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Evaluation of a Centralized Substation Protection and Control System for HV/MV Substation

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Abstract

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Today, conventional substation protection and control systems are of a widely distributed character. One substation can easily have as many as 50 data processing points that all perform similar algorithms on voltage and current data. There is also only limited communication between protection devices, and each device is only aware of the bay in which it is installed. With the intent of implementing a substation protection system that is simpler, more efficient and better suited for future challenges, Ellevio AB implemented a centralized system in a primary substation in 2015. It is comprised of five components that each handle one type of duty: Data processing, communication, voltage measurements, current measurements and breaker control. Since its implementation, the centralized system has been in parallel operation with the conventional, meaning that it performs station wide data acquisition, processing and communication, but is unable to trip the station breakers. The only active functionality of the centralized system is the voltage regulation. This work is an evaluation of the centralized system and studies its protection functionality, voltage regulation, fault response and output signal correlation with the conventional system. It was found that the centralized system required the implementation of a differential protection function and protection of the capacitor banks and busbar coupling to provide protection equivalent to that of the conventional system. The voltage regulation showed unsatisfactory long regulation time lengths, which could have been a result of low time resolution. The fault response and signal correlation were deemed satisfactory.

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Populärvetenskaplig sammanfattning

Andelen el som genereras av förnybara energikällor ökar för varje år, vilket ställer stora krav på dagens och framtidens elnät, främst på grund av att dessa källor av sin natur har en energiproduktion som är svår att förutsäga. Solceller och vindkraftverk genererar elektricitet proportionell mot solenergi och vindstyrka, vilka båda två är mycket svåra att förutsäga och påverka. Båda dessa källor ger även upphov till att elektricitet genereras av flera mindre producenter, till skillnad mot ett kärnkraftverk som ger en konstant effekt från ett fåtal verk i landet. Samtidigt som elen som matas in i nätet i allt större utsträckning blir svårare att förutspå ställer elkunder större krav på dess tillgänglighet och pålitlighet.

Dessa två faktorer kommer att forma framtidens elnät: Näten kommer att behöva ta emot el från oberäkneliga källor samtidigt som den ska levereras med större tillförlitlighet än tidigare. För att möta dessa utmaningar sker en övergripande utveckling och modernisering och effektivisering av systemen, vilket ofta benämns som att skapa "smarta" elnät. En del av denna utveckling sker inom fördelningsstationerna, som är knutpunkterna i nätet. En fördelningsstation är alltså där ledningar eller kablar möts och där spänningen ändras för de olika delnäten som bygger upp det totala, nationella nätet.

I dagens fördelningsstationer är kontroll- och skyddssystemen uppbygga av distribuerade intelligenta enheter (IED:er) som insamlar, behandlar och kommunicerar data oberoende av andra enheter i samma station. Systemet är alltså uppbyggt av ett stort antal oberoende system som utför snarlika uppgifter utan att kommunicera sinsemellan. Kommunikation till driftcentral sker från varje enhet, och en station kan med lätthet ha 50 databehandlings- och kommunikationspunkter. Vid ett framtida elnät med effektiv kommunikation mellan nätets noder krävs ett effektivt och lättöverskådligt system. För att försöka förenkla och effektivisera systemarkitekturen installerade Ellevio AB 2015 ett centraliserat system i en primär fördelningsstation. Till skillnad från det befintliga, konventionellt uppbyggda systemet består det nya enbart av fem sorters komponenter, dedikerade till var sin uppgift: Databehandling och styrning, kommunikation, ström- och spänningsmätning och brytarkontroll. Det nya, centraliserade systemet har sedan dess installation varit i parallelldrift med det konventionella, i den meningen att alla dess funktioner har varit i aktiv drift parallellt med det konventionella. Det kan dock inte styra över stationens strömbrytare och alltså inte utföra "skarpa" skyddsåtgärder. Den enda funktionen i skarp drift är spänningsregleringen, vars uppgift är att hålla nätspänningen inom vissa gränser.

Arbetet innefattade en utvärdering av det centraliserade systemet och bestod i att jämföra de båda systemens installerade skyddstyper, utvärdera det centraliserade systemets spänningsreglering, undersöka systemens reaktioner vid fel samt jämföra deras utsignaler. Resultaten visar att det centraliserade systemet för att ge ett ekvivalent skydd som det konventionella måste utökas med ett differentialskydd samt skyddsfunktioner för kondensatorbatterier och kopplingen mellan stationens skenor. Spänningsreglering var stabil, men vissa av spänningsavvikelserna tog otillfredsställande lång tid att bli bortreglerade. En djupare undersökning krävs för att undersöka detta närmare. Felreaktionerna och signalkorrelationerna mellan systemen bedömdes som tillräckliga.

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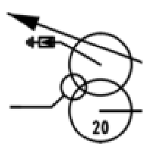
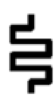
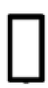
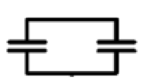
List of abbreviations

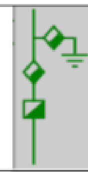
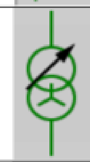
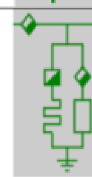
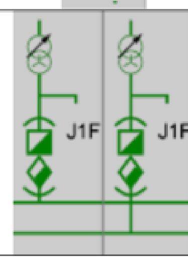
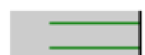
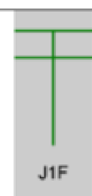
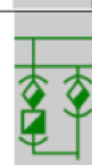
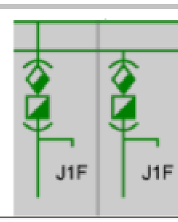
ABB - A multinational manufacturer of power electronics
A/D - Analogue-to-Digital
ARTOS - SASensor's operative system
BIM - Interface Module
BMPID - May Main Process Interface Device
CB - Circuit Breaker
CBFP - Circuit Breaker Failure Protection
CDF - Cumulative Distribution Function
CCU - Central Computing Unit
CIM - Current Interface Module
CPC - Centralized Protection and Control
dec1k, dec2k - SASensor's current decimation
DFR - Digital Fault Recorder
DSO - Distribution System Operator
DTL - Delayed Time Lag
GPS - Global Positioning System
HIS - Historical Information System, Ellevio's power grid database
HMI - Human Machine Interface
HV - High Voltage
IDMT - Inverse Definite Minimum Time
IED - Intelligent Electronic Device
IEEE - Institute of Electrical and Electronics Engineers
IM - Interface Module
IMU - Intelligent Merging Unit
I/O - Input/Output
LAN - Local Area Network
LL - Line-to-Line
LN - Line-to-Neutral
MATLAB - Matrix Laboratory, computing environment and programming language
MCEC - Mid-Carolina Electric Cooperative
MU - Merging Unit
MV - Medium Voltage
OS - Operative System
pdef - SASensor's directional earth fault protection
PDF - Probability Density Function
PID - Process Interface Device
pouv - SASensor's over/under voltage protection
PT - Power Transformer
ptoc - SASensor's overcurrent protection
pzso - SASensor's neutral voltage protection
RCC - Remote Control Centre
RTU - Remote Terminal Unit
SASensor - The CPC system evaluated in the study
SLD - Single Line Diagram
SCADA - Supervisory Control And Data Acquisition, a standard system for processes concerned with protection and control
VCU - Versatile Communications Unit
VIM - Voltage Interface Module
VRC - Voltage Regulation Control
VT - Voltage Transformer

List of symbols

Single line diagram component symbols

Symbol	Component	Function
	Surge arrester	Leads dangerously large currents to ground.
	Disconnector	Disconnects two parts of a power line. A filled component corresponds to it being connected.
	Instrument transformer	Transforms down the voltage to one suitable for measuring instruments.
	Portable earthing contact	Enables earth connection.
	Circuit breaker	A switch for breaking the current.
	Main transformer	Performs the main voltage or current step-down for further distribution in the grid.
	Reactive load	Compensates earth fault currents on the transformers neutral.
	Resistive load	Causes an active power generation of earth fault currents for measurement.
	Busbar	Distributes current between the different compartments.
	Battery (Capacitor bank)	Reactive power compensation.

SASensor class symbols

Class name	Protection	Symbol
Incoming overhead line	Breaker control, arcing earth fault, directional earth fault, overcurrent	
Power transformer	Gas formation, oil level, oil temperature, winding temperature, pressure, overcurrent, voltage regulation	
Earthing of a transformer (neutral)	Breaker control	
Incoming bay, double busbar (one connected to each busbar)	Breaker control, over- and undervoltage, overcurrent, neutral voltage	
General bay for double busbar	None	
Earthing bay, double busbar	Breaker control	
Coupling bay, double busbar	Breaker control	
Outgoing bay, double busbar	Breaker control, arcing earth fault, directional earth fault, overcurrent	
Breaker for transformer neutral	Breaker control	

1 Introduction

1.1 Background

Each year more electricity is generated by other energy sources than those conventionally used, such as hydro power and nuclear power. This development has led to increased demands on the functionality of the power grid as the energy output of the new sources are inherently less predictable than the conventional ones, as they do not have an even output of energy. Photovoltaic cells generate energy proportional to the solar energy they absorb and wind turbines generate energy proportional to the surrounding wind speed. Thus, the electrical output of these sources depend on events that cannot be controlled, which presents a challenge when integrating them into a grid that requires a controllable energy input. Unlike the renewable energy sources, conventional methods of energy generation like hydro, coal and nuclear power plants have outputs that can be continuously controlled and regulated to meet the demands of the grid. As long as the energy inserted into the grid has been generated by these energy sources there have been small incentives for a dynamic or "smart" grid. However, as a big part of the world's energy production is shifting to renewable energy sources, there are more demands for a dynamic power grid that can deal with local fluctuations in power generation and other challenges posed by the change in the way power is generated.

A possible solution to the problem of non-even energy output of the new energy sources is that of a grid made up of nodes with an efficient communication system that the nodes can use to interact with each other. The idea is that if for example photovoltaic cells in some part of a country are producing a surplus of energy while another part has a shortage, the two corresponding nodes could communicate with each other and solve the problem by transferring energy from the part with a surplus to the one with a shortage of energy. This would require a well-organized network where nodes can communicate with each other for instantaneous redirection of power. A grid constructed in this way would also be possible to protect against wide-area outages as power could be instantaneously redirected to alternate routes when the primary path was interrupted. For this to be a viable future possibility, the system architecture of electric substations would have to be simplified and optimized. As of today, the regular substation architecture is based on several, independent components and subsystems that function independently of each other with no central hub or data processing point. Each separate system monitors its dedicated bay and reports to remote control without synchronizing the data with the other systems in the station. As a result, the majority of the substation data is measured, reported and then discarded without further analysis. There is no central data aggregation point where the relay data could be used for station-wide control and monitoring. An effective communication system between substations would likely require some central node where the station data is analysed and communicated [1].

At the same time as the energy sources used for inserting energy into the grid are becoming less consistent, more demands are placed on the availability and reliability of it. This is driving a development of tools for protection, measurement and time synchronization of the grid. The introduction of these tools by dedicated third part companies require that the grid is able to handle implementation of hardware not taken into account when it was constructed, in many cases more than 50 years ago. These new instruments will also not be manufactured by the same company that built the grid, but by a company solely dedicated to the production and development of that single instrument or function. An efficient and sustainable grid in a rapidly changing energy industry thus requires a high level of adaptability and compatibility with new types of products[1].

This development poses three main challenges on the next generation electrical grid: It must be able to handle energy sources with energy outputs that are hard to manage and regulate, it must have a well-established communication system between the nodes that make it up and must be open to implementation of third party hard- and software [2].

1.2 Centralized Protection and Control

To meet the future challenges of the electric grid, the Swedish energy distribution company Ellevio[1] has implemented a new system architecture in a HV/MV (High Voltage/Medium Voltage) substation. The purpose of the project was to see if these challenges may be better met with a change in substation system architecture.

The system architecture implemented in the substation is based on the concept of Centralized Protection and Control (CPC). The idea is to centralize as many of the station's processes as possible into a central unit, as opposed to having the station made up of several autonomous systems that work and communicate independently of each other. The central unit would handle data processing, protective measures, control functions and communication with other stations and nodes in the grid network.

1.3 InteGrid

InteGrid[2] is an EU-financed organization with a vision to "Bridge the gap between citizens and technology/solution providers such as utilities, aggregators, manufacturers and all other agents providing energy services." with goals of integrating consumers and small-scale energy producers into the electricity grid while promoting a high percentage of renewable energy sources in the grid power production. InteGrid is concerned with demonstrating, testing and promoting technologies that help to realize this vision. Some of the key objectives are to develop and promote intelligent and adaptable tools for grid management, energy production and predictability as well as improved customer service and reliability of the grid.

To help realizing these goals, InteGrid has several demonstration projects located in Sweden, Portugal and Slovenia. The projects in Sweden are mainly directed towards demonstrating smart grid solutions, one part of which is the development of next generation systems for smart substations. As a result of this, an evaluation of the implemented centralized system is of interest [9].

1.4 Purpose and goal

The goal of this master thesis is to provide a basis for a thorough evaluation of the CPC system SASensor, installed in the substation in 2015. In addition to using existing methods for the evaluation, the work will result in the formulation and implementation of new methods for future studies of the system. The methods will be evaluated and applied on the existing data. However, the most important results will not be the system's performance, but rather the implementation of the devised methods.

Since the installation of the centralized system in 2015, its protection functions have been in so-called "shadow operation", meaning that they have not been able to control breakers and other switchgear. The functions have however been active and the command signals have been recorded, the only difference from sharp operation being that the command inputs to the breakers have not been connected. The only function that has been in active operation since the implementation is the voltage regulation.

The thesis will include the following:

- A thorough documentation of the protection functionality of the centralized system and a comparison with the existing, conventional system
- Method development and implementation for evaluating the voltage regulation and application on existing grid voltage data
- An study of the synchronization and reliability of the measurement signals of the centralized system

[1] https://www.ellevio.se/
[2] https://integrid-h2020.eu/

- A study of the time synchronization of the error and alarm messages of the two systems as well as the response of the two systems to a grid fault

The thesis does not include a thorough study of the exact implementation and inner workings of the centralized system. It is rather treated as a "black box" and the focus is foremost on its performance in comparison to the conventional system. Though a chapter is dedicated to describing the structure of the system, no code or other specific implementation solutions are analysed. Although the report contains some discussion and evaluation of the CPC-concept in whole, the absolute focus of the study is on the implementation of this particular system in this particular substation.

2 Centralized protection and control

2.1 Motivation and purpose

As mentioned, the main motivation for Centralized Protection and Control (CPC) is the simplification of the substation system architecture by placing all higher protection and control functions inside a main computer. As of today, the substation system is comprised of several autonomous systems that perform these tasks independently of each other. The technical prowess of modern IED (Intelligent Electronic Device) relays has enabled data collection and processing features at station bay level. Though this has had its advantages, advocates of a centralized system architecture claim that it has resulted in an unnecessarily complicated station architecture. There is no formal definition of what a CPC system is, but in [1] it is defined 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'. The main proposed advantages are that the simplified station structure would make the station easier to manage and facilitate maintenance and the implementation of new devices. As all of the measuring devices would send information to one computer for processing, that computer would have access to more data for fault prediction and station wide decision making. The data aggregation and increased computing power of a central computer would enable complex data processing and fault detection algorithms that are impossible to implement in a conventional system. For example, if one current measuring device malfunctions, the current that it was monitoring can be calculated as all of the other currents in the station are known by the same central unit. Another proposed benefit is the ease of implementation of third party functions, as installing a new function would rather be a question of updating the software than installing and testing a physical relay.

2.1.1 Examples of CPC system architectures

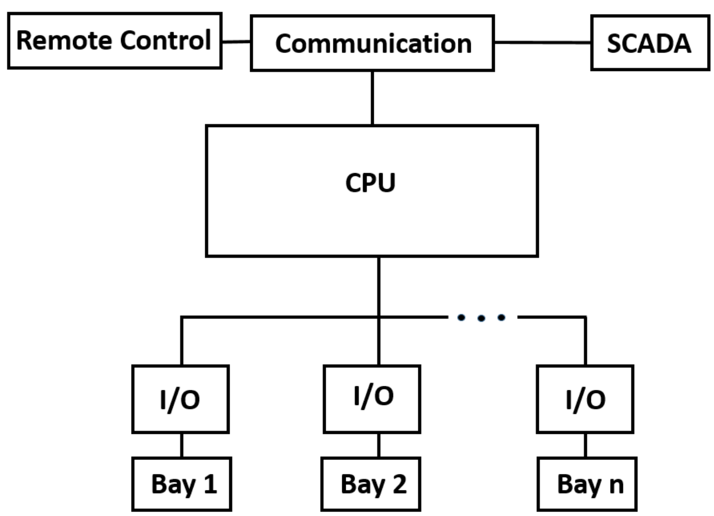


Figure 1: Conceptual CPC system architecture.

Figure 1 shows the basic idea of a substation system architecture based on centralized rather than distributed protection and control. It has a distinctly hierarchical architecture, with the bay level apparatus at the lowest point of the scheme. Each of these use some sort of I/O device for analogue-to-digital conversion (though they may perform other tasks as well). However, these devices are not independent IEDs, but governed by one or more central CPUs.

As the CPC concept is more of a system architecture philosophy than a defined system there is no official architecture standard. Rather, there are several possible architectures that implement the

CPC concept. The basic idea is that there is some centralized processing unit that has access to all station bays. However, some proposed architectures only utilize the CPC processing unit as a back-up system, providing station control only when the conventional bay level IEDs fail. Figure 2 shows a model with a redundant CPC unit integrated into a conventional substation architecture. The IEDs at bay level perform data collection and processing while communicating with each other over a station-spanning LAN, with the CPC acting as a backup system that could be used for further data processing and recording.

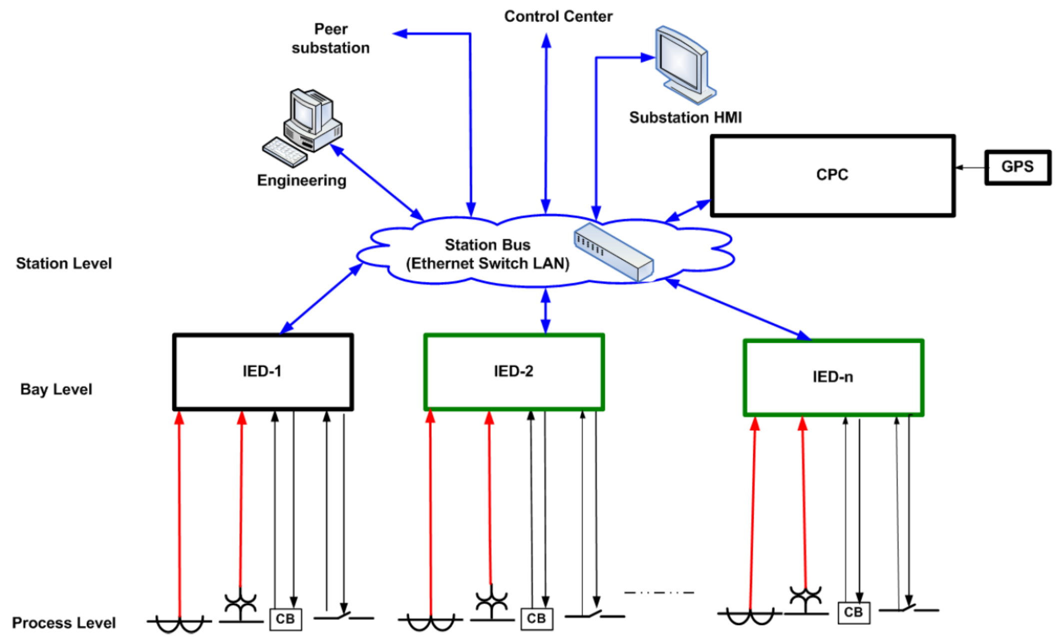


Figure 2: CPC system architecture with the central computer only performing backup and redundancy duties [1].

Other architectures utilize the central unit as the sole data process center and use bay I/Os only for data gathering. Figure 3 shows a substation architecture where all of the IEDs have been replaced by MUs (Merging Units) that only perform measurements and communicate them to the central CPC computer. They do not interpret or process data, instead they are governed by the central computer. As this system would be completely dependent on the CPC computer functioning, there is a backup computer for system redundancy, should the primary computer fail. All internal and external communication is handled from the CPC, which at a grid level would make this station a one component node.

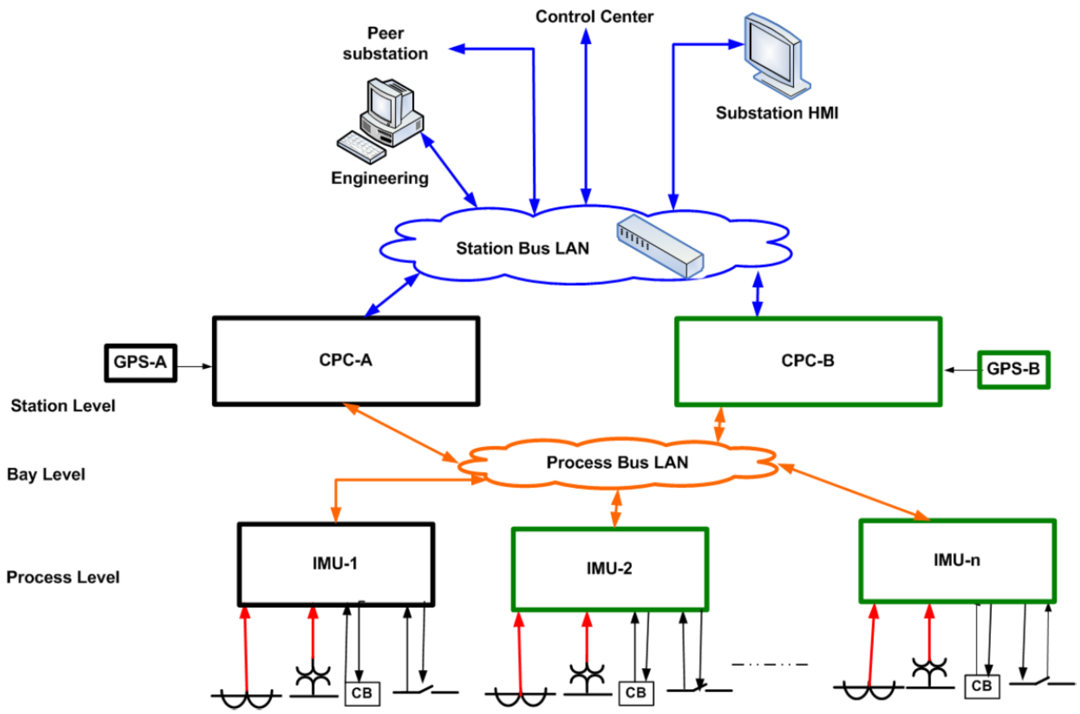


Figure 3: CPC system architecture with the central computer performing all protection and control with no IED autonomy [1].

Figure 4 shows a station architecture that is a combination of the two shown above. In this system, the IEDs and the CPC complement each other. If a CPC architecture would be integrated into an already existing station, this is perhaps the most probable system architecture outline as it wouldn't let the already implemented modern IEDs go to waste. In this sort of architecture, the IEDs would be best suitable for direct bay level protection and control while the CPC would handle station level management. An example would be that the IEDs perform direct security measurements while the CPC performs fault prediction and advanced data processing. However it is implemented, it requires careful post-installation coordination and synchronization of the two systems.

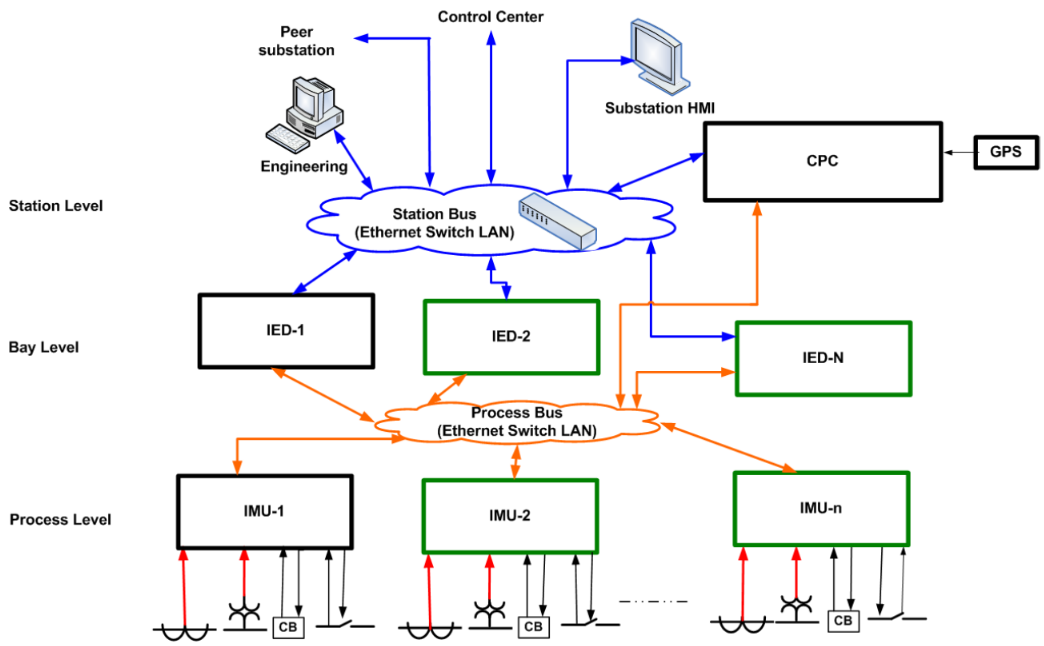


Figure 4: CPC system architecture with both the central computer and IEDs performing protection and control. The duties of the respective systems can be distributed after user preferences [1].

2.2 Examples of actual CPC implementations

iSAS

The Russian Distribution System Operator (DSO) Tumenergo has implemented a substation architecture that could be viewed as a slightly distributed CPC system. It is named iSAS and is implemented in a 110/10 kV station Olympic in Siberia. The station has two high voltage lines leading to two transformers with feeders to several busbars for further distribution. One of the fundamental properties of the system is its software, which is created so that the user can decide where to place its individual functions. It is therefore "hardware independent" and can be implemented in very diverse system types. The primary goal of the project substation was not to test the CPC concept but actually to find the optimal structure for implementing the iSAS system [1].

The system is comprised of five layers, shown in figure 5.

Layer 1: The first layer of the system is connected to the primary equipment of the switchyard. It is made up of Process Interface Devices (PIDs) which somewhat resemble IEDs and MUs. Each switchgear has its own PID and each bay has a Bay Main PID (BMPID).

Layer 2: The second layer is a communication system that links the switchgear to central computing.

Layer 3: The third layer houses the computational power, which is split into four devices: Metering and power quality monitoring, main protection and control, backup protection and control and recording of events.

Layer 4: The fourth layer is another communication system that communicates between the computing centre and the rest of the world. It has connections to the control centre, system operator office, SCADA as well as with the HMI which is how the station is manually handled.

Layer 5: The fifth and highest layer holds all interfaces. From here the system is controlled by a human operator.

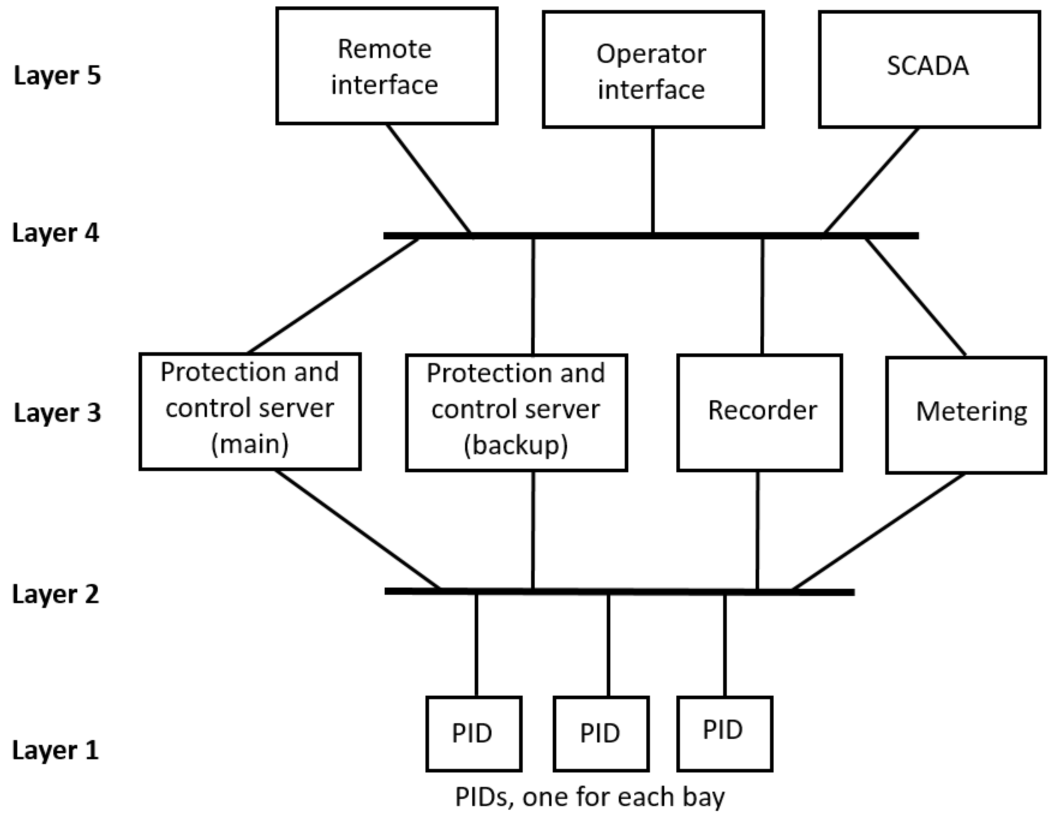


Figure 5: The system architecture of iSASarch. It is made up of five layers, each with well defined, exclusive duties [1].

SASensor

SASensor is a CPC substation system developed by Locamation, a solutions provider for CPC systems. It is based on the concept of a simple system architecture with as few component types as possible. As architecture type, it is most reminiscent of that shown in figure 3, where the only intelligent device monitoring protection and control tasks is the Central Computing Unit (CCU). All processes are divided into three categories - measuring, computing and communication. The associated functions are placed in one of the corresponding components: Measuring and monitoring is handled by Interface Modules (IMs), data processing is handled by the CCU and external communication is handled by the Versatile Communications Unit (VCU) [14],[13].

At bay level there are only three types of components: CIM (Current Interface Module), VIM (Voltage Interface Module) and BIM (Breaker Interface Module). The main function of the current and voltage modules are to act as measuring devices with A/D converters for the CCU. All of these modules are designed to have a lifetime greater than 30 years and to require low maintenance operation, which includes future development. They are therefore designed to be simple to integrate into any imaginable architecture that may be invented in the near future [14-18].

An outline of the SASensor system architecture is shown in figure 6. The bay switchgear is connected to the interface modules that perform monitoring and conversion tasks. These are in direct contact with the CCU, which may have a backup in case of malfunction or maintenance. This unit acts as the “brain” of the substation and its purpose is to handle all protection and control functions of the substation. The CCU is designed as an “all-in-one” box and is the fundamental component of the centralized system. It handles all of the tasks previously done by decentralized intelligent devices and can, as it has a larger data inflow from all parts of the station and more processing power than the conventional IEDs, perform more advanced processing algorithms.

All of the communications are handled by the VCU, into which the user interface is also implemented. It is connected to remote operation centres, maintenance, back office and if need be other substations. It can also be connected to a GPS antenna for improved time accuracy [19].

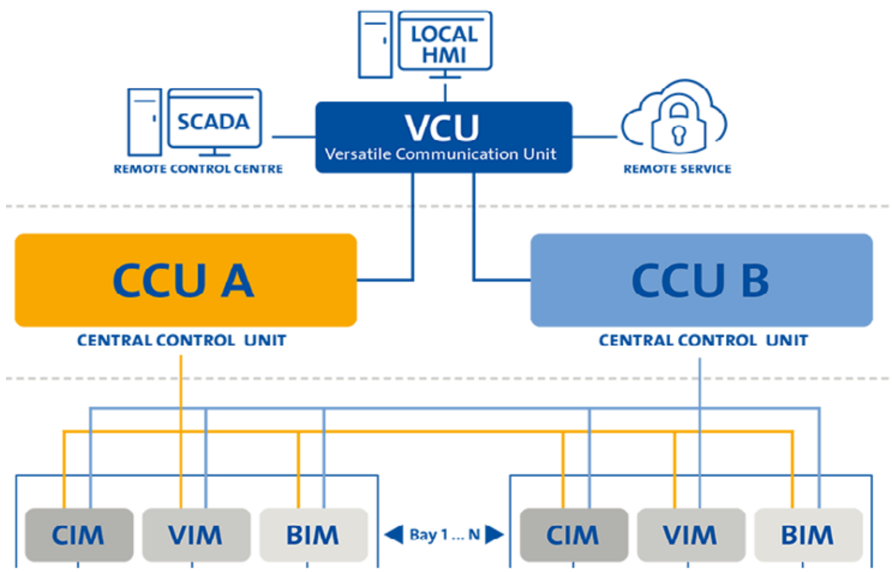


Figure 6: The system architecture of SASensor. The BIM, CIM and VIM modules only measure data and perform no data analysis, all advanced processing and communication is performed by the control and communication unit, respectively [14].

2.3 The SASensor modules

2.3.1 The Central Computing Unit (CCU)

As stated above, the CCU is the core of the SASensor system, as it handles all of the data processing and synchronization, interfaces and so forth. It is designed as an “all-in-one box” and it essentially acts as the governing unit of the system and contains all of the functionality for protection, control and monitoring of the substation. One of the intentions with its design is to construct a central unit that is “hardware independent”, meaning that its functionality is not reliant on any particular hardware to contain its intended functionality and it is possible to construct out of commercial, multi-functional hardware [18].

In essence, the CCU consists of a single board computer with a hard disc and several Ethernet ports for communication with other station modules. The computer runs Locamations own developed operative system ARTOS, an open real-time OS which, although it is developed by Locamation, is open for third-party development of application and functions. All communication of the CCU is through fibre-optic ports, to maximise electromagnetic shielding of the signals. Redundancy of the system is achieved by duplicating the CCU, which is achievable due to all of the functionality being dependent only on the software, which is easily duplicated [18].

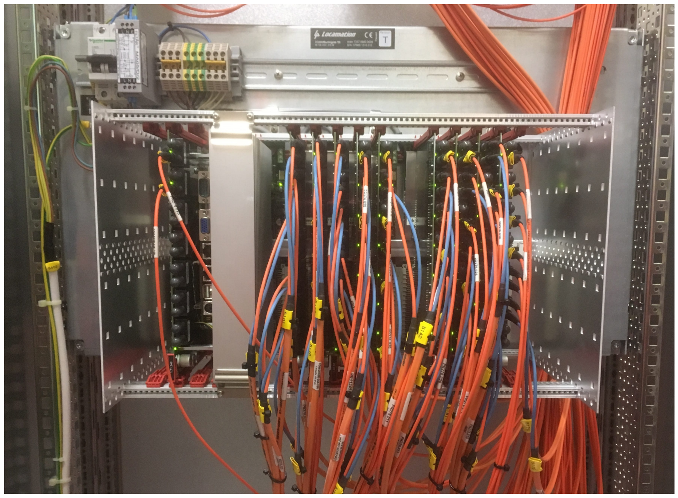


Figure 7: The Central Computing Unit installed in the substation

2.3.2 The Versatile Communications Unit (VCU)

The VCU handles all outgoing communication from the station system, and enables connection to remote control centres and SCADA through wide area networks and Ethernet communication through fibre optic cables. It communicates according to the 100Base-FX Ethernet protocol. It can be connected to GPS antenna for increased time accuracy. In essence, it functions as a serial media converter and receives data from the CCU, which it converts and transmits to the end receivers. It is designed to be compatible with all major communication systems, such as modem, 3G, PLCC etc [19].

Figure 8: The Versatile Communication Unit installed in the substation

2.3.3 The interface modules: CIM, VIM and BIM

The interface modules of the SASensor system in effect take the place of the conventional protection relays, and are placed by the lines and components that require protection and measurement. In difference to the conventional relays, they do not have any functionality other than what is strictly required of them for the CCU to monitor and control the station. Thus, the current and voltage modules are in essence analogue-to-digital converters and do not have any means of receiving commands from the CCU and can not execute protective measures on their respective switchgear components. The breaker module functions oppositely: Its only functionality is to monitor and control the breakers and to change their state according to commands sent by the CCU [14].

The VIM digitizes analogue voltage measurements from the secondary windings of a voltage transformer, preserving data of relevant harmonics and other quantities. It may be coupled to instrument transformers in star, delta and three single-phase configuration and can measure voltages ranging from 0 to 187 V with a defined accuracy from 100 mV and has a bandwidth from 10 to 3840 Hz. It has an internal clock, which is calibrated during installation, however the CCU resamples the VIM data to compensate for time differences between the modules [17].

The CIM works, for the most part, in analogy with the VIM, except that it measures current instead of voltage. It has three phase inputs and two separate measuring intervals (for currents in the line), one from 1 mA to 7.2 A for normal signals and one for fault (short circuit) currents from 100 mA to 500 A. These are coupled to two input cores: The Measurement input and the Protection input. The inputs are identically processed, the only thing that differs between them are the ranges [16].

The BIM is an input/output interface for switchgear monitoring and control. It has ten inputs for breaker position and alarm indications and eight relay outputs for normally open contacts. It receives switching commands from the CCU by shielded fibre optic cables. Double commands are always sent, to minimize the risk of unnecessary switching. The module has continuous self-monitoring and any affected outputs are blocked in the case of detected errors [15].

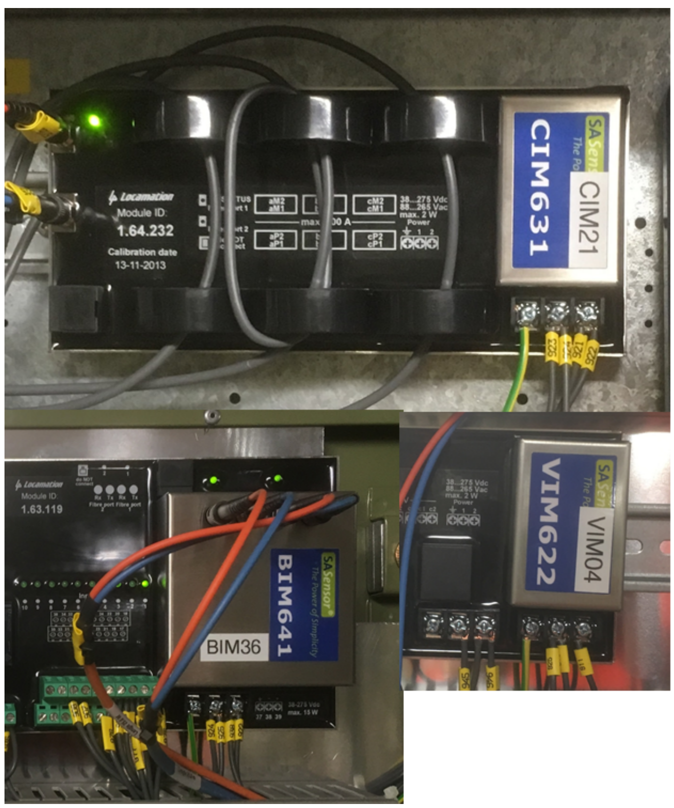


Figure 9: The three interface modules: CIM, VIM and BIM.

3 Theory

Below, fundamental concepts and components that are necessary for the understanding of the report are presented and briefly explained.

3.0.1 Three-phase voltage

The voltage in the grid is so-called three phase, meaning that it is delivered in three conductors, but the voltage in each phase is shifted a third of a period compared to the others. Representing this using phasors, this means that they are shifted 120^o from each other. There are several advantages to using three-phase power systems instead of one-phase, the most prominent being that the power delivered is constant (in a one-phase circuit it varies periodically with time) and that the phase currents all cancel out in the nodes. A balanced three-phase power system therefore has constant delivered power and does not need a neutral phase.

In a three-phase system, there are two types of voltages: Line to line, V_{LL}, and line to neutral, V_{LN}, voltage. V_{LL} is the voltage difference between the three phases (or lines) that make up the circuit and V_{LN} is the voltage over the loads of each individual phase. They relate to each other as follows:

$$V_{LL} = \sqrt{3} V_{LN} \tag{1}$$

[10],[3]

3.1 The electrical grid

The electrical grid is the network used for supplying electrical energy and power to consumers. It is made up of two separate parts, the transmission system and the distribution system. A schematic diagram of the grid is pictured in figure 10.

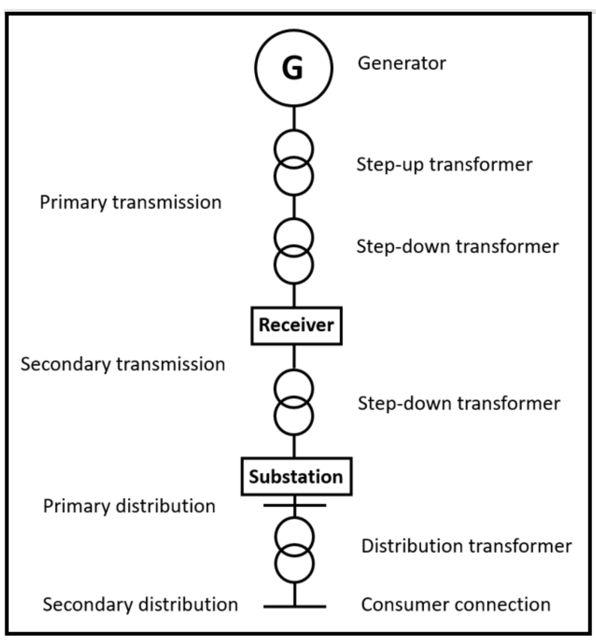


Figure 10: A simple diagram of the national transmission and distribution network.

3.1.1 Primary transmission

In the diagram, electricity is generated at medium voltage (typically tens of kilovolts) at the generator (G) and is directed to a step-up transformer which increases the voltage, usually at least one order of magnitude. The step up to such a high voltage is to minimize power loss in the transmission line, which is the resistance of the line multiplied by the current squared:

$$P_{loss} = I^2 R \tag{2}$$

where P_{loss} is the power loss per phase and I and R are the current and resistance of each phase.

The grid power per phase requested by grid consumers is $P_c = IV$, where V is the phase voltage, which in turn means that

$$P_{loss} = R\frac{P_c^2}{V_p^2} \tag{3}$$

and thus the power loss is proportional to the line voltage squared. To minimize this loss, the voltage in the lines is as high as possible. The power is transmitted at this voltage over large distances, as power stations are generally not situated close by consumers [3].

3.1.2 Secondary transmission

The voltages used in primary transmission are much too high to use in urban areas and the voltage is transformed down to a more reasonable voltage (in this case back to around ten kilovolts) at a safe distance from the consumers. From here the electricity is directed to distribution substations where it is again transformed down in the secondary transmission part of the grid [3].

3.1.3 Primary and secondary distribution

The substations transform down the voltage further and distributes it to high voltage consumers and to additional transformers (primary distribution) from where it is directed into households and such in the secondary distribution system [3].

3.1.4 The electrical substation

One of the fundamental components of the energy grid is the substation. It can be thought of as a node in the grid's network and its general purpose is to connect power lines from two parts of the grid while also possibly altering the power in some way, often by transforming the voltage. One example of this is stepping down the high voltages in the national power grid to a voltage better suited for use in regional areas. As the voltages in the grid have magnitudes of several hundred kilovolts in the national power lines to the 230 volts in regular sockets with likewise varying current, reliable safety measures are necessary to prevent the wrong voltage magnitudes at the wrong place [7].

3.2 Relay protection

The main task of a grid protection system is to rapidly and selectively identify faults. Once a fault is detected it should be isolated and the corresponding circuit should be disconnected to minimize damage to the grid and affected customers. Because of the large voltages and currents in the grid, fault currents tend to be large enough to cause serious damage both in the form of damaged equipment and interrupted production and is a serious safety concern for station personnel. The protection devices must therefore be able to perform their tasks as quickly and precisely as possible and, as these measures often involve shutting off power in a section of the grid, great care must be taken to ensure that it is done only when necessary [6].

Protection devices in substations are largely made up of protective relays which are categorized into two groups: switching relays and measuring relays. Measuring relays measure some kind of quantity, for example voltage or current, and depending on the measured value may take some kind of protective action. Switching relays perform some sort of switching task, like the opening of a circuit breaker [8].

3.2.1 Relays

A relay can conceptually be thought of as a circuit that controls another circuit. This is often done by generating a magnetic field with a coil and using the field to alter the state of a contact in another circuit. A simple and still commonly used type of classical electromechanical relay operates as depicted in figure 11.

In this example of a relay circuit, a coil wrapped around an amplifying magnetic core creates a magnetic field that causes a movable contact to close a circuit. Thus, an easily operated low voltage control circuit can be used to open or close a more sophisticated, possibly high voltage circuit.

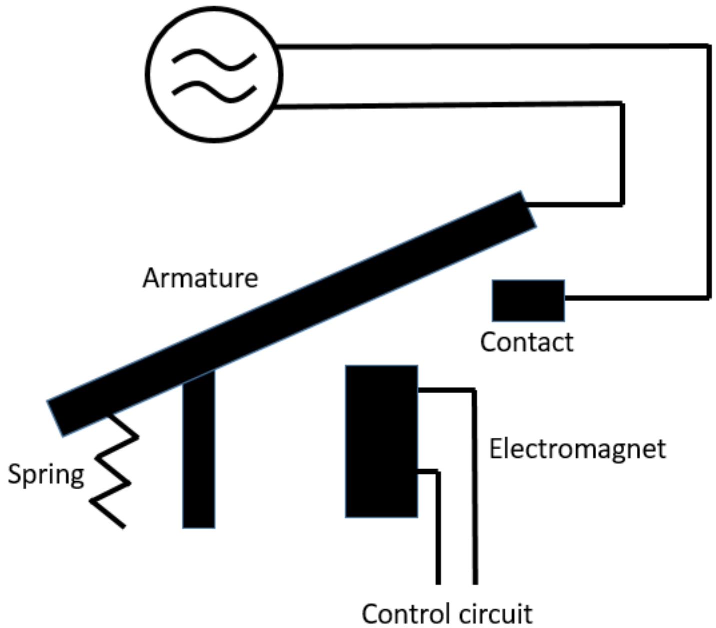


Figure 11: A schematic picture of a classical electromechanical relay circuit.

Numerical relays

Numerical relays are, unlike classical relays, constructed of digital microprocessors and are rather small computers than circuits. As such, they have several advantages compared to classical relays as they among others functions can have algorithms for data processing, self-supervision, event recording and control interfaces. Several types of protection may also be integrated into the same device. Since the 1990's, numerical relays have been the dominating component in substation protection [8].

3.3 Types of substation component protection

There are several components of a substation, for example transformers, power lines, busbars etc, that require protection. There are several different concepts used for protecting these components, and below are listed the most common types.

3.3.1 Limit protection

The general idea of limit protection is to continuously measure a quantity and to take protective measures such as the opening of a circuit breaker whenever the value of that quantity exceeds a set limit. It can be implemented in several ways:

Overcurrent and Time-Overcurrent Protection

Protective measures are taken whenever a current larger than a certain limit is detected. These may be taken as soon as the overcurrent is detected, or the system can wait a set amount of time before acting. This time can either be constant or proportional to the size of the current. If the time delay is constant the protection is called Delayed Time Lag (DTL) relay protection and if it depends on current size it is called Inverse Definite Minimum Time (IDMT) relay protection [7].

Overload Protection

The temperature of a circuit component is monitored and compared to a temperature model of the same component. If the temperature of the component and its model differs more than a certain limit an alarm signal is sent. This method is effective but dependent on an accurate temperature simulation model of the component [7].

Frequency protection

The system's frequency and its time derivative are measured, none of which may diverge too far from a set value. This alarm seldom triggers a breaker as problems of this kind are usually caused by an over- or underproduction of power. Thus the response is usually a redistribution of system load [7].

Voltage protection

The voltage of the system is measured and, like the other types of limit protection, may not differ too much from a certain value. As in the case of frequency protection, this usually results in a redistribution of load [7].

3.3.2 Comparison protection

Comparison protection works on the principle of comparing two values of a quantity, for example voltage or current, that can be obtained from different parts of the station or set by some model of the system. This comparison could either be made for each sample or for a mean over some timeframe, like a fraction of the phase period [7].

Differential protection

The amplitude and phase of currents before and after a component are measured and compared. If they match, there is no fault inside the component but if they don't, there may be a malfunction inside it and an alarm signal is sent. This is one of the most common protection methods, especially for transformers [7].

Busbar protection

As a busbar is a node in the station's circuit, according to Kirchhoff's current law the sum of all currents entering it must be equal to zero. If the sum differs from zero by more than a set limit, the breakers that connect the busbar to the stations lines will open. This is often implemented with switching and measuring devices on several places along the busbar that send current data to a centralized unit which processes the information and sends alarm signals to the switching units [7].

Directional and distance protection

As the impedance of a transmission line is proportional to its length, in the event of an earth fault the measured impedance of the line will be less than its rated value. Comparing these two values can give an estimation of where along the line that fault has occurred. The reactive component of the impedance may also give an inclination of the fault's location: If it is more inductive than its rated value the fault is likely on the transmission line and if it is more capacitive it is probably located inside a load of some kind. Several relays using distance protection may have overlapping protection regions for better determination of the fault position. This type of protection is however not widely used in substations but rather on national grid lines [7].

3.3.3 Instrument protection

There are several protective devices that directly measure quantities of the system's components rather than voltage or current. Most of these systems are concerned with transformer protection, as they are the principle components of most substations. Examples of transformer protection devices are Buchholz relays, a gas detector used to determine if the transformer oil is boiling, and pressure, temperature and oil level monitors. Similar systems exist for the protection of other components of the substation [7].

3.3.4 Autoreclosing

Many of the faults that occur on the power grid system have a transient nature and the problem often "solves itself" without the protection system having to do much more than to stop the flow of current as long as the fault is present. An example of these kinds of faults is a tree that falls and bounces on a transmission line. For the fraction of a second that the tree is in contact with the line there is an earth fault current but as soon as the tree loses contact with the line there is no need for any further protective processes.

To handle this common type of fault, an "autoreclosing" system is connected to most circuit breaker devices. If a fault current is present, the breaker opens the circuit but will after a certain amount of time test to see if it is safe to close it again. If a fault current is still detected the breaker will again open the circuit. After a certain number of tests, it will assume that the fault is stationary and leave the circuit open until manually reset [7].

Autoreclosing is a convenient way of avoiding power loss due to common, harmless events but requires secure and synchronized communication between the breakers and the protection system as it would be potentially catastrophic to continuously send electricity through a fault. Figure 12 shows a schematic diagram of a reclosure event. As soon as the fault current (F) is detected the command for opening the circuit is given. After a certain amount of time, the command is given to close the circuit again. If the fault current has disappeared, the system power loss is very brief and an unnecessary power outage is averted [8],[4],[7].

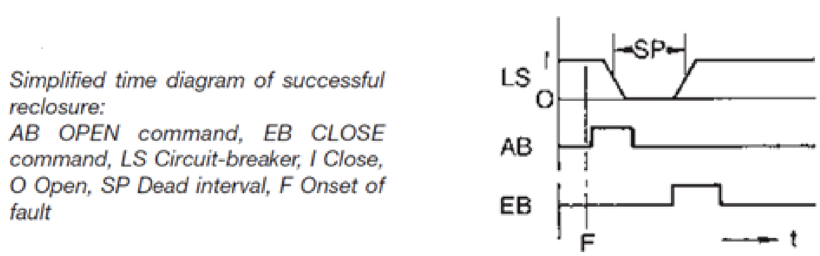


Figure 12: A diagram of an autoreclosure event.[7]

3.4 Relay protection schemes

There is no official standard for substation protection, but several different standards from different manufacturers. Most of them use variations of the aforementioned protection types to protect the most vital parts of the station (busbars, transformers, etc.). Below are some possible implementations in typical substation architectures.

3.4.1 ABB recommended standard

Figure 13 shows a basic ABB scheme for protecting switchgear, lines and transformers in a substation. Two different configurations are presented, one as a recommended standard and another for increasing the protection. In the standard protection scheme, the cable is protected by overcurrent and ground-fault protection system. There are also options for distance, differential, overload, frequency and voltage protection. The overhead line has a standard protection of overcurrent, autorecloser and ground current protection. The same protection types as for the cable may be used for further protection of the line. The transformer only has a standard configuration of overcurrent, differential, overload and Buchholz (gas detection) protection. The busbar has the centralized protection scheme mentioned above [7].

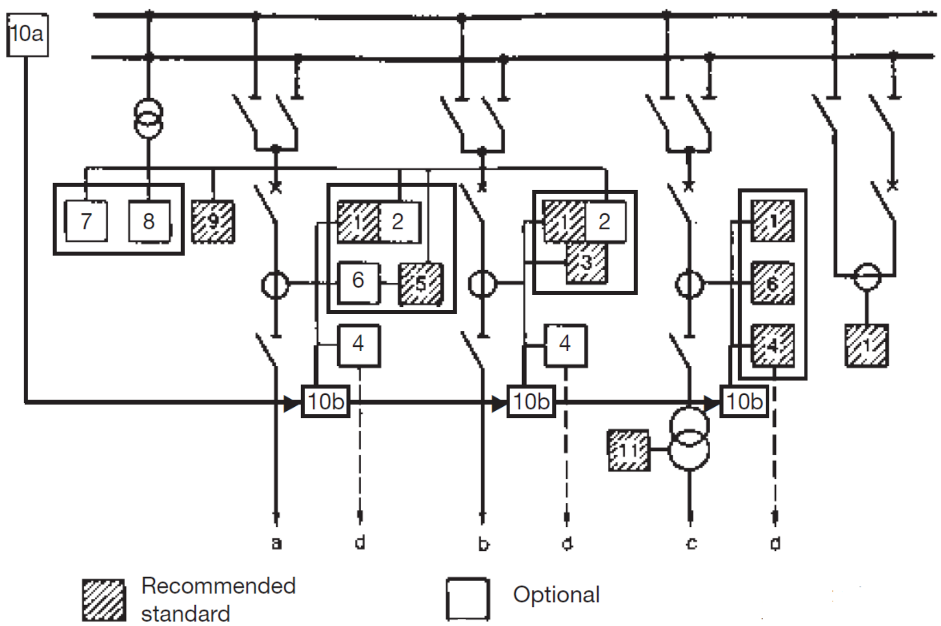


Figure 13: A standard ABB protection scheme for two busbars, one transmission line, one cable and one transformer.
a) Cable, b) Overhead line, c) Transformer, d) Auxiliary line
1. Time overcurrent protection 2. Distance protection, 3. Autorecloser, 4. Differential protection, 5. Directional ground fault protection, 6. Overload protection, 7. Frequency monitoring, 8. Voltage monitoring, 9. Ground-fault indicator monitoring, 10. Busbar protection (10a. Central unit, 10b. Bay unit), 11. Buchholz protection, transformer temperature monitoring [7].

3.4.2 Mid-Carolina Electric Cooperative

Figure 14 shows another, somewhat different protection scheme. It developed by the Mid-Carolina Electric Cooperative (MCEC) when searching for an optimal protection scheme using state of the art protection relays. An advantage of this scheme compared that in figure 13 is that it is evident which relays protect which parts of the transformer. The protective relays are labeled according to the IEEE C37-2 standard, and the labels correspond to the following relays [11]:

- REF: Earth fault protection
- 27: Undervoltage protection
- 50/51N: Overcurrent protection
- 59: Overvoltage protection

- 79: Autorecloser
- 87: Differential protection

All of the parts of the station (both sides of the transformer, the busbar and the lines) have protective relays for overcurrent and differential protection. Further, the lines have autorecloser relays and the transformer neutral has earth fault protection. The only difference to the standard protection system in figure 13 is that there is differential as well as overcurrent protection on the lines. This type of protection configuration with the optional expansions mentioned by figure 14 can therefore be viewed as a standard protection scheme for sufficient relay protection [12].

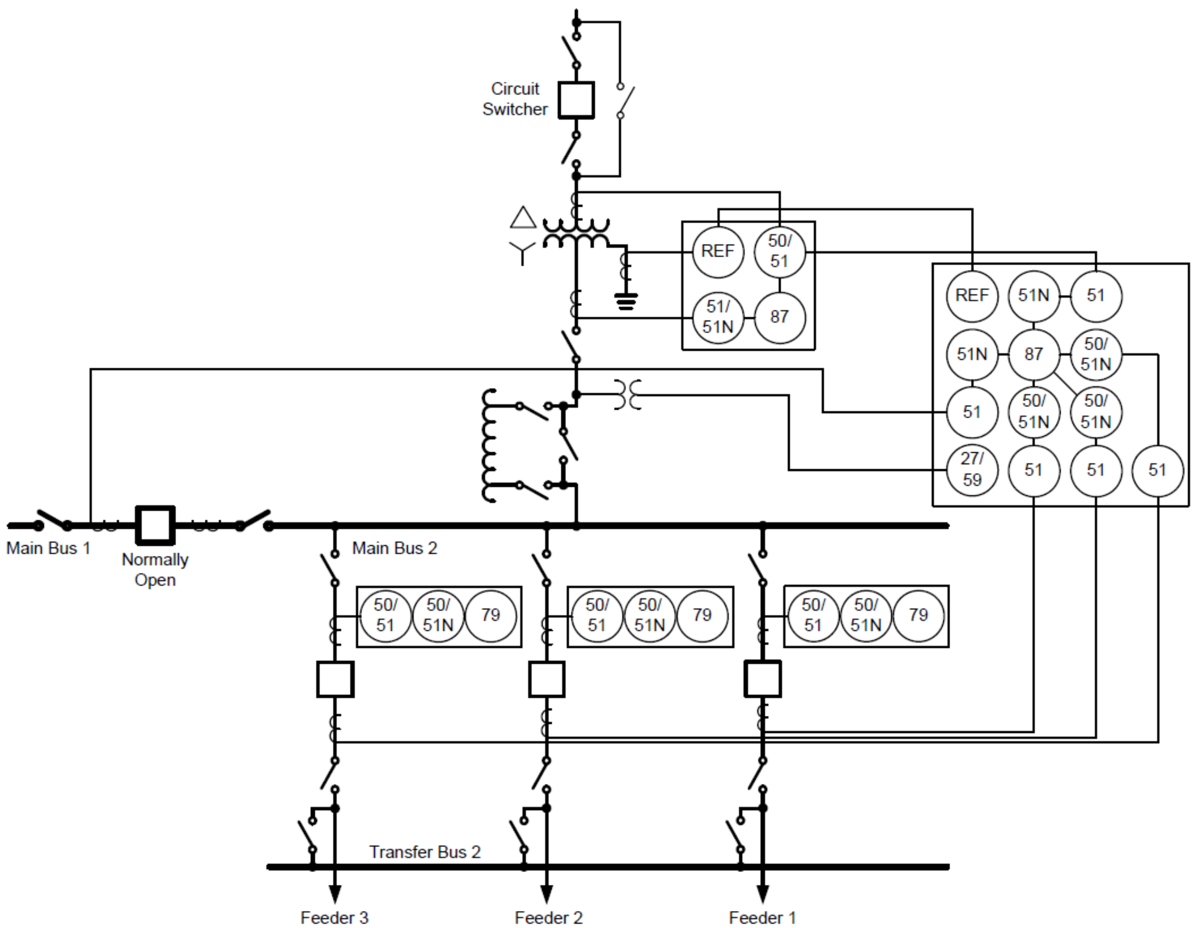


Figure 14: The protection scheme developed by MCEC.[12]

For the evaluation of the protection functions of the centralized system vs the conventional, the two systems reviewed above were used as reference.

3.5 Voltage regulation

In power stations, voltage regulation is achieved by altering the winding ratios on the transformers, resulting in a change of the output voltage, within some predetermined values. The number of windings are altered by so-called “taps” that effectively shorten the winding on the primary side of the transformer. A schematic tap changing configuration with five taps is shown in figure 15.

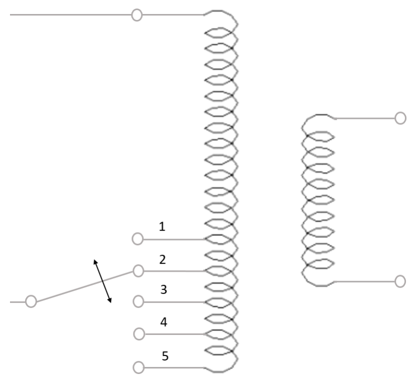


Figure 15: A schematic of a tap changing device.

The changing can be performed either manually or (more commonly) automatically by a regulating feedback circuit. A schematic of such a circuit is pictured in figure 16.

The output voltage of the power transformer (PT) is measured by an instrument voltage transformer (VT) and compared to a desired reference voltage V_{ref}. Depending on the control error ($V_{ref} - V$), the motor alters the taps to minimize the error. There may also be protective devices that break the tap circuit if the voltage deviates from the reference too much to be altered by the changing of a tap, or if the current becomes strong enough to damage the equipment. Often, this requires that the regulation has its own protective devices, as the regulation equipment may require lower overcurrent limits than what causes the regular relays to trip.

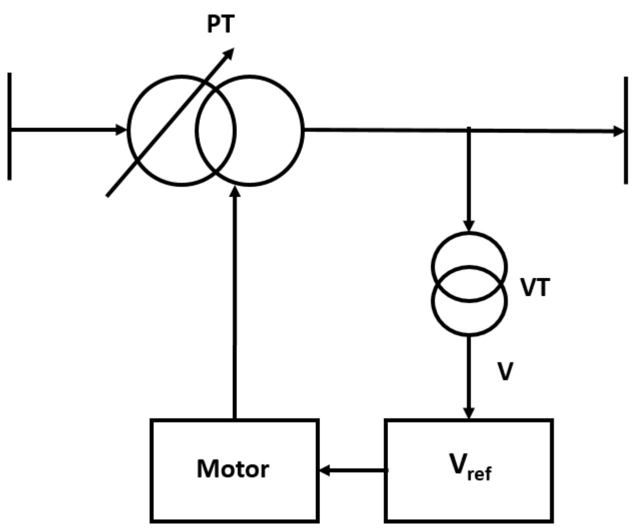


Figure 16: A schematic of a tap changing feedback loop.[12]

As the taps alter the voltage in discrete steps there must be some level of tolerance in the system. This is denoted ΔV and called the “bandwidth”. As long as the control error is less than this tolerance no tap changing will occur. To avoid unnecessary regulation in cases when the voltage deviates beyond the limits for only a short period, a time delay is often implemented on the regulation. This delay can be either inverse or definite, which is analogue to the time delay discussed in the context of autoreclosing in section 3.3.4. In the case of a definite time delay, the time delay is the same no matter how far the voltage deviates from the limits, while in the case of an inverse delay the time delay shortens with larger deviations. The concept is visualized in fig 17. There are several different types of functions for computing the inverse time delay, with the most common one (and the one used in the substation) being:

$$t = \frac{T}{2^{B-1}} \tag{4}$$

where

$$B = \frac{|V - V_{ref}|}{\Delta V} \tag{5}$$

T is a set time (the regulation time when the voltage is at the limit), V is the measured voltage, ΔV is the bandwidth and V_{ref} is the set voltage value.

As soon as the control error is greater than ΔV for longer than the time delay, the regulation will cause the altering of transformer taps to change the voltage until it is within the limits.

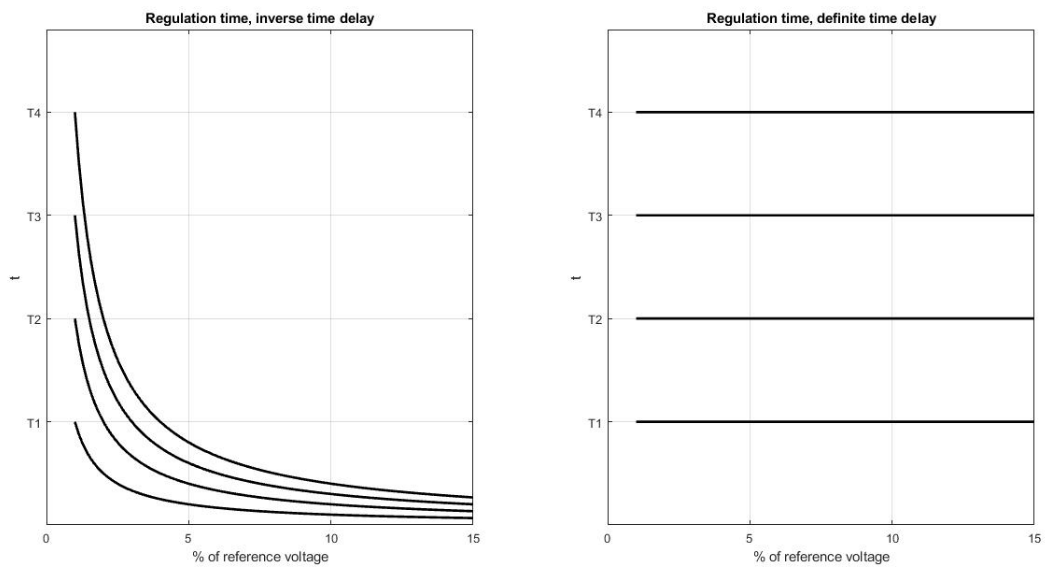


Figure 17: Inverse and definite time delay. For inverse delay, the delay time shortens with higher regulation error. For definite delay, the delay time is constant regardless of regulation error.

3.6 Line drop compensation

The voltage measurements for the regulator are most often taken close by the transformer. However, as the set voltage level is required by consumers separated from the station by several kilometres of transmission lines, so-called line drop compensation is often implemented. Through this, the voltage drop along the lines is compensated for and the voltage at the end of the line is equal to the desired regulation voltage. The voltage drop per phase is estimated to be

$$V_r = \sqrt{3}\frac{IR}{V} \tag{6}$$

for the resistive voltage drop and

$$V_x = \sqrt{3}\frac{IX}{V} \tag{7}$$

for the reactive voltage drop.

Here, I is the current per phase, R is the resistance of the line (Ω/phase) and X is the reactance of the line (Ω/phase). Both R and X are proportional to the line length. This compensation ensures that the voltage is equal to the rated voltage where the consumers need it and not just by the transformer [20].

3.7 Statistical evaluation method

A central part of the evaluation of the voltage regulation at the substation was to calculate the mean time between voltage deviations. This number is a good way to estimate how effective the regulation of a system is, as a small number implies a system with many deviations outside of the allowed limits. A high number suggests that the voltage seldom deviates outside of the limits, implying an effective regulation and a stable system. This is a powerful tool as the distributions derived can be used to calculate the reliability of the system.

If the probability of the system failing before a certain amount of time is modelled as a probability function $F(t)$, then this probability can be modelled as the integral of a probability density function (PDF) $f(t)$ from zero to the specified time:

$$F(t) = \int_0^t f(t)dt \tag{8}$$

If $F(t)$ is the probability that a system fails in a time t, then the probability that it doesn't fail in that time is 1–$F(t)$. This is the definition of the reliability function, $R(t)$:

$$R(t) = 1 - F(t) \tag{9}$$

If the regulation deviations (each time the voltage deviates outside the limits) are considered independent of earlier deviations, the time between them follows an exponential distribution, with the PDF

$$f(t) = \lambda e^{-\lambda t} \tag{10}$$

where λ is the *failure rate*, i.e. the inverse of the average time between deviations.

The probability distribution (or, rather, the *cumulative distribution function*, CDF) is then

$$F(t) = \int_0^t \lambda e^{-\lambda t}dt = 1 - e^{-\lambda t} \tag{11}$$

The reliability function is then, according to equation 9,

$$R(t) = 1 - F(t) = e^{-\lambda t} \tag{12}$$

As the failure rate λ is the only parameter needed for modelling the system in this way, it is very convenient to use for comparing to systems against each other, as the only difference between them is that they have different values of λ. Luckily, λ is very straightforward to measure, as it simply is the inverse of the average time between deviations outside of the limits [21].

4 The substation in the study

4.1 The surrounding grid

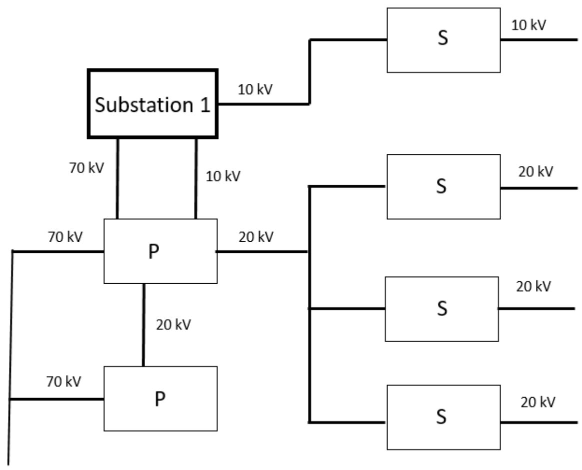
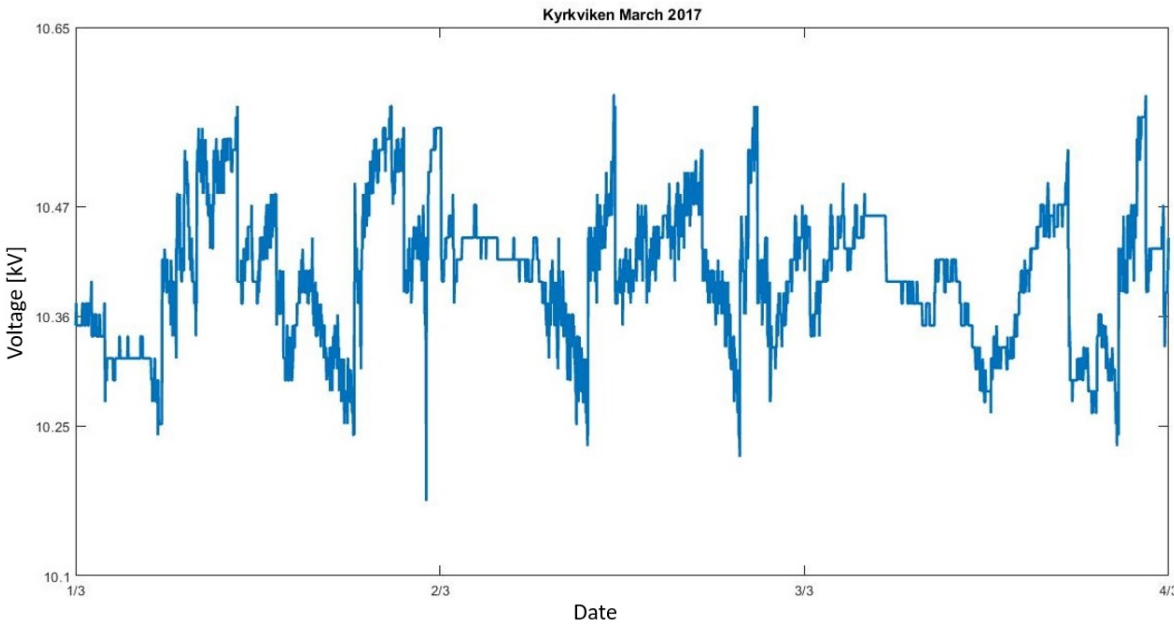


Figure 18: Schematic of the surrounding grid with all voltage levels. The substation in the study in named "Substation 1". The primary substations (P) transform the electricity from high (>50 kV) to medium voltage (between 50 and 1 kV) and the secondary (S) from medium to low voltage (<1 kV).

The substation is one of seven substations in the surrounding grid. The grid is separated from the rest of the regional grid and its small size and autonomy has made it attractive for testing of the CPC system architecture.

The grid has a partially radial structure and is fed at two points, one for normal operation and the other as backup. It has three voltage levels: 70 kV, 20 kV and 10 kV. A schematic of the grid is presented in figure 18. The simple geometry of the grid means that, should the implementation of the new system into a single substation be deemed successful, the new system architecture could easily be tested on a grid where all of the substations were implemented with the new system. The types of consumers in the grid are for the most part residential, with some larger plants and factories. Thus, the grid is made up of several, small consumers rather than a few, heavy loads. This has the consequence that the load profile varies considerably during the course of a day, as the grid voltage spikes during mornings and evenings and drops during mid days and nights, as can be seen in figure 19. A grid with a wider distribution of consumers would have smaller variations, as the factories and offices where the residents go to work each day would compensate for the voltage loss during the middle of the day. This consumer profile can potentially pose challenges for the voltage regulation of the substations in the grid as they must compensate for the variance in grid voltage several times a day [5].



[8]

Figure 19: Voltage profile of the grid from the 1st to the 3rd of March 2017.

4.1.1 Single line diagram

Figure 20 shows a single line diagram of the substation. It is a compact way of representing a complex coupling scheme by way of symbols for common power system components such as transformers and power lines. It also has the advantage of being capable of representing a three phase circuit as having only one phase.

The main task of the substation is to transform incoming voltage from the transmission system at 70 kV to 10 kV for further urban distribution. As can be seen in the diagram, the incoming electricity is passed through a system of measuring and protection devices before encountering the transformers. The 20 MVA transformers transform voltage from 70 kV to 10 kV before passing it on to a busbar with 18 outgoing lines which distributes it to the grid. 14 of these lead to neighbourhood consumers, two distribute the voltage to secondary substations and the last two are a back up connections to a primary substation. Connected to the busbar are two capacitor banks with reactive loads at 2 and 3 Mvar to compensate for the reactive effect of the system. The transformers neutral is connected to reactive and resistive loads for compensating earth fault currents, as well as removing the risk for arcing earth faults.

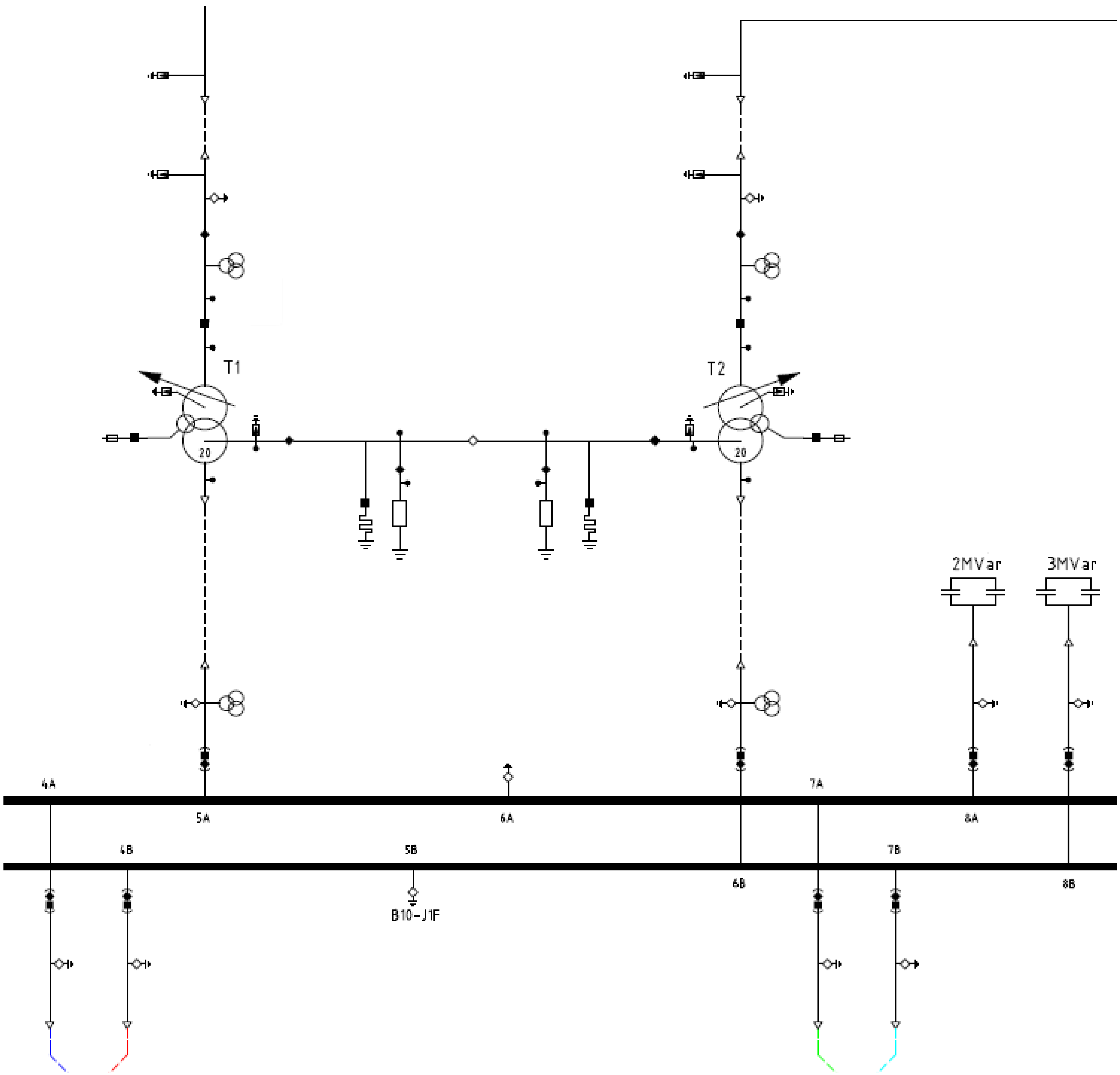


Figure 20: single line diagram of the substation.

5 Method

5.1 Protection functions

The protection functions of the CPC system were comprehensively reviewed, including the logical structure and composition of functionality used to provide the desired protection. They were reviewed both on an individual and on a station-wide level to provide a full oversight of the system's protection configuration. The same was done for the conventional protection functions and both systems were compared on both scales. As the old system fulfills the standards of Ellevio, a part of the evaluation of the new system was simply to determine if it provided equivalent protection. For wider analysis both systems were compared to the standards detailed in section 3.4.

5.2 Voltage regulation

The SASensor voltage regulation function was reviewed and compared to the pre-existing voltage regulation function. To evaluate the performance of the regulation, the voltage of the portion of the grid connected to the station will in the future be analyzed and compared to other, equivalent grid portions regulated by stations with conventional voltage regulation. To enable this comparison, a script was constructed and implemented in MATLAB to extract relevant quantities from voltage data [20],[21]. These were:

- The average value of the voltage and a comparison with the set value of the regulation
- The average deviation of the voltage from the regulation limits
- The average, standard deviation and variance of the voltage during the period
- The proportion of time that the voltage has been outside the limits
- The average time between voltage deviations
- The average regulation time, i.e. the time between a deviation and the voltage's return to the limits
- The dependency of the regulation time on the size of the voltage deviation

5.3 Signal correlation

It was examined whether the log signals of the CPC system convey the correct voltage, power and current values and if there is any time delay in the system's output signals. To do this, the CPC system's log files were compared to reference values and their time behaviour were compared to a continuous measurement. The reference values were taken from Ellevio's Historical Information System (HIS), and for the time comparison a Metrum SPQ measurement unit was connected to all three phases in bay 5A, right "underneath" transformer 1. This bay was chosen as it is the feeder line of the busbars as well as the source of the input values of the voltage regulation. A power quality meter measured voltage, current and power from the 28th to the 30th of April 2018. During this time, there were no significant disturbances in the grid.

The time resolution for the CPC system and the Metrum device was five and ten minutes, respectively. This may seem like a low resolution, but is standard for power grids, as storing values over time with too high resolution would demand too much data storage. These minute average value logs along with recordings of any deviations are the way that such quantities are stored, and are thus of utmost importance for a power station system.

5.3.1 Metrum SPQ

The Metrum SPQ is a power quality meter, developed by Metrum Sweden AB, that measures all standard electrical quantities. It fulfils class A of IEC 61000-4-30 and may thus be used as a reference instrument, however it was in this case used to evaluate if the variations of the SASensor output signals were correct. It saves the signals as ten-minute averages as well as recording harmonics, maximum and minimum values, among other things not used in this study [29].

5.4 Fault responses and error messages

The centralized system's reaction to a cable error-induced ground fault was analyzed and compared to the conventional system. The time stamps of most common error messages that the two systems share were also reviewed to investigate their time synchronisation and correlation. To enable this, a review of SASensor's Digital Fault Recorder (DFR) was made, and the recordings of the DFR for 2017 were analyzed and compared to the alarm messages of the conventional system. Any time delay in the messages was noted.

The list of all alarm messages sent by the two systems in the station was examined and all messages were sorted according to type and log time. They were then compared and any time delay between the two systems were noted. As the two systems did not always send the same messages, the number of times each message was sent from each system in each month was noted.

For the study, only the message types concerning voltage deviations and switchgear positions were considered. These types were chosen for the analysis since they were the only ones with an occurrence frequency that gave statistical relevance (the other types of alarm messages were only received a couple of times).

6 Description of the centralized and the conventional systems

The following sections provides descriptions of the protection functions and voltage regulation of the two systems in the substation.

6.1 Protection functions

6.1.1 SASensor

The protection system implemented in the substation is, as stated above, based on the concept of centralized protection and control. As such, a big part of the functionality of the system is concentrated in the virtual station that is "built" in the station's Human Machine Interface (HMI). In the HMI, all of the station's bays are represented by classes, which mirror their corresponding bay's behaviour and contains all of their functionality. Changing the settings of the components of a bay is therefore done from the HMI by altering the corresponding class, instead of the physical component. Further, implementing a new function in a bay is done by performing a software upgrade of its class, unless the new functionality requires measurement data not provided by the already installed interface modules. In a conventional system, this would require the installation and configuration of a new physical relay. Care is taken to keep the total number of classes to a minimum, enabling the same HMI to be used as a base for new, similar substations.

The substation is implemented in the SASensor system as pictured in figure 21 and 22.

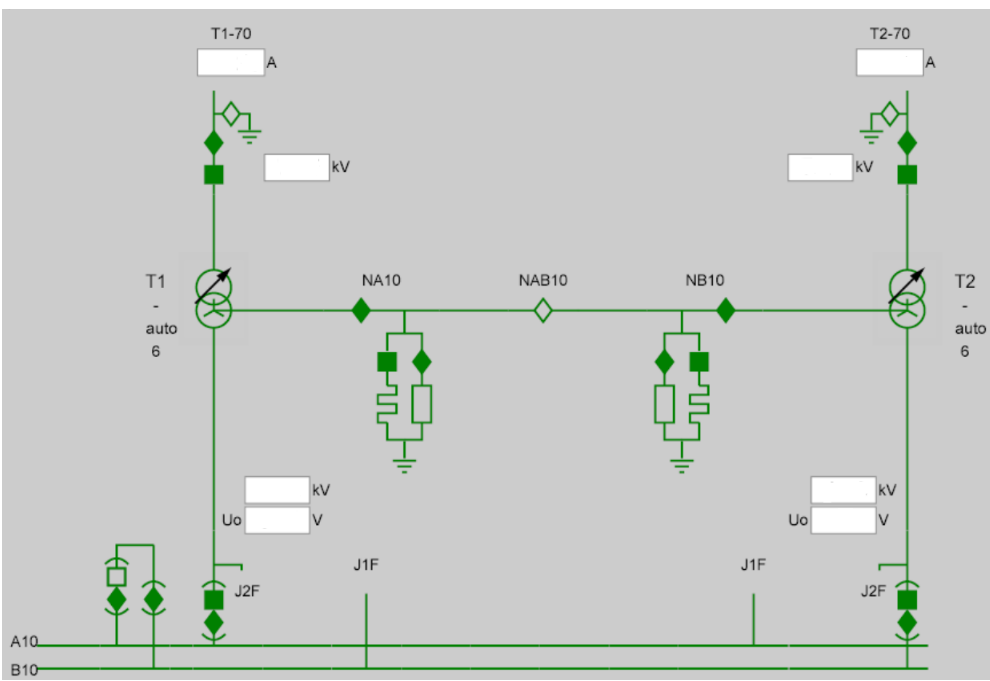


Figure 21: The interface representation of the 70 kV side of the station.

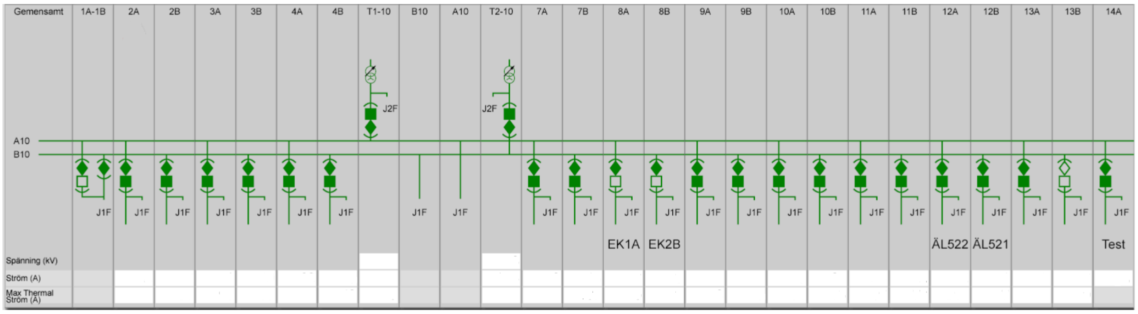


Figure 22: The interface representation of the 10 kV side of the station.

There are three types of classes: Bay classes, logic classes and substation classes. Bay classes are used to configure bays in the substation, logic classes provide supporting functionality of the bay classes and substation classes contain functional descriptions of all non-bay oriented classes. An example of a bay class is a 10 kV line. It has a certain configuration of interface modules protection algorithms based on the modules output data and functionality (for example, overcurrent protection requires current measurement data from a CIM and a breaker requires an output signal from a BIM). The different functionalities of a class are separated into five categories:

- The functional blocks, i.e. how the required functions are implemented. This scheme determines the modules required for a certain bay and what protective functions their outputs should be used for. It also describes functionality such as the filtering of signals before a module and how a protective function's outputs should be coupled to the input of a breaker module.
- The events that trigger an alarm and causes the protective device to trip. It can also contain events that do not require an alarm to trip but still need to be registered.
- A list of exactly how the inputs of the modules should be connected.
- Which signals that are to be recorded by the Digital Fault Recorder (DFR).
- Which signals are to be continually recorded, even though there is no fault or abnormality. These signals are converted to five-minute mean values.
- Which signals that are to be ignored when the class is being tested.

In the substation, nine classes are used for the protection system. They are, from top to bottom in the station diagram in figure 21 and 22: An incoming overhead line, a power transformer, a breaker for a transformer neutral, a transformer with a reactive coil, an incoming line into a busbar, a general busbar, an earthing bay for a busbar, a busbar coupling and an outgoing line.

Incoming overhead line

This class models the overhead lines entering the station at 70 kV. The major functions implemented in this class are:

- Voltage and current measurements
- Overcurrent protection, directional earth fault and arcing earth fault protection
- Control and position indicators of circuit breakers

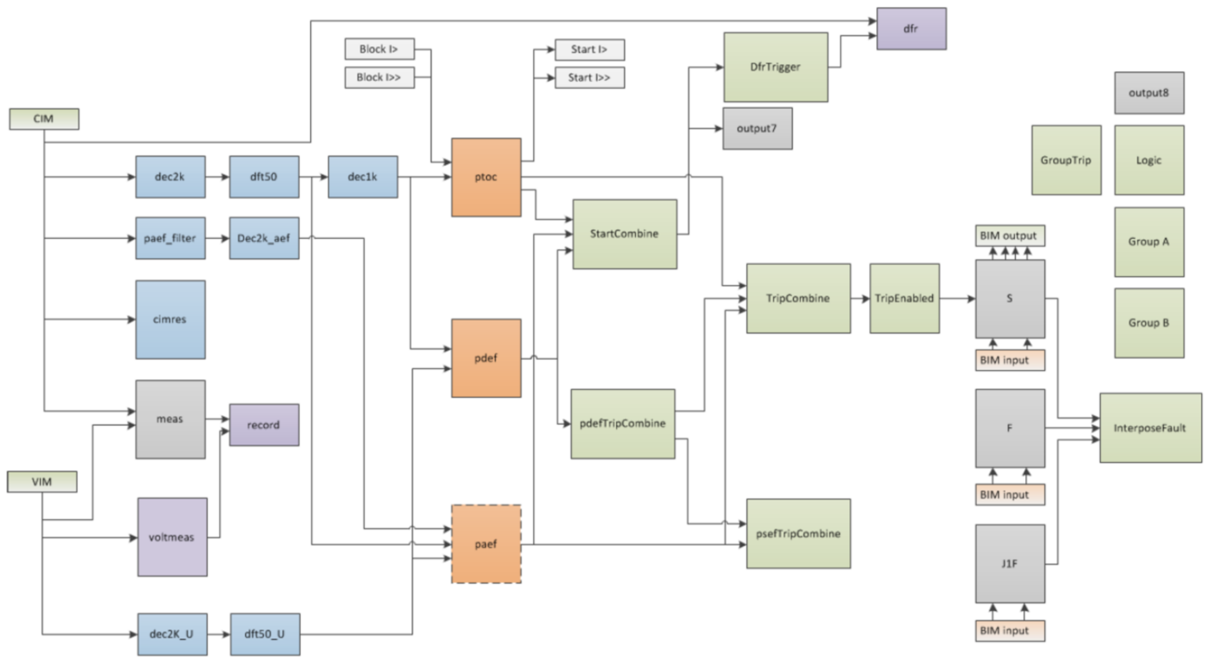


Figure 23: Function block overview of the class for the incoming overhead line.

It has all three types of interface modules (CIM, VIM and BIM) for breaker control and for current and voltage measurements. The overcurrent protection (ptoc) requires current decimation (dec2k and dec1k) to 1 kHz and 50 Hz filtering (dft 50). The same current signal as well as a similarly filtered voltage signal are both input signals into the directional earth fault protection (pdef). The same signals along with a second further filtered current signal are the inputs for the arcing earth fault protection. The output signals are all combined and connected to create inputs for the disconnectors and breakers of the class, as well as serving as inputs for the Digital Fault Recorder DFR that records all notable events. These events are the statuses of all interface modules and breaking devices, initiation and status of protection functions and external signals from the transformer class, such as low gas pressure and operation mode.

Power transformer

This class handles the voltage regulation control, further detailed in section 6.2.

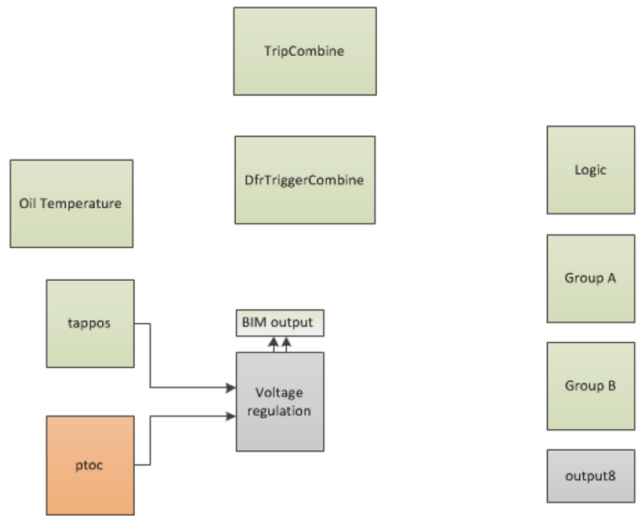


Figure 24: Function block overview of the class for the power transformer.

As stated, the main function of this class is the voltage regulation function and it obtains its module measurements from other, connected classes. Using this, it has overcurrent protection on all phases. It has external measurements that are performed on the transformer itself, concerning oil temperature, level and quality, winding temperature, detection of broken fuses, pressure and tap position. As this class has no DFR connections, there are no defined events.

Earthing of a transformer

This class models the transformer neutral configuration in the substation. It has no protection or measurement functions; the only functionality is that of monitoring and controlling the breakers and the disconnectors. The events are also coupled to those of the breaker modules and other breaking gear.

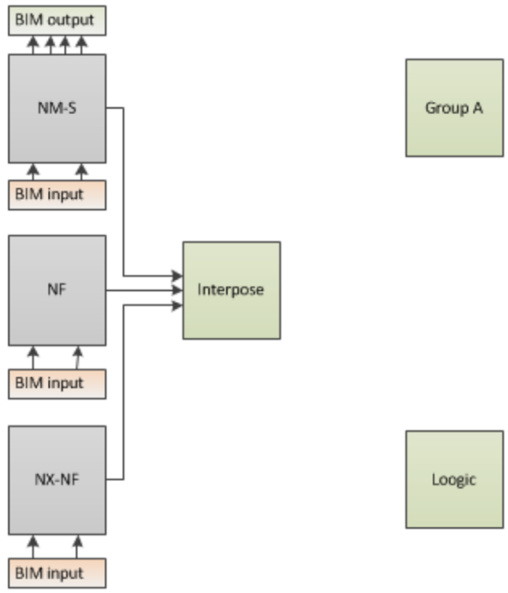


Figure 25: Function block overview of the class for the transformer neutral.

Incoming bay

This class represents the incoming bays from the transformers into the busbars. It has all three interface modules and several protection functions. The main functionality is:

- Position indicators and control of all breakers, switches and disconnectors
- Measurements from interface modules
- Overcurrent, over/under voltage and neutral voltage protection.

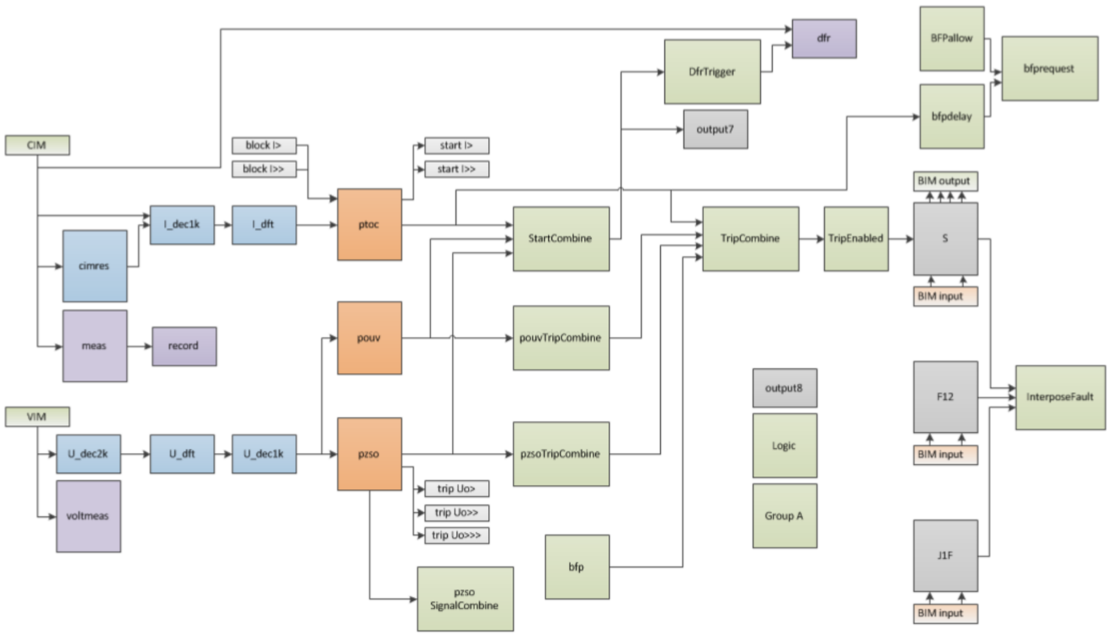


Figure 26: Function block overview of the class for the incoming bay.

The outputs from the current and voltage modules are filtered and decimated before providing inputs to the overcurrent (ptoc), over/under voltage (pouv) and neutral voltage (pzso) protection. The outputs from these functions are connected to breaker devices. All measurements are provided to the fault recorder. The events are similar to those in the incoming line class in they mostly concern the protection functions and the status on the breaking gear.

Double busbar

This class does not contain any own functionality, but is to be combined to other classes in the same system. It is coupled to a class for obtaining the neutral voltage of the busbars by measuring the voltage of two phases to be used for earth fault protection in other bays.

Earthing bay

This class models the earthing of the busbars in the station and only contains breaker module functionality. As there are no analogue signals from a VIM or CIM there is no recording of events.

Coupling bay

This class represents the coupling of the two busbars. The only functionality it contains are for the breakers. As there are no analogue signals from a VIM or CIM there is no recording of events.

Outgoing bay

This class models the outgoing bays in the station. The main functionalities are:

- Monitoring and control of breaking gear
- Voltage and current measurements (voltage measurements from the busbar neutral voltage class)
- Overcurrent, directional earth fault and arcing earth fault protection

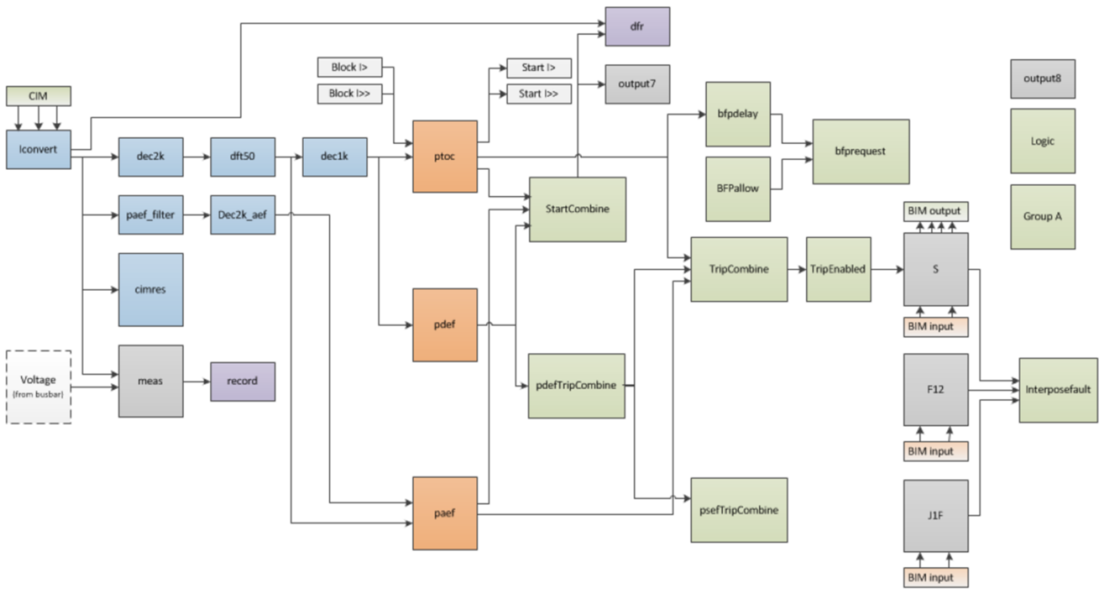


Figure 27: Function block overview of the class for the outgoing bay.

The outgoing bay class uses similar functions like the one previously displayed. The inputs to the protection functions are filtered outputs from the current and voltage modules and the ouputs from the three protection functions are used as inputs to the breaker control functions. Events concern breaker status and protection algorithms.

Breaker for transformer neutral

This class handles the breaking on the transformer neutral and thus only contains a breaker module for breaker control. As there are no analogue measuring modules, there are no recordings or events.

6.1.2 The existing protection system

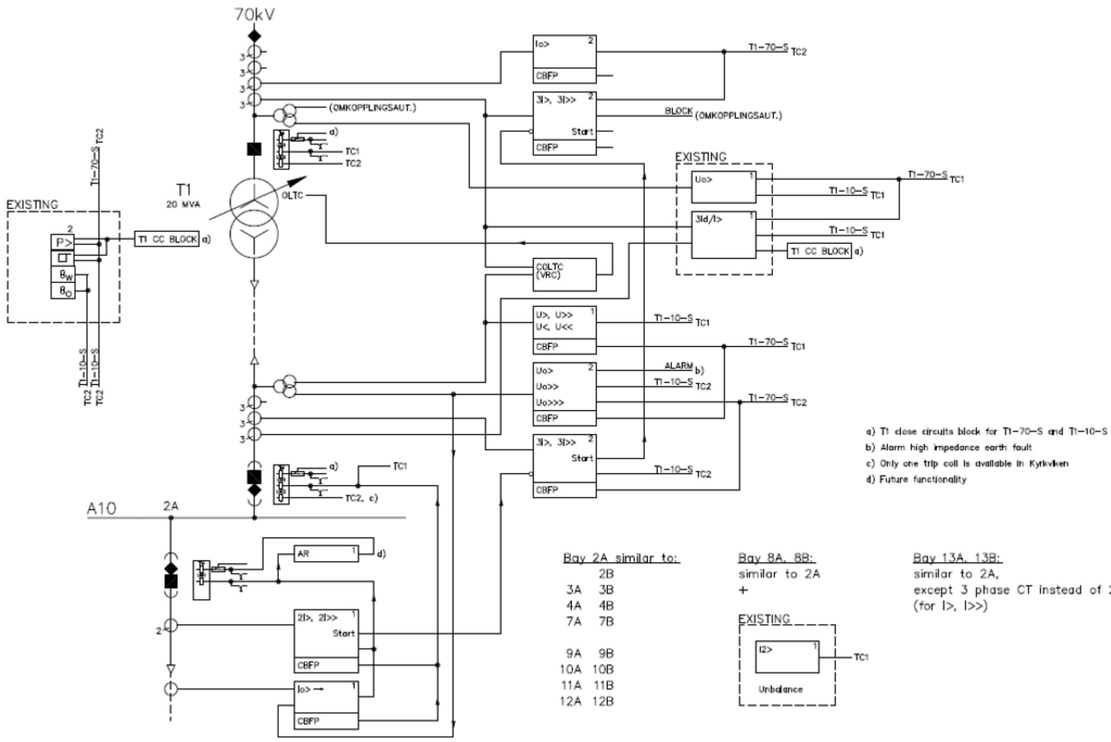


Figure 28: Overview of the conventional relay protection system [23].

The pre-existing protection system in the substation is a conventional relay protection system, where the protection of every critical component is governed by a dedicated relay. Each relay monitors the relevant voltage or current by its corresponding component and performs all necessary protection and control duties, including remote communication with remote monitoring devices and SCADA.

The station is a high to medium voltage (HV/MV) transformer substation with two voltage levels, 10 kV and 70 kV. It is comprised out of three main types of components: transformers, lines, busbars and breakers. Out of these, the components that require protection are the transformers, the breakers and the lines. Busbar protection would have been desired in a larger station, however it has in this case been deemed sufficient to monitor the lines going in and out of the busbars. All the protective relays have circuit breaker failure protection (CBFP).

Above the transformers, at the 70 kV level, the lines are protected by earth fault protection (Io) and three-phase overcurrent protection (3I> and 3I>>). The transformers themselves are protected both "indirectly", by current and voltage monitoring of the in- and outgoing lines, and "directly", by monitoring of physical quantities of the transformers themselves. The direct protection is performed by monitoring the transformer oil's temperature, gas formation due to boiling oil, the oil level, the pressure inside the transformer and the temperature of the windings. The indirect protection is comprised of zero-sequence overvoltage protection (Uo) and three-phase differential protection (3Id/I). Relays measuring the voltage over and under the transformers use the measurements both for performing protective under- and overvoltage protection (U>, U>>, U< and U<<) and for voltage regulation. The transformer neutral protection is seen in the overview scheme of the whole station and the basic is a Peterson coil (that compensates earth fault currents in the transformer).

At the 10 kV level, below the transformers, the feeder lines are protected by 2-phase overcurrent protection (2I>, 2I>>) and earth fault protection. The breakers have independent arcing protection. Not pictured in figure 28 are the capacitor banks, that have relay current monitoring that reacts to any fault currents between the banks.

The protective relays

The overcurrent protection relays are of type SPAJ 3C5 J3, which is a definite time protection relay. This means that the time delay can not be made to depend on the magnitude of a fault current, instead each relay can be set to its own time delay. The relay has two settings depending on the size of the current, indicated by the symbols I> and I>>. If the current is between the two set values the definite time delay function of the relay is activated, i.e. the relay waits for a certain amount of time until taking protective measures. If the current is above the second value, there is no delay and the relay acts instantly [25].

The earth fault protection relays are of type SPAS 1B1 J3. It is a directional earth fault relay and determines the direction to fault by measuring the phase shift between the voltage and the current. It is activated in the case of a current, voltage or phase shift exceeding a set limit [25].

The differential protection relay is of type SPAD 3A5 J3. It continually measures the current on both sides of the transistor and compares to a tolerance current. If the difference in current between the sides of the transistor exceeds the tolerance current the relay trips. The tolerance current is set from 20% to 50% of the relay's nominal current. The relay does not have a time delay functionality [26].

The neutral voltage protection is of type SPAU 1K100 J3. It has two time delay functions, the primary one is always set to about 250 ms and the secondary one is user-definable at even seconds (0, 2, 4 ...). The relay is reset when the voltage is 4 % underneath the set limit [27].

6.2 Voltage regulation

6.2.1 SASensor

Functional overview

In SASensor, the practical parts of the regulation (the tap switching) are the same as for the conventional system. The difference is the software, which is based on the SASensor Voltage Regulation Control Function (VRC).

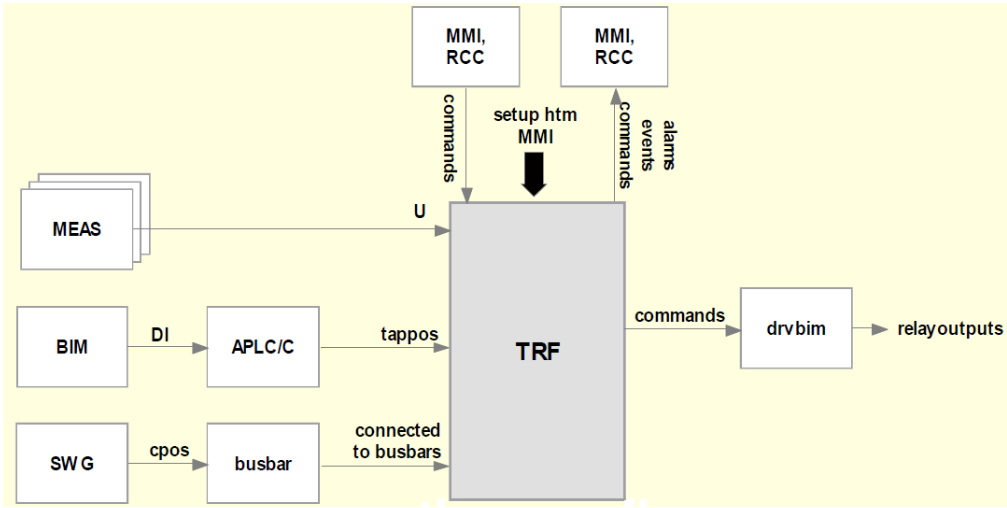


Figure 29: Functional overview of the voltage regulation function in SASensor.[30]

Figure 29 shows an overview of the implementation of the VRC function in SASensor. In the software, the voltage regulation of all transformers in the station is represented by the software module TRF. It receives voltage measurements (MEAS), tap position (tappos) and busbar breaker status (cpos). It can also receive commands from the web interface (MMI) or from the remote control centre (RCC), such as what mode to operate in or if it is to change its status. It sends alarm and event messages to the MMI and RCC and gives commands to the breaker modules connected to the tap changer of the transformer to lower or increase the busbar voltage.

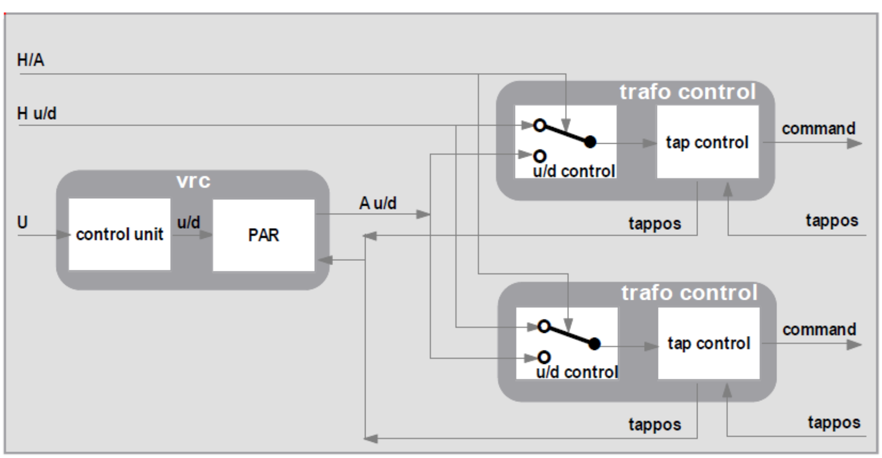


Figure 30: Functional overview of the TRF function block in SASensor.[30]

The TRF block, pictured in figure 30, has three internal blocks, a VRC (Voltage Regulation Control) block and one trafo control (transformer control) block for each transformers coupled to the voltage regulation.

Every second, the voltage measurements are used as input signals to the VRC block, which calculates the regulation strategy. This results in the sending of an up (u) or down (d) command to the PAR (parallel voltage control module) which, in the case of automatic master-slave mode, sends the signal further to all transformer control blocks, ensuring that they all get the same command input. After a certain time delay, a command signal is sent to the tap changers which results in an altering of the busbar voltage. The actual regulation is however performed individually to compensate for the fact that the changing of the taps in the different transformers may not take the same amount of time.

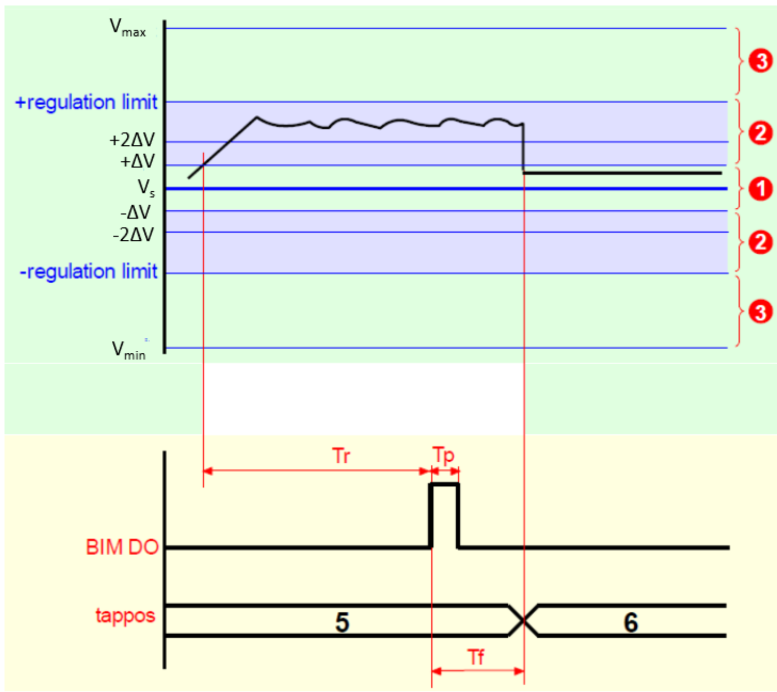


Figure 31: Time/Voltage diagram showing the voltage regulation function's response to a voltage deviation.[30]

Figure 31 shows a time versus voltage diagram during the changing of a tap to regulate the voltage. V_s is the voltage that is desired to be maintained at the busbars, ΔV to $-\Delta V$ is the bandwidth, i.e. the voltage span in which no regulation is done. If the voltage is between $\pm\Delta V$ and $\pm V_{max}$, regulation will be performed automatically. T_r is the reaction time, i.e. the time it takes for the regulation to start. When the voltage is equal to $V_s \pm \Delta V$, the reaction time is the longest and it decreases linearly until the voltage is $V_s \pm 2\Delta V$, after which it is always the minimum time. The time characteristic is shown in figure 32.

T_p, the pulse time, is the time it takes for the tap change command to be sent and T_f, the follow-up time, is the time taken from when the voltage has exceeded the limits long enough for the regulation command to be sent until the tap changing happens.

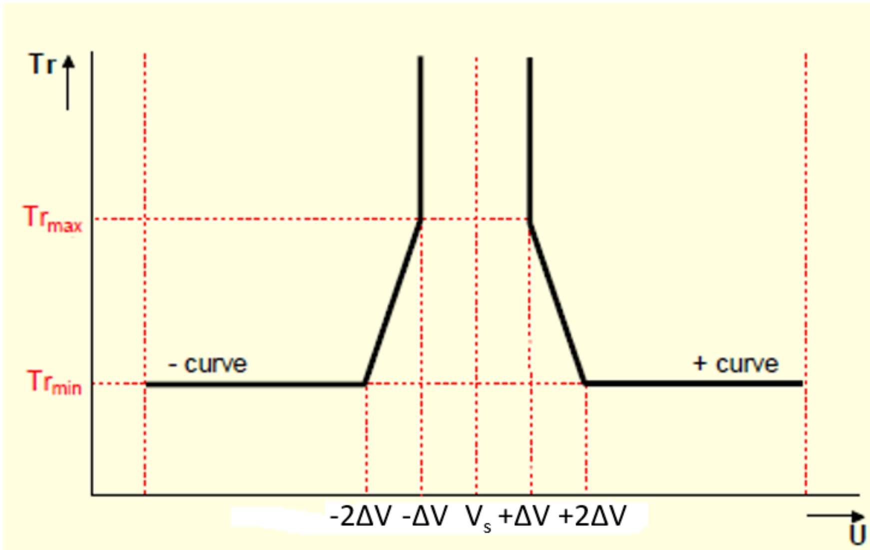


Figure 32: Time characteristic of the regulation response of the VRC function.[30]

Line drop compensation

The voltage regulation function has line drop compensation, which in the documentation is named compounding. It is however implemented in a slightly different way than in the conventional system. The formula used for calculating the voltage at an arbitrary point in the grid network is:

$$V_{bl} = \sqrt{(V_b - a)^2 + b^2)} \tag{13}$$

where

$$a = \frac{-(RP + XQ)}{V_b} \tag{14}$$

and

$$b = \frac{-(XP - RQ)}{V_b} \tag{15}$$

V_{bl} is the compounded voltage, i.e. the voltage that is to be kept at the chosen point in the grid. V_b is the busbar voltage, R and X are the resistive and reactive resistance of the connecting cables (like in the conventional model), P and Q are the active and reactive components of the power. When this compensation is in effect, V_{bl} is the voltage that is compared to the voltage limits in the regulation function[30].

6.2.2 The conventional system

The substation has two parallel power transformers that can be set to two modes, master-slave (where the regulation on one transformer governs that of the other) or individual operation. During low-load periods like summer, one transformer is disconnected but its regulation follows that of the connected one in a master-slave manner. Thus, when both come online they will output the same voltage. When both are connected, they are regulated independently of each other.

The two transformers have 19 taps that each change the voltage by 1.67 %. The bandwidth is approximately 1.34 % of the reference voltage [20].

6.2.3 The evaluation script

The following sections provide a review of the script and its functionality. The complete MATLAB code is presented in the Appendix.

Reading and plotting substation voltage data

As voltage data retrieved from Ellevio's Historical Information System (HIS) are in the form of Excel worksheets, the data is read using the standard MATLAB function xlsread that translates an Excel worksheet into a numeric matrix. However, other formats may be used.
The data is then plotted with lines showing the regulation limits and the set value of the regulation. Figure 33 shows voltage data from the substation the first of March 2018.

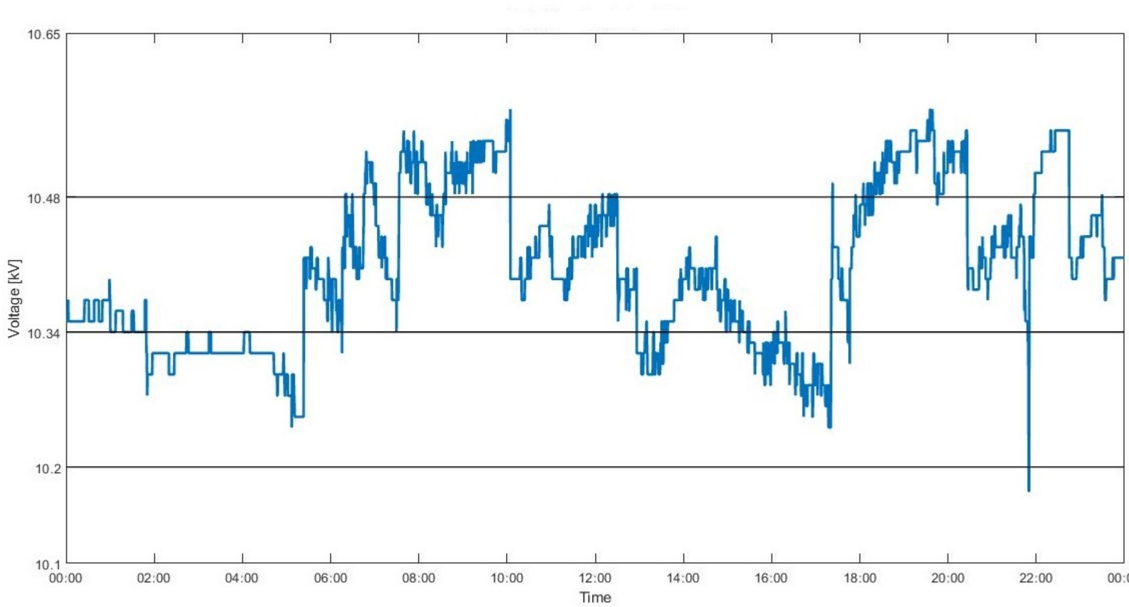


Figure 33: An example of voltage data read from HIS, taken from the substation as one second averages during the first of March, 2017.

Average, relative average error, standard deviation and variance

The standard deviation and variance are all calculated using MATLAB's standard functions `std`, `var` and `mean` and will thus not be demonstrated here. The average is compared to the set value using the relative average error, defined as

$$E_{rel} = |\frac{V_{set} - V_{avg}}{V_{set}}| \tag{16}$$

Deviation from the limits

The mean deviation from the limits and the proportion of time that the voltage has been outside of the limits are calculated. This is done by comparing the data points with the limits and sorting those that are too high or too low into two vectors. From these, the limits are subtracted and their average values are calculated to obtain the average deviation above and below the limits. This is done individually for deviations from both the lower and upper limits and, if both types of deviations exist, for all deviations regardless of type. To obtain the proportion of points outside of the limits, the number of deviating points are simply divided by the total number of data points. It should be noted that in this part of the script, no interpolations are made between data points to increase the accuracy and the method is therefore highly dependent on the resolution of the data. The deviation time is therefore a qualitative evaluation method and requires that the compared data sets are relatively similar in terms of resolution and magnitude.

To summarize, this part of the script provides:

- The deviation of all voltage values outside of the limits
- The deviation of all voltage values higher than the upper voltage limit
- The deviation of all voltage values lower than the lower voltage limit
- The average deviation of all voltage values outside the limits
- The average deviation of all voltage values higher than the upper limit
- The average deviation of all voltage values lower than the lower limit
- The proportion of time that the voltage is outside limits
- The proportion of time that the voltage is higher than the upper limit
- The proportion of time that the voltage is lower than the lower limit

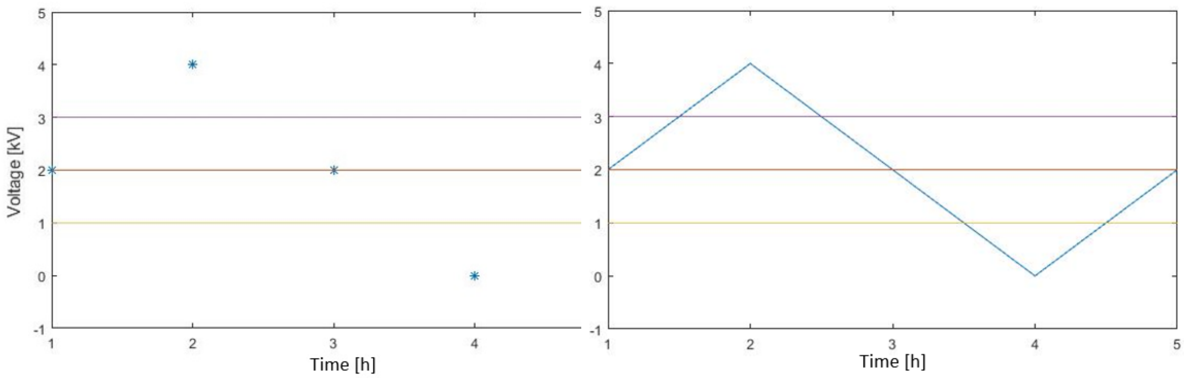
Regulation time

The next quantity to be calculated is the regulation time: The time it takes for the voltage to return to between the limits. To do this, it uses two functions that take the voltage data set and the corresponding limit and returns a vector of the time length of each deviation. If there are no deviations to one side of the limits, the corresponding functions will simply return a zero. The functions interpolate linearly between the first and last points of deviation and the ones before the first and after the last point, to compensate for the resolution of the data. The functions are used as follows:

To demonstrate how this works, a voltage data vector was constructed as [2 4 2 0 2] with upper and lower limits set to three and one. The set value was two. The voltage data points and the limits are pictured in figure 34a. Figure 34b shows what the regulation time functions "see", which is linear interpolations between the data points. The functions then calculate the time that the curve in figure 34b is outside the limits. This gives:

- Regulation time for high deviations: 1
- Regulation time for low deviations: 1
- Average regulation time for high deviations: 1
- Average regulation time for high deviations: 1
- Average regulations time for all deviations: 1

Which is correct. It should be noted that in this case the time would be the same with or without the interpolation, however it is only because all of the lines have a derivative equal to ± 1. As soon as this is not the case, the interpolation will result in a more accurate value.



(a) (b)

Figure 34: A representation of how the regulation time is calculated. a) A plot of the vector with the elements represented as points on a graph. b) Linear interpolations between the elements. The regulation time is the time from when the line crosses a limit until it returns.

The regulation time functions

The two functions used for calculating regulation time work in complete analogy; calculating the time that the voltage is outside the respective limit. If the data sets begin or end with deviations, i.e. if the voltage is outside of the limits when the set starts or ends, those deviations are ignored as it is impossible to know their duration.

As soon as the one of the functions encounter a data point that is outside of the limit and who's preceding point is inside the limits, it makes a linear interpolation between these points and uses this to estimate at what time the line crosses the limit in the following way:

$$y = kx + m \Leftrightarrow t_{lim} = \frac{V_{lim} - m}{k} \tag{17}$$

The script then counts steps until it encounters a point inside the limit and does the same interpolation again. It ends by summing the two interpolations and the steps between them.

The function ends by investigating if there any deviations at all by checking if the regulation time vector is empty or not. If empty, it is simply set to zero.

Time between events

After calculating the regulation time, the script calculates the average time between events. An event begins when the voltage deviates outside the limits and ends when it returns to inside the limits. The time between two events is therefore the time between when the voltage returns to when it deviates again. To do this, a function is called which returns a vector with all such times. It then takes the average of these vector elements to calculate the mean time between events.

The event time function

The function calculates the time when no event occurs, in a similar way as the regulation time functions, by linear approximations between data points inside and outside of the limits. It has the data set and the limits as input arguments and outputs a vector with the number of time steps between every event.

First, it creates two vectors that contains all the times when the voltage crosses the limits. It starts by testing whether the voltage deviates from outside one limit to outside the other in one time step.

If not, it compares the points in analogue to the regulation functions. The difference between the elements in the out- and in-vectors is the time between events, with care taken if the voltage started or ended outside of the limits, in which case the first or last crossing is ignored.

Regulation time and deviation size

The last thing that the script does is to plot the regulation time of an event against the maximum deviation of that event. This is done by constructing a matrix where the rows represent vectors containing the indices of all data points involved in each event. The matrix has a number of rows equal to the number of events and the number of columns of the longest event (which therefore has the biggest number of data points). To compensate for the fact that not all events have the same number of indices, zeros are used to fill the unused places. For example, if the voltage data vector is constructed as [2 4 5 4 2 0 5 2], pictured in figure 35, with voltage limits equal to 1 and 3, then the matrices representing high and low deviations equal:

$$\begin{bmatrix} 2 & 3 & 4 \\ 7 & 0 & 0 \end{bmatrix}$$

for high deviations, as the points involved in the two high deviations are number 2, 3 and 4 for the first deviation and 7 for the second. For the low deviations, the matrix is simply

$$\begin{bmatrix} 6 \end{bmatrix}$$

as there is only one low deviation and there is only one point involved in it.

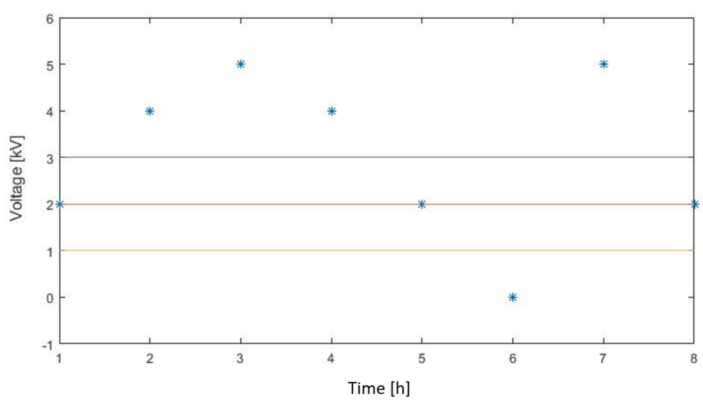


Figure 35: A plot of the demonstration vector [2 4 5 4 2 0 5 2], with lines representing the limits and the set value.

These matrices are used to create new matrices with the indices replaced by the voltage values in the corresponding data points. In the case of the demonstration vector, this gives:

$$\begin{bmatrix} 4 & 5 & 4 \\ 5 & 0 & 0 \end{bmatrix}$$

for the high deviations and

$$\begin{bmatrix} 0 \end{bmatrix}$$

for the low. In this case, it can be confusing that the unused places are filled with zeros while zero is a possible value. In a real scenario the voltage would never reach zero unless there was a large malfunction in the system which would be identified in another way.

The maximum deviations are calculated as the maximum or minimum values of the rows of the new matrices and placed in two vectors, for low and high deviations. In this way, the maximum deviations from each subsequent event are ordered, just as in the regulation time function which contains the regulation time for the events in the same order. These are then plotted as regulation time against maximum deviation.

The event index function

To link deviations to certain data points, a function is used that uses the voltage data set and the high and low limits as inputs and outputs the two matrices with indices of each event. It starts by using similar methods as the aforementioned functions to find the time when the voltage crosses the limits, resulting in four vectors that contain the time when the voltage deviated upwards or downwards and when it returned. Using this, two vectors containing all indices between the limit crossings are created. Using these, it is possible to link all data points outside the limits to certain events.

7 Results

7.0.1 Comparison between the protection functionality of the two systems

Bay	Conventional	CPC	ABB (rec standard)	MCEC
Incoming line, 70 kV	Earth fault, 3-phase definite time overcurrent	Directional and arcing earth fault, 3-phase definite/inverse time overcurrent	Overcurrent protection, earth fault	Unspecified
Transformer, direct protection	Oil temperature, oil level, pressure, Buchholz, winding temperature	Oil temperature, oil level, pressure, Buchholz, winding temperature	Oil temperature, oil level, pressure, Buchholz, winding temperature	Not specified
Transformer, indirect protection	Zero-sequence overvoltage protection, 3-phase differential protection, over- and undervoltage protection	Zero-sequence overvoltage protection, 3-phase overcurrent protection, over- and undervoltage protection	Overcurrent protection, differential protection, over- and undervoltage protection	Overcurrent protection, differential protection, over- and undervoltage protection
Transformer neutral	None	None	None	None
Incoming line to busbar, 10 kV	Integrated in indirect transformer protection	Overcurrent protection, over- and under voltage protection, neutral overvoltage protection	Overcurrent, directional earth fault	Overcurrent protection
Busbar	None	None, voltage measurements	Decentralized busbar protection (differential)	None
Capacitor bank	Unbalance current monitoring, 2-phase definite overcurrent, earth fault	None	None	None
Busbar coupling	2-phase definite overcurrent, earth fault	None	None	None
Outgoing cable, 10 kV	2-phase definite overcurrent (3-phase in 13A to Koltorp), earth fault	3-phase definite/inverse overcurrent, directional and arcing earth fault	Overcurrent, directional earth fault	Overcurrent, autorecloser

Figure 36: A comparison between the protection functionality in the conventional and centralized systems as well as the previously reviewed systems.

Figure 36 shows a summary of the protective functions in each part of the station. The two systems mentioned in section 2.1.1 are used for comparison. Following section provides a more in-depth review of the functions in each type of bay.

Incoming line, 70 kV

The incoming line is in the conventional system protected by earth fault and overcurrent protection relays. The overcurrent relay has a user-adjustable definite time delay but no inverse time delay functionality. The earth fault relay is directional with no arcing functionality, which is not needed as the neutral is grounded. The instrument transformer is connected to all three phases and thus even symmetrical faults on all phases, however unlikely, will be detected.

In the CPC system the incoming line is also protected using earth fault and three-phase overcurrent protection. The earth fault function has both directional and arcing functionality and the overcurrent function has both inverse, definite and instant time delay.

Both systems meet the ABB standard, and the biggest difference is that the CPC system has an inverse time function. The MCEC does not have the incoming line included in its protection scheme.

Transformer

The transformer has the same direct protection in all systems: The level, temperature and physical state of the transformer oil as well as the internal pressure and temperature of the tap windings are monitored.

The equipment and lines surrounding the transformer are in the conventional system protected by zero-sequence voltage (in the case of an earth fault), 3-phase differential and over- and undervoltage (from the voltage regulation) relays. The two reference systems have the same type of protection: Overcurrent, differential and voltage protection. The CPC system lacks differential protection, but shares the other types of protection.

Transformer neutral

None of the systems have dedicated neutral protection, except for breaker control. However, the neutral itself consists of a Peterson coil, which in itself provides protection.

Incoming line, 10 kV

In the conventional system, as the incoming line to the busbars are in direct contact with the transformer, it is protected by the same relays as the transformer itself. This means that it has zero-sequence voltage and over- and undervoltage relays (the differential protection only concerns the transformer). In the CPC system, the protection of the incoming bay is designed the other way around, having the indirect protection functions in the class for the incoming bay. Thus, it has overcurrent, over- and under voltage protection and neutral overvoltage protection (for ground faults).

The systems in the substation both have superior functionality in comparison to the reference systems.

Busbar

None of the systems have dedicated busbar protection. The CPC has a voltage measurement module with the purpose of being of use in the future as basis for protection of the outgoing lines.

The MCEC system does not have any busbar protection and the ABB has the same type of protection as discussed in section 3.2.

Capacitor bank

The conventional system has the same functionality implemented in the capacitor bank bay as the outgoing bays: 2-phase time definite overcurrent and directional earth fault protection. Aside from this, it also monitors any unbalance currents between the capacitors in the bank. In normal operation, the capacitors should be in balance, with no current flowing between them. A current is therefore a sign that there has occurred a disturbance. As the CPC system does not have any class for the capacitor banks it therefore has no protective functions. The two reference systems do not have any specifications of capacitor bank protection.

Busbar coupling

The conventional system has the same protection functions on the busbar coupling bay as the outgoing bays: 2-phase time definite overcurrent and directional earth fault protection. The CPC system has breaker control but no other functionality.

Outgoing cable

The conventional system has two-phase (three-phase for bay 13A and 13B) definite time overcurrent protection and directional earth fault protection on all outgoing cables. The CPC system has three-phase, inverse time overcurrent protection and directional and arcing earth fault protection on all lines.

The same protection concept is implemented in the ABB system. The MCEC system has, different to the other systems, an autorecloser. This is however deliberately not implemented as any faults on the cables are assumed not to be of transient character.

7.1 Voltage regulation

The script, demonstrated in section 7.2.3, was used to analyse the time regulation of the centralized system. Voltage data was obtained from the voltage logs at the station from the 1st to the 10th of March, 2017. The time resolution was five minutes, which may be too coarse for a fair evaluation as the regulation is meant to happen in a matter of seconds or minutes, which opens the possibility that some voltage steps may be hidden. An ideal evaluation requires simultaneous data from a comparable station, preferably in the same grid. This was not possible in the scope of this project. However, the data can be used to draw conclusions of the system by comparing the actual values to the set values of the regulation function.

Figure 37 shows the voltage data from the log files of the centralized system. The lines in the figure indicate the set value of 10.34 kV and the voltage limits at 10.48 and 10.20 kV. As can be seen, the voltage is for most part inside the limits, but deviates a few times during the period. The key values for evaluating the regulation mentioned above are presented in table 1. First, the set values are presented and then the values describing the overall deviation and behaviour of the voltage. The subsequent values regard the specific deviation behaviour and how quickly the system regulates the voltage back to within the limits.

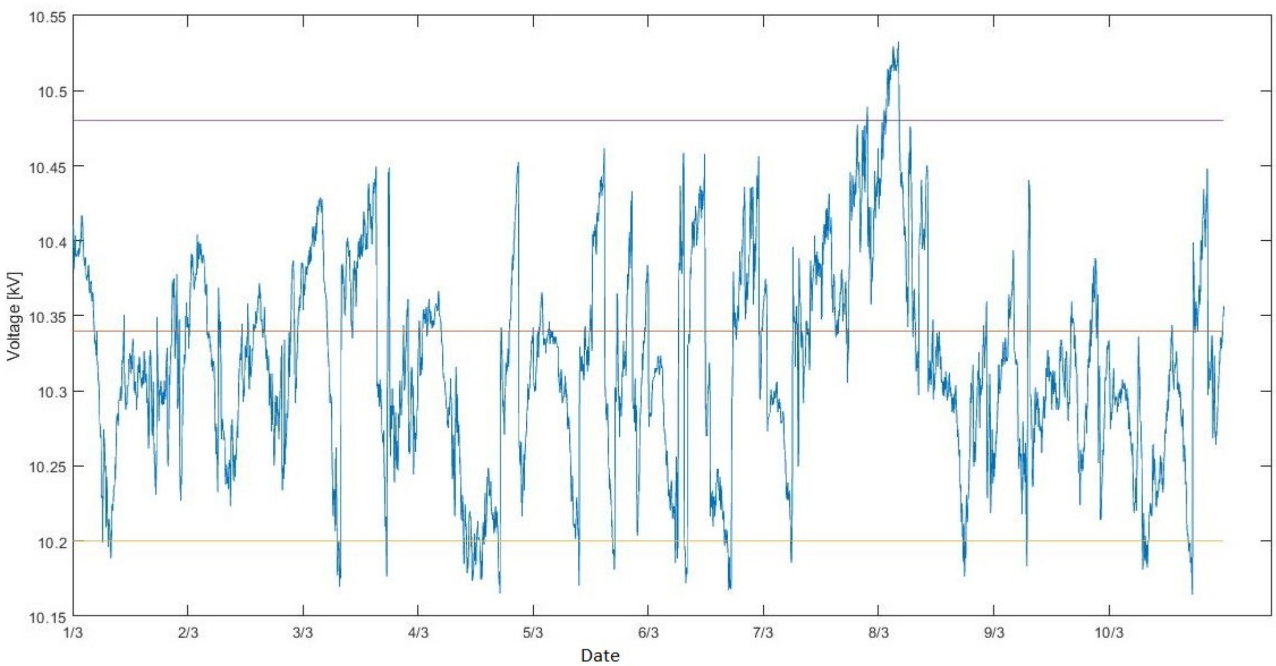


Figure 37: Voltage data from 1/3 to 10/3 2017. The time resolution is five minutes. The lines indicate the set voltage and the lower and upper voltage limits.

Type of delay	Time [s]
Reaction time, same direction T_{r1}	30
Reaction time, opposite direction T_{r2}	60
Follow up time T_f	20
Pulse time T_p	1

Table 1: Set regulation time delay values in the HMI.

Set voltage V_s [kV]	10.34
Upper limit $+\Delta U$ [kV]	10.48
Lower limit $-\Delta U$ [kV]	10.20
Standard deviation [kV]	0.0686
Average voltage [kV]	10.318
Deviation of average voltage from set voltage E_{rel}	0.21 %
Proportion of time outside limits	5.2 %
Average deviation [kV]	0.018
Average regulation time T_r [min]	22.23
Average time between deviations [min]	80.61

Table 2: Evaluation values obtained by the script for the voltage data presented in figure 37.

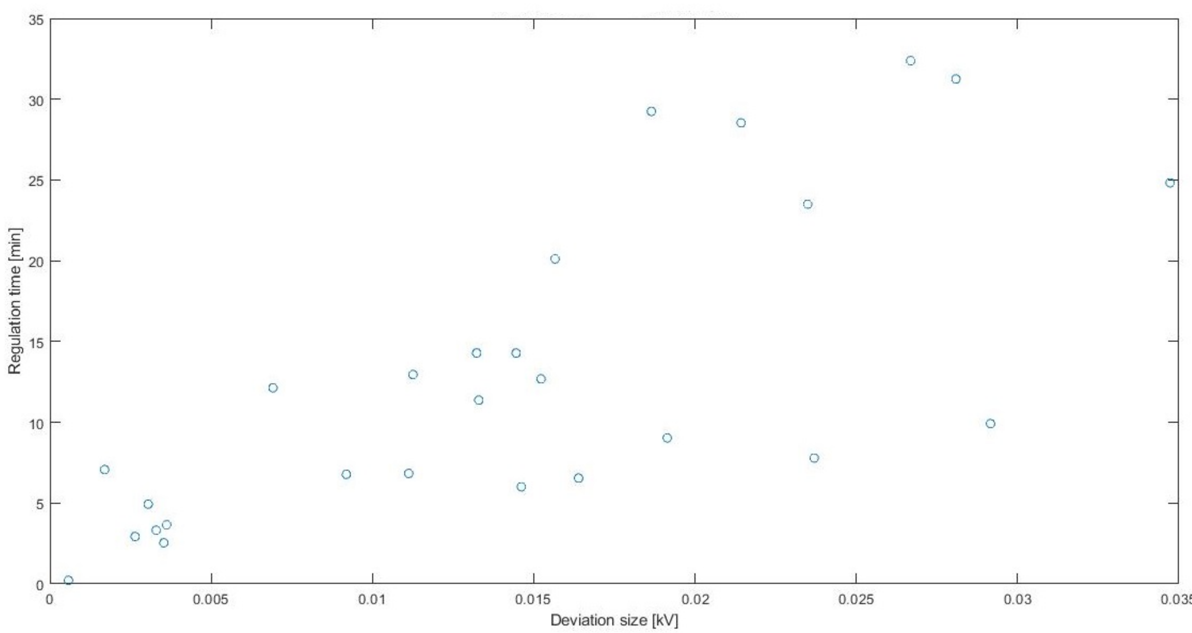


Figure 38: Time delay characteristic of the voltage regulation.

7.2 Signal correlation

7.2.1 Reference values

As stated, HIS was used to obtain reference values for the current and voltage of the two systems (the conventional and the centralized) and the Metrum SPQ device was used to evaluate the adherence of the system to changes in voltage and current, that the uncertainty in the HIS data was too large to show. The values in HIS are averages of the current and voltage of all three phases and thus the three-phase average was taken of the Metrum and log files as well. In HIS, the values from the two systems did not match perfectly and thus provided a tolerance level to the value of the measured quantities: If the values from the log files correspond to the HIS values as well as the difference between the two data series, they are precise within the limits of the resolution of HIS.

At first, the Metrum measurements were constantly greater than the measurements obtained from the centralized system. As they were on average above 11 kV it was assumed that the device was incorrectly calibrated, as such a high voltage would have tripped the station's protection systems. Further, the purpose of the Metrum measurement was not to supply data with the correct value, just with the correct time dependence. Thus, the values obtained from the Metrum device were shifted so that they were as close as possible to the values obtained from the SASensor log files, eliminating any deviations due to offset differences. By doing this, any differences in the time-dependent behaviour of the data series was evident.

To calculate the time delay between the measurements, corresponding points in both data sets needed to be identified. To do this, voltage and current peaks were used as reference points as those were the most distinct points. Peaks were defined as where derivative of the interpolated lines between the points changed sign. It was assumed that the time delay of the centralized system would not exceed its resolution. Therefore, if a peak was delayed by more than five minutes, it was ignored as that peak would correspond to a peak that was not visible due to the resolution being too low. Some examples of peaks that were treated differently according to the assumption are presented in figure 39. Peak 1 is an example of when the Metrum signals peaks before the CPC signal while in the case of peak 2 both signals peak at the same time. In the case of peak (or rather valley) 3 the signal from the centralized system apparently peaks before the Metrum signal, which is ignored as the Metrum signal is used as reference. The peak is thus assumed to correspond to a "hidden" peak that is invisible due to the resolution being too high.

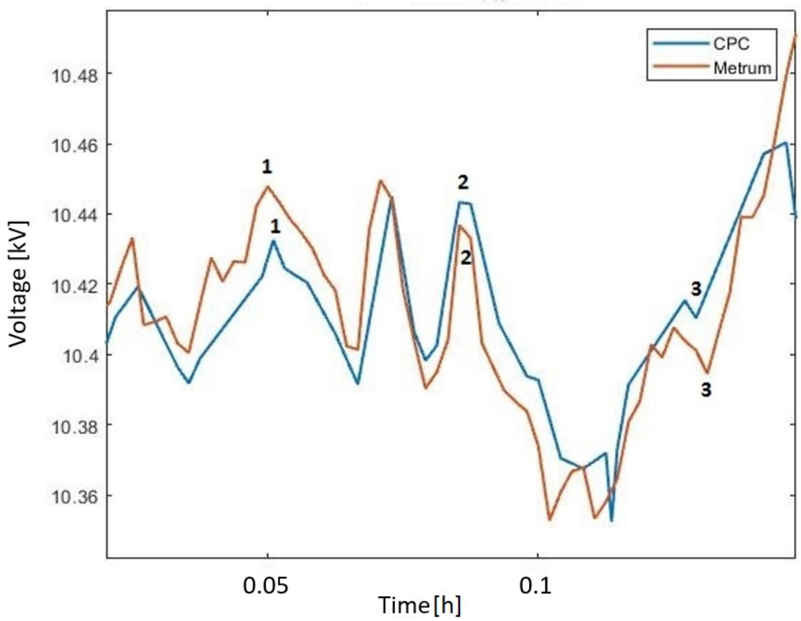


Figure 39: Examples of matched peaks in the signal comparison.

7.2.2 Magnitude comparison with HIS

Figures 40 and 41 show the signals obtained from both systems from HIS and the logs files of the centralized system.

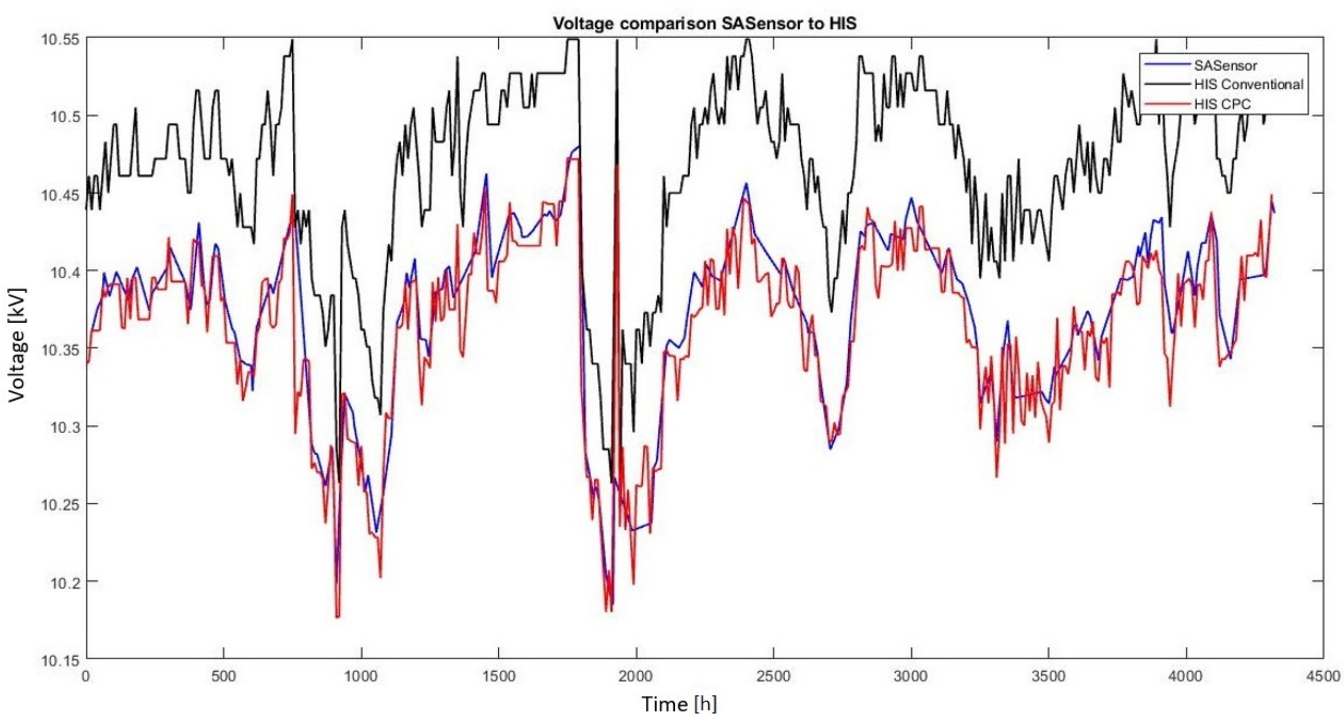


Figure 40: Voltage signals from HIS and the centralized system logs over three days

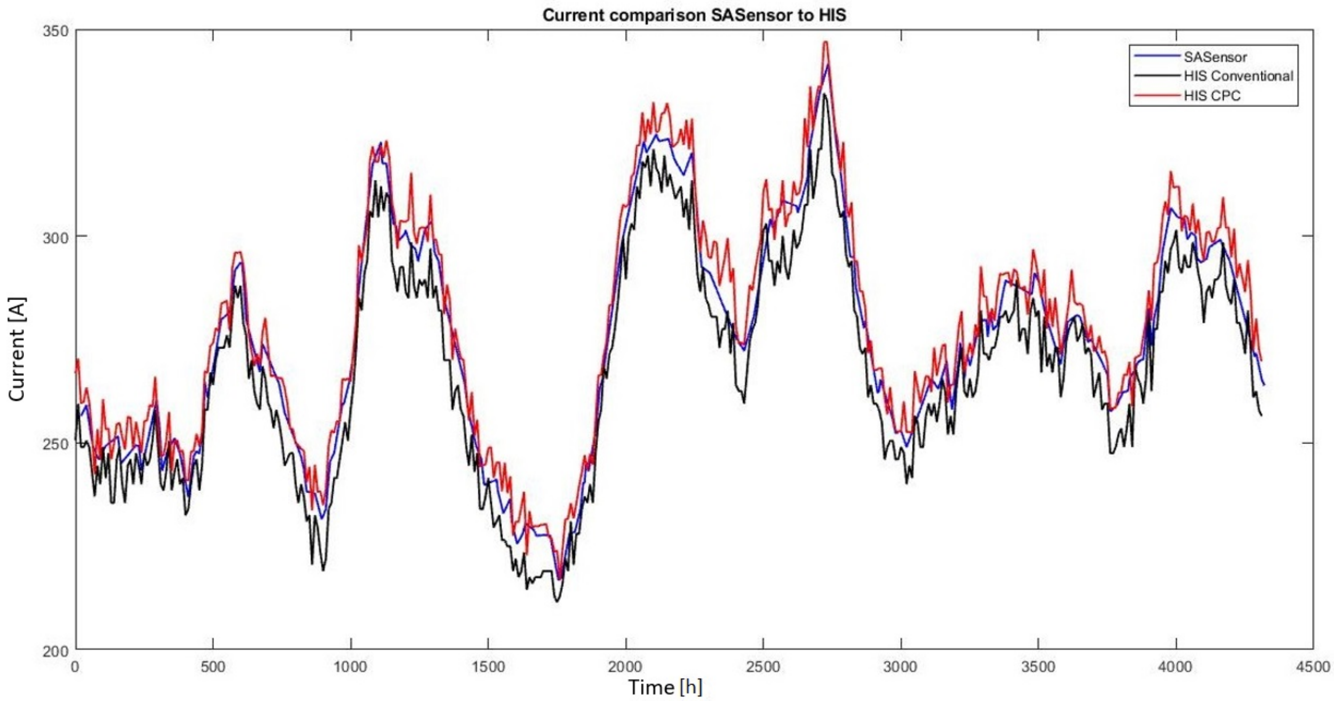


Figure 41: Current signals from HIS and the centralized system logs over three days

7.2.3 Time synchronization comparison with Metrum SPQ

Figures 42 and 43 show the log signals from the Metrum device and the CPC system. As the Metrum device was not calibrated thoroughly the two measurements deviate from each other but follow each other in time.

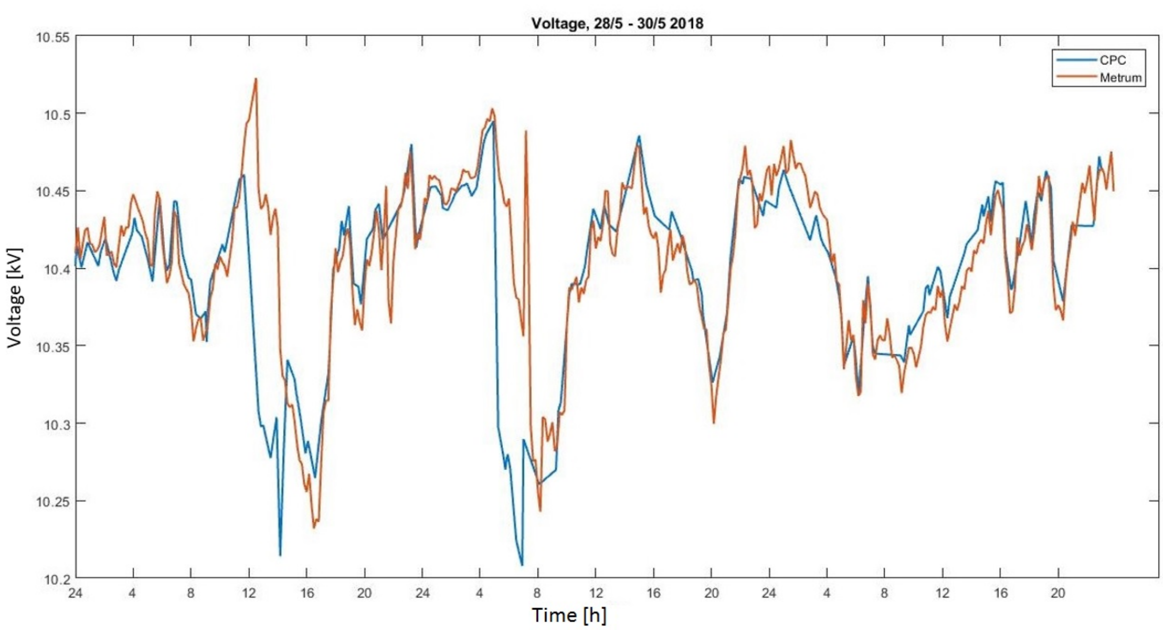


Figure 42: Voltage signals from HIS and the centralized system logs over three days

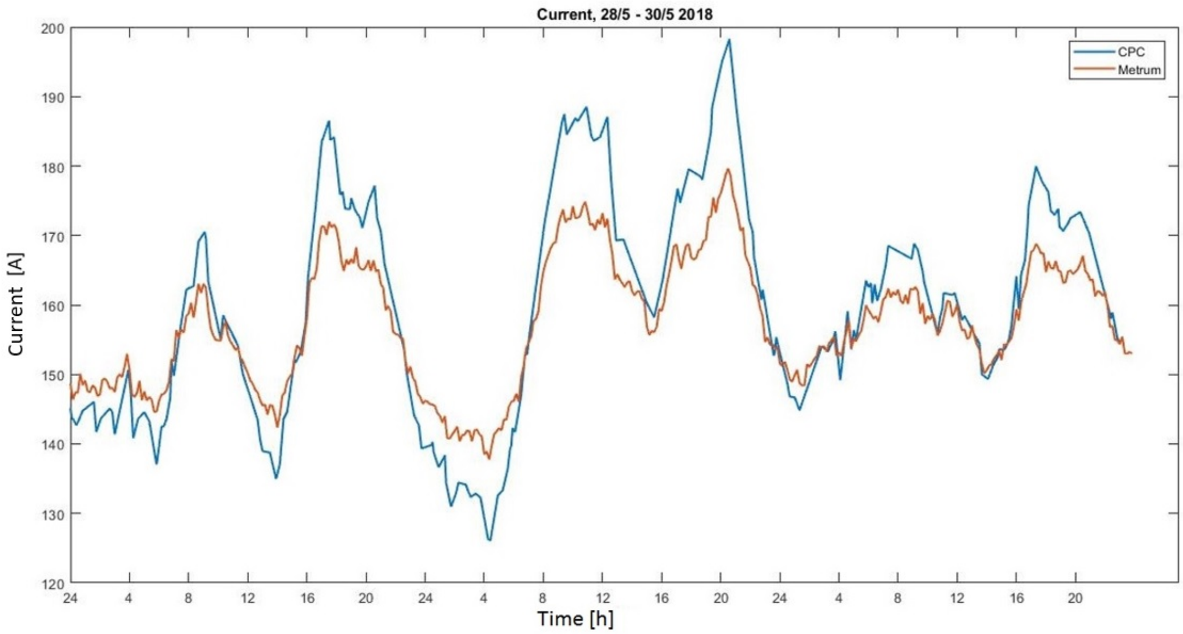


Figure 43: Current signals from HIS and the centralized system logs over three days.

The time delay for the signals are presented in table 3. The voltage and current logs of the centralized system apparently lag behind the Metrum measurements with an average of 1.86 and 1.72 minutes, respectively.

	Time delay [minutes]
Voltage	1.86
Current	1.72

Table 3: Time delay of the voltage and current signals using peak matching with a resolution of five minutes.

7.3 Fault recordings and messages

A comparison was made between the two system's alarm systems. The CPC-system has a so-called Digital Fault Recorder (DFR) that, in the case of certain class-specific events, records the state of the bays represented by the classes. In case of events, the VCU notifies the "remote alarm system" and logs the time and type of event. This is done in parallel with the conventional system's RTU (Remote Terminal Unit) that sends similar messages. For the systems to be equivalent, they should react simultaneously and equivalently, i.e. at the same time and for the same reason. As the CPC system is in "shadow operation" it does not govern any breakers and can thus only indicate how it would have reacted. However, for this study it was assumed that the system was properly connected and that the command signals would have activated the corresponding protective process.

7.3.1 The digital fault recorder

Figure 44 shows all recorded signals in the case of an intermittent earth fault affecting bays 2A, 7A, 9A, 10A, 12A, 13A and transformer 1. When the interface modules associated with the bays measured a current and voltage outside of the set limits, an event signal was sent to the DFR, which then recorded and stored relevant signals before, during and after the event. In this case the activated protection functions were overcurrent protection on both sides of the transformer and directional earth fault protection in all of the outgoing bays.

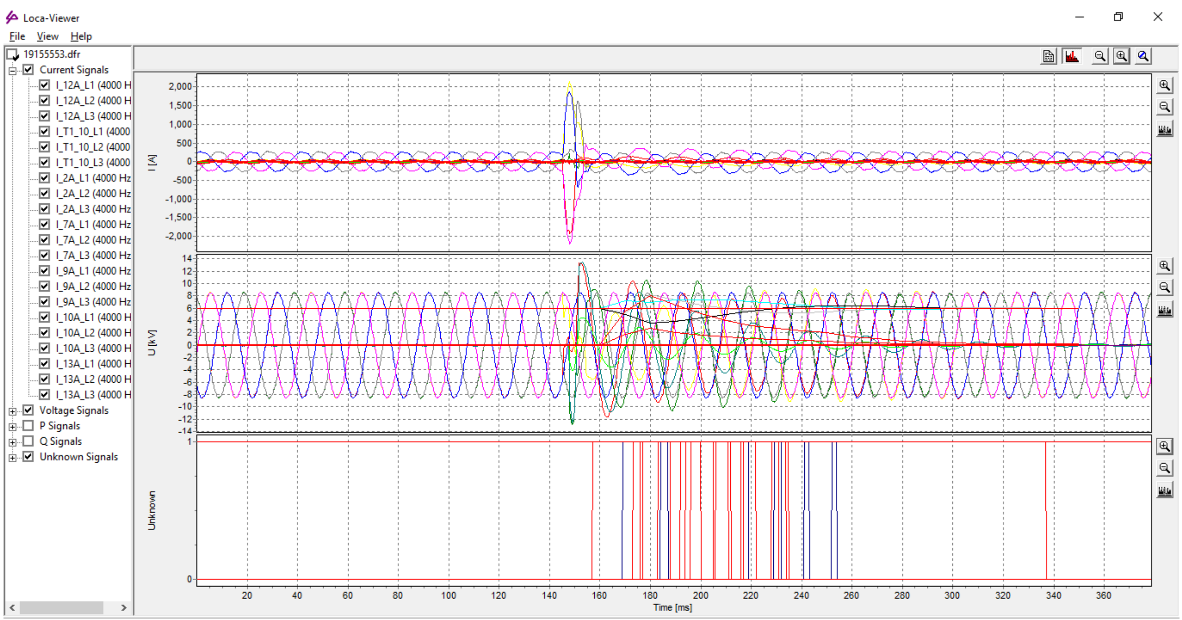


Figure 44: The interface of the Digital Fault Recorder in the case of an earth fault. The graph shows the current, voltage and signals of the protective functions active in all of the concerned bays.

7.3.2 Message time synchronization

In an ideal scenario, both of the systems would have the same type of reactions to the same type of events. While this in true in both cases, the different nature of the two systems results in some type-specific events. As the CPC-system only has one central data processing computer, the CCU, it has alarm messages for the specific malfunctioning of that device. As the conventional system does not have that sort of object in its architecture there are no alarm messages related to it. Instead, it has messages concerning the performance of the relays, which the CPC does not. When comparing the alarms of the two systems, the comparison was only made between messages that they both shared, or that could be interpreted as corresponding message types. For the most part, these concerned voltage fluctuations and deviations outside of the limits and breaker position indications. The absolute majority of the events did not lead to any direct consequences being taken, like the opening of a breaker.

7.3.3 Number and types of messages

The alarm messages sent from both systems in 2017 concerned voltage deviations on both the 70 kV and 10 kV sides of the transformers and position indications of breakers disconnectors and switching gear. The results are presented in table 2.

	Voltage deviation			Breaker and disconnector position indications	
Month	CPC	Conventional		CPC	Conventional
Jan	20	12		12	12
Feb	8	6		0	2
Mar	8	0		0	0
Apr	23	0		0	0
May	19	3		16	12
Jun	26	15		0	0
Jul	56	24		0	0
Aug	12	6		0	0
Sep	12	3		0	0
Oct	40	6		0	0
Nov	16	0		0	0
Dec	20	0		0	0

Table 2: The number of times a certain type of alarm message has been received by Ellevio's Historical Information System.

7.3.4 Time delay

In all cases except one, the message from the CPC-system arrived before the corresponding message from the conventional system. In the one case that the conventional system was faster, the CPC message was received less than one second later. Figures 45 to 46 show the time from the receiving of the alarm message from the CPC-system to the receiving of the same message from the conventional system. This was done for messages concerning voltage deviations and breaker position indications, as they were the message types that were received often enough to give some statistical significance.

The time resolution of the logs is in seconds, meaning that a delay time of 2 seconds mean that the actual delay time is between 1.5 and 3.5 seconds. Thus, a delay time of zero seconds does not mean that there was no delay, just that it was less than one second.

	Voltage deviation	**Breaker and disconnector position indications**
Mean [s]	5.49	8.07
Standard deviation [s]	7.91	7.42

Table 3: Time delay between corresponding messages of the two systems.

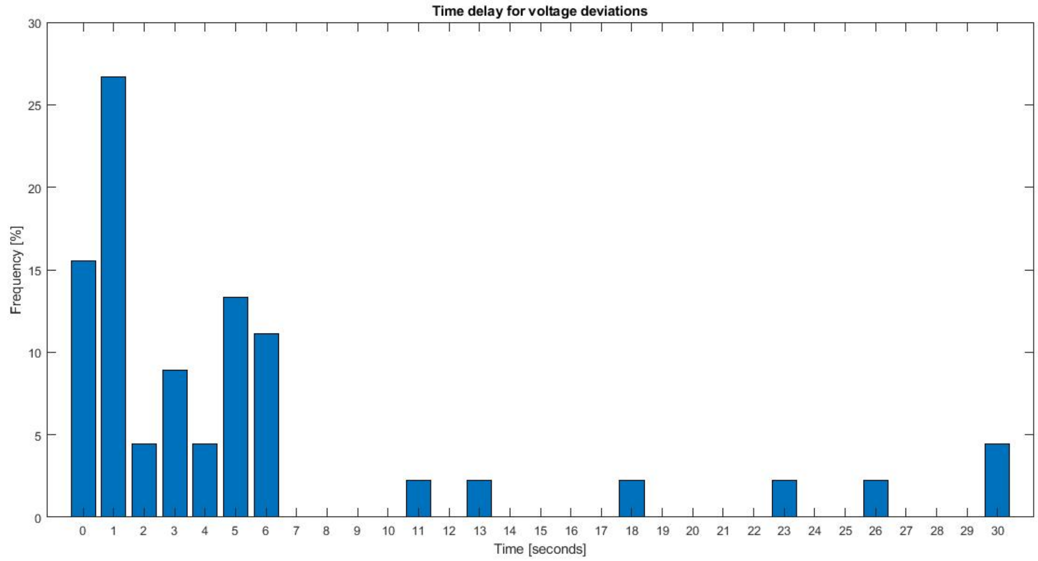


Figure 45: Frequency of each time delay for messages concerning voltage regulation.

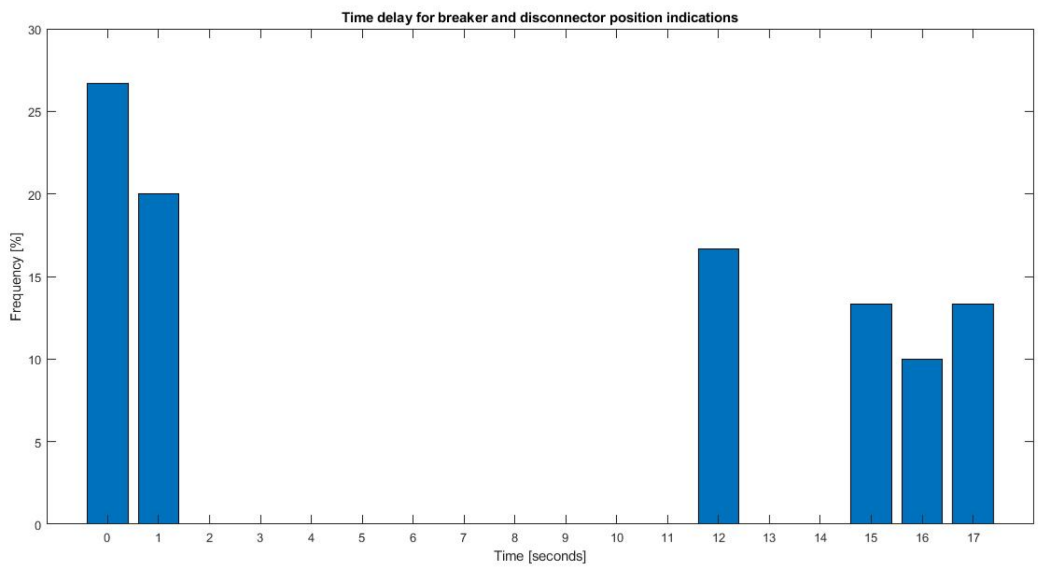


Figure 46: Frequency of each time delay for messages concerning switchgear position indications.

7.3.5 Earth fault 26/5 2017

During the whole of 2017 there was one major disturbance in the 10 kV grid due to a cable fault. This caused the breaker 9A-10-S (bay 9A on the 10 kV side of the station) to open due to the ensuing earth fault. Unfortunately, there was no recording from the conventional system in the Historical Information System so it was not possible to analyze the eventual time delay between the two. However, the conventional system reacted fittingly, opening the correct breaker to clear the fault current.

Figure 47 shows the Digital Fault Recorder's recording of the event. According to the recording, it took the system about 1.8 seconds to clear the fault current.

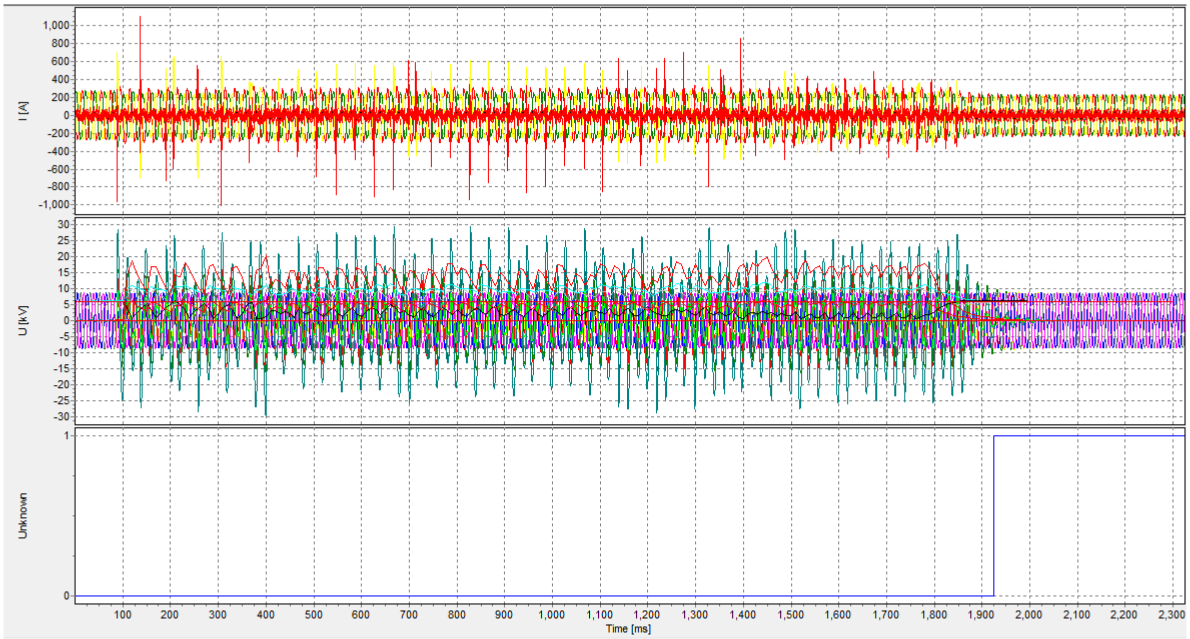


Figure 47: The active signals recorded by the DFR in the earth fault.

Bay	Protective function
T1 10 kV (5A)	Under- and overvoltage, neutral voltage
2A	Directional earth fault
3A	Directional earth fault
4A	Directional earth fault
7A	Directional earth fault
9A	Directional earth fault, breaker opens
10A	Directional earth fault
11A	Directional earth fault
12A	Directional earth fault
13A	Directional earth fault

Table 4: The protective functions activated in the earth fault.

Table 4 shows which protective functions that were activated in which bays. As evident, directional earth fault protection was activated in all outgoing bays from transformer T1 but only the signal in bay 9A caused the opening of a breaker. Thus, the recording agrees with the actual events. In the transformer bay the voltage protection was activated, for both the transformer and the neutral earthing bay.

8 Conclusions

8.1 Protection functions

The two systems have equivalent protection functionality on most of the components. In the case of the incoming line, direct transformer protection, neutral, incoming line to busbars, busbars and the outgoing cable the centralized system has protection at least equivalent to the conventional. Both systems fulfil both ABB and MCEC standards. However, in three cases the conventional system has functionality superior to the centralized: The protection of the transformers, the busbar coupling and the capacitor banks. The conventional system utilizes differential protection on the incoming and outgoing lines of the transformers, unbalance current monitoring on the capacitor banks as well as earth fault and overcurrent protection on the capacitor banks and busbar couplings lines. To reach a level of protection that matches the current protection, implementations of these functions are required.

In the case of the busbar couplings the implementation should be simple to do, as it should not differ substantially from the instalment of the functions in the outgoing lines of the station. The busbar coupling class already exists in the HMI, and the only part missing is the protection functions, which require the installation of current and voltage modules. The same is true of the differential transformer protection, where the class requiring the protection, the incoming line to the busbars, already exists. Further, the required modules are already in place.

The protection of the capacitor banks may require more work to match the already implemented functionality, as that class does not exist in the HMI and would need to be constructed. It would also, as for the busbar couplings, require installation of a current module into the bay. The complex nature of the bay may present further difficulties in the module installation, unlike the simpler line bays.

8.2 Voltage regulation

According to table 2, the voltage follows the desired overall behaviour rather well as the average voltage deviates very little from the set voltage. The relative deviation of the average voltage from the set value is 0.2 %, which is better than most comparable stations.[20] The standard deviation is also low, which implies that the grid voltage is stable, with few deviations from the tolerance levels. Comparing the values regarding the regulation time with the set values presented in table 1, the actual regulation time is rather long, as it takes the system an average of twenty minutes to regulate the voltage back to within the limits. As the set values are of the order of minutes, the system should have had time to regulate the voltage back to within the limits several times during that period. If this really is the case and not just a consequence of the low resolution, the regulation time is a matter of concern and requires further study. Something further surprising about the long regulation time is that it would be expected that the deviations would be "smoothed out" as the values are five-minute averages. Thus, a short deviation would be ignored as values inside of the limits (where most values are) would alter the average so that the short deviation would be invisible. That there, despite this, are deviations that are several reaction times long is surprising and implies that the voltage regulation may require further evaluation.

The time delay was set to definite time, i.e. that the regulation time delay is the same for all deviations, regardless of their size. No deviation is more than one tap step outside of the limits, so the regulation time should not depend on the size of the deviation. However, figure 38 implies that there is a somewhat linear relationship between the regulation time and the size of the deviation, though it is hard to say with confidence. This would be expected if the deviations were larger than one regulation step as a deviation of two steps would require two regulations, resulting in two time delays. However, this is not the case and the time should be constant. As there are several examples in the graph of deviations that are equal in size but with differing regulation times, no one relationship can explain the behaviour. This could, as previously mentioned, be a consequence of the time resolution as regulations could be "lost" in the averages that make up the points. A linear relationship could be expected in such a case that the voltage is oscillating over the limits, where the system would therefore not regulate it but the average voltage could still exceed the limits. This is however still unlikely since such an oscillation would have a low deviation and would not give rise to the increased regulation time for higher oscillations.

Close study of the data implies that the script functions correctly and that it may be used for further studies of voltage regulations, foremost as a comparison tool when either comparing similar stations or when comparing a stations set behaviour to its actual performance.

8.3 Signal correlation

8.3.1 Magnitude comparison with HIS

As evident, the signal from the centralized system is within the error margins of the HIS logs, for both voltage and current. In the case of voltage it closely follows the HIS values of the same system, which is to be expected since both are generated by the same system. The most important comparison is however with the conventional system, which differs by approximately 0.1 kV (0.093 kV). As the difference is approximately as large as the uncertainty in HIS, it can not be said with certainty that there is a consistent deviation. However, earlier studies of the conventional voltage regulation imply that the voltage values generated by the conventional system are roughly 0.1 kV too high.[20]. Subtracting this from the values of the conventional system greatly improves the correlation, implying that the log files of the centralized system agree with the other recorded values as far as can be determined by the HIS resolution.

In the case of current, the measurements from the centralized system deviated from the conventional system with approximately 6 A, which corresponds to a relative deviation comparable to that of the voltage (around 1.5 %). This implies that even these values agree as well as possible, within the bounds of the resolution.

The log files of the SASensor system provide values of comparable accuracy to those of the conventional system. The magnitude of the values match those obtained from HIS within the error limits, especially if one takes into account the 0.1 kV shift in voltage values of the conventional system, implied in earlier studies. Further studies to evaluate the signal accuracy of both systems would investigate which of the systems that provides the most accurate values. The Metrum SPQ has such functionality that it can be used as a reference instrument and can thus be of use in such an investigation. It was not used as such in this study, as it requires a measuring time length of eight days and extensive calibration which could not be carried out in this study due to time limitations in the reservation time of the device.

8.3.2 Time synchronization with Metrum SPQ

The results of the analysis of the time delay signify that any eventual time delay is well below the time resolution of the log files. Strictly interpreted, the results imply that there is no time delay in the context of this method. However, a more lenient interpretation would be that the results provides an upper limit of the time delay, which in the context of historical log files is adequate. To discern a time delay in the actual signals, real-time measurement values need to be obtained from the system. This either requires direct and continuous in-station or remote monitoring, which will be made possible in the near future as a dedicated server for remote monitoring and control of the station is planned for installation in autumn 2018.

Within the limitations of the used method, the signals from the centralized systems both seem to provide measurements that agree with the values obtained from the reference measurements utilized by Ellevio. As the log files agree with these, which meet the standards of Ellevio, this implies that they are accurate enough to replace the measurements of the conventional system in the eventual station wide implementation of the centralized system and replacement of the conventional system.

8.4 Fault recordings and messages

The fact that the messages from the centralized system were received before the corresponding messages from the conventional system is probably a consequence of the centralized systems lesser and more efficient data processing. Instead of demanding the cooperation of several systems (all involved relays and the RTU), all of the data processing is made in one unit which is directly compatible with the communication unit. One should note that the several second delay of the messages does not mean that the system would not react to a fault in that time, which would result in a station wide trip. It rather means that the recorded time of occurrence of an event will potentially be erroneous by several seconds, which could cause serious problems when diagnosing and investigating faults. If the event time of a voltage deviation may be up to 16 seconds late and may have different time delays depending on where in the station it occurs, diagnosing the problem may become significantly more difficult. This is with all probability a situation where the centralized system shows more efficiency usability than the conventional system and where there are advantages with the full implementation of it.

The analysis of the centralized system's response to the earth fault suggests that it provides adequate protection for the faults that it is designed to respond to. As the cable fault analyzed in the study was the only fault that occurred in the grid during 2017 it is the only protection functionality that can be studied in "sharp operation". However, it is enough to indicate that the system responds suitably to faults in the parts of the grid that is to be protected by its protection systems. Further studies in the response of the system's protection functions would require both simulated tests and controlled "real" faults. The centralized system is well suited for such tests as all of the protective functions can be tested "at once", as opposed to a conventional relay system where the relays need to be tested one by one. The output of the modules are easily simulated and fault values can thus be inserted into the system without affecting the surrounding grid.

9 Discussion

The purpose of this study and evaluation of the centralized system implemented in the substation is to act as a basis for the future decision of whether to continue with the system in actual operation and replacing the entire conventional system. Until this date, the protection functions of the centralized system have been in so-called shadow or piggyback operation and have not governed the protection of the system. In a future complete implementation, all of the conventional relays will be removed and the centralized system will assume full operation of the station. Future work will utilize the methods developed in this work to make further investigations of the consequences of implementing the centralized system. If the decision is taken to proceed with the centralized system, a possible future step is the implementation into all of the substations in the grid, which would give insights into how the architecture works when all of the stations in a grid have the same centralized system architecture. As all of the stations in such a grid would have the simplified outward communication system, there are possible benefits to be had by synchronizing them to each other and build a grid out of communicating stations. Such benefits are however outside of the scope of this study.

In this section, a broader discussion is presented for the possible advantages of the new system and for the CPC concept in itself, as well as further discussion of the evaluation methods and recommended future studies.

9.1 Protection functions

One proposed benefit of a centralized system based primarily on its software is that the implementation of a new function is simply a case of developing an update to the software running the system. In the case of SASensor, where the interface modules monitor all relevant quantities in the power lines and components, the relevant input parameters that a new function would require are most likely already implemented. Thus, the new function would simply consist of a new way to use the same output data. No new modules and hardware would have to be implemented in the station for the new function, as would be the case of a conventional relay, where a new function requires the installation of a new relay. Though there are examples of conventional substation systems utilizing relay concepts more open for user-implemented solutions, the broad majority of the relay market is still concentrated on relays with functionality specifically requested by the consumer.[31] In other words, the SASensor system is rather unique in the sense that it is possible for users to implement functionality after the system has been implemented, which gives the concept an edge as it is theoretically possible to implement functions that do not exist at the time of its implementation. As of the centralized system in this study, the protection functions mirror those of the conventional system, which is the first step in the implementation in a conventional substation. For further implementation to be made, it must first be ascertained whether the new system can provide as good protection as the old one could. When that is done, it can be decided whether to proceed with the development of other functions, that is not possible to implement in a conventional system.

As of today, the centralized system does not provide protection that matches that of the conventional system and thus also the standard of Ellevio. For a station wide implementation to be in question, the centralized system requires differential protection on the transformers, earth fault and overcurrent protection on the capacitor banks and busbar coupling as well as additional unbalance current monitoring on the capacitor banks. This is however a good opportunity to utilize the centralized system openness to third-party implementations.

9.2 Voltage regulation

The script implemented for analysing the voltage regulation of the centralized system appears to be working satisfactorily and has completed a thorough review using test data with known results. The script obtains values useful for comparison of the voltage regulation with other stations. As for the apparent regulation behaviour of the system, taking into account the fact that the data had a five-minute resolution: If one does assume that the resolution is not too low and that the regulation may be fairly evaluated using the resolution of the log files, it becomes evident that the regulation time is several times larger than desired. The set regulation time delay is of the order of one minute, but the apparent regulation behaviour obtained from the data implies that the time delay may be as much as twenty minutes. That the voltage deviates from the limits 5 % of the time also implies that the regulation is not working optimally.

To investigate the reason for this, a more rigid investigation would have to be made, using voltage measurements with higher resolution. As a suggestion the Metrum SPQ device, used in the signal correlation evaluation, could be employed if properly calibrated to give reliable reference values. This device can give a higher resolution and would remove the uncertainty of the results stemming from the that fact the data obtained may hide regulation steps. Further, the regulation of other similar substations in the grid would have to be investigated for a fair evaluation to be possible. A reason for the apparent unsatisfactory behaviour could be that the grid voltage is due to spontaneous fluctuations because of consumer behaviour, and that the difficulty has less to do with the performance of the voltage regulation of the station. The overall behaviour of the voltage is satisfactory, as the average voltage deviates very little from the set value and that it during the entire period is far from the limits of what the regulation is capable of handling.

The surprising behaviour of the time delay characteristic may also be a consequence of the low resolution and the apparent linear relationship between deviation size and regulation time may be a coincidence. An explanation may also be that the values corresponding to the lowest deviations are due to small fluctuations over the limits that do not require any regulation to disappear. As these deviations would be random, the likelihood of them disappearing until the next time step is rather large, which could be a possible explanation to the small deviations having the smallest regulation time. However, the regulation time was definite and should therefore not be dependent on deviation size and figure 38 still implies a somewhat linear relationship, even when neglecting the points with a regulation time shorter than five minutes. This implies that further work should be devoted to the time characteristic of the voltage regulation.

For a future evaluation of the system, a method would have to be devised for the simultaneous measuring of similar stations in the same part of the grid as the station in this study. As of today, all stations transmit voltage measurements to HIS, however due to how the measurements are converted from the station RTU the voltage resolution is about 0.1 kV. As that is of the magnitude of regulation limits, it would theoretically be impossible to discern whether the voltage exceeds the limits and if it has changed by a step or not. A possible method would be to make simultaneous measurements with the Metrum device or a similar instrument at another equivalent station and use those values as reference for the evaluation. Once these values are obtained, the script may be used for a comparison of the regulation functions.

9.3 Signal correlation

As far as the sensitivity of the methods used can discern, the two systems appear to be well synchronized and transmit the correct magnitudes and time of voltage and current. As stated above, the Metrum SPQ could, with proper calibration, be further utilized for better reference values for the voltage and current. To improve the study of the systems time synchronization, it would be recommended to use an instrument that is able to provide continuous measurements of the values and to obtain the corresponding values from the centralized system. It would require an investigation of whether this is possible to achieve, but it should be possible since the instantaneous measurements are displayed in the system's HMI, but it may require access to a dedicated server, which can provide continuous monitoring of the system. Such a server is scheduled to be delivered to Ellevio in autumn 2018 and could likely be used for such a study. However, as stated above, the two systems appear to be well synchronized and to transmit correct voltage and current values.

9.4 Fault recordings and messages

As the centralized system is fully digitized and has direct contact with the remote control centre through the VCU it is expected that the messages from it should be processed before those from the conventional system. In the conventional system, several relays as well as the RTU and other systems are involved in the transmitting of error messages, which understandably requires longer data processing. The centralized system is made up of modern computers with superior processing capabilities compared to the older relay systems in the conventional system. The delay of the messages of the conventional system can also not be explained by any faults in the synchronization of the two systems, as that would result in a constant time delay. As it is now, there is a big dispersion in the time delay between the systems, with some delays being less than a second and some ranging up to twenty seconds. Without a thorough investigation it is hard to answer the question of why this is, but it is evident that the centralized system has a better capability of transmitting error messages that are logged with the correct time, as the messages of the conventional system can potentially give time stamps that are delayed by several seconds. Though this, as stated before, does not mean that it would react to a fault with a several-second delay, it could potentially impede in the diagnosis of a fault, as the delayed time stamps could make it difficult to establish an order and time of events leading to a fault.

In the case of the response to the cable fault, it appears that the centralized system responded satisfactorily, with the activation of the correct protection functions and with a signal confirming the opening of a breaker in the affected bay. This response mirrors that of the conventional system, which implies that this part of the centralized system's protection is adequate.

9.5 Concluding remarks of the centralized system

It is after this study difficult to say whether the centralized system should be taken into direct operation of the substation. However, the methods proposed and used in this thesis can be of use in further evaluation of the system. The factors that hinder the full implementation is foremost the missing protection functions, but there have also been indications that the voltage regulation requires a more thorough review using data with better resolution. The fault message and signal correlation analysis implies that the functionality of the centralized system surpasses that of the conventional, however some further study may have to be conducted to fully determine if this is the case. Recommended future studies are presented in the previous sections and if these are done successfully, the recommendation is that the centralized system is put into active operation of the substation.

9.6 Further discussion

The idea of a centralized and simplified system architecture may seem like the most reasonable path towards an electricity grid that can handle a rapid evolution in energy production, a changing market and still improve customer service and grid reliability. There are however some aspects that need to be considered. The first issue is that of security. CPC advocates argue that since one powerful device is easier to protect than several ones with lesser processing capabilities, the CPC architecture should lead to fewer malfunctions and less down time of the system[1]. However, though it may be true that a decentralized system may malfunction in more ways than a centralized, the fact is that if the central unit malfunctions, the whole network may be severely damaged. In a decentralized network, there are less single malfunction types that would affect the whole station as no single node governs all the others. In a centralized network however, all of the malfunctions of the central device can potentially close down the whole network. Essentially, one would expect a station built with a centralized architecture to have fewer issues but the ones that happen to be more severe. Though there are well-defined protocols for redundancy of station security there is always some small probability of failure, and in the case of a centralized system this failure, however unlikely, would give bigger consequences than that of a decentralized system. In a world where directed cyberattacks are becoming more common, it may always be a risk to centralize too many functions as offensive techniques tend to evolve faster than defensive ones. As substations already are possible targets for malign intrusions it would be unfavourable to make them more attractive for potential cyberattacks [32].

A benefit with the CPC concept is that there is a rather simple solution to the problem concerning redundancy and security. As the system is defined by the software in the central unit, a duplication (as in the case of SASensor) directly guarantees N1 redundancy. Further, as the modules are significantly less complex than modern protection relays, the risk that one of them will malfunction is less probable and has lesser consequences. Given this, redundancy of a CPC-system is more cost effective than one built using a conventional architecture, as the centralized units are seldom built using more complex hardware than an industrial computer. Protection relays are constructed specifically for their purpose and thus cost more in relation to their functionality and processing power. To duplicate each individual relay is, for a large station, significantly more expensive than duplicating the significant units in a CPC-system[33]. For higher redundancy, the solution is as simple as duplicating the central device as many times as required. For each duplication, the risk drops substantially and with correct protection, such a system should be at least as secure as a conventional one [33].

The simplification of substation system architectures is not a new endeavour: The first attempt can be traced back to approximately the same time as when computers started to be adopted for business. The first concept reminiscent of CPC was proposed in 1969, even though the first centralized architectures were implemented about ten years later, when Westinghouse constructed an "Integrated Modular Protection and Control System". Further attempts have been made by General Electric and the Swedish utility Vattenfall, among others. The purpose of these systems were not specifically to centralize the architecture, but to simplify it. The idea behind distributed systems implemented in most substations today is not the result of a deliberate optimization process, it is rather the result of a gradual evolution of the energy grid as a whole [1].

When the concept of the grid was conceived in the end of the 1800's, the only safety device that existed was the fuse. As the grid has become more complex over time, the safety devices have grown with it. As soon as a safety concern has been identified, a protection device has been invented to handle it. The result of this process is the protection systems of today, where each relay is concerned with only one type of protection and where there is no overlying structural logic. Nowhere is there a holistic approach that considers the whole system. This is logical if one considers that many of the hazards that the relays of today protect against were identified before the invention of the technological tools that such a system would require. However, today such tools are available and it seems that it has only been a matter of time before a substation scheme is invented that takes the whole station into account. Instead of each relay acting solely on the information gathered in its own bay, a central unit could govern the whole station and make station-wide decisions based on station-wide data. It is in this light that the CPC concept should be viewed: It is a proposed method to utilize modern technology to make the substation system more efficient and logical. Its purpose is to transform the substation system from one where the pieces work independently of each other into an optimized system that uses each component to its fullest potential. It is not the only possible approach to such a system, and the difficulty in defining the concept lies in that it is defined by its purpose rather than its form. It is however based on this that the CPC concept should be judged: The question should be whether it is the most efficient way to optimize the protection and control system of a substation. As of today, there is no real alternative instead of simply developing better conventional relays that continue the conventional approach. However, as this approach has been implemented by chance rather than after careful consideration, the recommended way forward must be the CPC concept. The fact that it is the only approach that takes into account the technological possibilities of today, rather than being bound by limitations that have to do with the historical development of the grid, being the obvious reason [1], [13], [31], [32].

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10 Appendix

The script

Here follows the MATLAB script developed for evaluating the voltage regulation of a substation.

```
load voltage % Load the voltage data file


% Read the voltage data file
% voltage_data = xlsread('HIS\KV 1-3.xlsx');
voltage_data = voltage;
% Timevector (corresponds to rows in the excel file)
time = 1:length(voltage_data);

% Make helplines for the limits
set_val = 10.34;
lim_low = 10.2;
lim_upp = 10.48;

set_vec = set_val*ones(1,length(voltage_data));
low_vec = lim_low*ones(1,length(voltage_data));
upp_vec = lim_upp*ones(1,length(voltage_data));

% Plot with helplines
plot(time, voltage_data)
hold on
plot(time, set_vec, time, low_vec, time, upp_vec)
ylabel('Voltage [kV]')
xticks([1 length(voltage_data)/10 2*length(voltage_data)/10 ...
    3*length(voltage_data)/10 4*length(voltage_data)/10 ...
    5*length(voltage_data)/10 6*length(voltage_data)/10 ...
    7*length(voltage_data)/10 8*length(voltage_data)/10 ...
    9*length(voltage_data)/10 ])
xticklabels({'1/3' '2/3' '3/3' '4/3' '5/3' '6/3' '7/3' '8/3' ...
    '9/3' '10/3'})

figure
plot(time, voltage_data,'*')
hold on
plot(time, set_vec, time, low_vec, time, upp_vec)


% Create a vector containing all values that are outside the limits

j = 1;
k = 1;
for i=1:length(voltage_data)
    if voltage_data(i) < lim_low % Compares with the lower limit
        err_vec_low(j) = voltage_data(i);
        j = j+1;
    elseif voltage_data(i) > lim_upp % Compares with the upper limit
        err_vec_upp(k) = voltage_data(i);
        k = k+1;
    end
end

% Calculate mean deviation and the proportion of time outside of limits

% For deviations from upper limit
if exist('err_vec_upp') == 1 % See if there are any deviations from the upper limit
    error_upp = err_vec_upp - lim_upp; % Calculate deviation from upper limit
    mean_error_upp = mean(error_upp); % Compute the average deviation
    err_prop_upp = length(error_upp)/length(voltage_data); % Compute relative deviation time
end
```

```
% For deviations from lower limit
if exist('err_vec_low') == 1 % See if there are any deviations from the lower limit
    error_low = (err_vec_low - lim_low)*-1; % Calculate deviation from lower limit
    mean_error_low = mean(error_low); % Compute the average deviation
    err_prop_low = length(error_low)/length(voltage_data); % Compute relative deviation time
end

% Total deviation and proportion
if exist('err_vec_upp') == 1 && exist('err_vec_upp') == 1 % See if both types of deviations exist
    error = horzcat(error_low, error_upp); % Combine both error vectors
    mean_error = mean(error); % Compute the average deviation
    err_prop = length(error)/length(voltage_data); % Compute relative deviation time
end

% Get the mean time for a value outside of the limits to be
% regulated back.

regtime_upp = regtime_upp(voltage_data, lim_upp);
regtime_low = regtime_low(voltage_data, lim_low);

% Average time for regulations above and below the limits
mean_regtime_upp = mean(regtime_upp);
mean_regtime_low = mean(regtime_low);

% Average total regulation time
if mean_regtime_upp ~= 0 && mean_regtime_low ~= 0
    mean_regtime_tot = (sum(regtime_upp) + sum(regtime_low))/(length(regtime_upp) ...
        + length(regtime_low));
end

% Calculate mean time between events

TBE = no_event_time(voltage_data, lim_upp, lim_low);

MTBE = mean(TBE);

% Variance and standard deviation
variance = var(voltage_data);
dev = std(voltage_data);
mean = mean(voltage_data);

% Relative average error
rel_mean_err = abs(set_val - mean)/set_val;

% Want to plot the regulation time as a function of how far outside the
% bounds that the voltage is. Plot the max of an event over the regulation
% time

% Create a matrix with all high and low events and all indices associated
% with each event. Plot the max deviation of each event against the
% corresponding regulation time

[event_mat_upp, event_mat_low] = event_index(voltage_data, lim_upp, lim_low);

[num_events_upp, event_ind_upp] = size(event_mat_upp);
[num_events_low, event_ind_low] = size(event_mat_low);

% Get the max value in each event from voltage_data

event_val_upp = zeros(size(event_mat_upp));
event_val_low = zeros(size(event_mat_low));

% Get corresponding voltage value from each index outside of voltage limits

for i = 1:num_events_upp
   for j = 1:event_ind_upp
       if event_mat_upp(i,j) ~= 0
           event_val_upp(i,j) = voltage_data(event_mat_upp(i,j));
```

```
        end
    end
end
for i = 1:num_events_low
    for j = 1:event_ind_low
        if event_mat_low(i,j) ~= 0
            event_val_low(i,j) = voltage_data(event_mat_low(i,j));
        end
    end
end

% Get the max deviation from each event

event_max_upp = zeros(1,num_events_upp);
event_min_low = zeros(1,num_events_low);

for i = 1:length(event_max_upp)
    event_max_upp(i) = max(event_val_upp(i,:));
end

[l_event_val_low, w_event_val_low] = size(event_val_low);

for i = 1:length(event_min_low)
    k = 0;

    for j = 1:w_event_val_low

        if event_val_low(i,j) > 0
            k = k+1;
        end
    end
    event_min_low(i) = min(event_val_low(i,1:k));

end

event_dev_upp = event_max_upp - lim_upp;
event_dev_low = zeros(1,length(event_min_low));
for i = 1:length(event_min_low)
    event_dev_low(i) = abs(lim_low - event_min_low(i));
end


% Plot the regulation for each event against the maximum deviation of the events.

regtime_upp = regtime_upp*5; % Time factor of five minutes
regtime_low = regtime_low*5; % Time factor of five minutes

figure
plot(event_dev_upp, regtime_upp,'*')
figure
plot(event_dev_low, regtime_low,'*')
figure
plot(horzcat(event_dev_low, event_dev_upp), horzcat(regtime_low, regtime_upp),'o')
title('Regulation time vs deviation size')
ylabel('Regulation time [min]')
xlabel('Deviation size [kV]')
hold on
pf = polyfit(horzcat(event_dev_low, event_dev_upp), horzcat(regtime_low, regtime_upp),1);
plot(horzcat(event_dev_low, event_dev_upp), pf(1)*horzcat(event_dev_low, event_dev_upp) + pf(2))
ylim([0 35])

% -------------------------------------------------------------

function [regtime_low] = regtime_low(voltage_data, low_lim)

i = 1;
j = 1;
k = 1;
```

```
while i<length(voltage_data)
    if i == 1 && voltage_data(i) < low_lim
        while voltage_data(i+j) < low_lim
                j = j+1;
        end
        i = i+j;
    else
    if voltage_data(i) < low_lim
        if i > 1
            % Look backward
            linfit_b = polyfit([i-1, i], [voltage_data(i-1), voltage_data(i)], 1);
            regtime(k) = i - (low_lim - linfit_b(2))/linfit_b(1);
        end

        % Look forward
        while voltage_data(i+j) < low_lim && i+j < length(voltage_data)
                j = j+1;
        end

        if i+j < length(voltage_data)
            linfit_f = polyfit([i+j-1, i+j], [voltage_data(i+j-1), voltage_data(i+j)], 1);
            regtime(k) = regtime(k) + (low_lim - linfit_f(2))/linfit_f(1) - i;
            k = k+1;
            i = i+j;

        elseif i+j == length(voltage_data) && voltage_data(length(voltage_data)) > low_lim
            linfit_f = polyfit([i+j-1, i+j], [voltage_data(i+j-1), voltage_data(i+j)], 1);
            regtime(k) = regtime(k) + (low_lim - linfit_f(2))/linfit_f(1) - i;
            k = k+1;
            i = i+j;

        else
            regtime = regtime(1:(length(regtime)-1));
            i = i+j;
        end
    else
        i = i+1;
    end
    j = 1;
    end
end

if isempty('regtime') == 1
    regtime_low = 0;
else
    regtime_low = regtime;
end

end

% ---------------------------------------------------------------

function [regtime_upp] = regtime_upp(voltage_data, upp_lim)

i = 1;
j = 1;
k = 1;

while i<length(voltage_data)
    if i == 1 && voltage_data(i) > upp_lim
        while voltage_data(i+j) > upp_lim
                j = j+1;
        end
        i = i+j;
    else
    if voltage_data(i) > upp_lim
        if i > 1
```

```
            % Look backward
            linfit_b = polyfit([i-1, i], [voltage_data(i-1), voltage_data(i)], 1);
            regtime(k) = i - (upp_lim - linfit_b(2))/linfit_b(1);
        end

        % Look forward
        while voltage_data(i+j) > upp_lim && i+j < length(voltage_data)
                j = j+1;
        end

        if i+j < length(voltage_data)
            linfit_f = polyfit([i+j-1, i+j], [voltage_data(i+j-1), voltage_data(i+j)], 1);
            regtime(k) = regtime(k) + (upp_lim - linfit_f(2))/linfit_f(1) - i;
            k = k+1;
            i = i+j;

        elseif i+j == length(voltage_data) && voltage_data(length(voltage_data)) < upp_lim
            linfit_f = polyfit([i+j-1, i+j], [voltage_data(i+j-1), voltage_data(i+j)], 1);
            regtime(k) = regtime(k) + (upp_lim - linfit_f(2))/linfit_f(1) - i;
            k = k+1;
            i = i+j;

        else
            regtime = regtime(1:(length(regtime)-1));
            i = i+j;
        end
    else
        i = i+1;
    end
    j = 1;
    end
end

if isempty('regtime') == 1
   regtime_upp = 0;
else
    regtime_upp = regtime;
end

end

% -------------------------------------------------------------

function [event_mat_upp, event_mat_low] = event_index(voltage_data, lim_upp, lim_low)

j = 1; % out_upp
k = 1; % in_upp
m = 1; % out_low
n = 1; % in_low
for i = 2:length(voltage_data)

    % If the voltage crosses both lines from the bottom
    if (voltage_data(i) > lim_upp && voltage_data(i-1) < lim_low)

        out_upp(j) = i;
        j = j+1;
        in_low(n) = i;
        n = n+1;

    % If the voltage crosses both lines from the top

    elseif (voltage_data(i-1) > lim_upp && voltage_data(i) < lim_low)

        out_low(m) = i;
        m = m+1;
        in_upp(k) = i;
        k = k+1;
```

```
    else

    % If the value is too high
    if voltage_data(i) > lim_upp
        % If the value before is inside bounds
        if voltage_data(i-1) <= lim_upp
            out_upp(j) = i;
             j = j+1;
        end

     % If the value is inside bounds
     elseif voltage_data(i) <= lim_upp && voltage_data(i) >= lim_low
         % If the value before is too high
         if voltage_data(i-1) > lim_upp
             in_upp(k) = i;
             k = k+1;
         end
    end
     % If the value is too low
     if voltage_data(i) < lim_low
         % If the value before is inside bounds
         if voltage_data(i-1) >= lim_low
             out_low(m) = i;
             m = m+1;
         end

      % If the value is inside bounds
     elseif voltage_data(i) <= lim_upp && voltage_data(i) >= lim_low
          % If the value before is too low
          if voltage_data(i-1) < lim_low
              in_low(n) = i;
              n = n+1;
          end
     end
    end
end

% If the voltage starts or stops outside, remove the first or last event
if in_upp(1) < out_upp(1)
    in_upp = in_upp(2:length(in_upp));
end
if out_upp(length(out_upp)) > in_upp(length(in_upp))
    out_upp = out_upp(1:(length(out_upp)-1));
end
if in_low(1) < out_low(1)
    in_low = in_low(2:length(in_low));
end
if out_low(length(out_low)) > in_low(length(in_low))
    out_low = out_low(1:(length(out_low)-1));
end

size_upp_vec = zeros(1,length(out_upp));
for i = 1:length(out_upp)
    size_upp_vec(i) = in_upp(i) - out_upp(i);
end

size_upp = max(size_upp_vec);
event_mat_upp = zeros(length(out_upp),size_upp);

size_low_vec = zeros(1,length(out_low));
for i = 1:length(out_low)
    size_low_vec(i) = in_low(i) - out_low(i);
end

size_low = max(size_low_vec);
event_mat_low = zeros(length(out_low),size_low);

% By use of out and in, figure out which indexes are in which events
```

```
for i = 1:length(out_upp)
    ind_upp = out_upp(i):(in_upp(i)-1);
    for j = 1:length(ind_upp)
        event_mat_upp(i,j) = ind_upp(j);
    end
end

for i = 1:length(out_low)
    ind_low = out_low(i):(in_low(i)-1);
    for j = 1:length(ind_low)
        event_mat_low(i,j) = ind_low(j);
    end
end

end

% -------------------------------------------------------------

function [TBE] = no_event_time(voltage_data, upp_lim, low_lim)

j = 1;
k = 1;
for i = 2:length(voltage_data)

    % If the voltage crosses both lines from the bottom

    if (voltage_data(i) > upp_lim && voltage_data(i-1) < low_lim)
        linfit = polyfit([i-1, i], [voltage_data(i-1), voltage_data(i)], 1);
        in_vec(k) = (low_lim - linfit(2))/linfit(1);
        out_vec(j) = (upp_lim - linfit(2))/linfit(1);
        k = k+1;
        j = j+1;

    % If the voltage crosses both lines from the top

    elseif (voltage_data(i-1) > upp_lim && voltage_data(i) < low_lim)
        linfit = polyfit([i-1, i], [voltage_data(i-1), voltage_data(i)], 1);
        in_vec(k) = (upp_lim - linfit(2))/linfit(1);
        out_vec(j) = (low_lim - linfit(2))/linfit(1);
        k = k+1;
        j = j+1;

    else
    % If the voltage crosses the lower limit
    if voltage_data(i) < low_lim && voltage_data(i-1) >= low_lim

        linfit = polyfit([i-1, i], [voltage_data(i-1), voltage_data(i)], 1);
        out_vec(j) = (low_lim - linfit(2))/linfit(1);
        j = j+1;
    end

    % If the voltage comes back through the lower limit
    if voltage_data(i) >= low_lim && voltage_data(i-1) < low_lim

        linfit = polyfit([i-1, i], [voltage_data(i-1), voltage_data(i)], 1);
        in_vec(k) = (low_lim - linfit(2))/linfit(1);
        k = k+1;
    end

    % If the voltage crosses the upper limit
    if voltage_data(i) > upp_lim && voltage_data(i-1) <= upp_lim

        linfit = polyfit([i-1, i], [voltage_data(i-1), voltage_data(i)], 1);
        out_vec(j) = (upp_lim - linfit(2))/linfit(1);
        j = j+1;
    end

     % If the voltage comes back through the upper limit
```

```
    if voltage_data(i) <= upp_lim && voltage_data(i-1) > upp_lim

        linfit = polyfit([i-1, i], [voltage_data(i-1), voltage_data(i)], 1);
        in_vec(k) = (upp_lim - linfit(2))/linfit(1);
        k = k+1;
    end
    end

end

% The time between events is the time between that the voltage crossed a
% border until it came back again

% If the voltage starts and stops inside
if (voltage_data(1) >= low_lim && voltage_data(1) <= upp_lim)
    if (voltage_data(length(voltage_data)) >= low_lim && voltage_data(length(voltage_data)) <= upp_lim)
        for i = 1:length(out_vec)-1

            no_event_time(i) = out_vec(i+1) - in_vec(i);

        end
    end
end

% If the voltage starts and stops outside

if (voltage_data(1) < low_lim || voltage_data(1) > upp_lim)
    if (voltage_data(length(voltage_data)) < low_lim || voltage_data(length(voltage_data)) > upp_lim)
        for i = 1:length(out_vec)

            no_event_time(i) = out_vec(i) - in_vec(i);

        end
    end
end

% If the voltage starts outside and stops inside

if (voltage_data(1) < low_lim || voltage_data(1) > upp_lim)
    if (voltage_data(length(voltage_data)) >= low_lim && voltage_data(length(voltage_data)) <= upp_lim)
        for i = 1:length(out_vec)

            no_event_time(i) = out_vec(i) - in_vec(i);
        end
    end
end

% If the voltage starts inside and stops outside

if (voltage_data(1) >= low_lim && voltage_data(1) <= upp_lim)
    if (voltage_data(length(voltage_data)) < low_lim || voltage_data(length(voltage_data)) > upp_lim)
        for i = 1:length(in_vec)

            no_event_time(i) = out_vec(i+1) - in_vec(i);

        end
    end
end

TBE = no_event_time;

end
```