VIABILITY ASSESSMENT FOR CENTRALIZED PROTECTION AND CONTROL SYSTEM ARCHITECTURES IN MV SUBSTATIONS

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ABSTRACT

This paper performs a viability assessment of the centralized substation protection and control (CPC) system in a number of architectures, using a modified algorithm of the Block-Layer reliability technique and a specific objective cost function. This paper describes the concept of centralized protection in substations and a number of involved architectures. Moreover, it describes the modified algorithm for reliability analysis and its important considerations. In this study, seven cases are simulated in order to: (i) assess substation protection and control architectures; (ii) calculate the reliability indices at the delivery points; and (iii) quantify the total costs for each case. These cases consist of traditional, centralized and hybrid architectures, being the latter a combination of the others. Results show that the centralized approaches are significantly more reliable than the traditional and cost-benefit increase with the increase of number of process bays in the substation. Furthermore, the hybrid architectures show a compromise between cost and system availability in comparison with the others. The simulations were performed considering a 40-year project life cycle.

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.

Reliability has long emerged as an important part of power system assessment. Reliability indices are used to quantify levels of availability [4] and, in combination with cost analyses, they can be employed to measure cost-benefit and plot cost-reliability curves. For an accurate reliability assessment, it is crucial to set an appropriate model for the involved components and to have on reach an efficient method to simulate the systems under focus, thus acknowledging intrinsic and relevant features.

In this context, this paper performs a viability assessment based on two sets of calculations focusing on reliability and costs. The first investigates indices the possible network architectures and their impact to the process level through equipment-centered reliability from the perspective of three types process bays (busbar, feeder and transformer). The latter translates these architectures into monetary figures.

This paper consists of five sections. After the introduction, the methodology describes the centralized substation protection and control, the reliability tool and cost functions under focus. The third section describes the test substation and its studied cases as well as the employed parameters. The fourth section summarizes and explains the results from the viability analyses. The last section contains the conclusion.

METHODOLOGY

This section describes the centralized substation protection and control system. It also details the techniques involved in the reliability and economic assessments of this study.

Centralized Protection and Control System

The centralized protection and control system is characterized as a “computing platform capable of providing protection, control, monitoring, communication and asset management functions” at high-speed time-stamped performance [3]. Further, the CPC removes partially or entirely the functions from the bay level to the station level, *i.e.*, protection and control operate through the Ethernet network in the station computing platform. This was facilitated with the standardization in the form of protocols, such as the IEC 61850, and technological improvements in the communication networks. However, the CPC system is not yet formally defined [3]. This concept, notwithstanding, is based on the inclusion of high-speed communication to substation protection and control, thus improving reliability and condensing the substation secondary equipment.

The traditional substation protection and control is comprised of IEDs that receive signal direct from the instrument transformers (or sensors) at the bay level. The IEDs are then connected via Ethernet network to a substation gateway, to adjacent substations and to the SCADA system, using the IEC 61850-9-2. In the CPC system, the CPC unit, where protection and control are performed, is otherwise not directly connected to instrument devices. The CPC is connected to the Ethernet network and the intelligent merging units (IMU) acquire signal from the sensors in the process bay. In the context of this paper, the role of the IMU is to perform traditional merging unit functions, include basic protection and control functionality and serve as backup to the CPC unit. In addition, high-performance computing platforms, sensors (instead of instrument transformers) and other recently technological improvements are included to enhance the CPC system performance.

A CPC system can consist of a number of communication media, particularly involving the type of media (copper wiring, optical fiber), the level of redundancy and to which devices it must be directly connected. In addition, it can consist of a hybrid architecture, in which it combines decentralized and centralized systems. Fig. 1 shows a general possibility of the hybrid secondary system architecture. Other variations and approaches for architecture are detailed in [3] and [5]. ABB has installed a pilot project in Noormarkku, Western Finland, where a CPC unit was employed to one primary substation in order to verify the operability of this novel system [5].

Adjusted Block-Layer Reliability Method

The Block-Layer reliability method was developed and described in [6]. Its principles consist of dividing any distribution network into at least four blocks of components and three layers. These blocks and layers are associated according to their functions, geographical location and criticality to the system. The method enables the estimation of partial and system reliability indices to the distribution delivery points and acknowledges the existence of load-influencing and equipment-influencing failures that affect the total network cost function and availability. An adjusted version of this reliability assessment tool can be extended to substation protection and control systems. However, it is important to highlight that this study will focus on quantifying failure in the secondary equipment to the delivery point, according to primary equipment bay (busbar, feeder and transformer bays).

Fig.1 schematizes the adjusted Block-Layer reliability method applied to substation protection and control systems. It includes four layers (process, bay, station and inter-substation layers) and three interfaces. The IEDs concentrate the measurements from the instrument transformers (current and voltage transformers), *i.e.*, include merging units, and emit signals to the circuit breaker. The schematic includes the main set of components (namely block), while other smaller components are added to their related main block.

The Process layer involves the instrument transformers that acquire measurements to the protection and control system. This layer does not include any other primary equipment. These are already included to the distribution system analysis and this study maintains its independency from the primary equipment. The Bay layer includes the IEDs at each protection bay. In this study, we consider one busbar bay, ten feeder bays and one transformer bay. The Station layer comprises the communication network (Ethernet) and the CPC system. This layer supports the horizontal and vertical communication in the substation. In addition, the inter-substation layer groups the communication connections between this and adjacent substations. In this paper, we neglect failure propagation from and to adjacent substations.

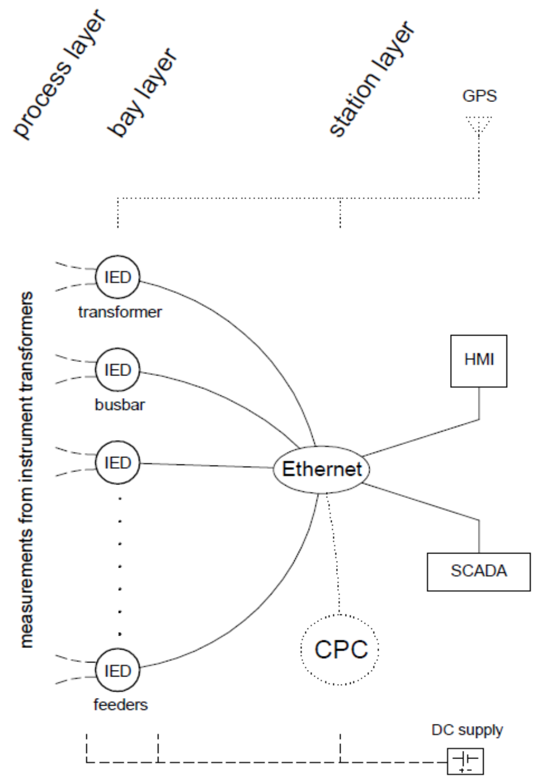

Fig. 1. Schematic of the Block-layer reliability technique adjusted to secondary substation systems connected to the process level (left) and to adjacent substations (right). Time-synchronization sources (GPS) and DC supplies are parallel components, crossing several layers, consequently they are not included to any layer.

Moreover, the interfaces group the interconnections (optical fibers and wiring) and interfacing smaller components used to connect different communication protocols to merging units and IEDs. It also includes the human-machine interface (HMI) and the SCADA as a generalization to all possible interfaces between the operator and the system. In parallel, the model includes time-synchronizing source (represented by the GPS) and DC supply. In case of failure in one of these, this method interprets this as common-mode events.

Cost Functions

The economic part of the viability assessment includes an objective cost function schematized in Fig. 2. This function has four addends and two parts: a capital (investment and renewal) and an operational (repair and scheduled maintenance) part. The investment of components (C_{inv}) happens at the base year and should be reviewed after the end of their life cycle, represented by cost of renewal (C_{ren}). The cost of repair ($C_{m.rep}$) quantifies the cost to repair all failing equipment during the project period and the cost of scheduled maintenance ($C_{m.sch}$) quantifies the routine maintenance in all substation.

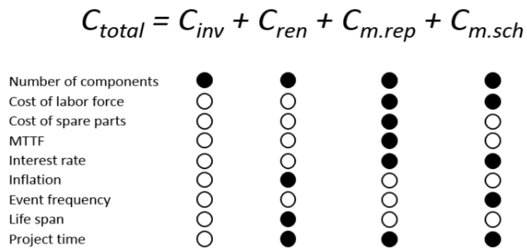

Fig. 2. The objective cost function in this study and its components in which, from left to right, stand for: investment, cost of renewal, cost of repair and cost of scheduled maintenance. Below it, the considered parameters for each component are marked in full dots, if present, and in blank, if not present.

Equation 1 transcribes the components of the total project cost (C_{total}) into more details. It considers the number of components of each project and the year until the project time ends. The subindices "*i*" and "*n*" stand for, respectively, the year (from the base year 0), and the number of components. It is stated as:

$$C_{total} = \sum_{i=0}^{P}\sum_{n=1}^{N}\left(c_{inv} + k_{inf_i} c_{ren} + k_{inf_i} U.c_{m.rep} + k_{int_i} T.c_{m.sch}\right)\Big|_n \qquad (1)$$

In which:

c_{inv} investment [€];
$c_{m.rep}$ cost of spare parts and labor force [€/h-a];
$c_{m.sch}$ cost of labor force [€/h-a];
c_{ren} equipment renewal cost [€];
C_{total} total project cost in the considered period [€];
k_{inf} discount factor related to inflation at the *i*th year;
k_{int} discount factor related to interests at the *i*th year;
N total number of components;
P project time [a];
T component life cycle [h/a];
U unavailability at the *i*th year [h/a].

Equation 1 differs from the previous approaches, [6], [7], [8], for the reason that this analysis does not include primary equipment from the process level. In other words, it does not account for load growth nor power and energy losses in the system. With this, the equation delivers analytically, nevertheless, an equipment-oriented instead of a load-centered assessment.

SIMULATION

The simulation consists of seven cases. They comprise traditional, centralized and hybrid secondary system architectures. This paper interprets as traditional architecture a generalized solution traditionally used in substations in which each bay protection and control functionality is performed at bay level in its respective IED. The IEDs are connected to the Ethernet network that provides communication between these, the HMIs, SCADA and the other substations. The centralized approach, conversely, which is the focus of this study, embodies IMUs (replacing IEDs) and CPC units directly connected to the Ethernet network. In this approach, all protection and control functionality are performed in the CPC and the basic protection of each bay in the respective IMU. The hybrid architecture is a superposition of both previous approaches and reflects the scenario in which a substation is retrofitted to accommodate a CPC unit.

Fig.3 details the test substation used in this study. It divided into: one HV/MV transformer bay, protected by the RET relay; one busbar bay, protected by the REB relay; and ten MV feeder bays, each protected by one REF relay. The transformer is connected to the upstream network specified as grid, while the feeders follow towards the downstream networks that, in this study, is denominated as the delivery point.

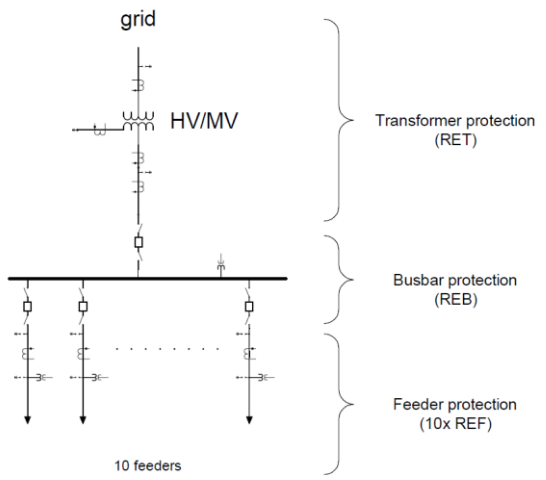

Fig. 3. The diagram details the test substation with its one transformer bay (RET relay), ten feeder bays (REF relay) and a busbar bay (REB relay).

The seven studied cases simulated in this research are described as:

- Case 1: traditional architecture, single Ethernet network, IEDs and instrument transformers;
- Case 2: traditional architecture, redundant Ethernet network, IEDs and instrument transformers;
- Case 3: traditional architecture, redundant Ethernet network, IEDs and instrument transformers (not redundant), fully redundant (n-1 criterion);
- Case 4: centralized architecture, single Ethernet network, IMUs, sensors and single CPC system;
- Case 5: centralized architecture, redundant Ethernet network, IMUs, sensors and redundant CPC system;
- Case 6: centralized architecture, redundant Ethernet network, IMUs, sensors (redundant) and redundant CPC system, fully redundant (n-1 criterion);
- Case 7: hybrid architecture, redundant Ethernet network, IEDs with merging units functionality,

instrument transformers and single CPC system.

Table I shows the list of the considered components and systems employed in this study. It compiles the mean time to repair (MTTR), in hours; the mean time to failure (MTTF) in years; the component availability (A) in percentage; and component price for investment and renewal, both given in euros per unit. This study considers a 20-year life cycle for all components. These figures are fundamentally based on [5] and [9] and can vary depending on the component manufacturer. Table II exhibits the number of type of components utilized in each studied case, listed from 1 to 7. These cases are arranged as in Fig.1.

TABLE I. Component parameters.

Component	MTTR [h]	MTTF [a]	A [%]	price (inv.) [€/u]	price (ren.) [€/u]
Current/voltage transformer	48	100	99.9945	3 000	1 000
Current/voltage sensor	24	500	99.9995	1 000	1 000
Copper wiring	24	100	99.9972	200	200
Opt. fiber (short)	24	500	99.9995	300	300
Opt. fiber (long)	24	500	99.9995	1 000	1 000
IMU	24	100	99.9972	3 000	3 000
IED	24	100	99.9972	6 000	6 000
Ethernet network	24	50	99.9945	13 900	7 000
CPC unit	24	100	99.9972	20 000	10 000
DC supply	24	100	99.9972	20 000	20 000

Component pricing is estimated based on the Finnish regulation model in order to provide input for the economic assessment [9]. Moreover, the project time is 40 years, inflation is 1 % and interest rate 6 %. These values are widely accepted in the context of electrical systems in Finland [7].

TABLE II. Quantity of components in each simulated case.

Component	1	2	3	4	5	6	7
Current/voltage sensor	0	0	0	27	27	54	0
Current/voltage transformer	27	27	27	0	0	0	27
Copper wiring	27	27	54	0	0	0	27
Opt. fiber (short)	0	0	0	29	31	56	2
Opt. fiber (long)	12	24	48	12	24	48	24
IMU	0	0	0	12	12	24	0
IED	12	12	24	0	0	0	12
Ethernet network	1	2	2	1	2	2	2
CPC unit	0	0	0	1	2	2	1
DC supply	1	1	2	1	1	2	1

The redundant Ethernet networks are connected according to the parallel redundancy protocol (PRP) [3]. The centralized and hybrid cases utilize sensors instead of instrument transformers. A failure in synchronization can lead to the collapse of the protection and control apparatus; however, this simulation neglects this (the effect is the same for all cases, for all of them have one time-synchronization system).

RESULTS & DISCUSSION

The results from the reliability part of the assessment are distributed into Tables III and IV, while the economic part of the assessment to Table IV and Fig. 4.

Results

Table III resumes results for each tested case, according to busbar, feeder and transformer bays. The reliability indices mean time to failure (*MTTF*) and unavailability (*U*) are given in years and in minutes per year, respectively. These values show the effect of bay protection on reliability at the process level.

TABLE III. Protection mean time to failure and unavailability at the feeder, transformer and busbar bays.

Cases	Feeder Bay		Transformer Bay		Busbar bay	
	MTTF [a]	*U* [min/a]	*MTTF* [a]	*U* [min/a]	*MTTF* [a]	*U* [min/a]
1	22.73	77.76	6.58	319.65	2.43	880.96
2	23.81	74.61	6.67	316.50	2.44	877.81
3	31.25	60.48	7.14	302.37	2.50	863.68
4	124.97	11.52	11.90	221.74	4.17	633.43
5	125.00	11.53	11.90	221.74	4.17	633.43
6	<<< P	0.00	<<< P	0.09	<<< P	0.76
7	31.25	60.48	7.14	302.37	2.50	863.68

<<< P indicates values manifold higher than the project time

Table IV complements Table III. It shows the equivalent effect of failure in the protection and control system on the distribution points and the project cost. The mean time to failure (*MTTFt*) measures the time in year in which a failure in the secondary system is propagated to the delivery points, while the mean time to failure (*MTTFn*) measures the effect of the communication network. The probability (*Prob*) quantifies the chance that a fault in a bay is cleared by the protection of an adjacent bay in this substation. The capital cost (C_{cap}) and the operational cost (C_{op}) are expressed in euros.

TABLE IV. Reliability indices from total protection failure to delivery points, capital and operational costs.

Case	*MTTFt* [a]	*MTTFn* [a]	*Prob*	C_{cap} [€]	C_{op} [€]
1	99.19	45.45	$4.58{\cdot}10^{-6}$	247 978	981 095
2	100.00	<<< P	$4.43{\cdot}10^{-6}$	270 358	1 256 348
3	<<< P	<<< P	$3.77{\cdot}10^{-6}$	398 128	1 450 020
4	100.00	<<< P	$1.34{\cdot}10^{-6}$	161 986	922 171
5	100.00	<<< P	$1.34{\cdot}10^{-6}$	211 126	1 222 310
6	<<< P	<<< P	$3.85{\cdot}10^{-10}$	339 158	2 349 800
7	<<< P	<<< P	$3.77{\cdot}10^{-6}$	312 890	1 281 234

<<< P indicates values manifold higher than the project time

Fig.4 shows the normalized total cost of the secondary system per MV feeder in euros using (1). It shows substations with five to thirty MV feeders employing the traditional (case 2) and the centralized (case 5) architectures.

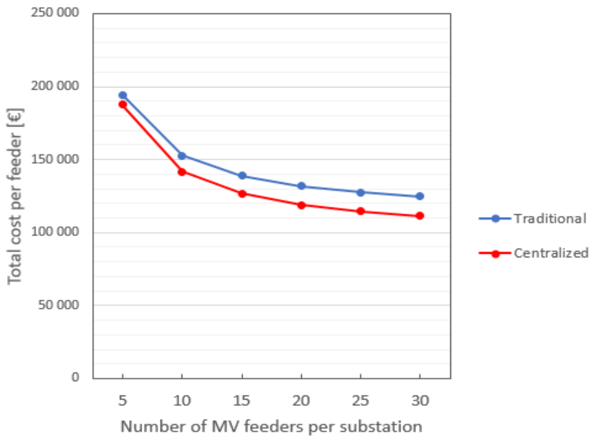

Fig. 4. The normalized total cost of the secondary system per MV feeder in traditional and centralized architectures for substations.

Discussion

The two inversely proportional indices in Table III, indicate a strong non-linearity between the level of redundancy and the total system average availability. This is explained from the analytical formulation of the *n*th-order failure. Second-order failures are highly more improbable than a first-order ones involving the same equipment. The probabilities in Table IV indicate that the more redundant the system is (transition from case 1 to case 3 and from case 4 to case 6), the less likely it is to cause protection failure. However, this comes with a higher cost, particularly in cases 3 and 6 that fulfill the N-1 criterion. Fig. 4 implies that the higher the number of outcoming MV feeders in a substation, the higher is the difference of total cost between fully centralized and decentralized (traditional) architectures.

Comparing the three different simulated architectures (centralized, traditional and hybrid), it is possible to infer that the level of redundancy is the main aggravating factor. The centralized architecture employs functionality redundancy, *i.e.*, protection and control located both in the CPC unit and in the IMUs. The traditional architecture, conversely, has to rely on the duplication of bay level components.

The centralized architecture consist of fewer components to perform functionality redundancy and backup, which facilitates installation, maintenance and replacement. This can be inferred from comparing cases 3 and 4. Further, the elimination of copper wiring significantly improves reliability at each bay. In older substations without Ethernet network, this elimination reduces investments, maintenance and the number of man-hours [10].

CONCLUSION

The present paper performed a viability assessment focusing on reliability and economic approaches with a number of substation protection controls system architectures enabled by the use of communication solutions. The obtained results vary greatly, thus exposing a range of system availability. The CPC architecture showed a significantly higher availability in comparison to the traditional approaches using functionality redundancy.

The selection of architecture for a project depends on the philosophy of protection and the defined specifications. This indicates that an optimal alternative requires other types of parameters, including equipment compatibility. The hybrid approach is an easier solution to integrate CPC systems to an existing secondary system when the existing protection relays have full IEC 61850-9-2 capability. In this context, the centralized architecture shows a condensed and reliable solution, thus simplifying maintenance and component number in a substation.

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