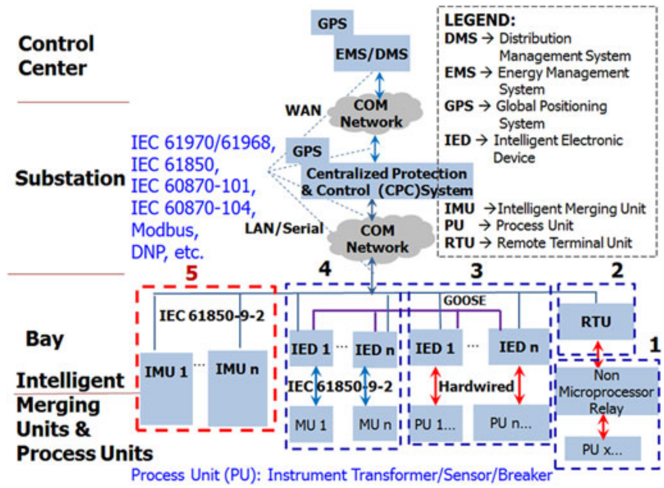

Fig. 1. Evolution of protection, control, monitoring and communication system leading to CPC [11].

digitized analog values from merging units (MUs) to intelligent electronic devices (IEDs) using IEC 61850-9-2. Block 5 shows the transfer of sampled analog values from intelligent merging units (IMUs) to CPCs as well as GOOSE messages from CPCs to IMUs, and MMS messages transferred from IMUs to the CPC using fiber optical communication.

The optical isolation between IMUs and the CPC enables the use of off-the-shelf hardware for the CPC, which is very important for the deployment of CPC. Most protection functions from distributed IEDs within a substation are integrated into the CPC. Advancement in low-cost, high-performance computing platforms and availability of standardized high-reliability communication technologies make them very attractive for the application of CPCs. The CPC architecture is driven by many factors: reduction in capital expenditure (CapEx) including the wiring, reduction in operation expenditure (OpEx) including easy replacement of hardware at the end-of-useful life [12] and seamless upgrade of firmware without any downtime, to name a few.

The MU is a device that connects to instrument transformers and/or sensors and publishes digitized analog measurements to a substation communication network that can be used by other devices. Under the IEC 61850 standard, a MU only publishes sampled values and can interface with traditional instrument transformers, as well as non-conventional instrument transformers like Rogowski coils [13] and electronic voltage dividers. The remote I/O module (RIO) is intended to be the status and control interface for primary system equipment such as circuit breakers, transformers, and isolators. RIOs under IEC 61850 may support only GOOSE publish and subscribe communications, or may also support MMS client and server communications.

The process interface unit/device (PIU/PID) combines a MU and a RIO into one device. The PIU/PID can publish analog values and equipment status, and accept control commands for equipment operation. From an installation standpoint, a PIU/PID can make more sense in many applications than separate MUs and RIOs.

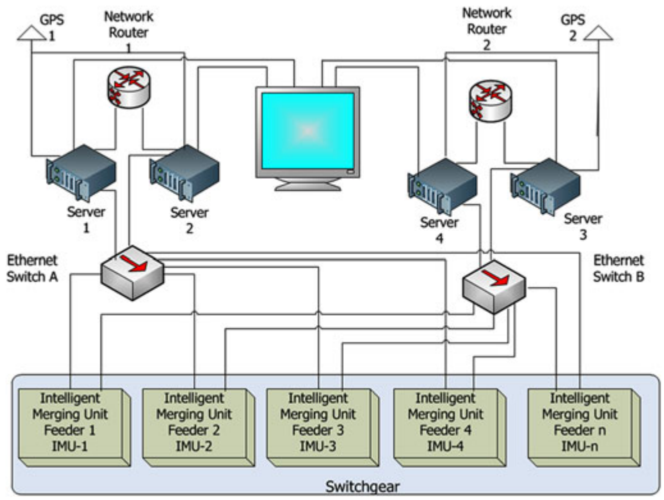

Fig. 2. Server based CPC system [11].

The IMU shown in Fig. 1 adds RMS-based (simple to derive from sampled values) overcurrent and overvoltage back-up protection functions in a PIU/PID to prevent damage to the related primary equipment in the event of total communication failure between the IMU and CPC during abnormal system conditions.

Communication architecture for CPC requires reliable and secure communications infrastructure. There are a number of existing standard redundant protocols used in substation Ethernet LANs that provide network fault detection, isolation, and restoration for resiliency including IEC 62439-1 Spanning Tree Algorithm (STA) using Spanning Tree Protocol (STP), Rapid Spanning Tree Protocol (RSTP) and Media Redundancy Protocol (MRP) to name a few. Other emerging redundancy protocols without fault detection but that help provide zero (0) second recovery time and zero-packet loss include IEC 62439-3 protocols called High-availability Seamless Redundancy (HSR) and Parallel Redundancy Protocol (PRP). According to the IEC 61850 Ed 2, the applications using the process bus Sampled Value (SV) and GOOSE messaging require bump-less calculations and low loss communication that can be achieved in HSR/PRP networks. Other examples of future potential technologies/protocols are Time Sensitive Networks (TSN) based on IEEE 802.1 series with Deterministic Ethernet (DE); Software Defined Network (SDN) based on IEEE projects P1903 and 802.1CF; etc.

A computing platform based on server technologies for the CPC is shown in Fig. 2 [11]. Time synchronization between the substation protection and control system (servers in Fig. 2) and IMUs is achieved using precision time protocol (PTP) as per IEEE 1588-2008 (v2).

This architecture also harmonizes operational technology and information technology requirements and can support the implementation of advanced control and monitoring functions like state estimation, power quality (PQ), voltage-VAR optimization (VVO) and conservation voltage reduction (CVR), fault location, isolation and service restoration (FLISR/FDIR), and demand response (DR), while also providing asset management information [11].

C. Comparison of Traditional and CPC Approach

Table I shows the comparison between the traditional and the CPC approaches. The traditional approach refers to all possible technologies—electromechanical, solid-state and IED or a combination of the above technologies applied on a per bay basis. The CPC approach is defined at the beginning of Section II. It is important to note that a change in paradigm is necessary in the design, testing, operation, and maintenance of the CPC system.

III. CPC Architecture, Reliability, Cost, and Testing

The WG K15 report [1] discusses possible architectures of a CPC. The reliability and cost of various architectures are compared, along with a discussion on testing and maintenance of a CPC.

A. Architecture

The WG K15 report discusses five possible architectures of a CPC. Fig. 3 shows one of the architectures (5a), ranked highest in the report, where IMUs at the process level are interfaced with CPCs over process bus Ethernet LAN. PIU/PID or a combination of MU and RIO can also be used in place of the IMU. Redundant current or voltage transformer secondary windings and switchgear I/Os are connected to completely redundant IMUs and CPCs. In addition, IEC 62439-3 proposes network-level redundancy architectures with cross connections to enhance system reliability.

B. Reliabilty and Cost

The reliability and availability of the possible CPC architectures are evaluated in the report. Several network topologies such as Cascade, Ring, Star-ring, and Redundant-ring can be implemented. As reported in [14], redundant-ring provides the highest reliability, while the cascade configuration provides the least reliability.

The Ring configuration is selected for reliability evaluation and comparison as it provides the average reliability and cost among all possible configurations. Time synchronization can be employed using different techniques—LAN-based time synchronization as described in IEEE 1588 shows highest reliability [14].

Reliability is represented as a mean time to failure (MTTF). The MTTF values of various protection devices for reliability calculations are presented in [1]. Using these individual component values, the MTTF and availability of various CPC architectures are calculated, assuming: 1) the reliability of the copper cables is one, 2) instrument transformers and circuit breakers are not part of the reliability calculation, 3) the protection element implemented in the CPC requires access to various data provided by a combination of 16 devices including IEDs and MUs, and 4) the process bus or the station bus includes four Ethernet switches connected in a Ring configuration.

Table II shows the availability and MTTF of possible architectures as introduced in [1]. As shown, Architecture 5a has the highest rank while Option 2 of Architecture 4 has the lowest rank.

TABLE I
COMPARISON BETWEEN TRADITIONAL AND CPC APPROACHES

Feature	Traditional Approach	CPC Approach
Relay Asset Management	Many relays need to be separately identified, specified, configured, tested, and maintained along with separate records for each device.	A limited number of devices need to be identified, specified, configured, tested, and maintained along with separate records for each device.
Device Management	Each protection IED in a substation typically has numerous configuration choices to enable various features. Firmware versions must be tracked and updated periodically.	A reduced count of devices makes management easier and also the feature set is reduced and limited compared to traditional methods.
Maintenance	Routine maintenance can be frequent and requires experienced and well-trained staff along with expensive calibrated testing equipment. P&C IED maintenance per bay is easily achieved due to separate IEDs per bay.	Limited maintenance is required as the entire substation P&C system uses fewer physical devices, though experienced and well-trained staff are still required for maintenance. More robust and reliable systems can be engineered at a lower cost depending on substation size. P&C IED per bay does not exist, and hence independent per bay maintenance is an avoidable challenge.
Security	Multitude of protection IEDs provides more access points for cyber threats.	Very limited number of access points which can also be managed better.
Interoperability	Disparate protocols and difficult to standardize. Modifications to the substation automation system can be complicated.	Capitalizes mainly on the IEC 61850 technology and can be more easily adopted than the distributed protection IED model. User requirement of engineering knowledge such as "GOOSE" messaging configuration between IEDs will not be required as it will be internal to the system.
Substation Master Interface	Depending upon the technology, the protection IED may have no communication interface with an RTU or data concentrator. More recent technologies have protection IEDs tightly integrated into a substation automation system to transfer data in and out of the substation with limited intelligence.	The CPC becomes the "Gatekeeper" of Device Dynamic Models. Relays are ubiquitous. This provides a master intelligent node for substation-to-substation interaction. Collected data is reduced to information via the dynamic state estimation. Information is exchanged between substations, with control center and downstream intelligent devices versus raw data; tremendous reduction in communication needs.

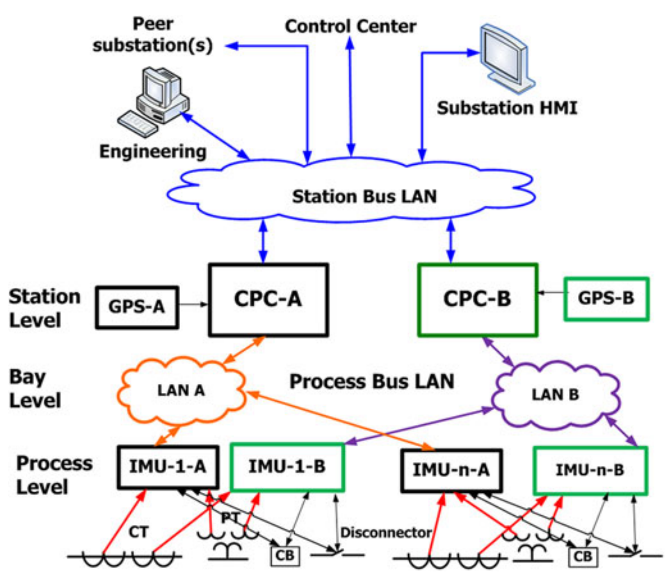

Fig. 3. One CPC architecture in a substation (Architecture 5a, [1]).

TABLE II
PERFORMANCE EVALUATION OF DIFFERENT ARCHITECTURES

	Availability	MTTF (Yrs)	Rank
Architecture 1	0.99930983	3.9	4
Architecture 2	0.999266029	3.7	5
Architecture 3	0.999474115	5.0	2
Architecture 4 (Option 1)	0.99930983	3.9	4
Architecture 4 (Option 2)	0.998866402	2.4	6
Architecture 5	0.999342683	4.0	3
Architecture 5a	0.999999524	5.9	1

TABLE III
COST EVALUATION OF DIFFERENT ARCHITECTURES

	Cost	Cost Rank	Reliability Rank
Architecture 3	$2 \times C_{CPC} + 72{,}000$	1	2
Architecture 5	$2 \times C_{CPC} + 76{,}000$	2	3
Architecture 5a	$2 \times C_{CPC} + 150{,}000$	3	1

Architectures that employ a CPC for the primary protection of substation apparatus are considered in the cost analysis, and are limited to Architectures 3, 5, and 5a, where sampled values are transmitted by merging units to the CPC either directly or through a switched network. An approximate approach is adopted in this analysis by considering the cost of the main equipment. In practice, accurate cost analysis should be done including the cost of installation, commissioning, and testing.

Table III shows the cost of the possible architectures studied here. C_{CPC} is the cost (in USD) of a CPC. While providing highest reliability, Architecture 5a is also the most expensive. The costs of Architectures 3 and 5 are very close while Architecture 3 is more reliable with a MTTF of five years as compared to four years for Architecture 5.

C. Testing and Maintenance

The CPC concept does not change the general need for testing protection and control systems, but this concept can change the specific requirements for, or methods of, testing. The biggest change is that the CPC separates the application controller (and therefore, application program) from the physical I/O devices. This allows for separate testing of the CPC and the I/O devices, and sets different testing goals for the CPC and the I/O devices. This modular nature also allows for comparisons that can change many current testing activities into future self-monitoring activities: comparison between I/O signals and measurement in one CPC and comparisons of operating decisions between two CPCs [1].

There are, in general, four different types of testing required or typically performed on protection and control products and installations: 1) Acceptance, 2) Commissioning, 3) Maintenance, and 4) Troubleshooting.

The implementation of the CPC concept where the protection and control system is integrated into a virtual controller communicating to distributed physical I/O, impacts the methods used for all of these testing types.

IV. Demonstration Project

A software-based substation protection, automation, and control system (PACS), iSAS, by LYSIS LLC in Russia is in trial operation at the 110/10 kV *Olympic* substation in the town of Surgut in northwest Siberia [15]. The substation is owned by Russian Distribution System Operator (DSO) *Tumenenergo*. The philosophy of iSAS is based on PAC function element implementation as per IEC 61850 logical nodes (LN). The software modules were developed independent of particular hardware and could be placed in dedicated IEDs as well as in one powerful computer.

A. Overview of iSAS Project

The *Olympic* substation has two power transformers, two incoming 110 kV overhead power lines, and 40 feeders connected to four 10 kV busbars. The goals of the project are to 1) search for an optimal system architecture, as well as methods and approaches for iSAS lifecycle management, 2) research and analyze system characteristics and behavior under real-life conditions, 3) provide technical and economic analysis at all stages of the system lifecycle, 4) provide reliability analysis and 5) quantify the advantages and disadvantages of the PAC system, for wider use by the DSO.

The PACS has to perform the full functionality of protection, control, and metering systems for the entire substation according to regulatory standards and customer requirements. The project has five phases: 1) Design, 2) Procurement, installation and testing, 3) Trial operation for one year, 4) Analysis of regulators requirements, rules, and standards, and proposing amendments in these documents for homologation of software-based PAC systems in the Russian market, and 5) Certification of measuring method for process bus-based systems with separate measuring (process interfacing devices, PID) and calculation (IEDs) parts.

During trial operation, the existing system and the new system will work in parallel and the iSAS will only record issuing of control commands without directly controlling primary equipment. A decision to switch over to the new PAC system for real control of the substation will be made based on results of the trial operation. LYSYS LLC has completed the first two phases and the system is in trial operation.

B. iSAS PACS Architecture

The core of the PACS is the iSAS software suite. The logical structure of the system is independent of its physical implementation. An optimization was done to define the most suitable and effective physical system structure for this particular substation. PAC function availability and the maximum affordable repairing rate were applied as system quality metrics. Normative values of system metrics were taken from the conventional PAC system of the same substation. The customer's requirements, such as placing revenue metering and PQ functionality into a dedicated server with its separate cabinet, were taken into consideration. Optimization studies resulted in the system structure shown in Fig. 4.

Protection: The protection system provided for the two 110 kV power lines (including differential and distance functions), 110 kV busbar protection, and 110/10 kV transformer protection that includes automatic voltage regulation. The 10 kV transformer side, consisting of bus-bars and feeders, has implemented overcurrent protection with bus-blocking logic, under frequency load shedding, and under frequency load restoration.

Control: The control system can automatically perform predefined sequences of operations including changes in protection setting and control algorithms. All control functions are accessible to the operator via local HMIs as well as through local and remote SCADA using a virtual telecontrol gateway.

Revenue Metering: A revenue metering system is implemented in compliance with energy market rules and is integrated into the existing DSO billing system.

Fault Location and Power Quality (PQ): The fault location function is provided for the 110 kV power lines with an error goal of $\pm 5\%$ of line length. The PAC system provides a comprehensive record of PQ parameters at the four 10 kV system busbars as per IEC 61000-4-30 and IEC 61000-4-7.

Monitoring and Recording: The monitoring and recording subsystem has two components: alarm and event management (AEM) and transient recording. AEM detects the alarm state of monitored parameters, and provides alarm and archived event lists. Alarm state detection is based on a predefined configuration that includes a logical scheme and activation conditions. Some custom LNs were developed to model AEM functions as per IEC 61850. The alarm and event messages are logged and accessed by a standard IEC 61850 Log service. IEC 61850-9-2LE sampled values data streams (80 and 256 sample/cycle) are recorded. The function records in COMTRADE format as per IEC 60255-24:2013/IEEE Std. C37.111-2013.

The optimized PACS structure has five layers as shown in Fig. 4.

Layer 1: The first layer is the interface to primary equipment using PIDs. The current and voltage transformers for protection and metering of 110 kV lines are connected to the Bay Main PID (BMPID). The BMPID was installed into a cabinet near the line AIS CB drive's cubicle and include control interfaces of switching devices. The BMPID has a modular structure and has two optical Ethernet interfaces connected to a PRP redundant network. The BMPID implements IEC 61850 logical nodes XSWI, XCBR, TCTR, TVTR, and the other configurable sensor models. The BMPID supports both IEC 61850 GOOSE and sampled values protocols. Time synchronization of the BMPID is accomplished with the IEEE 1588v2 protocol. There are redundant 220 V AC/DC power supplies installed into devices. Redundant BackUp PIDs for current and voltage for protection and circuit breaker control and monitoring are placed in separate cabinets in the switchyard. Switchgear emulators have been installed in the BMPID and BackUp PID cabinets. 10 kV PIDs, mounted in switchgear cubicles, are combined devices

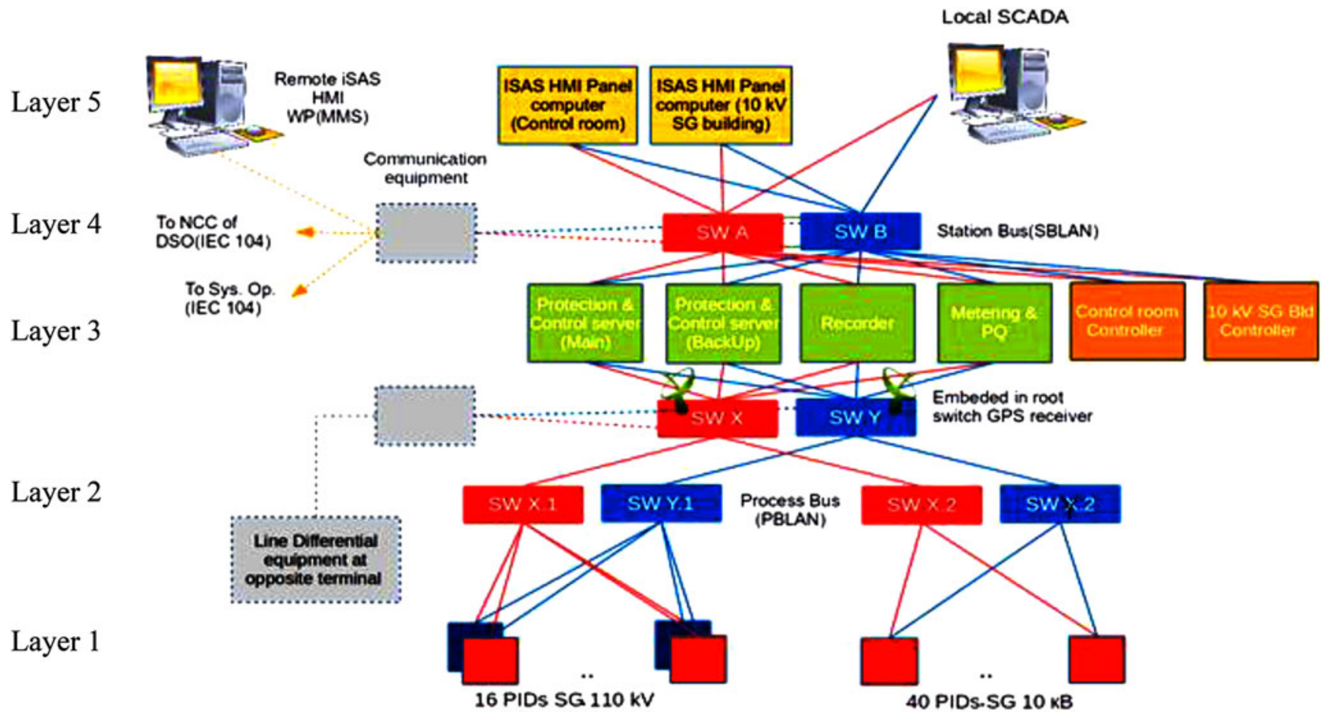

Fig. 4. The PACS structure of 110/10 kV "Olympic" substation in Northwest Siberia, Russia [15].

and provide measurement of currents and control of bay circuit breaker, earth switch, and interlocking arrangements. The 10 kV PID also provides information from arc sensors. These devices do not have redundancy except for the 10 kV incomers and tie breakers.

Layer 2: Layer 2 is a process bus LAN (PBLAN) which uses double star topology with PRP support, and all devices connected to PBLAN are double attached nodes. The PIDs have 2x100BASE-FX interfaces, while data processing devices are connected to optical PBLAN with a redundant 1000BASE-SX interface. Root switches of PBLAN double stars have embedded PTP servers and play a role of precision timing source for PIDs and other system equipment using the GLONASS satellite system.

Layer 3: Layer 3 of the system is composed of computational devices that receive and process input data, make decisions, and perform actions. Based on optimization results, customer requirements, and chosen hardware capabilities, the complete PACS functionality has been divided among four powerful servers: the main and backup protection and control (P&C) servers, the metering and power quality server, and the substation-scale faults and transient events recorder server. These servers were installed into two cabinets, with the main and backup P&C servers mounted separately. The cabinets are installed in an existing communication equipment room with strong immunity from electromagnetic influences.

The servers are connected to both LANs as double attached nodes. The servers support the PRPs to communicate with field PIDs through PBLAN. RSTP is used to connect to the substation bus ring. Red Hat Linux OS with real-time extensions and iSAS applications are installed on the servers. Complete protection and control functionality is performed by 2546 logical nodes. The nodes have been distributed between ten virtual IEDs (vIEDs) which are similar to physical IEDs with their own MMS servers and work asynchronously with the other vIEDs, even if they are placed in the same computational hardware.

Layer 4: A Station Bus LAN (SBLAN) is the fourth layer of the system. The SBLAN is formed by an RSTP ring based on two SBLAN switches. The SBLAN uses the same trunk cables as the PBLAN in some places, with different fibers.

Main communication services use IEC 61850-8-1 MMS reporting, logs retrieval, and controlling services. MMS reports are created and sent by IEDs to HMI and local SCADA devices. IEC 60870-5-104 protocol is used to communicate with the DSO's National Control Center (NCC) and with the system operator branch office. The iSAS software incorporates the special object that converts the IEC 61850 data into IEC 60870-5-104 protocol based on information provided in IEC 61850-80-1. Hypertext transfer protocol based software is used for metering data transfer to the DSO's billing system.

Layer 5: The fifth layer includes the operator's HMIs and NCC as well as other external interfaces. The software installed in the operator panel is a part of the iSAS suite and provides a visualization tool based on a mosaic-like concept using IEC 61850 MMS client. Each small piece of the interface, such as a lamp or button, is an element of the complete picture; that has inputs, outputs, and parameters.

The DSO office has one remote operator workstation with iSAS HMI software with same capabilities as panels in the substation. One more interface is provided only for monitoring data exchange with the system operator branch office. Another interface is available for the communication with NCC of DSO with both monitoring and control of data exchange. Both interfaces use the IEC 60870-5-104 protocol.

V. Emerging and Future Applications

We discuss here some of the emerging and future applications that are either not possible or difficult to implement within a single IED in a substation, but are possible when data from many IEDs, and in some cases, where data from neighboring substations, are used. These features can be implemented at the substation level within a CPC. More details about these applications are discussed in the WG K15 report [1].

A. Incipient Fault Detection

Incipient fault detection refers to detection of faults during their beginning stage so that remedial actions may be taken to avoid catastrophic failures. Examples include loose or noisy primary connections, fuse failures, impending arrester or insulator failures, capacitor can failures, and sporadic foreign interference identification. Incipient splice failure detection in underground cables is already available, and similar techniques are being field tested to be able to detect incipient arrester failure as well as incipient failures of capacitor cans, power transformers, and VTs. Bushing failures have traditionally been predicted through manual testing. Field tests are currently underway to gather data for the in-service predictive actions for impending incidents and conditions [16], [17].

B. State Estimation-Based Protection Schemes

The dynamic state estimation (DSE) based protection method (a.k.a. setting-less protection) requires a monitoring system for the component under protection that continuously measures terminal data (such as the terminal voltage magnitude and angle, the frequency, and the rate of frequency change), and other variables such as temperature, speed, etc., as appropriate, and component status data such as the tap setting, breaker status, etc. The dynamic state estimation processes these measurements and determines whether the measurements are consistent with the model of the protection zone, i.e., whether the measured data "fit" the model. A good fit between the measurements and the model equations indicates normalcy and also provides an independent verification of the model of the protection zone [18].

An overall generic demonstration of the setting-less protection approach is shown in Fig. 5. The DSE-based protection requires threshold settings similar to differential protection and no coordination with other protection functions. The thresholds can be quite refined and expressed in statistical terms or in terms of probability that the measurements do not fit the model of the protection zone. This type of threshold is implemented within the DSE and provides a reliable way to detect internal faults or internal abnormalities of the protection zone. The more accurate the instrumentation is, the sharper the detection of the fault condition becomes.

Another advantage of the DSE-based protective relay is that the relay continuously monitors the validity of the protection zone model. It can then make this model available to other applications. Since each application may need the model in a specific form and format, a filter can be employed to transform the model from the DSE-based protective relay format to the specific format of the specific application.

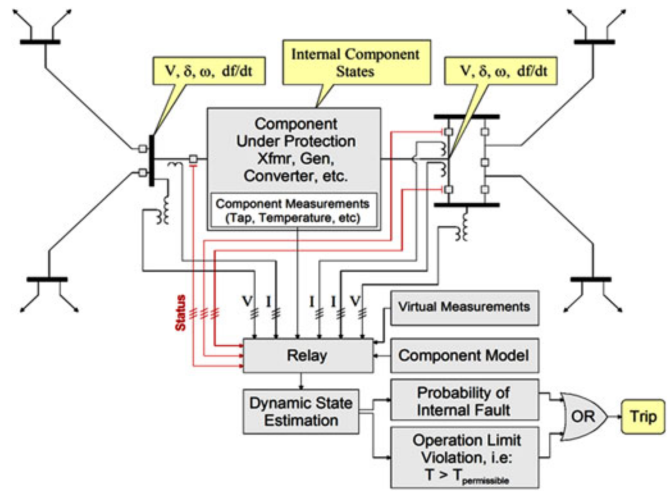

Fig. 5. DSE-based protection embedded in CPC.

C. Pattern Classification-Based Protection Schemes

Pattern classification essentially involves selecting representative features from a certain dataset and mapping the selected feature(s) to class(es). The idea behind feature selection is to retain the optimum characteristics necessary for the recognition process and reduce the dimensionality of the measurement space, so effective and easily computable algorithms/methods can be devised for classification. Pattern classification employs well-known heuristic methods such as neural network and fuzzy logic that look at the selected features from input signals, and classify the features into domains that differentiate between faulted states and normal states, and also allow classification of fault types and other fault properties such as location, fault resistance, etc. [19].

The power system can benefit from a global layer of knowledge that oversees the protection and breaker operation. This knowledge will either corroborate the protection action or invalidate it. This knowledge can result in averting or significantly alleviating a potential blackout. To work toward such a system, disturbance signatures from phasor measurement units (PMUs) can be utilized. Pattern recognition can be very useful to classify disturbances using features extracted from disturbance files as reported in [20] using real data from four PMUs.

VI. Conclusion

Advancements in centralized protection and control systems, within a substation, have been reviewed in this paper. The evolution of protection and control systems with specific emphasis on CPC has been presented. It has been shown that existing technologies support the deployment of CPC as demonstrated by the referenced pilot (trial) project. Promising emerging and future technologies that can exploit the CPC approach have also been briefly reviewed. These novel technologies, when appropriately applied, significantly improve the reliability of protection and control systems and the power grid at an affordable cost with enhanced capability and maintainability.

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