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Importance of IED performance on process bus applications

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1 INTRODUCTION

The progression of technology within substations has seen a migration of away from traditional hardwired solutions, towards Ethernet architectures. As a first step, IEC 61850 brought the ability to exchange data between devices and systems more readily than before, particularly in the case of binary GOOSE exchanges, and reporting. In the first installations, some dating back nearly 10 years, the focus on IEC 61850 was for system engineering, not time-critical duties such as tripping.

Today, the digital substation is very much a reality, with contracts under execution. In such architectures, the scheme engineering has migrated to a full Ethernet implementation, with GOOSE being used for circuit breaker tripping purposes, and the analogue measured values being communicated by IEC 61850-9-2.

This means that the time-critical fault clearance chain is now implemented using the process bus, extending between the relay room and the yard. In the process bus architecture, a number of intelligent electronic devices must partner together, using the communication network in order to achieve fault clearance times equivalent to those for historical hardwiring.

Merging units capture current (CT) and voltage (VT) measurements in the yard, which are then published as IEC 61850-9-2LE sampled values, then communicated to a subscribing devices such as protection relays. Any trip command is then communicated back to the yard – either to a discrete switchgear control unit, or back to the original merging unit.

Each function performed within the merging unit, the relay, and any intervening network components (such as Ethernet switches) must be performed in real-time, with the minimum amount of latency. No part of the chain must impose an undue delay, if the speed and consistency equivalent to traditional hardwired architectures are to be achieved or bettered.

This paper discusses the design approach, and unique hardware and software implementation which has been undertaken to design a high-speed merging unit for transmission-class applications. Section 2 describes the main requirements for a merging unit. Section 3 shows the characteristics of the Field-Programmable Gate Array (FPGA) devices and compares them with traditional processor architectures and performance. A low latency SMV publisher, fast GOOSE publisher and subscriber and High-Speed High-Break output contacts merging unit implementation is shown in Section 4, able order to provide a reaction time of less than 200 microseconds. Finally, section 5 presents practical test results of the innovative hardware design in comparison to standard IEDs. Lastly, the conclusions and recommendations for future work are presented in Section 6.

2 MERGING UNITS

In conventional substations, every device in the relay room, such as protective relays and digital fault recorders, has its own acquisition system. All the cables from the switchyard (including those from the instrumentation transformers and circuit breakers), are directly connected to the analogue and binary inputs of these devices. IEC 61850 process bus has changed this approach and now the Ethernet network is the means of data transportation from the switchyard to the relay room [1], [2].

With this approach, most of the copper cables used in conventional installations to connect field devices, such as instrument transformers, circuit breakers, etc., to IEDs are replaced by messages in a fiber optic communication network. Within this context, current and the voltage signals are sampled and converted to digital values, which are then transmitted through the network in standardized messages known as Sampled Measurement Values (SMV), as described in IEC 61850-9-2 [4] and IEC 61869-9 [6]. Binary signal information such as circuit breaker state and command is transmitted through the network in standardized GOOSE (Generic Object Oriented Signal Events) messages, as described in IEC 61850-8-1 [5]. A new IED called Merging Unit (MU), installed on the switchyard and connected directly to the CT and VT is responsible for the conversion of all these signals to network messages.

In terms of analog measurements, merging units must provide SMV packets with the magnitude and phase accuracy similar to that provided by the conventional acquisition system in order to keep the requirements of the system [3]. Furthermore, since the SMV messages do not carry timestamp information, but only sample count, merging units need to provide stable samples with relation to time. It means that, for example, in the case of a nominal frequency of 60 Hz and a sample rate of 80 frames/cycle (protection profile), every sample must be sent to the network spaced in 208 microseconds. Additionally, it is imperative that the first sample of the second be as close as possible to the PPS (Pulse per Second) turnover. Good stability of the Merging unit is defined to these characteristics and they are strongly dependent on the performance of the internal algorithms to process the data and keep the time synchronization of the acquisition system.

As for status of binary inputs, GOOSE messages must be sent through the network with the minimum delay in order to provide similar performance of the hardwired signals, even more crucially when the MU is receiving a trip command to be relayed to the circuit breaker. The delay to receive and process the message and provide a reaction can be critical to the protection scheme. Thus, the delays must be near instantaneous to not compromise the behavior of the system, mainly when considering the time delay to effectively close the trip contact.

3 FPGA AND MICROPROCESSORS

The most common architecture for microprocessor IED devices is to carry out the signal acquisition, protection functions, and Ethernet packets management, in a centralized processor. This processor also needs to manage the configuration, control HMI and other internal services. Typically, such devices use an operating system (OS) to manage the processor concurrent schedule and its interface with the other circuits.

If we focus on the MU application, even in real time OS, it is not possible to guarantee that the time delay between the signal acquisition and the SMV being sent through the Ethernet port does not vary over time. However, this may be circumvented with the use of Field Programmable Gate Array (FPGA) to control the critical processes. This is achieved due to the multiple threads running concurrently at the hardware level of the FPGA system, operating fully in parallel and independent fashion. This way, by controlling the traffic in the Ethernet ports in a FPGA circuitry, nondeterministic delays can be eliminated. Furthermore, for the non-critical applications such as configuration and HMI management, it is possible to use a soft/hard-core processor running any flavor of OS within the FPGA.

4 MERGING UNIT HARDWARE IMPLEMENTATION

Merging units replace the I/O interfaces of the relays. They receive GOOSE messages in order to command the circuit breakers and send GOOSE messages to the network to signalize the current status of the switches in the switchyard. Related to the analog measurements, sampled values replace the data provided by the conventional acquisition system of the relays. Thus, these measurements must consider the same requirements in terms of stability, latency and time synchronization of the traditional acquisition systems.

For accurate performance, it is imperative that the sampling rate of the MU device be stable. It means the time between two consecutive samples transmitted through Ethernet must be the same. Using FPGA latency can become so low to the point of being negligible. In the MU320 implementation, an FPGA controls the analog acquisition system, creates the Ethernet packets and manages the traffic in the Ethernet ports. The soft/hard-core processor manages the configuration and provides the model for the SV packet to be transmitted. Figure 1 shows a block diagram of a solution based on FPGA implementation.

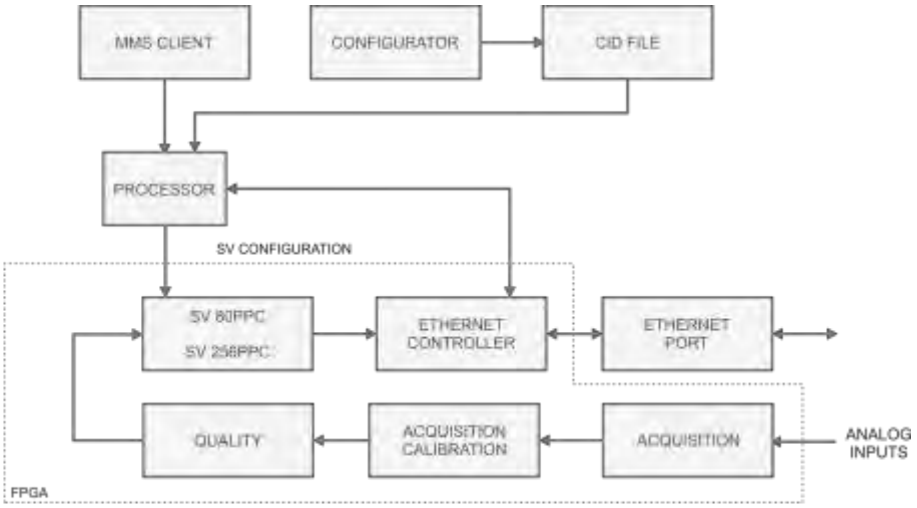

Figure 1. Block diagram for sampled values publishing based on FPGA.

For the GOOSE messages, process the Ethernet packet in the processor is a typical solution due to the commercial availability of GOOSE processing libraries for different operating systems. In this scheme, to generate a GOOSE message, it is necessary to read binary inputs and insert the resulting packet on the Ethernet output buffer. Since the network traffic varies, there is a non-deterministic delay from the binary input be read, be processed by the processor and the GOOSE message be sent. Similarly, the time delay to activate a binary output will depend on the time delay to process the GOOSE message contents received from the Ethernet input buffer.

Because the binary input/output status is available on hardware level as well as the controller of the Ethernet interface, it is much more efficient to generate or receive GOOSE messages on hardware level, with no delay inserted.

With the architecture based on an FPGA and a soft/hard-core processor, general packets from/to the processor and GOOSE packets from/to the GOOSE Publisher/subscriber can be controlled in the hardware level. Because the FPGA controls the Ethernet traffic to/from the Ethernet interface, GOOSE messages are prioritized and are not delayed even in case of a huge traffic of general packets from/to the processor.

Since the state of a binary input is available to the GOOSE Publisher, the implementation relies on a hardware block capable of creating and sending GOOSE packets, publishing the information to the Ethernet controller to be distributed on the network. Considering the packets from GOOSE publisher have a higher priority, the GOOSE message is sent to the Ethernet port with no delays.

GOOSE messages received from the Ethernet port are redirected to the GOOSE subscriber hardware block that parses the message to identify changes in the attribute of binary data in the GOOSE Control Block. According to the configuration of the IED and the contents of the GOOSE message received, the state of a binary output is changed.

In this approach, the configuration of the GOOSE messages to be received and transmitted by the IED is established by the processor and fully configurable by the user. The block diagram for the implementation of the GOOSE Publisher and the GOOSE Subscriber is shown in Figure 2 and Figure 3 respectively.

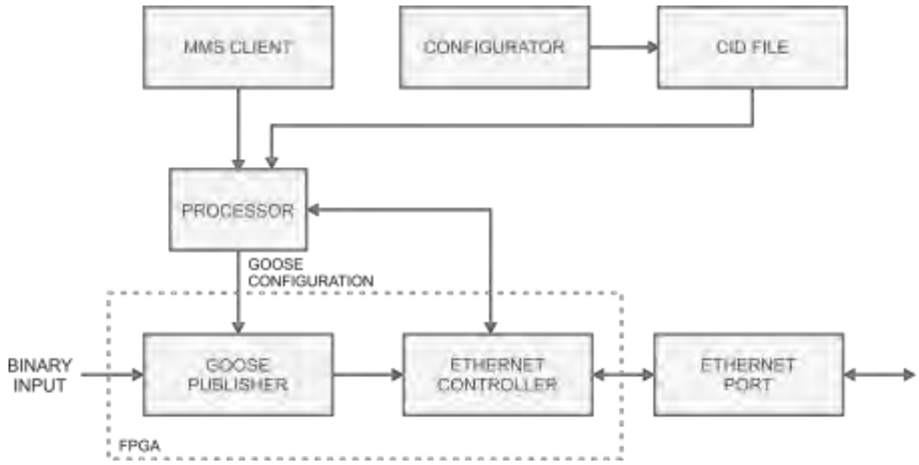

Figure 2. GOOSE publisher block diagram.

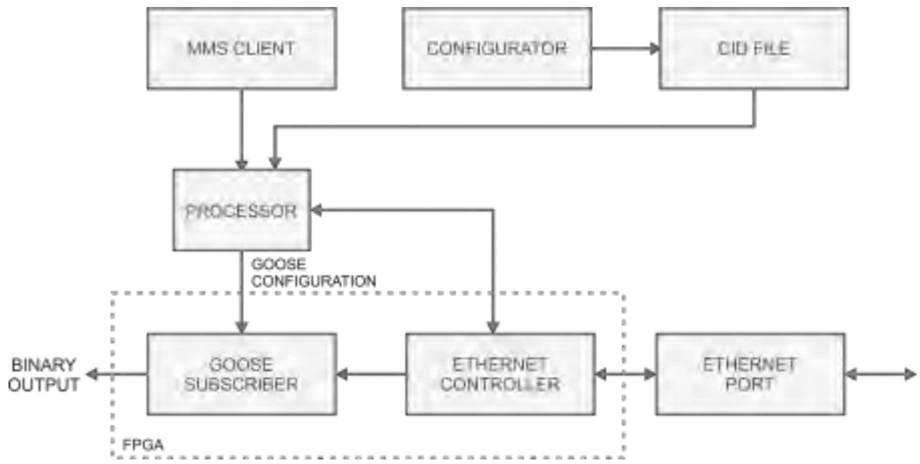

Figure 3. GOOSE subscriber block diagram.

Considering the binary output can be related to the trip command, the GOOSE messages must not be only received faster but the trip contact must be closed faster as well. Conventional solutions are based on electromechanical relays that have a slower reaction (around 5 milliseconds) due to the mechanical switching time delay.

In order to provide a complete solution, an innovative high speed trip contact (fast make) performs a faster reaction (in order of microseconds). This fast make is achieved using a static switch, with a conventional contact closing in parallel, to achieve a higher carrying, and to offer a high inductive break rating.

5 PERFORMANCE TESTS

Figure 4 shows the test setup for GOOSE performance. All IEDs are synchronized via IRIG-B by an RT430 Grandmaster GPS clock. The MU320 (1), IED (1) and IED (2) also receive a PPM signal from the GPS clock on one of their binary inputs. These IEDs are also programmed to send a GOOSE message with a dataset including the binary input used for the PPM signal. All this network traffic is routed to a T1000 Ethernet Switch and then to an RPV311 Digital Fault Recorder, where the messages are received through the electrical Ethernet port and their time-stamping recorded.

Additionally, another merging unit with a high-speed high-break board, MU320 (2), is programmed to receive the GOOSE messages from all the IEDs and translate the dataset to a binary output. This output is connected to an RA331 acquisition module, which is the binary input of the DFR system. This measures the combined delay of decoding and switching of the physical output contact of MU320 (2), plus the time to process and send the GOOSE messages from MU320 (1), and IEDs (1) and (2). The test serves a dual purpose. On one hand it evaluates the performance of the MU320 on tripping a virtual circuit breaker, although in the test case the switching load is purely resistive. On the other, it shows the IEDs performance of GOOSE time-stamping, i.e. detecting a change and encoding a message, and processing, i.e. publishing the message on the network.

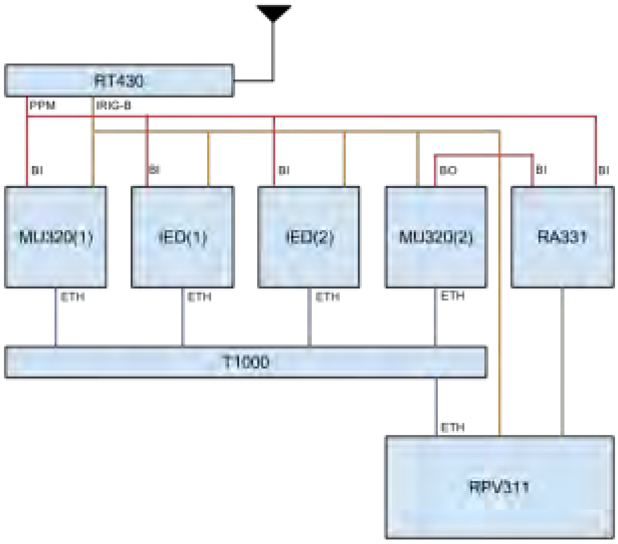

Figure 4. GOOSE performance test scenario and IED interconnection.

The results for the GOOSE time-stamping are presented on Figure 5. The influence of the IED implementation on the overall result is clearly seen. While the FPGA implementation falls within the 0.2 milliseconds range, microprocessor based IEDs range to some to dozens of milliseconds.

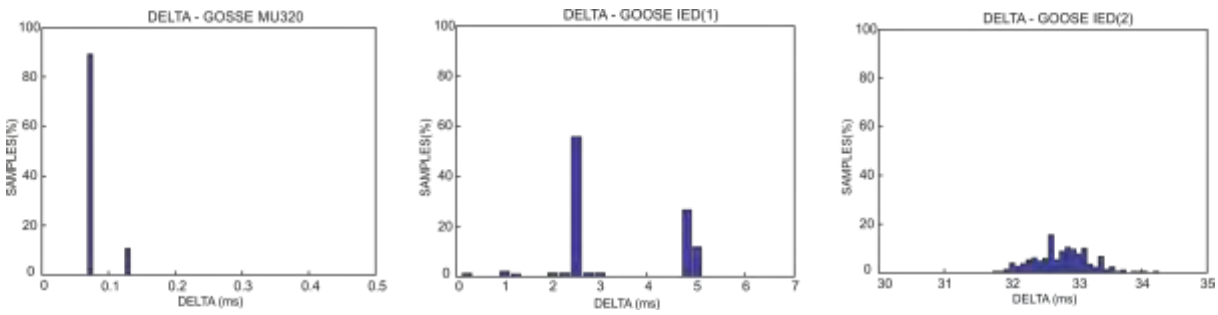

Figure 5. Test results for logical time-stamping of GOOSE, MU320 (1) (left), IED (1) (center) and IED (2) (right). Vertical axis in number of samples N and horizontal axis time delay in ms.

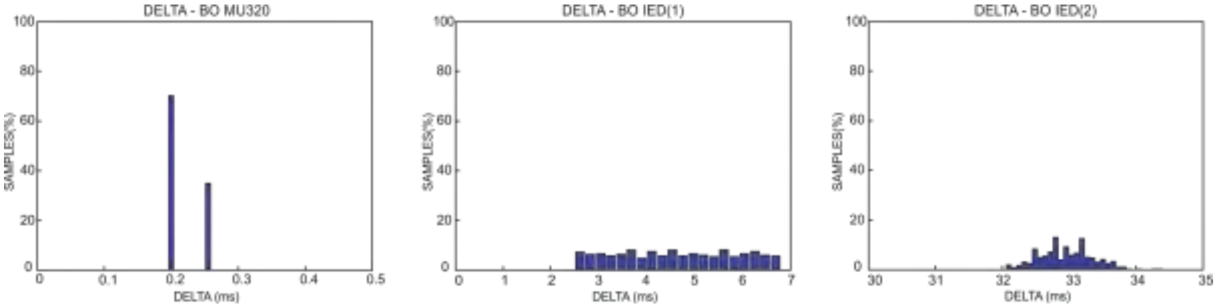

Figure 6. Test results for physical contact output, MU320 (1) (left), IED (1) (center) and IED (2) (right). Vertical axis in number of samples N and horizontal axis time delay in ms.

On Figure 6 the performance of the physical output of the MU320 when actuated by the GOOSE of various IED is presented. Once again, the influence of the truly parallel processing is clear on the results. The MU320 results present a pattern of virtually double processing time (2 MU320 on the loop) and almost negligible contact switching delay. The concentrated distribution shows that there is very little variance in the processing time and contact switching. IED (1) presents a more evenly distribution, even though most of its time-stamps fall into two values on the first test. That is due to a delay in the actual publishing of the message, where a second source of variance in the delay is introduced. IED (2) distribution is virtually the same as the prior test case, showing that the processing time of the MU320 compared to that of the IED is virtually inexistent. In all cases the mean output time has risen slightly, on the same degree as the MU320 delay, as expected by the inclusion of MU320 (2).

6 CONCLUSION

The paper discusses how the use of merging units is becoming the new standard for power system protection and how their performance is crucial for proper power system protection. The influence of different approaches of hardware implementation in the resulting performance of the IEDs is discussed and comparative test results are presented.

The very low standard deviation of FPGA hardware is clearly seen on the results presented, eliminating most of the jitter and variance of the IED response and providing results more consistent to the traditional hardwired signals. Furthermore, the drastic speed of logical GOOSE message processing using FPGA is also clearly demonstrated, reducing processing time almost in 20 to 350 times that of the microprocessor IEDs used in comparison.

On the physical contact switching test, it can be seen that combining the high-speed outputs and the FPGA hardware the overall processing times are really low. Even with two MU chained, the total delay for decoding a change of state in a binary input, encoding a GOOSE message, transmit and decode that same message, and finally actuate on a binary output is always less than 0.3ms. When compared to traditional systems, which rely on cascaded switching operations, this incurs in a drastically lower delay for the transfer of information.

As a conclusion, with the optimization of real-time performance of the merging units and other components of the digital substation, not only can we match, but also surpass the performance of traditional hardwired stations, meanwhile making use of the IEC 61850 added benefits. Interoperable solutions built to international communication standards deliver the security, dependability, speed and availability demanded by utilities.

For future works, the test cases may be expanded so that individual IED performance may be evaluated, without cascading the connections. Furthermore, a larger number of sample may be collected and their statistical data gathered, to summarize important conclusions and saliences more clearly.

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S.6-2. Framework for Process Bus Reliability Analysis

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KEYWORDS

Reliability, Process bus, IEC 61850, Merging Unit, Sampled Measured Values

ABSTRACT

Several pilot projects related to the Process Bus are being executed with the main goal to certify the reliability of the network as the mean to transmit information which is critical to the integrity of the protection system. This paper presents a methodology to evaluate the process bus reliability based on the reliability model for various network topologies. Considering the MTBF of the elements of the protection system, the reliability level of the whole system was determined and the results were analyzed.

1. INTRODUCTION

In the power sector the system security is vital to keep the stability in energy supply to consumers. Traditionally, protection engineers are conservative with respect to preserving the integrity of all the elements that make up this system. Depending on the voltage levels in substations, the use of redundancy in protection schemes is used to mitigate the risks of problems [1].

In conventional substations, every device in the relay room, such as protective relays and digital fault recorders, has its own acquisition system. All the cables from the switchyard (including those from the instrumentation transformers), are directly connected to the analogue inputs of these devices. IEC 61850 [2] process bus has changed this approach. The network is being considered as the means of data transportation from the switchyard to the relay room [3]. Both utilities and system integrators recognize the benefits and the economic viability of using Ethernet communication network to interconnect Intelligent Electronic Devices (IEDs) inside the substation control house. IEC 61850 considers this level of communication as the Station Bus.

In addition to the Station Bus, IEC 61850 considers another level of communication, namely, the Process Bus. The Process Bus is intended to replace most of the copper cables used in conventional installations to connect field devices, such as instrument transformers, circuit breakers, etc., to IEDs by messages in a fiber optic communication network. Within this context, current and the voltage signals are sampled and converted to digital values, which are then transmitted through the network in standardized messages known as Sampled Measurement Values, as described in IEC 61850-9-2 [4] and IEC 61869 [5]. This conversion is performed by a device called Merging Unit (MU).

The use of Process Bus in power systems has been considered the newest wave of technological evolution. However, it has not been widely adopted yet, probably because power system professionals are not so confident about using Ethernet networks to transmit information which is critical to the system secure operation. Different network approaches provide different reliability levels. In this paper, the reliability of different topologies is obtained by using a methodology for creating models based on the reliability of each element that makes up the structure of the whole network communication, from the measuring elements (merging unit) up to the command to the drive (protection relay). Based on the estimation of the MTBF (Mean Time Between Failures) of each element of the network, the reliability of the system is obtained, and it is possible to evaluate the effect of the redundancy.

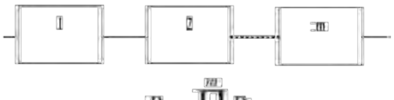
2. RELIABILITY

A widely accepted definition of reliability is that it is the probability of a device performing its function properly, for a certain period of time, under given operating conditions [6]. The use of the theory of probability in engineering problems is viewed with skepticism by those who consider engineering as something purely deterministic. However the integration of statistics and probabilities is a natural thing in the analysis of possible results by creating hypothetical scenarios in order to evaluate the possibilities of occurrence of different situations. The use of redundant systems has been considered in several situations. According to [7], redundancy is the existence of more than one means to perform a given function. This consideration is closely linked to reliability and suggests an improvement in the conditions of the system being analyzed.

The methodology to provide the reliability level of the protection system is based on the creation of reliability models that relates the individual reliability of all the units that compose it. Considering these models, quantitative levels of reliability of the whole system is obtained. Depending on the complexity of the system, different approaches can be used to provide the reliability model of the system. Some methods are shown as follows.

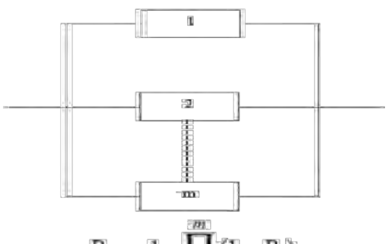
2.1.Block Diagrams

In block diagram models, according to [8], each block represents a unit. In the series configuration, all the units must work normally for the system success. For independent failing units, the reliability of the m-series system is shown in figure 1a. In the parallel configuration, at least one such unit must operate normally for the system success. The m-parallel system reliability is shown in figure 1b. Mixed configuration considers the composition of the series and the parallel models for creating a specific model.



$$R_s = \prod_{i=1}^{m} R_i$$

a) series configuration



$$R_{ps} = 1 - \prod_{i=1}^{m} (1 - R_i)$$

b) parallel configuration

Fig. 1 – Block diagrams.

Rs and Rps are the reliability level for the series and parallel models, respectively and, Ri is the reliability level for the i-th unit of the diagram.

2.2. Complex methods

More complex systems require more specific methods to provide a reliability model. The fault tree is a deductive system analysis by which the analyst postulates that the system could fail in a certain way and attempts to find out how the system or its components could contribute to this failure [8]. It represents the occurrence of an event by the relationship of a set of entities called "gates" and the Boolean algebra between them. Figure 2 shows an example of a Fault Tree Analysis (FTA) diagram.

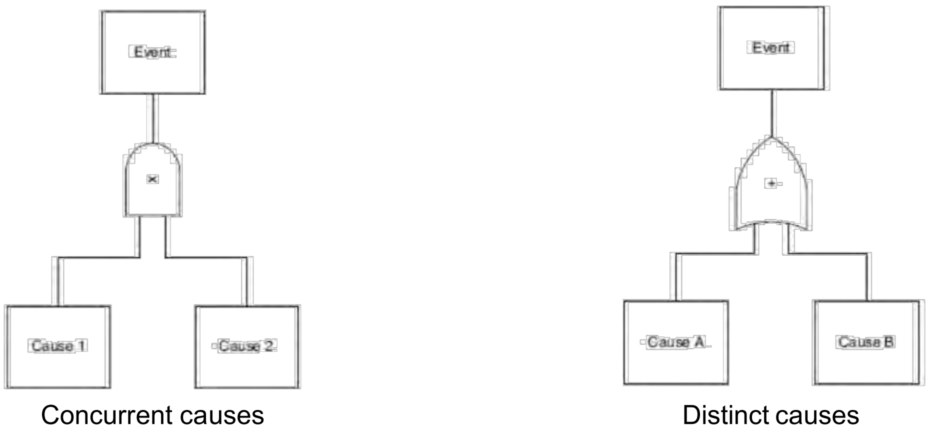


Fig. 2 – Basic logic diagrams.

Another method is based on the Boolean logic tables. Considering different scenarios, a logic table is created, the conditions of success are determined, and the probability of the occurrence of these scenarios is calculated to provide the level of reliability of the system.

3. PROCESS BUS RELIABILITY MODELS

The conventional protection systems, from the point of view of interconnection between switchyard equipment and IEDs, are simple structures that are composed of the protection relay which is installed in the control room and the cables that connect it with the switchyard elements. Regarding the level of reliability, the protection system is related to the level of reliability of the wiring, instrument transformers, and protection relays. For the IEC 61850 Process Bus, different topologies for the network can be created with the final goal of realizing the interconnection of multiple transmitters and receivers of data information. For a more practical analysis, some scenarios that tend to be more common choices for building the process bus are considered.

The purpose of this paper is to analyze the reliability of the protection system in order to compare the reliability of different topologies of the process bus and the conventional approach. For the analysis, the communication structures and the devices inserted in it will be evaluated. Because of the length of the cables from the switchyard elements to the merging units are inherently short, these cables were not considered in the analysis. For simplicity, digital instrument transformers won't be considered in this study. As such, both the conventional approach and process bus share the same instrument transformers and their reliability is not part of the models.

In order to provide the reliability model for the conventional architecture, the copper cables and the protective relay were considered. The reliability model is based on the series block diagram, shown in (1). In some cases, the redundant protective relays are demanded to enhance the reliability of the system. Two protection relays with independent wiring have been considered. The model considers a composition of series and parallel block diagrams, such model is shown in (2).

$R_S = R_{CC1}{*}\ R_{RL1}$ (1)

$R_{SR} = [1 - (1 - R_{CC1}{*}\ R_{RL1}){*}(1 - R_{CC2}{*}\ R_{RL2})]$ (2)

Where, RS, RSR, RCC1, RCC2 and RRL are the reliability level of the protection system without and with redundancy, copper cables that connects the switchyard elements to the relays, and protective relays respectively.

Based on the communication architecture of each scenario, a model related to the reliability of the protection system in the process bus approach is established, according to the following:

3.1. Scenario 1: One merging unit, one relay and one switch

It is considered that a merging unit installed in the switchyard and close to some field element, such as a current transformer (CT), is connected to a protective relay through a switch. Both protective relay and MU are connected to this switch via a fiber optic cable. The relay, the switch and the cable which interconnects them are in the relay room, while the MU is installed in an appropriate panel in the switchyard and the cables that connect it to the relay room are housed in conduits crossing the substation. Figure 3 illustrates this interconnection.

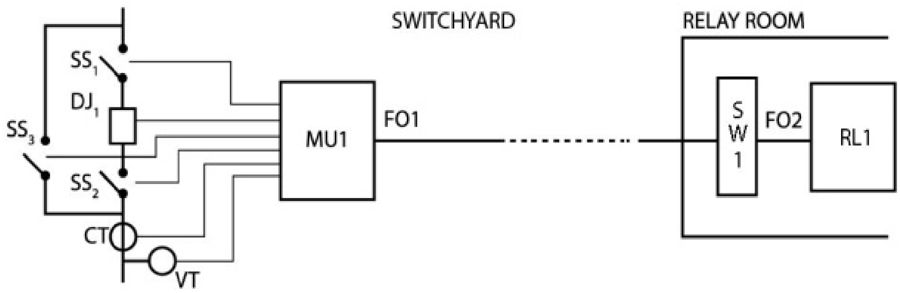


Fig. 3 – Network topology for a simple process bus.

To obtain the model of this topology, which is a very basic process bus, the block diagram of a series model was considered. The reliability model for this scenario is shown in (3).

$R_{SIST}=R_{MU1}{*}R_{FO1}{*}R_{SW1}{*}R_{F02}{*}R_{RL1}$ (3)

Where, RSIST, RMU1, RFO1, RF02, RSW1, and RRL1 are the reliability level of the protection system, merging unit, optical fibers 1 and 2, switch and protective relay, respectively.

3.2. Scenario 2: Two merging units with redundant acquisition, one relay and one switch

The use of MU increases the risk of the protection system based on process bus. The alternative to mitigate this risk is the use of two MUs measuring the same signals simultaneously and sending data to the network, as shown in Figure 4.

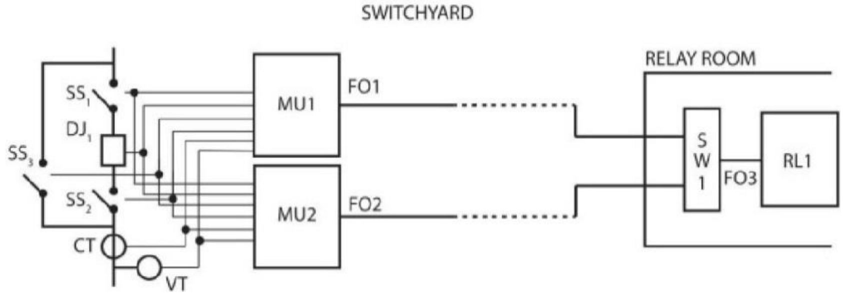


Fig. 4 – Network topology with redundant acquisition.

In this condition, the protective relay must be able to receive and process packets from two MUs simultaneously. There is no redundancy in the network structure. The model for determining the reliability of the protection system in this topology, based on the mixed block diagram, is shown in (4).

$$R_{SIST} = [1 - [(1 - (R_{MU1}*R_{FO1})) * (1 - (R_{MU2}*R_{FO2}))]] *R_{SW1}*R_{F03}*R_{RL1} \quad (4)$$

Where, RSIST, RMU1, RMU2, RFO1, RF02, RF03, RSW1, and RRL1 are the reliability level of the protection system, merging units 1 and 2, optical fibers 1, 2 and 3, switch and protective relay, respectively.

3.3. Scenario 3: One merging unit and one relay with redundant Ethernet ports, two switches

In this topology is added another level of redundancy: the use of redundant network ports with the PRP (Parallel Redundancy Protocol) protocol [9]. Thus, the whole structure of the process bus shall be doubled and all the information that is transmitted by the merging unit is sent by two different paths to reach the IEDs. Figure 5 illustrates this scenario.

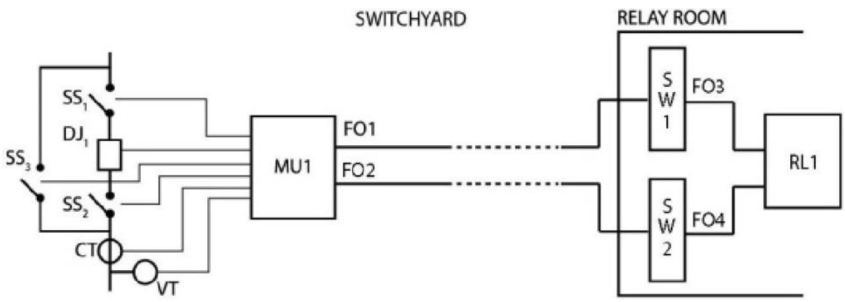


Fig. 5 – Process bus considering redundant architecture.

The model for reliability in this configuration, obtained from the representation of mixed block diagram, is given by

$$R_{SIST} = R_{MU1}*[1 - (1 - (R_{FO1}*R_{SW1}*R_{FO3}))*(1 - (R_{FO2}*R_{SW2}*R_{FO4}))]*R_{RL1}$$

Where, RSIST, RMU1, RFO1, RF02, RF03, RF04, RSW1, RSW2, and RRL1 are the reliability level of the protection system, merging unit, optical fibers 1, 2, 3 and 4, switches 1 and 2, and protective relay, respectively.

3.4. Scenario 4: Two merging units (redundant acquisition) and one relay with redundant Ethernet ports, two switches

Performing the integration of the topology of Scenarios 2 and 3, one obtains a system that considers the redundancy of MUs and communication structure. In this context, a topology where the most vulnerable parts in the system are duplicated in order to mitigate the risk of failure is presented. Two MUs measuring the same switchyard signals are interconnected to two switches installed in the control room by a redundant link. A protective relay with redundant network ports and able to manage the information from two merging units is connected to these switches. This topology is shown below.

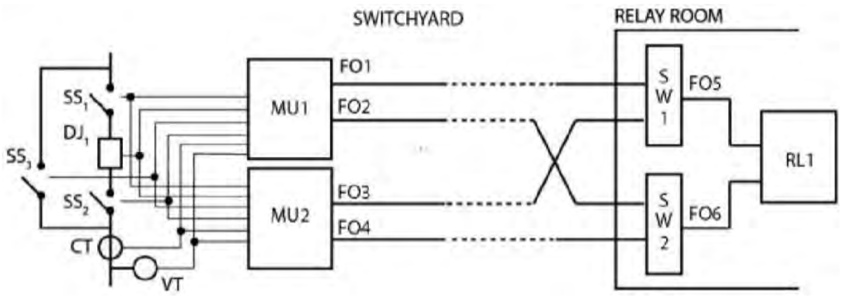


Fig. 6 – Process bus with redundant acquisition and redundant network architecture.

In order to model this system the FTA method was used considering a fault in the protection system as the event to be mapped. A fault tree consists of several levels of events connected by AND and OR logic gates. The resulting model was obtained by describing logically the set of possibilities of failure for all the units that are part of the protection system being analyzed (MUs, network structure and relay).

After substituting the logic gates diagram by mathematical expressions, the result is the reliability model shown in (6). From this model it is possible to obtain quantitatively the rate of failure of the protection system described in this topology.

$$\begin{aligned} R_{SIST} = {} & [1 - [1 - [1 - ((1 - R_{FO1})*(1 - R_{FO3})*R_{FO5}* R_{SW1})]*[1 - ((1 - R_{FO2})*(1 - R_{FO4})*R_{FO6}*R_{SW2})]]] * \\ & [1 - [(1 - R_{MU1})*(1 - R_{MU2})]] * \\ & [1 - [(1 - R_{FO1})*(1 - R_{FO2})*(1 - R_{MU2})]] * \\ & [1 - [(1 - R_{FO3})*(1 - R_{FO4})*(1 - R_{MU1})]] * R_{RL1} \end{aligned} \tag{6}$$

Where, RSIST, RMU1, RMU2, RFO1, RF02, RF03, RF04, RSW1, RSW2, and RRL1 are the reliability levels of the protection system, merging units 1 and 2, optical fibers 1, 2, 3 and 4, switches 1 and 2, and protective relay, respectively.

3.5. Scenario 5: Two merging units (redundant acquisition) and two relays (redundant protection) with redundant Ethernet ports, two switches

Depending on the voltage level of the power line and the element that is being protected, it is mandatory that the protection system consider a double measurement of voltage and current, so that there is a relay for primary protection and a backup in case of failure of the primary one [1].

Typically, in the conventional system, two independent sets of cables from the CT and the VT are taken to the relay room to be connected to each protective relay. An equivalent process bus topology considers the use of two MUs with redundant network ports connected to the switches by fiber optic cables. Protection relays with redundant network ports are also connected to the switches and execute the protection functions by considering the concept of the primary and backup protection scheme. Figure 7 shows this topology.

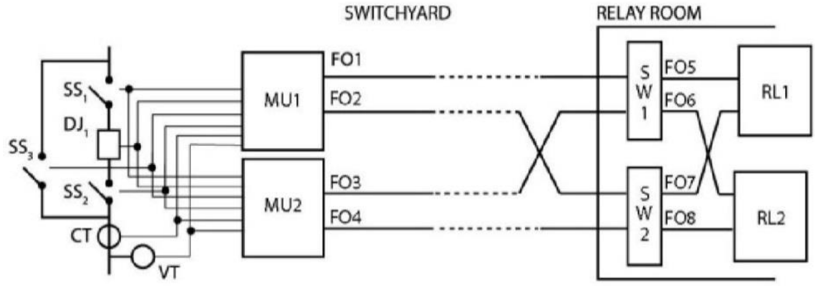


Fig. 7 – Process bus with acquisition and protection redundancy.

By using the FTA method, the reliability model of the protection system was obtained considering the failure of the system as the event to be mapped. The complete FTA is shown on Figure 8, and the resulting model in (7).

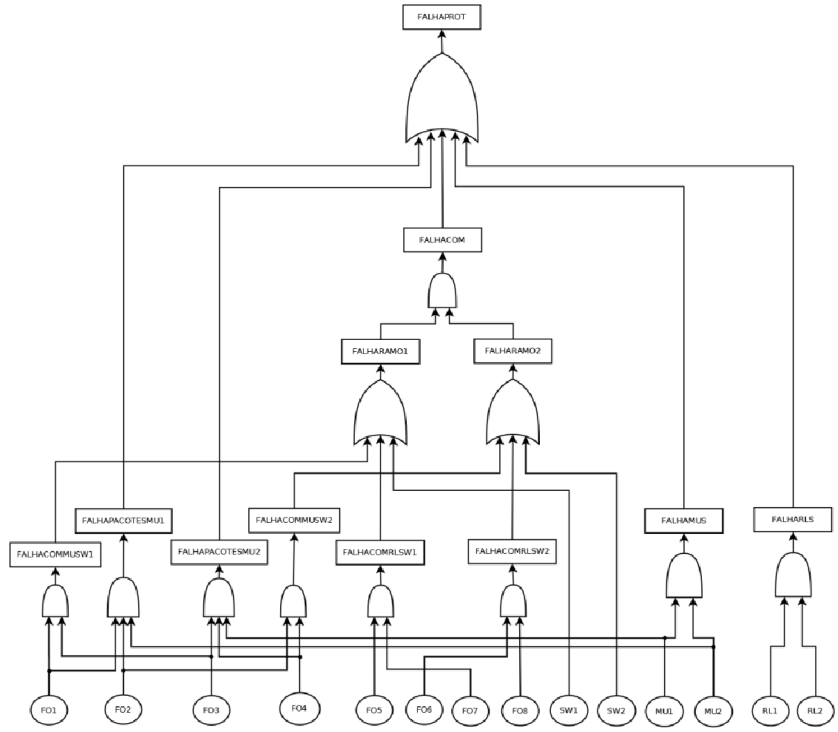


Fig. 8 – FTA analysis for scenario 5.

$$
\begin{aligned}
R_{SIST} = \; & [1 - [1 - [[1 - ((1 - R_{FO1})*(1 - R_{FO3}))]*[1 - ((1 - R_{FO5})*(1 - R_{FO7}))]*R_{SW1}]] * \\
& [1 - [[1 - ((1 - R_{FO2})*(1 - R_{FO4}))]*[1 - ((1 - R_{FO6})*(1 - R_{FO8}))]*R_{SW2}]]] * \\
& [1 - [(1 - R_{MU1})*(1 - R_{MU2})]] * [1 - [(1 - R_{RL1})*(1 - R_{RL2})]] * \\
& [1 - [(1 - R_{FO1})*(1 - R_{FO2})*(1 - R_{MU2})]] *[1 - [(1 - R_{FO3})*(1 - R_{FO4})*(1 - R_{MU1})]]
\end{aligned}
\tag{7}
$$

Where, RSIST, RMU1, RMU2, RFO1, RF02, RF03, RF04, RFO5, RF06, RSW1, RSW2, RRL1, and RRL2 are the reliability level of the protection system, merging units 1 and 2, optical fibers 1, 2, 3, 4, 5 and 6, switches 1 and 2, and protective relay 1 and 2, respectively.

3.6. Scenario 6: Ring network topology

In the previous topologies the switch is one of the key elements in the protection system. Its configuration is essential to providing the effective management of data exchange on the network, guarantying the traffic level and ensuring that there are no problems to deliver the packets or packet loss.

In the ring topology, the connection between different IEDs is performed by direct and sequential links between devices, providing a connection in series and forming a ring. In this topology there is no need to use a switch, because each device in the ring has two Ethernet ports that behave equivalently to a switch, transferring packets from one port to another, so that the data is going through the ring according to the criteria established by the network protocol. To ensure the zero recovery time in case of failure of one element of the ring, the HSR protocol (High-availability Seamless Redundancy) [9] is the alternative.

For the study of reliability of the ring topology, a 6-IED ring was assessed illustrating a protection system with several devices connected in a single ring. This topology potentially considers the protection of more than one bay in the ring or the addition of several devices that use data from the switchyard. According to [10], due to the heavy network traffic, the maximum number of devices in the ring to keep the bandwidth of 100 MBit/s is six. This case study considered the ring with three merging units and three protective relays, forming a protection system for three bays as shown in Figure 9.

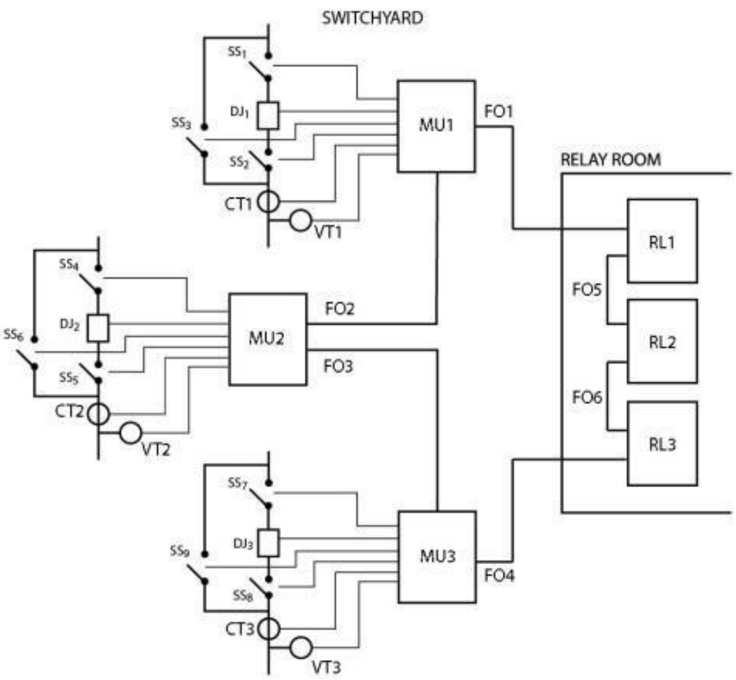


Fig. 9 – Three relays and three MUs in a ring topology.

The methodology used for determining the reliability model consists of mapping scenarios that identify the behavior of the protection system considering that at least one merging unit can communicate with a protective relay. For this case study, a combinatorial analysis of the elements that compose the protection system was performed, the scenarios were mapped and the failure hypothesis were evaluated.

In scenarios where the equipment and the links are not faulty, it is possible to guarantee the integrity of the protection system. In scenarios where one single failure occurs, there are situations where the integrity is maintained. In scenarios where there are two or more faults, it is not possible to fully guarantee that the system behaves as desired. System reliability is calculated by adding the probabilities of occurrence of the scenario with no failures and of the scenario with one failure. Equation (8) shows the model of reliability for the ring topology.

$$R_{SIST} = [(R_{FO})^{6} * (R_{MU})^{3} * (R_{RL})^{3}] + 6 * [(R\ \ )^{3} * (R_{MU})^{3} * (R_{FO})^{5} * (1 - R_{FO})] + 2 * [(R_{FO})^{6} * (R_{MU})^{3} * (R_{RL})^{2} * (1 - R_{RL})] + 2 * [(R_{FO})^{6} * (R_{RL})^{3} * (R_{MU})^{2} * (1 - R_{MU})] \quad (8)$$

Where, RSIST, RMU, RFO, and RRL are the reliability level of the protection system, merging units, optical fibers, and protective relay, respectively.

Performing similar analysis considering a ring of three elements (two MUs and one relay), the model of reliability is shown in (9).

$$R_{SIST} = [(R_{FO})^{3} * (R_{MU})^{2} * (R_{RL})] + 3 * [(R_{RL}) * (R_{MU})^{2} * (R_{FO})^{2} * (1 - R_{FO})] + [(R_{FO})^{3} * (R_{RL}) * (R_{MU}) * (1 - R_{MU})] \quad (9)$$

4. RELIABILITY ANALYSIS

Based on the previous section, different network topologies imply different models of reliability. The reliability for the whole protection system depends on each one of the elements that compose it. Each element has a probability of failure which is a function of the characteristics of the project and the components that it is based on. The better the quality, the lower the probability of equipment failure.

The reliability of products is closely related to the MTBF (Mean Time Between Failure). This value depends on the number of units analyzed and the time when these devices are in operation. Based on this information, it is possible to estimate the rate of failures of a piece of equipment within a given period of time and, therefore, the probability of failure or, in other words, its reliability level [7].

The reliability of some electronic equipment can be estimated according to (10).

$$R = e^{(-t/MTBF)} \tag{10}$$

Where, R, t and MTBF are the reliability level of the equipment, the time interval for the analysis and the mean time between failures for the equipment, respectively.

For a comparison of the reliability between different architectures, the MTBF of each network element was obtained in [11] and by surveying the manufacturers. Based on that, the reliability level of each element was established as shown in Table 1.

Element	MTBF (years)	Reliability
Protection relay	300	0,9967
Merging unit	300	0,9967
Switch	100	0,9900
Copper cables	100	0,9900
Fiber optic cables in the relay room	100	0,9900
Fiber optic cables in the substation switchyard	100	0,9900

Table 1 – Reliability for each element of the protection system.

Considering the reliability of each element of the protection system and the topology model, the reliability of the entire system can be calculated. The MTBF can vary from manufacturer to manufacturer and, therefore, the reliability level used in the analysis. By using the methodology presented in this paper, new levels of reliability can be verified.

Protection systems based on conventional approach, considering their models of reliability can provide the reliability levels as shown in Table 2.

Architecture	Reliability
No redundancy	0,9867
Primary and backup protection	0,9998

Table 2 – Reliability levels for the protection system considering conventional approach

Considering the process bus approach, based on the reliability of each element of the network and the models of reliability for each topology, the reliability for the protection system considering the scenarios presented in the previous section is shown in Table 3.

Scenario	Network topology	Reliability
1	One merging unit, one relay and one switch	0,9639
2	Two merging units with redundant acquisition, one relay and one switch	0,9767
3	One merging unit and one relay with redundant Ethernet ports, and two switches	0,9925
4	Two merging units (redundant acquisition) and one relay with redundant Ethernet ports, and two switches	0,9965
5	Two merging units (redundant acquisition) and two relays (redundant protection) with redundant Ethernet ports, and two switches	0,9999
6	Ring network topology with 6 IEDs	0,9911
	Ring network topology with 3 IEDs	0,9930

Table 3 – Reliability levels for the protection system considering process bus approach

Compared to the process bus, a conventional protection system uses a smaller number of elements, such as the protective relay and the copper cables that connect it to the elements of the switchyard. Therefore the level of reliability is intrinsically high. When considering the protection scheme with redundant relays, the level of reliability is even higher.

When the process bus approach is applied, the protection system as a whole becomes more dependent on electronic devices and their communication links. With a larger number of elements, naturally more vulnerable points appear in the system and the level of reliability may decrease when compared with conventional architectures. It is clear however, that by including different kinds of redundancy in the system the level of reliability increases drastically, ultimately surpassing the conventional approach.

Scenario 1 shows the most basic architecture of process bus. It is related to a simple protection system where switchyard elements are connected to a single relay by means of the Merging Unit, a switch and fiber optic cables. Since the reliability depends on all elements and there is no redundant elements, this topology has the lowest level of reliability.

In Scenario 2 simple redundancy is considered, i.e. the use of two merging units and two independent fiber optic cables in order to provide duplicated information on the network. Thus, the protective relay would have valid data to run the protection algorithms in the case of a failure of one merging unit. The network structure is simple, that is, packets from each merging unit are transmitted through a single communication link to a switch. However the reliability of the system is substantially higher compared to scenario 1 due to the duplicity of the branch of measurement.

In Scenario 3, both merging unit and protective relay support the redundancy protocol. Since each device is connected to two switches, there is a complete parallel way to provide data communication between the IEDs, which makes the structure of the network more robust, and, consequently, increases the level of reliability of the protection system. Considering a second merging unit to enhance the level of redundancy for the measurement of signals as shown in the Scenario 4, results in a reliability level even higher. In both cases, system reliability is already higher than the conventional protection architecture without redundancy.
In cases where the highest reliability level of the protection system is required, the use of redundancy

of protective relays is unavoidable. The use of Process Bus considering redundancy of measurements and network structure combined with redundant relays, as shown in the Scenario 5, provides the highest level of reliability, surpassing even the reliability of the conventional architecture with primary and backup protection schemes. Since the same signal is being monitored by two different units and the path for data transfer consists of a network structure with various combinations, the immunity to failures in the protection system is increased. Having two protection relays capable of acting simultaneously on the system, this immunity is even greater.

The ring topology shown in the Scenario 6 for both 3 and 6 IEDs presented high levels of reliability with fewer devices required, proving as a valid alternative to the PRP approach. It comes however at the cost of limiting the amount of elements in that comprise the network and may impose difficulties in scalability, being therefore more suitable for small applications. It is also important to notice that PRP redundancy becomes more cost effective in larger systems, were the switches may, for instance, be part of multiple measurement bays.

Assessing all topologies presented, it is observed that the higher the level of redundancy, the greater the reliability level of the system. The redundancy in the network structure makes the system more reliable, because it allows multiple paths for data transfer. The redundancy of devices makes the system less dependent of the integrity of the pieces of equipment that compose it. It is noticeable, however, that for partial redundant protection system certain Process Bus architectures, despite the high reliability presented, are still at slightly lower levels than the conventional approach. The impact of this difference can be minimized if some other non-quantifiable aspects are considered.

Because of the characteristics of the IEC 61850-based protocols, the use of Process Bus naturally allows an easier and continuous monitoring of the status of the devices in the network and the quality of the data that is transferred over the network. This feature allows for quick identification of problems and, consequently, the maintenance team is quickly called to solve them. Additionally, the maintenance of the devices becomes simpler because there are fewer cables connected to them, which minimizes the working time in case of need for replacement. Another very important factor to be considered is the drastic increase in safety, since only the merging unit receives signals from a CT. This means the control room environment is not subject to the dangers of CT circuit interruption.

Finally, due to standardized characteristics of the IEDs, the information that is transmitted over the network can be marked as "test mode", and in this situation, some specific devices can ignore the data. This tag is useful for periodic testing of the substation system, device isolation, and ultimately, in service testing, avoiding the need to make the whole protection system unavailable during the test. The flexibility for the expansion of the system is a key point. The addition of other devices in the process bus is simple, because basically it requires physical space, power supply and network cables. Thus, there is no need for shutdown of the system for the service.

5. CONCLUSIONS

In this paper, the reliability of different architectures of process bus was obtained by using a methodology that considers the reliability level for each element of the protection system. Based on the MTBF of these elements, the reliability level of the conventional approach and for several scenarios of process bus was determined. The results were compared and based on them, it is possible to verify that the reliability of the process bus in some topologies are equivalent or greater than the conventional approach. Considering the results of the reliability levels and the non-quantifiable aspects of the process bus, its use is very encouraging.

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С.6-3. Особенности совместного использования устройств релейной защиты на основе стандарта IEC 61850-9-2LE и защит с традиционными входными аналоговыми цепями.

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КЛЮЧЕВЫЕ СЛОВА
цифровая подстанция, устройства релейной защиты, стандарт IEC 61850-9-2LE, синхронизация, цифровые отсчеты.

1 ВВЕДЕНИЕ

В настоящее время в электроэнергетике происходит активное внедрение технологии «цифровой подстанции», ключевым моментом которой является применение «шины процесса» в соответствии со стандартом IEC 61850-9-2 [1] и проектами стандартов IEC 61869-9, IEC 61869-13. Ограничение стандарта IEC 61850-9-2 до практического применения на реальных объектах отражено в [2] (IEC 61850-9-2LE).

Внедрение новой техники в релейную защиту подстанции обычно происходит поэтапно. При плановой модернизации существующих объектов это может быть уровень одного или нескольких присоединений, уровень системы одного напряжения. При проектировании новых подстанций технология использования указанных стандартов может быть реализована полностью [3].

Имеются некоторые особенности применения на подстанции оборудования с одновременным использованием «шины процесса» и традиционных аналоговых сигналов от измерительных трансформаторов тока (ТТ) и трансформаторов напряжения (ТН).

2 ОСНОВНАЯ ЧАСТЬ

Необходимость синхронности получения цифровых отсчетов сигналов (ЦО, SV) и синхронности обработки информации в устройствах релейной защиты (УРЗ)

Получение цифровой информации о токах и напряжениях различных присоединений «цифровой» подстанции осуществляется с помощью электронных ТТ и ТН со встроенными преобразователями аналоговых сигналов в цифровой вид (ПАС, MU) в соответствии с проектом стандарта IEC 61869-9 или с использованием традиционных ТТ, ТН и автономных преобразователей аналоговых сигналов (АПАС, SAMU) по проекту стандарта IEC 61869-13 (рис. 1). Получение ЦО сигналов токов и напряжений в ПАС или АПАС производится с помощью аналого–цифровых преобразователей (АЦП). Одновременность фиксации (взятия) ЦО для всех используемых сигналов в пределах подстанции обеспечивается единым источником синхронизации (источник точного времени). Синхронизация может осуществляться по отдельной оптической или электрической сети (сигналы 1PPS, IRIG-B) или через «шину процесса» по стандарту IEC 61588 (PTP).

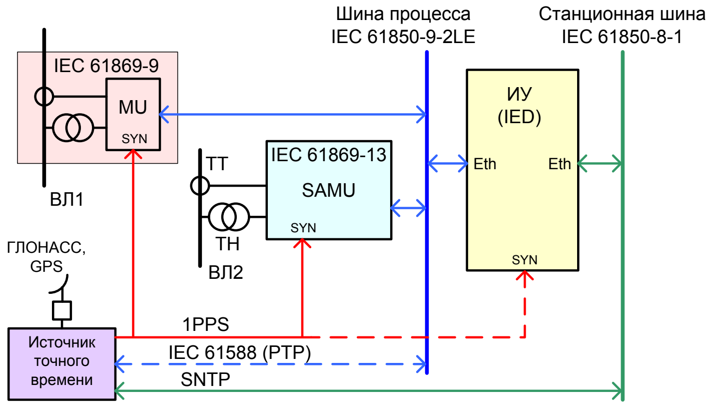

Рис. 1. Элементы «цифровой» подстанции

Каждый набор цифровых отсчетов сигналов, полученный в один момент времени, снабжается соответствующим номером, изменяющимся в пределах 0…3999 для частоты взятия отсчетов 4000 Гц (или в пределах 0…4799 для частоты взятия отсчетов 4800 Гц) и упаковывается в Ethernet-кадр, широковещательно отправляемый в сеть «шина процесса». Периодичность повторения номеров отсчетов – 1 с.

Устройства релейной защиты в пределах подстанции используют аналоговые сигналы в цифровом виде, полученные только по «шине процесса» IEC 61850-9-2

Подписчиками (приемниками) на конкретные потоки информации в сети «шина процесса» являются интеллектуальные устройства (ИУ, IED), выполняющие функции релейной защиты, противоаварийной автоматики и измерений. Каждое ИУ должно «собрать» ЦО с одинаковыми номерами для всех используемых в устройстве сигналов и только после этого использовать цифровые данные конкретных цифровых отсчетов для реализации необходимых функций.

Разная задержка выдачи кадров с цифровыми данными, отправляемых различными источниками сигналов (издателями) в сеть «шина процесса», по отношению к синхронизированному моменту взятия цифровых отсчетов и разные транспортные задержки приводят к необходимости ожидания приема всех используемых в ИУ наборов ЦО с одинаковыми номерами. По истечении допустимого времени ожидания цифровых данных с определенным номером, приемником принимается решение о восстановлении потерянных отсчетов или о формировании ошибки данных в «шине процесса». Решение принимается в зависимости от конкретной ситуации, в соответствии с принятой в ИУ стратегией приема и обработки сигналов.

Возникающие задержки при преобразованиях сигналов и транспортировке данных показаны в примере на рис. 2.

Для издателей. Предельно допустимая величина задержки (T_1 на рис. 2), отсчитанной от момента фиксации значения аналогового сигнала на входе преобразователя до выдачи Ethernet-кадра с соответствующим ЦО, регламентирована проектом стандарта IEC 61669-9 и применительно к сигналам, используемым в УРЗ, составляет 2 мс. Степень неравномерности выдачи Ethernet - кадров стандартом не определена.

Для подписчиков. Транспортная составляющая задержки Ethernet - кадров (T_2 на рис. 2) от разных издателей при приеме их в определенном узле сети также не определена и сильно зависит от архитектуры сети и от её загрузки.

Для нормальной работы вычислителя в ИУ, обработку значений принятых сигналов желательно производить равномерно, через фиксированные интервалы времени. Неравномерность поступления цифровых отсчетов на вход ИУ компенсируется с помощью «эластичного» буфера, на выходе которого информация выдается с периодом, косвенно синхронизированным с единым источником точного времени на подстанции. Глубина буфера автоматически регулируется в соответствии с принятым предельным временем ожидания ЦО с одинаковыми номерами.

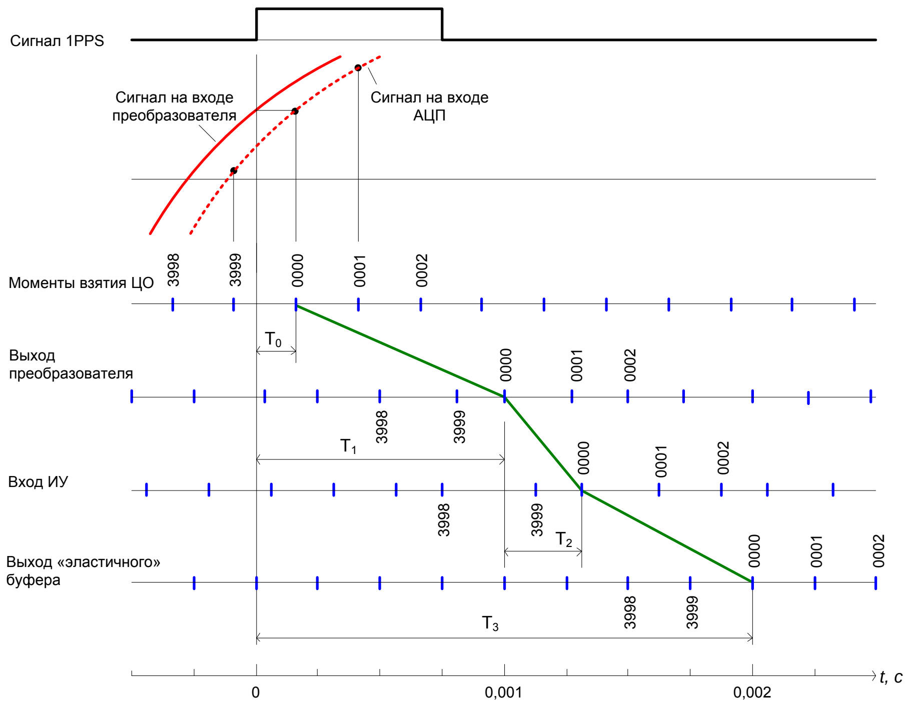

Рис. 2. Задержки, возникающие при преобразовании аналоговых сигналов в цифровой вид, передаче данных по сети и их обработке в ИУ

В приведенном примере T_3 - интервал времени между моментом фиксации ЦО в преобразователе сигналов и моментом его использования в ИУ.

Для ИУ, установленных на одной подстанции, использующих цифровую информацию от нескольких источников, синхронность обработки сигналов гарантируется нумерацией цифровых отсчетов при их фиксации на входе преобразователей сигналов в момент взятия ЦО. Это важно для защит шин, ошиновок, трансформаторов. Для дистанционных и токовых защит вся необходимая цифровая информация может быть получена от одного источника и будет находиться в одном Ethernet - кадре.

Дополнительные фазовые сдвиги сигналов промышленной частоты, полученные от разных источников (издателей) определяются:

- точностью синхронизирующих сигналов, поступающих в источники сигналов от системы единого времени (по стандартам отклонение нормируется в диапазоне ±2 мкс);
- интервалом времени между фронтом синхронизирующего импульса 1PPS и моментом «взятия» цифрового отсчета, которому присваивается номер «0» (интервал T_0 на рис. 2).

В соответствии со стандартами, интервал времени T_0 должен компенсировать задержку сигналов на входе АЦП аналоговыми фильтрами нижних частот (ФНЧ), подавляющими составляющие с частотой выше половины частоты взятия отсчетов.

Для случая применения на входе АЦП фильтров Баттерворта второго порядка с частотой среза 2000 Гц, задержка в передаче единичного ступенчатого сигнала на уровне 0,5 равна 114 мкс, а фазовый сдвиг на частоте 50 Гц составляет 2° (рис. 3).

Если в цепях предварительной обработки аналоговых сигналов использованы ФНЧ первого порядка, то задержка сигнала может составлять 200 мкс, а фазовый поворот 5°. Компенсирующая задержка T_0 в этом случае должна быть другой величины. Фазовый сдвиг сигналов на выходе такого ФНЧ при номинальной частоте также отличается от фазового сдвига сигналов для ФНЧ второго порядка.

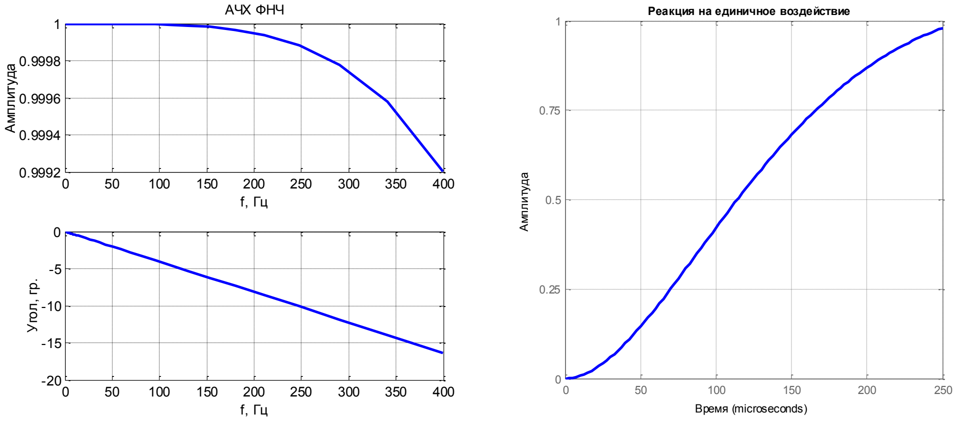

Рис. 3. Амплитудно-частотная характеристика ФНЧ второго порядка и задержка единичного сигнала входными фильтрами АЦП

В стандартах нет четких требований ни к задержкам T_0, ни к фазовым сдвигам сигналов на промышленной частоте, неодинаковость которых для преобразователей от разных производителей является погрешностью измерения сигналов по углу в пределах подстанции. Поэтому предпочтительным является использование на одном объекте (подстанции) источников сигналов с одинаковыми аналоговыми цепями для предварительной обработки сигналов. Такое условие гарантируется при использовании всех преобразователей на подстанции от одного производителя.

При наличии в устройствах ПАС и АПАС регулировки фазовых поворотов сигналов в небольших пределах, может быть осуществлена подстройка с использованием сертифицированного источника эталонных сигналов.

Требования к наличию синхронизации устройств ИУ от системы точного времени отсутствуют и достаточным является использование для целей регистрации событий SNTP сервера для корректировки часов реального времени устройств с точностью ±1мс.

УРЗ в пределах подстанции используют сигналы, полученные по «шине процесса» и полученные непосредственно от измерительных ТТ и ТН, с преобразованием в цифровой вид в самом ИУ

Этот вариант относится, прежде всего, к защитам многообмоточных трансформаторов, защитам шин и ошиновок, входные цепи которых могут быть комбинированными (рис. 4).

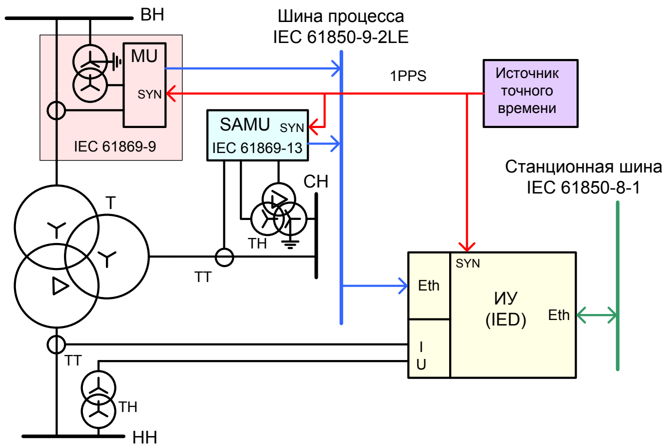

Рис. 4. Комбинированное использование технологий «цифровой» и традиционной подстанции на одном объекте.

Для такого применения, ИУ с комбинированными входами должно содержать устройство преобразования аналоговых сигналов, аналогичное использованному преобразователю в АПАС. Наличие в ИУ синхронизации начала преобразования от источника единого времени является обязательным требованием.

Ключевым моментом правильности совместного использования ЦО в комбинированном устройстве является нумерация цифровых отсчетов, полученных от АЦП в ИУ, по правилам, используемым при нумерации ЦО в АПАС. Задержка момента взятия ЦО с номером «0» по отношению к переднему фронту сигнала 1PPS (T_0 на рис. 2) должна быть такой же, как и в преобразователях сигналов (ПАС или АПАС) и может подстраиваться по эталонным источникам сигналов.

УРЗ в пределах «цифровой» подстанции используют сигналы, полученные по «шине процесса», но основные защиты линий связаны с обычными устройствами на подстанциях противоположных концов высоковольтной линии (ВЛ)

Даже при выполнении всей подстанции с использованием «шины процесса», алгоритмы выполнения некоторых типов защит требуют строго фиксированного промежутка времени между моментами взятия цифровых отсчетов в цифровых ТТ и ТН и моментами их обработки в УРЗ. Это требование касается, прежде всего, основных защит ВЛ, например дифференциально-фазных (ДФЗ) [4], так как полукомплекты защиты, установленные на вторых концах ВЛ могут быть обычными, без использования «шины процесса» (рис. 5).

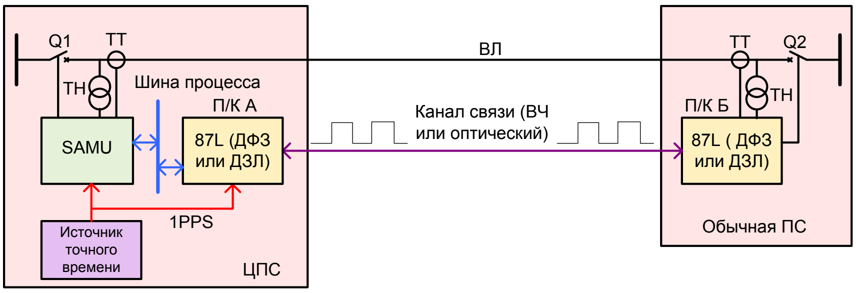

Рис. 5. Комбинированное использование технологий «цифровой» и традиционной подстанции на разных объектах.

Сравнение фаз токов по концам ВЛ в ДФЗ производится непосредственно в ВЧ канале связи и поэтому требуется согласование во времени положения ВЧ пакетов, формируемых органами манипуляции (ОМ) обоих полукомплектов.

В электромеханических, или микропроцессорных (МП) ДФЗ выходной сигнал устройства управления ВЧ передатчиком (сигнал органа манипуляции) сдвинут по отношению к мгновенным значениям контролируемых токов. Величина сдвига определяется используемой в ОМ фильтрацией и способом формирования импульсов управления. Так, например, для электромеханической защиты ДФЗ-201 и МП ДФЗ задержка сигналов управления пуском ВЧ передатчика T_{OM} составляет 3,3 мс или 60° для сигнала манипуляции промышленной частоты.

Если для «обычных» ДФЗ интервал времени между взятием ЦО и моментом его обработки строго определен, то для аналогичного ЦО, принятого ИУ по шине «процесса», существует неопределенность, связанная с конечным временем транспортировки данных через цифровые сети. Диапазон допустимых задержек передачи информации находится в пределах от десятков до нескольких тысяч микросекунд, что соответствует значительным неопределенным фазовым сдвигам вычисляемых векторных и мгновенных значений сигналов, полученных в соответствии с IEC 61850-9-2LE и традиционным путем.

Для устройства ДФЗ с использованием «шины процесса» предлагается ввести задержку обработки ЦО по отношению к моменту их фиксации на входе АЦП на фиксированное время, большее максимального времени транспортных задержек (T_C на рис. 6). В этом случае формирование сигналов управления ВЧ передатчиком, по отношению к ДФЗ на «обычной» подстанции, будет происходить с задержкой на время T_C, соответствующей дополнительному углу сдвига сигнала манипуляции на выходе ОМ на величину $\varphi = T_C*18000,(°)$ в сторону отставания и независящему от времени транспортировки цифровой информации по сети. Так, например, для принятой задержки $T_C = 0{,}003$ с, угол $\varphi = 54°$.

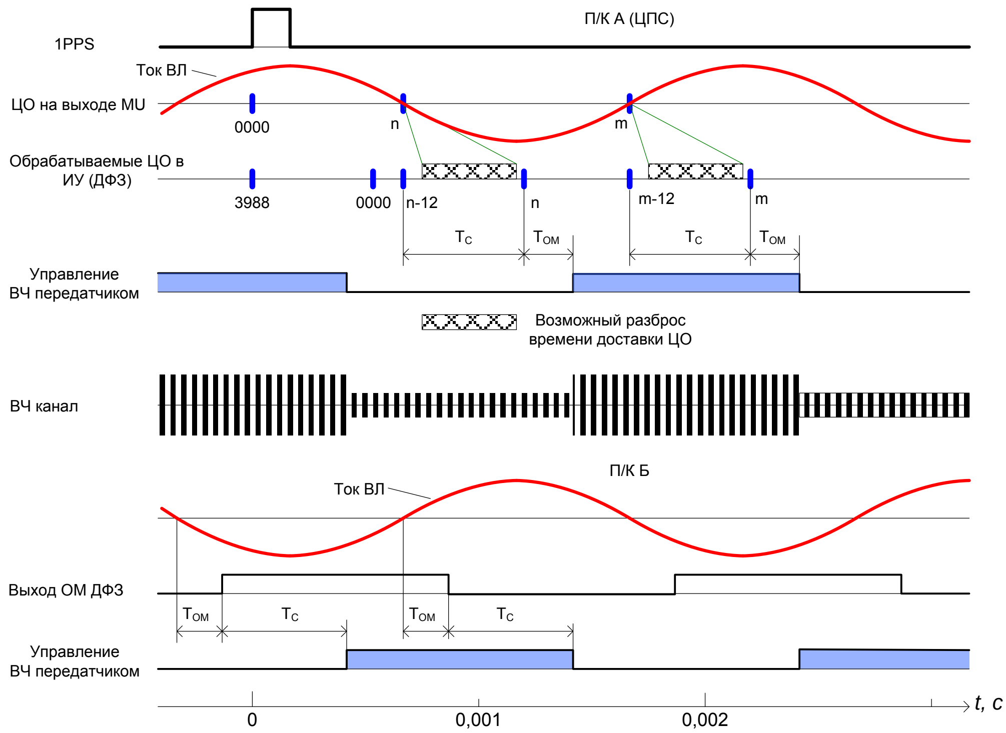

Рис. 6. Комбинированное использование технологий «цифровой» и традиционной подстанции на разных объектах на примере ДФЗ. Внешнее повреждение или нагрузочный режим ВЛ.

Управление глубиной «эластичного» буфера, в котором происходит задержка ЦО на фиксированное время T_C, должно осуществляться автоматически, путем синхронизации выдачи ЦО с необходимыми номерами от единого источника точного времени (1PPS, PTP), используемого на «цифровой» ПС для синхронизации устройств ПАС и АПАС.

Компенсация дополнительного фиксированного сдвига ВЧ пакетов, переданных по ВЧ каналу со стороны «цифровой» подстанции, может производиться путем задержки сигналов манипуляции ВЧ передатчиком на время T_C в полукомплекте «обычной» ДФЗ. Для МП ДФЗ указанная задержка может осуществляться с использованием кольцевого буфера фиксированной длины.

Синхронизация взятия цифровых отсчетов сигналов от источника точного времени в полукомплекте МП ДФЗ на «обычной» ПС не требуется.

При использовании в качестве основной защиты ВЛ дифференциальной защиты с цифровым каналом связи (ДЗЛ) [5] аналогичная задача решается тем же путем.

Роль «ведущего» полукомплекта ДЗЛ выполняет ИУ, установленное на «цифровой» подстанции. На роль «ведомого» устройства назначается полукомплект на «обычной» подстанции.

«Ведущий» полукомплект ДЗЛ синхронизируется от источника точного времени «цифровой» подстанции, а «ведомый» - синхронизируется по моментам взятия ЦО с «ведущим» полукомплектом стандартным для ДЗЛ образом, через цифровой канал связи между подстанциями. Компенсация фиксированного сдвига номеров обрабатываемых ЦО в разных полукомплектах ДЗЛ может осуществляться на «обычной» подстанции цифровой задержкой оцифрованных сигналов на заданное время T_C.

Экспериментальные исследования полукомплектов ДФЗ и ДЗЛ в режиме совмещения технологий «цифровой» и «традиционной» подстанции показывают стабильность их характеристик, полностью независимых от времени транспортировки цифровых данных через «шину процесса».

3 ЗАКЛЮЧЕНИЕ

1. Для уменьшения угловых погрешности измерений сигналов в пределах «цифровой» подстанции рекомендовано применение источников сигналов одного производителя или производить подстройку источников сигналов по углу под один эталон.

2. Комбинированное использование в устройствах релейной защиты сигналов, полученных в соответствии с IEC 61850-9-2LE и традиционным путем, требует обязательной синхронизации устройств ИУ от источника точного времени в пределах «цифровой» подстанции. Это же требование относится к ИУ, выполняющим функции ДФЗ или ДЗЛ

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ОАО «СО ЕЭС»

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C.6-4. XML and UML - What they are and Why We Need to Know Them?

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1 INTRODUCTION

The power system automation community is going through a period of transition from the world of hard wired systems and proprietary configuration and analysis tools into the world of distributed IEC 61850 communications based systems and object oriented standards based engineering and analysis tools. This requires the development of a new set of skills in order to help the specialists from our industry understand and use the new technology.

The main goal of this paper is to introduce the Extensible Markup Language (XML) and the Unified Modeling Language (UML) to the protection and control community and focus on the UML diagrams and XML files used in the IEC 61850 standard and in some IEEE standards related to protection and control in order to help the readers understand the diagrams and files included in or defined by the different standards.

The first half of the paper presents the Extensible Markup Language (XML) and the Unified Modeling Language (UML). It describes some of the key types of UML diagrams defined for the description of static structures of complex systems and the dynamic behavior between the different objects in the system, as well as the structure and components of an XML files. The second part of the paper discusses the use of UML diagrams and XML files in the definition of the standard.

Examples of the use of UML diagrams in IEC 61850 and in the description of the principles of operation of control commands are given later in the paper.

Examples of the use of XML in the IEEE C37.239: IEEE Standard for Common Format for Event Data Exchange (COMFEDE) standard are presented at the end of the paper.

2 WHAT IS XML?

XML is a markup language based on existing markup languages that have been used for different applications for many years. Even the Word version of this paper and the corresponding Power Point presentation use XML.

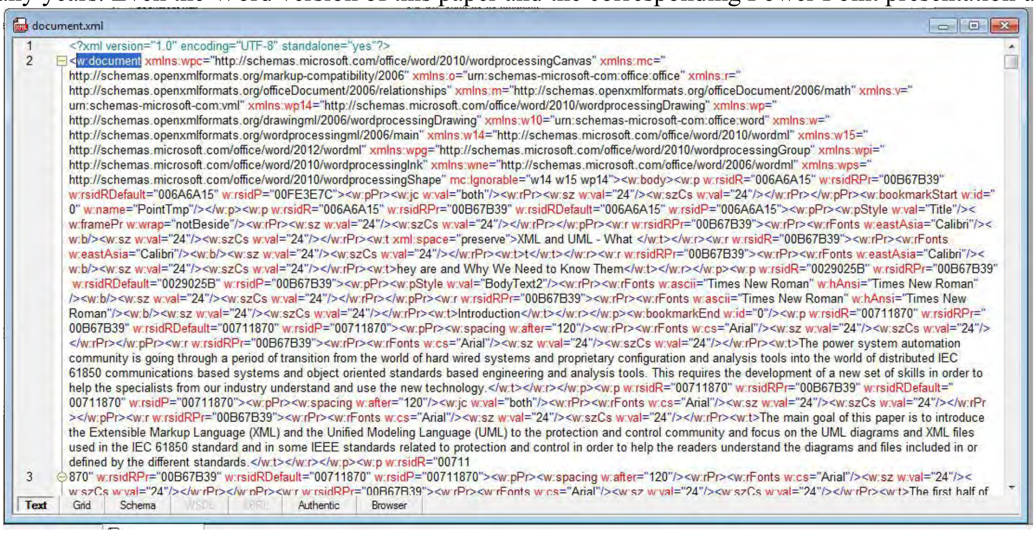


Fig. 1 XML version of part of the World file of this paper

Some of the acronyms that are used later in the text of the paper are as follows:
SGML - **S**tructured **G**eneralized **M**arkup **L**anguage
HTML – **H**yper**T**ext **M**arkup **L**anguage
XML - e**X**tensible **M**arkup **L**anguage

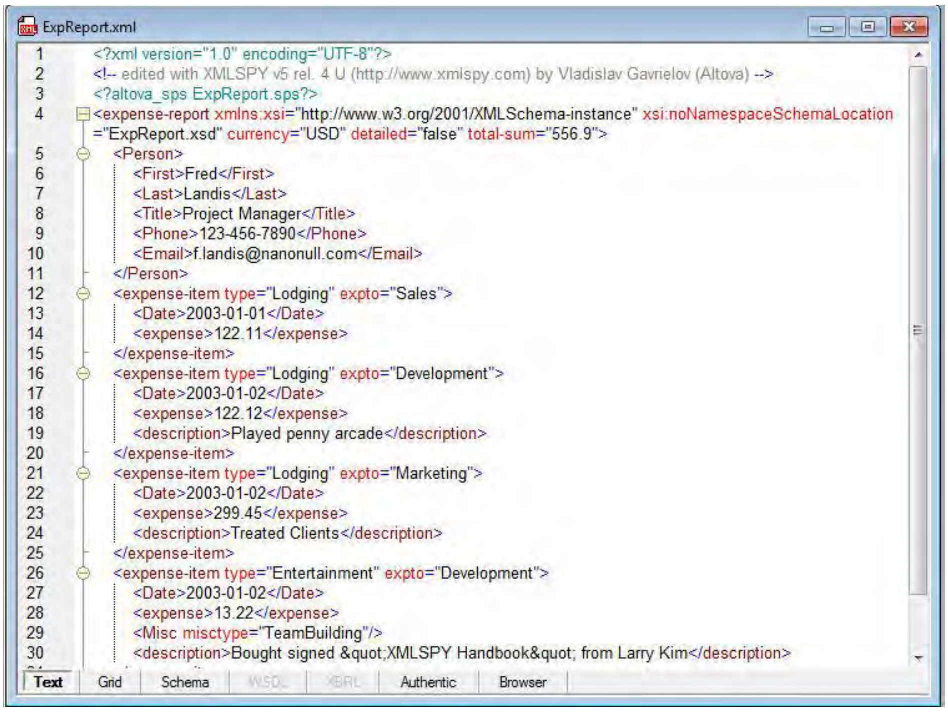
W3C – **W**orld **W**ide **W**eb **C**onsortium
XSL - e**X**tensible **S**tylesheet **L**anguage
CSS - **C**ascading **S**tyle **S**heets

XML was developed by members of the W3C and released as a recommendation by the W3C in February 1998. It is a simplified version of SGML and a cousin of HTML.

SGML was developed to standardize the production process for large document sets and .is an international standard (ISO 8879) that has been in use as a markup language primarily for technical documentation and government applications since the early 1980s.

The growing popularity of XML is the result of its flexibility and strength. It is extensible, because it allows you to extend the user’s ability to describe the domain specifics of the document. It is not only Microsoft Office that uses XML. It has other uses, such as being the base language for the Extensible Messaging and Presence Protocol (XMPP), as well as for Microsoft.NET Framework configuration.

In appearance, XML is quite similar to HTML. This similarity is due to the fact that they both use tags. In HTML, there is a specified set of tags that defines the format of the data.




```xml
<?xml version="1.0" encoding="UTF-8"?>
<!-- edited with XMLSPY v5 rel. 4 U (http://www.xmlspy.com) by Vladislav Gavrielov (Altova) -->
<?altova_sps ExpReport.sps?>
<expense-report xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance" xsi:noNamespaceSchemaLocation
="ExpReport.xsd" currency="USD" detailed="false" total-sum="556.9">
  <Person>
    <First>Fred</First>
    <Last>Landis</Last>
    <Title>Project Manager</Title>
    <Phone>123-456-7890</Phone>
    <Email>f.landis@nanonull.com</Email>
  </Person>
  <expense-item type="Lodging" expto="Sales">
    <Date>2003-01-01</Date>
    <expense>122.11</expense>
  </expense-item>
  <expense-item type="Lodging" expto="Development">
    <Date>2003-01-02</Date>
    <expense>122.12</expense>
    <description>Played penny arcade</description>
  </expense-item>
  <expense-item type="Lodging" expto="Marketing">
    <Date>2003-01-02</Date>
    <expense>299.45</expense>
    <description>Treated Clients</description>
  </expense-item>
  <expense-item type="Entertainment" expto="Development">
    <Date>2003-01-02</Date>
    <expense>13.22</expense>
    <Misc misctype="TeamBuilding"/>
    <description>Bought signed &quot;XMLSPY Handbook&quot; from Larry Kim</description>
```

Fig.2 XML version of an expense report spreadsheet

In XML, the user can create the tags required by the application domain. That is why XML is extensible – it extends the ability to describe a document, letting you define meaningful tags for your applications. For example, since any IED typically provides current measurements, for the phase A current measurement that is available as a floating point we can create a tag called <PhsAf>. In a similar way, we can create as few or as many tags as our document needs. It is obvious that we are extending the tags to identify elements by what they are -- not by how they look.

The extensibility means flexibility, but flexibility requires planning. To make good use of XML, we want to know and understand our documents: what pieces comprise them, how those pieces relate to each other, and how do we want to identify the different pieces. This is where the object models defined by IEC 61850 become the foundation for the development of XML files used in the standard.

XML is a Markup language because its purpose is to identify elements within the document. Without markup, the computer sees any document as one long string of text, with each character having equal importance to every other character. By marking up a document, we identify the bits and pieces in a way that gives them value and context.

The big advantage of XML is that it allows extensible markup, i.e. we can mark up the document in ways that match our substation protection, automation and control system needs.

However, markup is nothing but a way of identifying information. It does not program the data to act in a certain way, to display in a certain way, to do anything other than carry an identifying mark.

XML is a Language because it follows a firm set of rules. It allows us to create an extensible set of markup tags, but its structure and syntax remain firm and clearly defined. This does not mean that it is a programming language – it is not used to program a set of actions, but for a well-structured markup definition.

XML applies structure to documents and data. Since SCL documents are sets of related information, the structure is quite important. It is the way we put a skeleton behind the information, so that the pieces of information work together and make sense as a whole.

The document structure defines the elements which make up a document, the information we want to collect about those elements, and the relationship those elements have to each other. XML is used to markup the document, following the structure of the model. That is why XML is appropriate for describing the different aspects the substation configuration from the perspective of the substation automation system.

The document structure is called the Document Tree. The main trunk of the tree is the parent. All the branches and leaves are children.

Document trees are usually visually represented as a hierarchical chart.

Considering that the data object structure in IEC 61850 is also hierarchical, it is obvious that XML is very well suited for use as a SCL file format.

A well-formatted document is not sufficient. It also has to meet some constraints in order to make sense in the problem domain. The constraints enforce rules that determine the presence of elements and their attributes, as well as the order of these elements. These rules are part of what is defined as a Data Type Definition (DTD) or XML schema. This is the oldest schema inherited from SGML.

An important property of XML schemas is that they are also extensible, i.e. if necessary the schema can be extended to meet new requirements.

XML Schemas describes the structure of XML documents. The XML Schema language is also referred to as XML Schema Definition (XSD). XML Schemas are much more powerful than DTDs.

Any XML schema, including DTD, is a template for the markup of the document. That indicates the presence, order and placement of elements and their attributes in an XML document. In this sense it is similar to the object models of different elements of multifunctional IED's. IEC 61850 defines the classes that are later instantiated to build the object model of an IED. Different functional elements, for example a time-delayed overcurrent element can have multiple instances in a multifunctional protection IED. DTD has a "+" operator to indicate that more than one instance of an element is possible in the XML file.

HTML files appear to be very similar to XML files. This is due to the fact that both are defined from SGML. HTML is functionally a specific subset of SGML limited to the description of web pages.

Since XML defines the data structure, it will not display a page by itself. We must use a formatting technology, such as CSS or XSL to display XML-tagged documents in a Web browser.

Cascading Style Sheets (CSS), are the current way to display XML documents in a Web browser. CSS is a means of assigning display values to page elements.

Extensible Stylesheet Language (XSL) is an XML-based language for expressing stylesheets. With XSL, the user can make context-sensitive display decisions. XSL later split into the following XML languages:

- XSL Transformation (XSLT) for transforming XML documents
- XSL Formatting Objects (XSL-FO): for specifying the visual formatting of an XML document

3 THE UNIFIED MODELING LANGUAGE

Object modeling is one of the foundations of IEC 61850. The models in the standard represent the abstracts of the essential and communications visible parameters of the complicated real electric power systems world. This process of virtualization requires the use of modeling tools that can present the complex functionality of a substation and its protection and automation systems in a standardized way that is also easy to represent and understand.

In recent years UML (the Unified Modeling Language™) has become the common tool used in the modeling of any process, system or device. It is a standard language for specifying, visualizing, constructing and documenting different simple or complex systems.

Attempts to create an object-oriented modeling language began between mid-1970 and the late 1980s. Different competing methods had advantages and disadvantages. The experience from their use led to the development of UML that started in late 1994 when Grady Booch and Jim Rumbaugh of Rational Software Corporation began their work on unifying the Booch and OMT (Object Modeling Technique) methods. UML 1.0, a modeling language that was well defined, expressive, powerful, and generally applicable was submitted to the Object Management Group (OMG) in January 1997 as an initial RFP response. OMG has been since 1989 a non-profit, international, open membership, computer industry consortium and UML is one of its standards. The current "Available" version of UML is 2.0. The UML 2.0 Superstructure specification (already built into vendor products) has been completed, and is available to everyone for free download at http://www.uml.org/. Three separate parts of UML 2.0 - the Infrastructure (meta-metamodel), Object Constraint Language, and Diagram Interchange - are still undergoing their first maintenance and will become Available Specifications when this process is completed.

Several modeling tools are covered under the heading of the UML. It uses mostly graphical notations to express the design of software and other projects, systems or structures. Different types of diagrams can be used to present data structures, device and operator interactions or any other substation automation or protection related process. Using the UML helps project teams communicate, explore potential designs, and validate the architectural design of the system.

UML 2.0 defines thirteen types of diagrams, divided into three categories:

Structure Diagrams include six diagram types that represent static application structure: Class Diagram, Object Diagram, Component Diagram, Composite Structure Diagram, Package Diagram, and Deployment Diagram.

Behavior Diagrams include three diagram types that represent general types of behavior: Use Case Diagram, Activity Diagram, and State Machine Diagram.

Interaction Diagrams include four diagram types that represent different aspects of interactions. They are derived from the more general Behavior Diagram and include the Sequence Diagram, Communication Diagram, Timing Diagram, and Interaction Overview Diagram.

The use of UML requires good understanding of both the tools available and the problem domain they are applied to. In our case the problem domain is the substation, the substation protection and automation systems, including the communications system used by both. Different tools are available on the market and can be selected depending on the requirements of the application. One available option is the popular Microsoft Visio, which includes (among all other drawing tools) a set of UML diagram modules (see Figure 3).

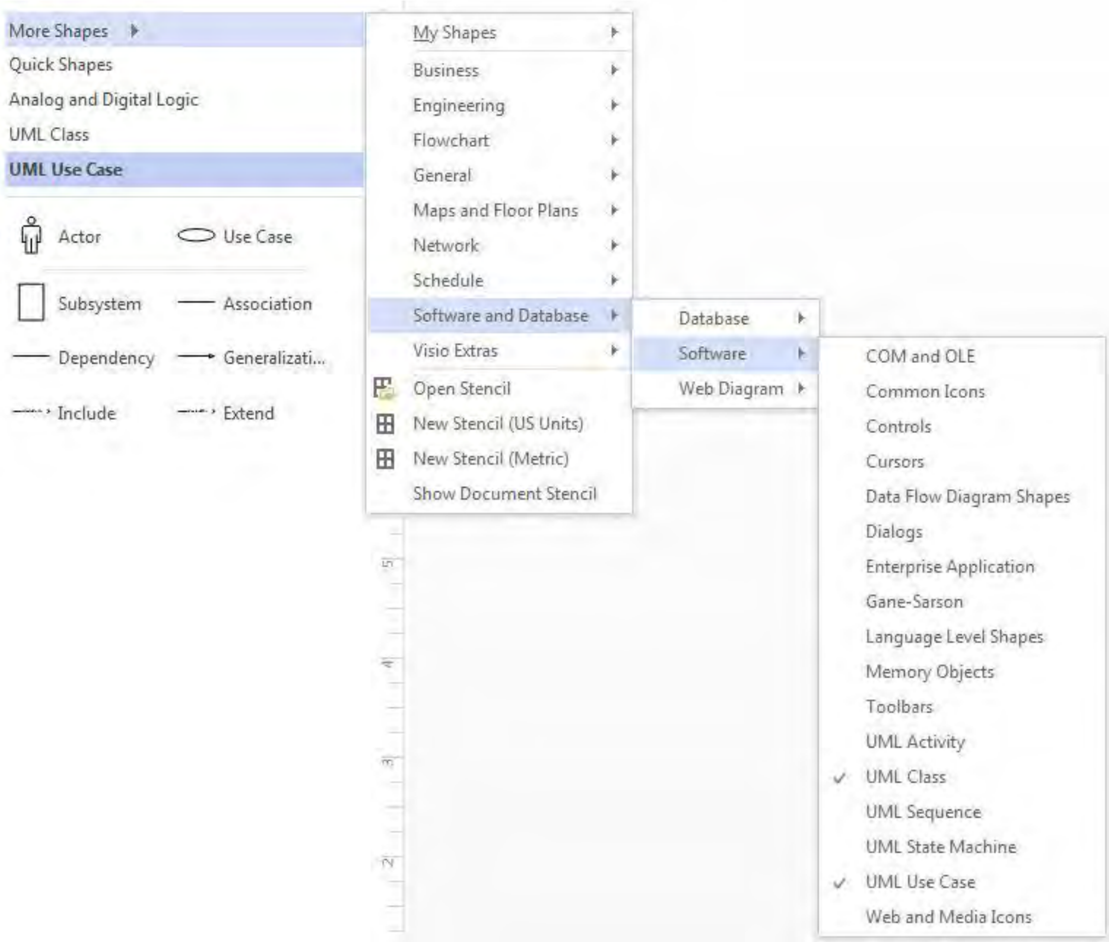


Fig. 3 UML support in Microsoft Visio

Since the UML is applicable to object-oriented problem solving, it is used in different parts of the IEC 61850 standard to represent in a standardized graphical way the complex models of multifunctional substation IEDs and their interface with the primary substation equipment and the communications network.

From the abstract modeling point of view, a model is an abstraction of the underlying problem, while the domain is the actual world from which the problem comes. There are three main components of a model:

- Functional model
- Object model
- Dynamic model

The functional model describes the behavior of the system under different conditions from the point of view of the user.

The object model represents the structure, including sub-layers and basic objects, data types, attributes, services and associations.

The dynamic model covers the internal behavior of the system, including the interaction between sub-systems and components, exchange of signals and conditions under which an action takes place.

The models of primary and secondary substation equipment consist of objects that interact by sending each other messages. The IEC 61850 object models include all three above-mentioned components and the communications visible attributes of what they represent. They have hierarchical structure that corresponds to their functional hierarchy. At the same time, the different functional elements in the system interact with each other to execute protection and control functions using specific services and following rules of behavior defined by the standard..

4 UML MODELING DIAGRAMS

UML uses different types of diagrams depending on the modeling requirements of the application – data structure, interaction, etc. The following is a list of the more commonly used diagrams:

- Use case diagrams
- Class diagrams
- Object diagrams
- Sequence diagrams
- Collaboration diagrams
- Statechart diagrams
- Activity diagrams
- Component diagrams
- Deployment diagrams

In the following sections we are going to briefly describe the diagrams used in the IEC 61850 standard.

4.1 UML: Class Diagrams

Class diagram gives an overview of a system by showing its classes and the relationships among them. Class diagrams are static - they display what interacts but not what happens as a result of the interaction.

UML class notation is a rectangle divided into three parts: class name, attributes, and operations.

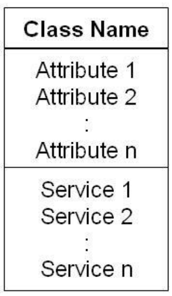


Fig. 4 UML Class notation

Class diagrams show not only the relationship between the components of the model, but also their interfaces. These are modeled using:

- Association - a relationship between instances of the two classes. There is an association between two classes if an instance of one class must know about the other in order to perform its work. In a diagram, an association is a link connecting two classes.
- Aggregation - an association in which one class belongs to a collection. An aggregation has a diamond end pointing to the part containing the whole.
- Generalization - an inheritance link indicating one class is a superclass of the other. A generalization has a triangle pointing to the superclass.

Multiplicity of an association end is the number of possible instances of the class associated with a single instance of the other end. Multiplicities are single numbers or ranges of numbers.

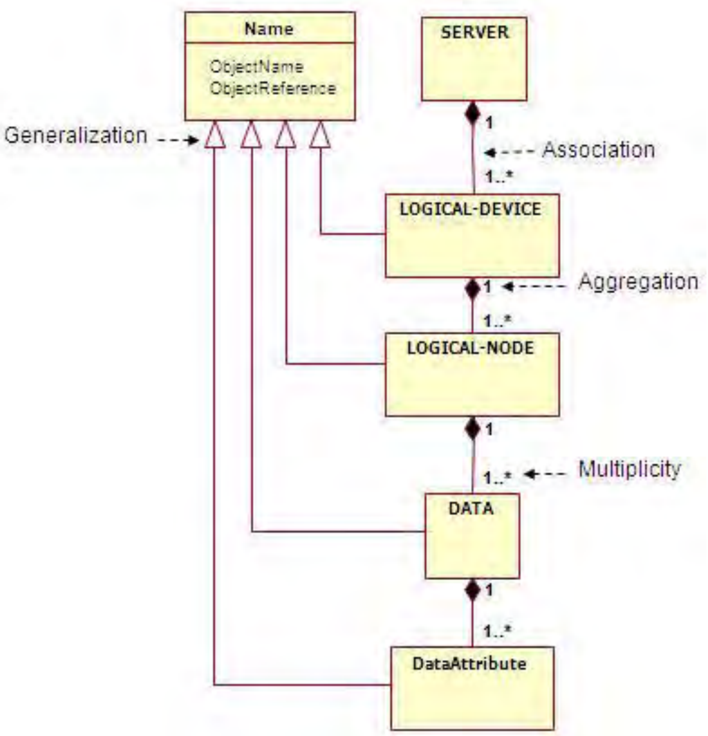


Fig. 5 UML Class diagram

The example in Figure 5 shows a generic UML Class diagram of the functional hierarchy of an IEC 61850 based server.

4.2 UML Object Diagrams

Object diagrams show instances instead of classes. They instantiate class diagrams as shown in Figure 4.

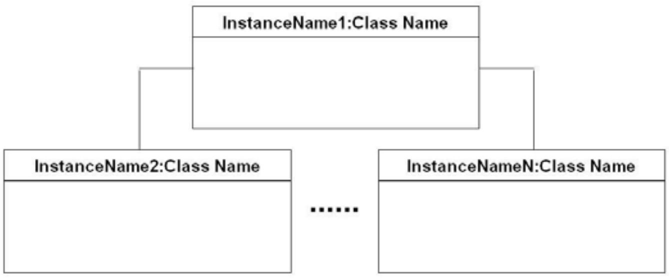


Fig. 6 Object diagram

4.3 UML: Sequence Diagrams

Class and object diagrams are static model views. They do not describe the behavior of the modeled system. Interaction diagrams are dynamic. They describe how objects collaborate.

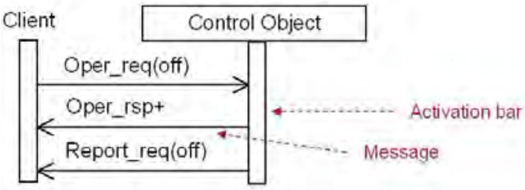


Fig. 7 Sequence diagram

A sequence diagram is one of two types of interaction diagrams and details how operations are carried out, i.e. what messages are sent and when.

Sequence diagrams are organized according to time and can help clarify a use case in order for it to be realized in software.

The example in Figure 5 shows the use of a sequence diagram to define the exchange of messages between an IEC 61850 client and a control object.

4.4 UML Statechart Diagrams

Objects have behaviors and states. The state of an object depends on its current activity or condition.

A UML statechart diagram shows the possible states of the object and the transitions that cause a change in state. They are very similar to the well known state machines and are used in the design process to help with the transition from the analysis of the system to its implementation.

The different states in these diagrams are represented as rounded rectangles.

Transitions are arrows from one state to another.

Events or conditions that trigger transitions are written beside the arrows.

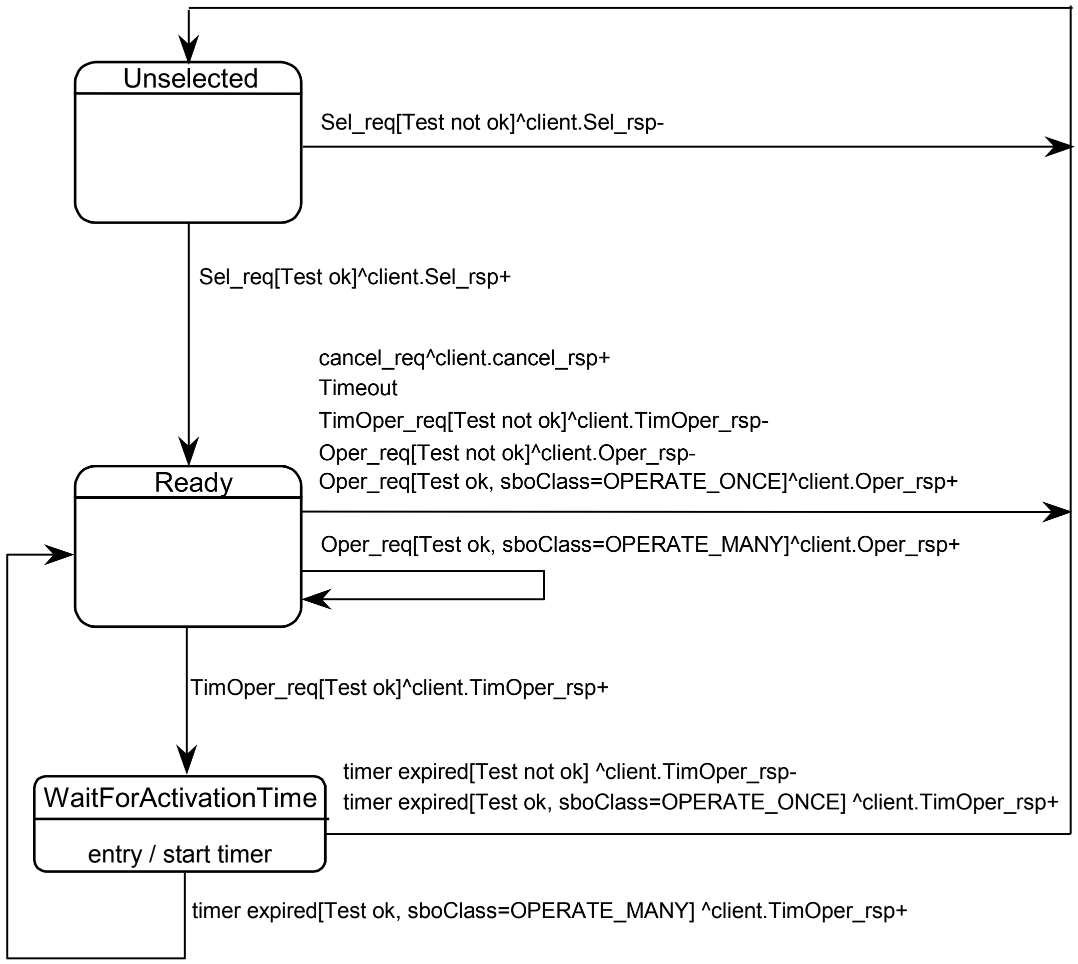


Fig. 8 Statechart diagram

The example in Figure 6 shows the statechart diagram of the Select Before Operate (SBO) function as implemented in IEC 61850 compliant systems.

5 UML AND XML USE IN IEC 61850

The different UML diagrams briefly described above are used in the IEC 61850 standard to present the abstract models of the substation domain. They represent the foundation of the definitions of the object models and services, as well as the Substation Configuration Language and the different types of files used to describe the functional hierarchy of the system and data used for exchange between IEDs and applications. Part 6 of the IEC 61850 standard specifies a description language for configurations of electrical substation IEDs – the Substation Configuration Language (SCL), based on UML and XML Version 1.0.

It is used to describe the substation connectivity, IED configurations and communication systems according to parts 5 and 7 of this standard. Description of the relations between the substation automation system and the substation (switchyard) itself

SCL was developed to support easier engineering of substation automation systems and application functions. It allows the description of a substation or an IED's configuration to be passed to a communication and application system engineering tool

The SCL files need to meet requirements related to the support of different phases in the engineering process. This is achieved through the use of UML and XML.

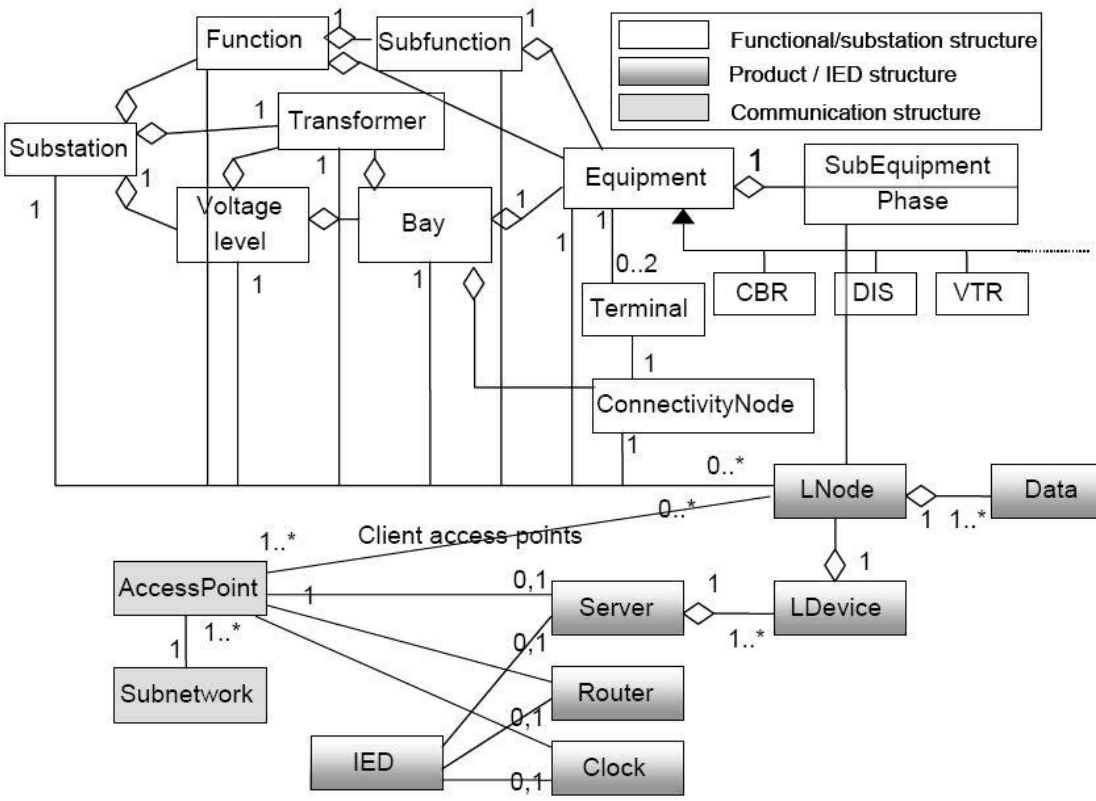


Fig. 9 Conceptual UML diagram of an IEC 61850 based system

Its main purpose is to allow the interoperable exchange of communication system configuration data between an IED configuration tool and a system configuration tool from different manufacturers.

The substation configuration language supports the development of engineering tools that are capable of describing:

- The substation one line diagram representing the different voltage levels, busses, transformers, bays and switching devices. The functional requirements should also be included in terms of allocation of logical nodes to the primary substation equipment.
- The IEDs to be used to perform the required functions based on a fixed number of logical nodes (LNs)
- The communication interface of the different IEDs – specifically their connection to the substation local area network
- The Client-Server and Peer-to-Peer communications for the specific substation automation system implementation

It needs to be understood that the standard does not define any specific software tools that support the intended engineering process. This is a task that the IED manufacturers, substation automation system vendors or third party providers have to develop based on the requirements of the market using the different types of files defined in the standard.

IEC 61850 defines four types of files required to support the intended engineering process. In order for an IED or a system solution by a manufacturer to be compliant with the standard, they have to support the use of the files described below directly from the IEDs or through tools delivered with the system. The structure of the files is based on UML models that are converted to XML files with different extensions used in the engineering of IEC 61850 based systems.

5.1 System Specification Description

The description of the system is the first step in the engineering process and until now has not been based on any standardized approach. The IEC 61850 engineering process envisions the use of substation specification tools that allow the user to describe the substation design and associated functional requirements for the substation protection and automation systems.

The data exchange from such a system specification tool and other tools utilized in the process should be based on the System Specification Description files defined in the standard. They have an SSD extension.

The SSD file describes the single line diagram of the substation and the functional requi9rements represented by logical nodes. The logical nodes can be abstract in the sense that they are not allocated to specific IEDs.

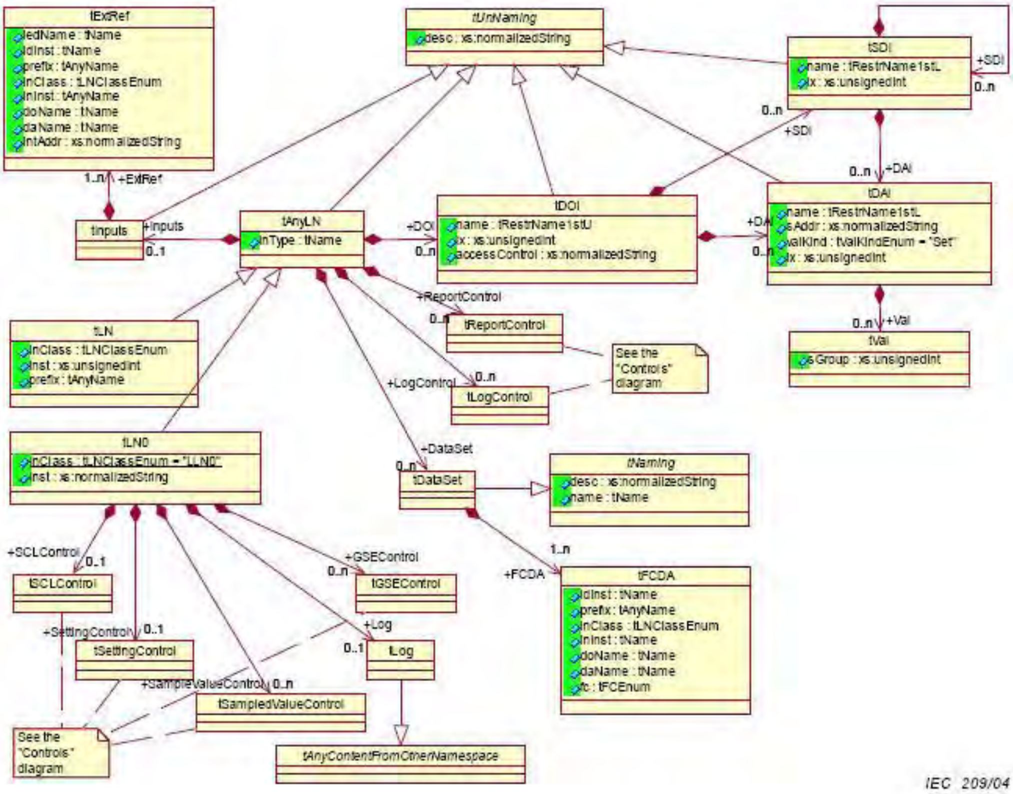


Fig. 10 IEC 61850 UML description of IED related schema part LN definition

5.2 IED Capability Description

The default functionality of an IED in the substation configuration language is represented by the IED Capability Description (ICD) file. It is used for data exchange from the IED configuration tool to the system configuration tool.

This ICD file describes the capabilities of an IED. It contains exactly one IED section for the IED whose capabilities are described. Since it represents the default functionality (i.e. before it has been configured), the IED name in this file is TEMPLATE.

The file also includes the different logical node types as they are instantiated in the device.

The file extension shall be .ICD for IED Capability Description.

IEC 61850 does not specify where the ICD file comes from. In IEDs designed for IEC 61850 environment and with large memory, this XML file may be available from the device itself.

For IEDs that are based on existing platforms that were adapted to support the standard, the manufacturer is required to provide tools that output ICD files.

```
<xs:complexType name="tIED">
    <xs:complexContent>
        <xs:extension base="tNaming">
            <xs:sequence>
                <xs:element name="Services" type="tServices" minOccurs="0"/>
                <xs:element name="AccessPoint" type="tAccessPoint" maxOccurs="unbounded">
                    <xs:unique name="uniqueLNInAccessPoint">
                        <xs:selector xpath="./scl:LN"/>
                        <xs:field xpath="@inst"/>
                        <xs:field xpath="@lnClass"/>
                        <xs:field xpath="@prefix"/>
                    </xs:unique>
                </xs:element>
            </xs:sequence>
            <xs:attribute name="type" type="xs:normalizedString" use="optional"/>
            <xs:attribute name="manufacturer" type="xs:normalizedString" use="optional"/>
            <xs:attribute name="configVersion" type="xs:normalizedString" use="optional"/>
        </xs:extension>
    </xs:complexContent>
</xs:complexType>
```

Fig. 11 Part of IEC 61850 XML file of IED

5.3 Substation Configuration Description

The configuration of the system is represented by the Substation Configuration Description (SCD) file. It contains:

- substation description section
- communication configuration section
- all IEDs

The IEDs in the SCD file are not anymore in their default configuration, but as they are configured to operate within the substation protection and automation system. These files are then used to configure the individual IEDs in the system.

5.4 Configured IED Description

The difference between the IED Capability Description (CID) file and the Configured IED Description file is that the second includes the substation specific names and addresses instead of the default ones in the first.

The CID file represents a single IED section of the SCD file described above.

6 COMMON DATA FORMAT FOR IED EVENT DATA

Another reason that we need to know XML is the standard data format developed by the IEEE PES Power System Relaying Committee in order to meet the need for standardization of the event reporting. It started a working group – H5b - in the Relay Communication subcommittee with the task to prepare a Report on a Common Data Format for IED Event Data.

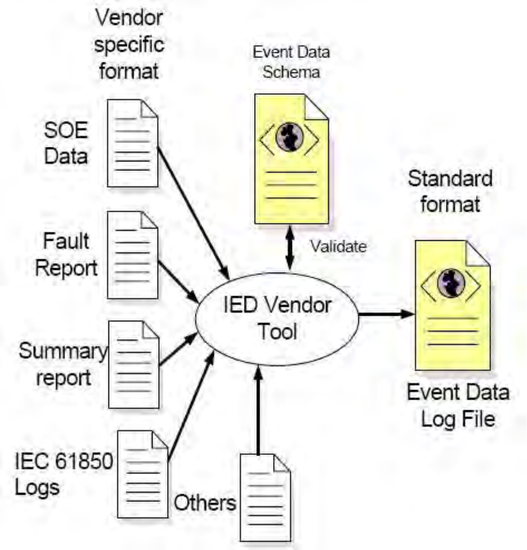


Fig. 12 Event data exchange process

The report defined a common XML-based file format for describing and exchanging event data records collected from power systems. It addressed the fact that protection relays and other IEDs store in their memory historical event data. The main categories of event data considered in this report were:

- Sequence of events (SOE)
- Fault reports
- Summary reports
- IED Status
- other

The content and the format of the data recorded are vendor specific and therefore cannot be easily integrated in a power network post analysis tool.

The main purpose of this file format is to facilitate power systems event data integration and analysis by enabling event data exchange between multiple data sources from different vendor devices and vendor-independent analysis tools.

The report was completed and published in 2008. A new working group (H16) was started with the task to define a new standard. The development and balloting of the standard has been completed and now it is available as C37.239-2010 IEEE Standard for Common Format for Event Data Exchange (COMFEDE) for Power Systems.

Currently a new working group in the IEEE PSRC is working on the development of another XML based file format for protection settings (COMSET).


```xml
<?xml version="1.0" encoding="UTF-8"?>
<!-- edited  by Brian Li (GE Digital Energy) -->
<?xml-stylesheet type="text/xsl" href="briantest.xsl"?>
<Log xmlns="http://www.pes-psrc.org/Subcommittee/H/COMFEDE"
   xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance"
  xmlns:SC-H_ComTypes="www.pes-psrc.org/Subcommittee/H/CommonTypes"
   xsi:schemaLocation="http://www.pes-psrc.org/Subcommittee/H/COMFEDE COMFEDE.xsd"
   version="2008" revision="A"
  LogName="testLogName" LogRef="testLogRef"  OldEntr="1" OldEntrTm="2009-09-09T13:24:36.638303Z" NewEntr="9" NewEntrTm="2009-09-09T14:24:33.961444Z">
  <Location stationName="Test Station" companyName="GE Digital Energy"
     bayName="testBayName" companyIdentificationCode="00" latitude="45.5" longitude="35.2" tmDT="true" tmOffSet="-300" tmUseDT="false">
    <SC-H_ComTypes:VoltageLevel unit="V">120</SC-H_ComTypes:VoltageLevel>
    <SC-H_ComTypes:IEDNameplate  name="F35 Demo" vendor="GE Digital Energy"
      hwRev="P" model="F35-G03-HCH-F8L-U5A-W7C" serNum="AURC04001333" swRev="5.71"/>
  </Location>
  <Entry EntryId="1" TimeOfEntry="2009-09-09T13:24:36.638303Z">
    <EntryData eventType="IEDEvt">
      <DataRef description="EVENTS CLEARED">EVENTS CLEARED</DataRef>
      <Value></Value>
      <Timestamp>2009-09-09T13:24:36.638303Z</Timestamp>
      <Quality validity="good"/>
      <ReasonCode dchg="true" qchg="false"/>
    </EntryData>
  </Entry>
  <Entry EntryId="2" TimeOfEntry="2009-09-09T13:25:19.070881Z">
    <EntryData eventType="SysEvt">
      <DataRef description="POWER ON">POWER ON</DataRef>
      <Value></Value>
      <Timestamp>2009-09-09T13:25:19.070881Z</Timestamp>
      <Quality validity="good"/>
      <ReasonCode dchg="false" qchg="false"/>
    </EntryData>
  </Entry>
```


Fig. 13   Example from an XML based COMFEDE file

7 CONCLUSIONS

XML and UML are some of the key technologies currently used in many domains and helping to improve the efficiency of different business processes. With the wide spread acceptance of IEC 61850 and the engineering process supported by it, it becomes essential for protection and control specialists to have a good understanding of what XML and UML are, so they can use them in their everyday work.

UML (Unified Modeling Language) uses mostly graphical notations to express the design of software and other projects, systems or structures. Different types of diagrams can be used to present data structures, device and operator interactions or any other substation automation or protection related process. Using the UML helps project teams communicate, explore potential designs, and validate the architectural design of the system.

UML diagrams are widely used in different parts of IEC 61850 to present the abstract models of the substation domain. They represent the foundation of the definitions of the object models and services, as well as the Substation Configuration Language and the different types of files used to describe the functional hierarchy of the system and data used for exchange between IEDs and applications.

XML applies structure to documents and data. Since SCL documents are sets of related information, the structure is quite important.

Part 6 of the IEC 61850 standard specifies a description language for configurations of electrical substation IEDs – the Substation Configuration Language (SCL), based on UML and XML.

The C37.239-2010 IEEE Standard for Common Format for Event Data Exchange (COMFEDE) for Power Systems is also based on XML.Currently a new working group in the IEEE PSRC is working on the development of another XML based file format for protection settings (COMSET).

Actual trends in development of Power System Relay Protection and Automation
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Russian National Committee

ABS Electro

C.6-6. Smart Power Substation Development in China

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KEYWORDS

Smart Power Substation, IEC61850, Data sharing, China

1 INTRODUCTION

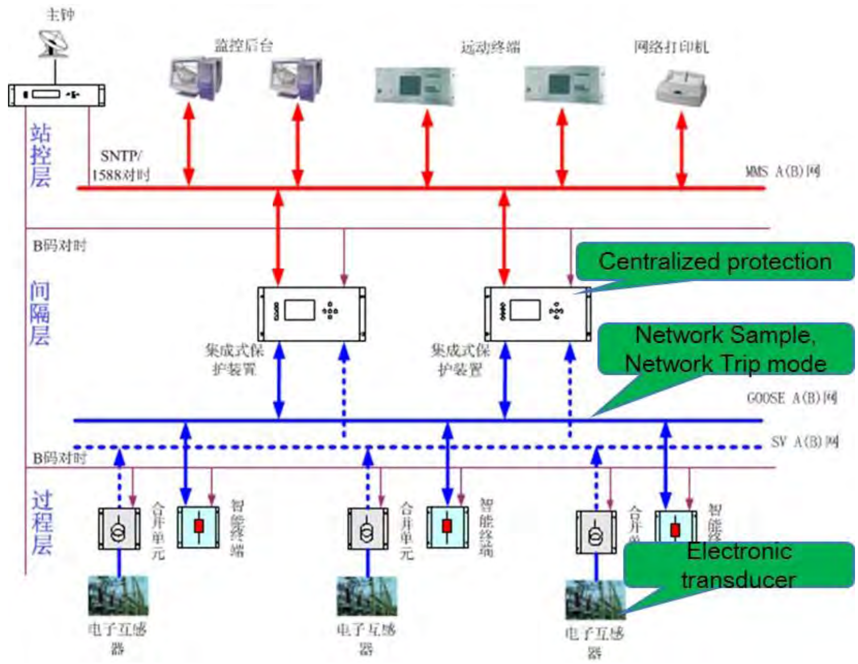
In 2009, the strategy of constructing a "strong and smart grid" was proposed according to the characteristics of energy resources and the fact of sustained and rapid economic development in China [1]. The strong and smart grid, characterized of informatization, automation and interaction, was planned based on a strong UHV power grid as the backbone network and the rest of lower voltage level grids as the basic strong network as well as a comprehensive information platform of communication as a support. Moreover, it contains six parts of power system including generation, transmission, transformation, distribution, consumption and dispatch. As a result, "power flow, information flow and service flow" are highly integrated in the strong and smart grid so that it becomes a strong, reliable, effective, environmentally friendly, open and interactive modern grid.

Before the proposal of the strong and smart grid, China has entered the stage of digital substation [2], as shown in Fig.1 (a). The digital substation focuses more on digital measurement and unified modeling based on IEC 61850 than intelligent function, but its ultimate purpose is intelligence. A smart substation needs to meet higher demands than a digital substation, so State Grid Corporation of China (SGCC) started to construct pilot projects of smart substation involving 24 local grid companies and covering 66~750kV voltage levels in 2009[3-4], as shown in Fig.1(b). These smart substations adopt AIS, GIS and HGIS and include outdoor, indoor and underground substations. By the end of 2012, 47 pilot projects of smart substation were all completed and put into operation. Much experience of constructing and operating the pilot projects were obtained and a standard system was established. In 2011, China entered the stage of overall construction of smart substation. By the end of 2013, there were 843 new smart substations in China.

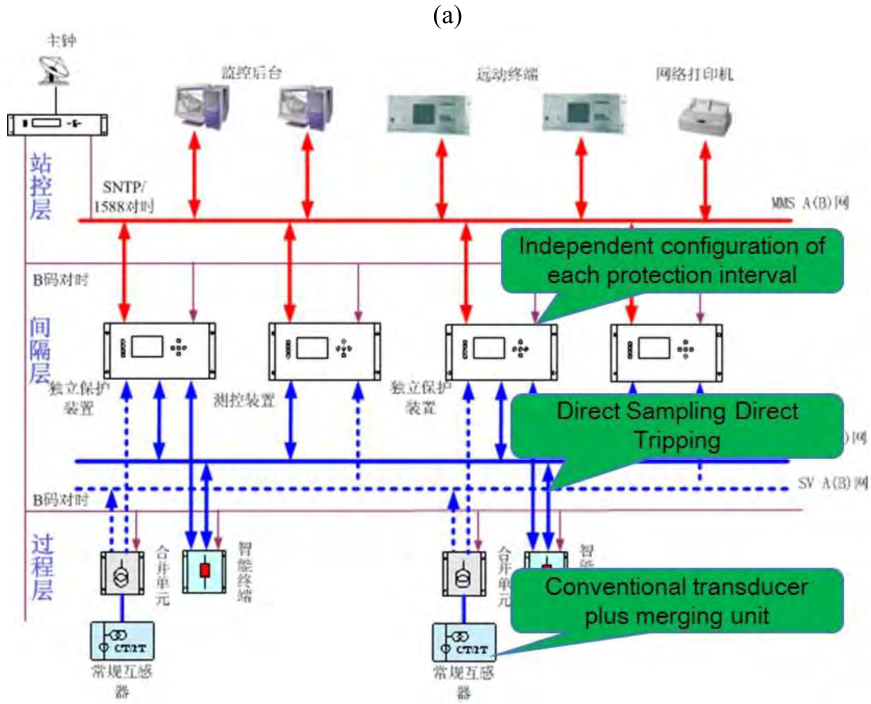
Some experience in this developing period has been achieved in China. In response to this situation, the status of smart substation development is systematically introduced in this paper. And the valued lessons and experience are all summarized.

2 THE MAIN ACHIEVEMENT IN SMART SUBSTATION CONSTRUCTION

Digitization of all information in station, networked communication platform, standardized information sharing and interactive advanced applications are initially achieved in China's smart substation[5-8], which improves the operation maintenance level and safe reliability of substation. In the process from pilot projects to overall construction, many theoretical and applied engineering problems are solved and several achievements are gotten in the areas of technology innovation, equipment development, standard establishment and construction:



(a)



(b)

Figure 1: Two stages of smart substation in China; (a) Digital substation; (b) Smart substation.

2.1 Digitization of substation information

47 pilot smart substations adopt Rogowski coil type of electronic current transformer (ECT), magneto-optical ECT and fiber optic ECT as well as capacitor voltage electronic voltage transformer (EVT), resistance voltage EVT, resistance and capacitor voltage EVT and fiber optic EVT respectively. In addition, some smart substations adopt the combination mode of the traditional voltage and current transformers and the merging unit to realize the digitization of analog voltage and current locally. As for breaker, an independent intelligent terminal is used to upload switching value locally. The digital voltage and current is transmitted by optical cable to separate strong electricity and weak electricity and simplify the design of secondary side. All information is shared in station so that it is possible to realize information integration and relevant extended application functions, and provide support for the integration and distribution of functions in station.

2.2 Primary equipment effectively become intelligent

On-line monitoring and intelligent components configuration on primary equipment can effectively promote the intelligence of its operation. On-line monitoring system based on sensors, IED components and background analysis system, can easily monitor real-time operation state of primary equipment, providing a wealth of information for equipment diagnosis. Currently, sulfur hexafluoride gas density and moisture content are used for breaker on-line monitoring; dissolved gas in oil and core earth current are adopted by main transformer on-line monitoring; leakage current and discharge times are used for lightning arrester on-line monitoring; partial discharge monitoring, however, is difficult to promote because of the insufficiency of technical maturity. The intelligent components of breaker consist of intelligent terminal, detecting unit and merging unit; intelligent components of main transformer mainly include nonelectric parameter protection, intelligent terminal, intelligent cooler control system and condition monitoring IED. The intelligent components are locally installed in control cabinet or terminal box, becoming unified interfaces of primary and secondary equipment.

2.3 IEC61850 standard fully gains application

The equipments in process layer, bay layer and station layer of intelligent substation all adopt the IEC61850 as communication standard. Part of primary equipment and auxiliary control system communications within the station is realized based on IEC61850; Based on IEC61850, the information model has been expanded and improved, station information collection has been unified, station panoramic data platform has been established, the application function has been provided with data and information in unified standard, and the uniform model interface has been provided. The architecture form "three layers of equipment, two layers of network" is adopted, the protection device use "directly sampling and directly tripping" principle, and GOOSE function is mainly used for transmitting position signal, blocking signal, soft strap switching, setting value switching and so on.

2.4 Obvious secondary equipment and system function integration

Intelligent substation gradually integrated automation, condition monitoring, auxiliary control and other functions, and turn them into integrated monitoring and control system, realizing the panoramic data monitoring. Station layer not only integrates the protection information substation, but also implements the sequence control, intelligent alarm and advanced application functions such as comprehensive analysis and the source side maintenance, effectively supporting "control integration", and turning the substation into a true information sampling and controlling point in power system. For bay layer equipment, protection, measurement and control integrated device is used for the 110 kV system, while protection, measurement, control and metering integrated device is adopted by 35kV and below system. In utility equipment, the station adopts integration of AC/DC power supply, monitoring control station uses AC power supply, DC power supply, AC uninterruptible power supply, and shares storage battery; the station adopts the integration of intelligent auxiliary control system, realizing the intelligent linkage control of image monitoring, security guard, fire alarm, fire control, lighting, heating and ventilation, environmental monitoring and other systems.

2.5 Energy saving and environmental protection

Compared with a traditional substation, the intelligent substation is more effective in energy saving, material saving and environmental protection. In an intelligent substation, secondary equipment is centralized, designed with compact structure, placed more rationally, but occupies less area; The secondary equipment in an interval is locally integrated in a control cabinet, with integrated devices of protection and measurement, integrated power-supply system, which decreases the number of devices and connections. The former cables are replaced by light and cheap optical cables, which saves nonferrous metals and is conducive to energy conservation and environmental protection.

3 THE EXISTED PROBLEMS IN SMART SUBSTATION CONSTRUCTION

Although some progress has been made in technological innovation, equipment development, standard setting, engineering construction and some other aspects, there is a gap between the overall level of intelligent substations and a world class power grid, especially in technological level, equipment level, design level, operational and managing level, and so on.

3.1 Equipment integration and technology application level needs to be improved.

Up to now, the integration of a substation just concentrates on secondary equipment. There is still no real integration between primary equipment, between primary equipment and secondary equipment, among primary equipment, secondary equipment and buildings, which causes some difficulties in the reduction of floor space. Since integrated design concept cannot be realized effectively and there is a lack of integrated debugging, many difficulties arise during field debugging, such as the mismatching between interfaces, disunity of model configurations and impropriety of insulation coordination. Although the digital acquisition of information from a station end has been realized and cables are replaced by optical cables, the workload of welding and operational maintenance isn’t reduced because the structure of communication network is complicated, information sharing degree is low, sampling is repeated and the number of switches and optical cables is large. So there is still plenty of room for optimization in information flow and network structure of substation. Online monitoring technology of equipment is not mature enough and the measurement accuracy is insufficient, so they can't provide a strong support for equipment operation and maintenance. Sensors are installed inside most of intelligent primary equipment. When a sensor malfunctions and needs to be repaired, primary equipment should be under the state of power off. This affects power supply reliability and data transmission reliability. The data transmitted to the background is different from the real one or contains big error. The development and realization of advanced application for integrated monitoring system is not perfect. Some functionality, such as distributed state estimation, is still in the stage of research and development and has not yet reached the practical level. Advanced application for substations’ coordination in a power grid and distributed control is still in the initial stage. The coupling between the platform and the application is so close that it causes many deficiencies, such as openness and expansibility, which makes it hard to accept new services and adapt to the rapid changes of existing ones.

3.2 The quality of the equipment products are not satisfactory

Due to the lack of measuring accuracy and product stability, electronic transformers are suspended in the beginning of the construction periods. Very fast transient over-voltages (VFTO), which are generated during the operation of isolating switches and breakers, have a serious impact on the electronic transformers and their data collectors, such as the accidents occurred at Fengzhou substation in Shanghai city, at Yiming substation in Shandong province, and at Southern Changshu substation in Jiangsu province. Electronic transformers are integrated with the primary devices outdoors. Thus, the stability and the accuracy of the measuring results are affected by the wide range of the ambient temperature. The network switches have an overheating issue, especially in the process layer. Thus, the operation situation needs to be monitored, and the power consumption and the cooling technology should be improved. The quality of MUs is not satisfied with outdoor installations. Besides, the secondary output waveforms have some unusual situations, e.g. disruption, offset and abnormal values. These situations can arise the protection mal-operation, even cause a damage to the external data collector in a serious occasion. The acquisition modules of the online monitoring intelligence components are vulnerable, and their communications with the background are easily disconnected. The built-in online monitoring sensors have a poor stability, and their interfaces with the primary devices have an installation problem.

3.3 The overall design has a potential for further improvement and optimization

The layout of the main electrical connection and the secondary network in the substation still needs an improvement. Due to the large quantity and the varied types of optical cables, as well as the unclear laying and welding interfaces, the optical cable connection scheme should be further optimized. Each manufacturer has a different understanding of the operation situations, the operating habits and IEC 61850 standards, resulting a compatibility issue in different devices. The design means is relatively insufficient. The design institutes only design virtual terminals with EXCEL or CAD software. It lacks a unified configuration software and the integrated design ability to output SCD files with ICD files from the secondary device manufacturers. Module design method is not implemented yet, resulting the lack of universality.

4 THE NEW GENERATION TREND OF SMART SUBSTATION

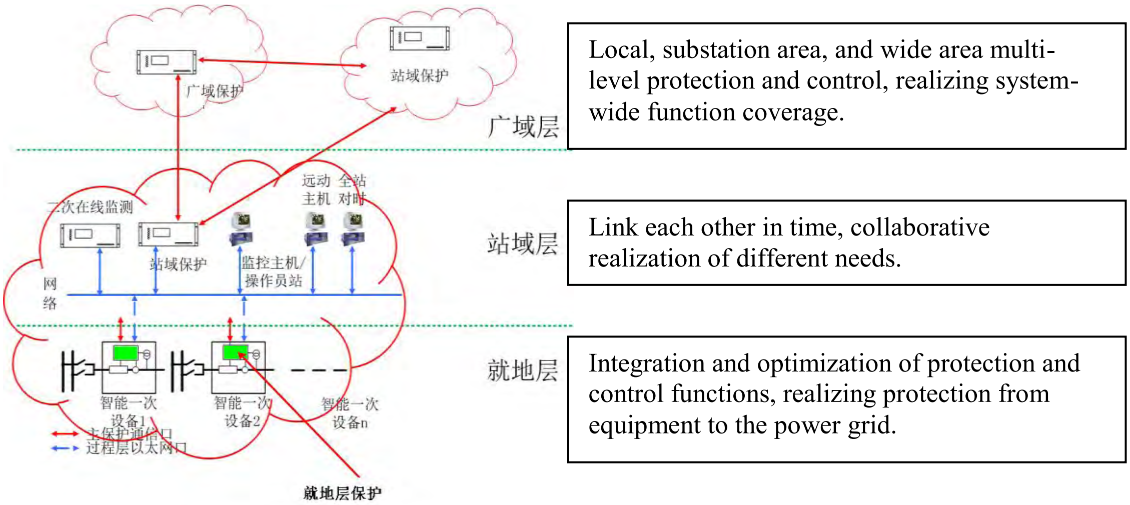


Figure 2: The new generation architecture of the Smart substation.

The new generation architecture of the Smart substation is shown in Fig.2 [9-10]. The hierarchical protection and control system is adopted [11-12]. While the local protection uses limited local information，realizes independent and decentralized protection function for single object, which can isolate the fault reliably and fast. Local protection requires synchronized sampling and fast tripping. So, bus bar protection and main transformer protection belong local protection. Local protection adopts Direct Sampling Direct Tripping mode, the operation is independent of external timing and communication network. The protection is arranged using prefabricated warehouse layout, which reduces the amount of secondary electric (optical) cable, simplifies the secondary circuit design, enhances reliability and realizes the sensitive protection of primary equipment.

Protection functions are integrated after careful verification of the protection performance and full consideration of the convenience of maintenance and repair operation. For example, the 110kV interval protection integrates functions including protection, control and metering measurement, 10/35kV interval protection employs all-in-one device which integrates functions of protection, control, inspection measurement, merging unit and intelligent terminal, and so on, as shown in Tab.1.

No.	Classification	Function module	Function description
1	Redundancy Protection function	110 kV line redundancy protection	As redundancy protection of a single set of protection
		Bus tie (segmentation) over-current protection	
2	Backup Protection optimization	Failure protection	Circuit breaker tripping failure protection function
		Backup protection acceleration	Substation internal fault location, shortening the fault clearing time of backup protection
		35 kV and 10 kV bus bar backup protection	Simplified bus bar protection function based on GOOSE
3	Safe and Automatic Control	Low frequency low voltage load shedding	Load shedding function under Low frequency low voltage
		Substation area spare power automatic switching	Spare power automatic switching function of multiple voltage level within substation
		Main transformer overload cut	Function of main transformer overload cut and load sharing
4	Wide-area Protection Control support	Wide area protection control substation	Collection , process and transmission of substation area information, sub-function of protection and control in area power system

Table 1: The function of the integrated protection in bay level

Based on multi-object information within the substation, substation area protection and control makes centralized decision, implements the protection redundancy and optimization, and realizes substation-level protection as well as safe and automatic control function, as shown in Tab.2. Substation area protection presents low requirements on the synchronization of data sampling and fast tripping of fault. Therefore, Network Sampling Network Tripping mode is employed. Wide area protection and control is intended for area power system. Related protection and stability control function is implemented by making decisions based on the collection of comprehensive information from multiple substations.

No.	Classification	Function module	Function description
1	Optimization of safe and stable control function	Regional safety and stability control	Realization of area power system safe and stable control function based on wide-area information
		Wide area low-frequency low-voltage load shedding	Allocation of load shedding amount and load shedding cycles
		Wide area out of synchronism disconnect	Optimized cross section selection to disconnect based on wide-area information
		Area power system self-healing function	Automatic recovery function of power system after clearance of fault
2	Optimization of protection function	Local power system redundancy protection	Emergency protection and failure protection function after loss of protection and control function of single substation
		Optimization of backup protection	Realization of area power system fault location, reduction of clearance time of backup protection

Table 2: The function of the integrated protection in substation level

5 CONCLUSION

With near to 10 years' development, three stages of substation intellectualization have been undergone. Based on the valued lessons in the 1st stage- digital substation, 47 pilot projects of smart substation have been put into operation in stage two in China by the end of 2012. And then China entered the new stage of overall construction of smart substation in 2012. There are 843 smart substations operating in China by the end of 2013. Much experience of constructing and operating the pilot projects were obtained and introduced in this paper. The ongoing or future developing directions of the smart substation are also presented in paper, while the hierarchical protection and control system would be adopted.

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С.6-8. Актуальные задачи совместного применения стандартов МЭК 61850 и МЭК 61970

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Ключевые слова: *системы автоматизации, стандарты МЭК, информационный обмен, релейная защита и автоматика, микропроцессоры, программное обеспечение, проектирование, моделирование, SmartGrid*

Одной из актуальных задач совместного применения стандартов МЭК 61850 и МЭК 61970 является повышение наблюдаемости электроэнергетической системы. Проблема наблюдаемости электроэнергетической системы впервые возникла при формировании автоматизированной системы диспетчерского управления (АСДУ) еще в конце 60-х годов XX века и была тесно связана с проблемой оценивания состояния. Исходная информация при управлении режимами электроэнергетической системы (ЭЭС) поступает в основном от телеизмерений. Состав измерений в общем случае может быть произвольным и зависит от оснащенности объектов энергосистемы соответствующими средствами измерений и каналами связи для передачи результатов измерений информации в диспетчерские центры. В диспетчерских центрах ставилась задача по полученным результатам телеизмерений оценить состояние энергосистемы, т. е. однозначно рассчитать параметры установившегося режима. Был разработан математический аппарат — оценивание состояния энергосистемы, который позволял рассчитать неизмеренные параметры режима, а также оценить погрешности измеренных величин. Вместе с тем существование решения и точность полученных оценок сильно зависят от объема измерений, их размещения, темпа сбора данных и динамики ЭЭС. Если состав измерений, получаемый по каналам телемеханики, обеспечивает заданную точность при оценивании состояния, то такая энергосистема считается наблюдаемой.

На сегодняшний день вопрос наблюдаемости ЭЭС в нормальном режиме решается средствами АСУ ТП, которые установлены на объектах ЭЭС. АСУ ТП, использующие современные технические средства сбора информации, позволяют измерять все электрические величины, необходимые для обеспечения наблюдаемости ЭЭС. Большое количество установленных измерительных устройств, с одной стороны, повышает точность оценивания состояния за счет избыточности измерений, с другой стороны, повышается риск возникновения грубых ошибок при привязке телеизмерений к схеме электрической сети. Одним из возможных подходов к решению задачи автоматизации привязки телеизмерений к электрической схеме сети является гармонизация стандартов МЭК 61850 и МЭК 61970 (CIM).

Сегодня в центрах управления сетями и диспетчерских центрах для эффективного ведения режима и управления оборудованием создается точная и однозначная модель энергосистемы на базе общей информационной модели энергосистемы (CIM), включая модели всех подстанций. Идеальным источником информации о подстанции для CIM энергосистемы является SCL-файл описания подстанции, включающий в себя однолинейную схему. SCL-файл описания подстанции создается на этапе проектирования АСУ ТП подстанции и актуализируется при вводе подстанции в эксплуатацию. Ввиду большего количества общих элементов между CIM и SCL-файлами целесообразно разработать методы и инструменты для обмена данными между этими двумя структурами. Фактически гармонизация этих двух стандартов является основой для информационной совместимости между технологиями SmartGrid [1].

Общие элементы между CIM и SCL

Описание подстанции в SCL и CIM по структуре совпадают и содержат следующие основные элементы:

Наименование	CIM (пакет Core)	SCL
Подстанция	Substation	tSubstation
Уровень напряжения	VoltageLevel	tVoltageLevel
Присоединение	Bay	tBay

В SCL и CIM также совпадает способ описания топологии электрической схемы. Это описание базируется на использовании понятия «Узла соединения» (Connectivity Node) и «Точки подключения» на силовом оборудовании (Terminal). Силовое токоведущее оборудование (ConductingEquipent) имеет одну или несколько точек подключения, которые соединяются с узлом, и, таким образом, устанавливаются связи между элементами схемы (рис. 1).

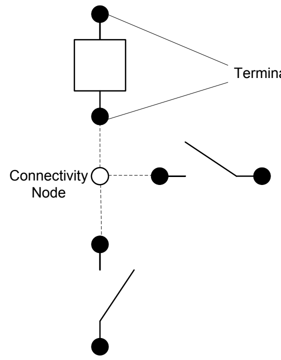

Рис.1. Описание электрических соединений в CIM и SCL

Различия между CIM и SCL

Несмотря на наличие общих элементов (дублирование) между CIM и SCL, эти модели изначально ориентировались на разное применение и по этой причине имеют ряд отличий. В силу этого CIM не может полностью заменить SCL, а SCL не может заменить CIM. CIM создавалась как универсальный способ описания энергосистем, который можно использовать в различных приложениях систем EMS, DMS и других. В число таких приложений входят расчет режима, оценивание состояние, управление основным оборудованием и др. Перед разработчиками CIM стояла задача разработать достаточно универсальный способ описания схемы замещения электрической сети, которое позволяет использовать это описание в различных разнородных приложениях. Разработчики SCL решали другую не менее сложную задачу – создание универсального формата для описания информационных связей на подстанции. Основное внимание было уделено модели данных в устройствах (логические узлы, типы данных и др.). Однолинейная схема в SCL позволяет связывать логические функции в микропроцессорных устройствах с элементами силовой схемы, с которыми эти микропроцессорные устройства взаимодействуют.

CIM ориентирована на описание графов сети, в то время как SCL-файл имеет достаточно строгую иерархическую структуру. Все приложения расчета режима оперируют узлами и связями, и CIM должна удовлетворять требованиям этих приложений. С другой стороны, SCL изначально ориентировался на подстанционное применение, где структуру можно выразить в виде иерархии, состоящей из фиксированного набора уровней (распределительных устройств, присоединений и силового оборудования).

В CIM для описания модели энергосистемы [2] используется RDF (Resource Description Framework),в то время как в SCL используется XML-формат (древовидная структура). Использование RDF в CIM вызвано необходимостью удобно представлять графы [3]. Структура RDF-записи (утверждения) имеет вид «субъект — предикат — объект». Например, активное сопротивление обмотки трансформатора, равное 0,39 Ом, может быть записано так: субъект – обмотка трансформатора (TransformerWinding), предикат – активное сопротивление (TransformerWinding.r), объект – значение 0,39 Ом. Если в качестве объекта используется не конкретное значение (число), а ссылка на другой объект (ресурс), то фактически образуется ветвь графа, связывающая два ресурса. Например, обмотка трансформатора X (TransformerWinding) относится к трансформатору Y (TransformerWinding.MemberOf_PowerTransformer), где X и Y – являются идентификаторами ресурсов. Таким образом, с использованием уникальных идентификаторов устанавливаются связи между ресурсами. В SCL также имеется система идентификации (с помощью атрибута name – технологическое имя). Отличием от CIM является то, что технологическое имя должно быть уникальным в рамках своего уровня в иерархии. Например, каждое присоединение в рамках одного уровня напряжение должно иметь уникальное технологическое наименование. Но два присоединения на разных распределительных устройствах могут иметь одно имя. Для того чтобы соединить точку подключения (Terminal) в одном присоединении с узлом (ConnectivityNode) в другом присоединении, у объекта Terminal есть несколько атрибутов: имя подстанции (substationName), имя распределительного устройства (voltageLevelName), имя присоединения (bayName), имя узла соединения (cNodeName). Только совокупность этих параметров образует уникальный идентификатор в рамках SCL-файла.

SCL-файлы включают в себя подробное описание микропроцессорных устройств, способов передачи данных (на верхний уровень и между устройствами) и команд управления. CIM ограничивается лишь описанием отдельных точек измерения и телеуправления без указания семантики (т.е. физического смысла) этих точек.

CIM содержит подробное описание электрических параметров схемы замещения. В SCL такое описание полностью отсутствует.

Формирование CIM для задач управления ЭЭС

Гармонизация стандартов МЭК 61850 и МЭК 61970 является достаточно важной задачей с точки зрения сокращения работы (исключение дублирования). В [4] были предложены возможные варианты совместного использования CIM и SLC для решения практических (прикладных) задач. С точки зрения повышения наблюдаемости ЭЭС наиболее перспективным подходом к формированию информационной модели ЭЭС является формирование CIM энергосистемы на базе SCL-файлов. В этом случае при включении подстанции в единую информационную модель энергосистемы необходимо преобразовать SCD (файл конфигурации подстанции) в CIM и сформированную модель включить в состав модели энергосистемы. Для этого получившаяся из SCL-файла модель должна быть дополнена недостающими параметрами (в том числе параметрами схемы замещения). В этом случае телеизмерения будут однозначно привязаны к элементам электрической схемы ЭЭС.

Способы гармонизации

Структура RDF-файла хорошо подходит для того, чтобы полностью включить в себя описание информационной модели подстанции (SCL) с использованием достаточно общего подхода [1]. Этот подход заключается в следующем:

- Разбиение элементов SCL-файла на объекты с уникальными идентификаторами, т.е. создание линейных списков объектов (подстанций, распределительных устройств, присоединений, силового оборудования, интеллектуальных электронных устройств).
- Присвоение каждому элементу уникального идентификатора.
- Установка связи между этими объектами с использованием этих идентификаторов.

Таким образом, можно сформировать CIM на базе SCL-файла, при этом совпадающие объекты в CIM и SCL будут заменены на единый гармонизированный вариант. Наличие единых идентификаторов и возможность перевода одних идентификаторов (SCL) в другие (CIM) позволяет выполнить и обратное преобразование из CIM в SCL.

Еще одной важной проблемой является необходимость в слиянии моделей. Например, на подстанции, которая уже включена в CIM, произошло расширение, и SCD-файл был дополнен. В этом случае необходимо повторно включить этот файл в CIM. При этом уже включенные части (дополненные соответствующими атрибутами) не должны быть затронуты. Такой механизм называется слиянием (Merging) и также должен быть основан на единой системе идентификации объектов.

Выводы

Гармонизация стандартов МЭК 61850 и МЭК 61970 является очень важной задачей с точки зрения технологий Smart Grid и позволяет повысить наблюдаемость энергосистем за счет однозначной привязки телеизмерений к электрической схеме сети. Объединить две модели можно только на основании единой системы идентификации объектов. Для упрощения этих задач (преобразование, объединение, слияние) должна использоваться система автоматизации проектирования, позволяющая работать с единой моделью данных (SCL и CIM).

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С.6-9. Опыт проектирования, наладки и эксплуатации подстанции 110 кВ с применением шины процесса Hard Fiber фирмы GE Multilin

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КЛЮЧЕВЫЕ СЛОВА: шина процесса Hard Fiber GE Multilin, наладка устройств РЗА

1 ВВЕДЕНИЕ

При разработке проекта подстанции с применением шины процесса Hard Fiber фирмы GE Multilin и его реализации, мы столкнулись с необходимостью изменения традиционных подходов к построению системы релейной защиты и автоматики. Отсутствие дискретных входов и выходов в терминале ДЗШ типа B95 plus и другие особенности системы Hard Fiber вызвали некоторые трудности при конфигурировании и наладке устройств РЗА. Доклад посвящён попытке решения возникших проблем на строящемся энергообъекте.

2 ОСНОВНАЯ ЧАСТЬ

2.1 Описание схемы подстанции

В феврале 2015 года в РУП «Гомельэнерго» введена в работу подстанция 110 кВ «Приречная», на присоединениях 110 кВ которой установлены микропроцессорные защиты фирмы GE Multilin с применением шины процесса Hard Fiber. Система включает в себя МП РЗА, оптические кабели и выносные модули ввода/вывода (УСО), которые получили название Bricks. В каждом Brick имеется 4 независимых цифровых ядра и, таким образом, к одному Brick можно подключить до 4-х устройств защиты по схеме «точка – точка».

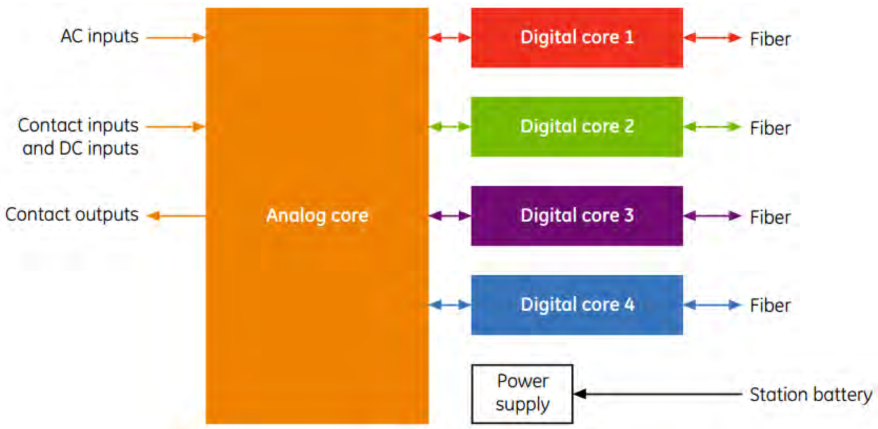

Рис.1: Внутренняя структура Brick

При построении системы РЗА на ПС-110 «Приречная» мы руководствовались двумя основными, взаимно противоречивыми, принципами:

1. Надёжность – применено полное аппаратное дублирование всех устройств;
2. Экономичность – максимальное использование всех возможностей каждого устройства для уменьшения числа используемых модулей и соединительных кабелей.

ОРУ 110 кВ ПС - 110 кВ «Приречная» выполнена по схеме двойная система шин с обходной. На каждом присоединении 110 кВ установлено по два модуля ввода/вывода (Brick), подключенных к разным кернам ТТ. Также на них заведены вторичные цепи ТН 1С.Ш. 110 кВ и ТН 2С.Ш. 110 кВ. Переключение с одного ТН на другой производится вручную испытательными блоками в зависимости от фиксации присоединения по системам шин. Защита каждого присоединения выполнена двумя одинаковыми терминалами (для ВЛ – D60, для трансформатора – Т-60), выполняющими так же функции автоматики выключателя. Оба устройства защиты каждого присоединения подключены к обоим Brick присоединения, и в случае неисправности одного из Brick автоматически переключается на второй. Оба Brick каждого присоединения действуют на оба соленоида отключения своего выключателя. Кроме того, выполнено прямое действие ключа управления со щита управления на один из соленоидов отключения по медному кабелю. В качестве защиты сборных шин 110 кВ применены два взаимно резервирующих устройства B95Plus. На рисунке 2. представлена схема подстанции и распределение устройств Brick и терминалов защит по кернам трансформаторов тока и напряжения.

2.2 Особенности, с которыми пришлось столкнуться при проектировании, монтаже и наладке системы РЗА подстанции.

2.2.1 Ввод/вывод действия защит и автоматики на выключатели производится не разрывом цепи включения/отключения, а воздействием на дискретный вход терминала защит.

2.2.2 В связи с отсутствием в терминалах ДЗШ дискретных входов и выходов, ввод/вывод действия ДЗШ на каждое присоединение производится ключом в шкафу защит присоединения воздействующего на дискретный вход терминала присоединения. В терминал ДЗШ состояние этого ключа передаётся по шине процесса путём обмена между ядрами Brick. Терминал ДЗШ постоянного опрашивает положение этого ключа и, если снят оперативный ток с этого терминала защит присоединения, действие ДЗШ остаётся введенным на отключение присоединения.

2.2.3 В связи с низкой надёжностью блок-контактом разъединителей 110 кВ производства Великолукского завода высоковольтной аппаратуры, фиксация присоединения по зонам ДЗШ определяется по вставленным испытательным блокам цепей напряжения ТН 1С.Ш. 110 кВ и ТН 2С.Ш. 110 кВ с использованием свободных контактов БИ.

2.2.4 Если на присоединении оба БИ не вставлены, то ток присоединения не участвует в расчёте дифференциального тока и ДЗШ (УРОВ) не действует на отключение этого присоединения.

2.2.5 При оперативных переключениях на ОРУ – 110 кВ необходимо ввести запрет АПВ при работе ДЗШ. Ключ ввода запрета АПВ расположен в шкафу защиты и автоматики шиносоединительного выключателя. Терминал ДЗШ постоянного опрашивает положение этого ключа.

2.2.6 Проверка защит может осуществляться двояко:

а) Наладка защит осуществлялась подачей токов и напряжений от испытательного устройства в Brick, расположенные на ОРУ – 110 кВ. При этом токи и напряжения в цифровом виде подаются во все устройства РЗА, подключенные к этим Brick (оба комплекса защиты присоединения и ДЗШ). Поэтому, в отличии от защит присоединений терминалы ДЗШ подключены только к конкретному Brick каждого присоединения. Это сделано для возможности поочерёдного вывода из работы и проверки ДЗШ без отключения первичного оборудования.

б) С помощью резервного Brick подключаемого в ОПУ к терминалу защиты присоединения переключением оптического патч-корда. При этом токи и напряжения подаются только в проверяемую защиту.

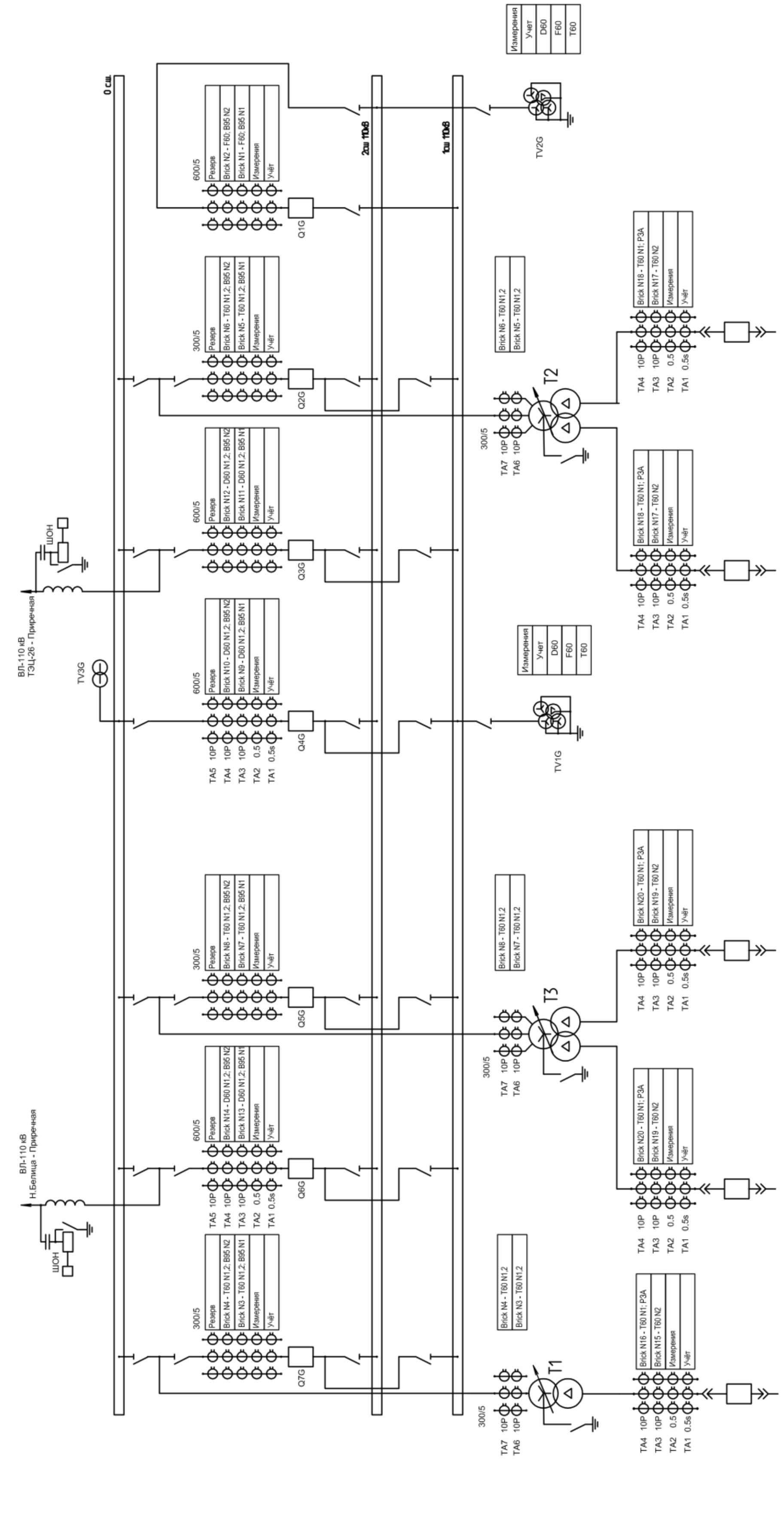

Рис. 2. Распределение защит и устройств Brick по кернам трансформаторов тока и напряжения

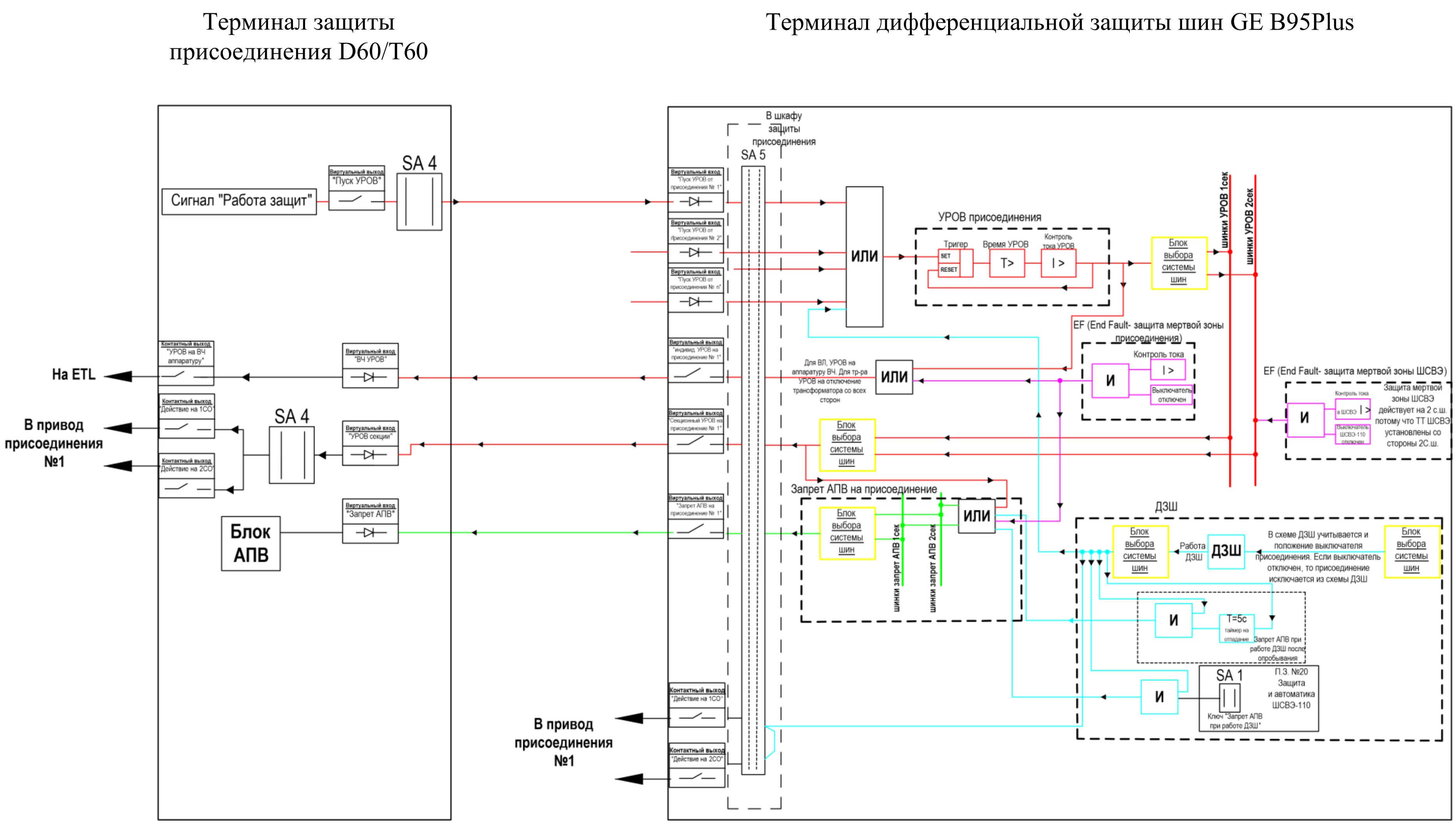

Рис. 2 Структурная схема взаимодействия терминалов защиты и ДЗШ

2.2.7 При переводе трансформатора на ОВ 110 кВ, Brick трансформатора переводятся на встроенные в трансформатор ТТ и, таким образом, защиты трансформатора переключаются на встроенные ТТ, ошиновка 110 кВ трансформатора выводится из ДЗШ и ДЗТ, и защищается защитами ОВ 110 кВ. Действие защит трансформатора вводится на ОВ.

3 ЗАКЛЮЧЕНИЕ

Ввод в эксплуатацию подстанции с применением шины процесса Hard Fiber фирмы GE Multilin показал, что:

- сократились затраты на монтаж вторичных цепей;
- практически отсутствовали ошибки в монтаже вторичных цепей;
- появилось множество вопросов, требующих дальнейшей проработки как то, недостаточное количество выходных реле в устройствах Brick, отсутствие дискретных входов/выходов в терминале ДЗШ, проблемы с сигнализацией срабатывания ДЗШ, необходимость приобретения оборудования для диагностики оптических кабелей, обучение персонала.

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S.6-11. IEC 61850- Concepts for Testing and Isolation of Signals

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KEYWORDS

IEC 61850, Testing, GOOSE, Sampled Values, Client/Server, IEEE 1588, Propagation Delay

1 INTRODUCTION

Since IEC 61850 became the widely used standard for substation communication with a lot of implementations testing is an important issue. Edition 2 is available since 2012 and offers a wide range of possibilities and sophisticated details. Due to the huge amount of prospects and different places where testing can be located and marked systematization will be presented. This paper describes an approach, how to combine the new possibilities with existing testing procedures for protection and control in substations. The timely delivery of mission critical information is one main aspect of power utility communication The test procedures for GOOSE performance of IEDs or the behavior of Sampled Values publishers take into account that some time is needed to transmit the data over the communication network. The paper shows the usage of new measurement equipment in networks and explains measurements.

2 TESTING

2.1 Issues

IEC 61850 was published in the early 2000s and is the state of the art standard for substation automation systems (SAS). Thousands of installations around the world demonstrate the success. Since the standard focuses on communication it was from the beginning the question- "How do I test when I just have an Ethernet cable connected to my intelligent electronic devices (IED)?" The first edition of the standard described several possibilities already. The experience shows, that not all details have been clarified and the usage was unclear for users and vendors. Due to this not all possibilities have been implemented or are supported by the tools. Edition 2 [1] clarified the issues and provides new possibilities. Since protection and control (PAC) systems are available [2] , people want to test them to be secure that they work properly. To avoid tripping of the circuit breakers, short circuit the current transformers, inject analogues and to allow a connection to startup and trip indications test plugs are very common in different countries [2].

2.2 Test-Bits

Some users expect a single test bit what is not defined in the standard in that manner. The reason is obvious. In IEC 61850 are several possibilities to communicate. We distinguish between client-server-communication used for SCADA purposes and real-time communication utilizing GOOSE and Sampled Values. Additionally the data model as defined in the standard is complex and multilayered- additional possibilities need to be found. Sometimes the later mentioned indication "test" in GOOSE according to [3] is also called "test-bit".

2.3 Test as Mode and Behavior

The classes for Logical Nodes (LNs) are defined in IEC 61850-7-4 [4]. Every Logical Devices (LD) consists of at least 3 LNs. Every LN got its own Mode (Mod). This mode can be as follows:

- *on*
- *on-blocked (name in edition 1: "blocked")*
- *off*
- *test*
- *test/blocked*

2.4 Test as Quality

In addition to Mod/Beh for every information available a quality (q) is defined. The encoding is explained in 8-1 [3], here we learn that bit string of 13 is currently used (Bit 0....Bit 12; Bit 11 is a Boolean attribute with the name "quality")

2.5 Test Indication in GOOSE

As already mentioned in part 8-1 [3] also for the GOOSE a parameter "test" is defined. It is transmitted in the GOOSE-PDU and could be used to decide if the GOOSE is published by an IED in test mode or not. It was rarely implemented by the vendors in IEDs according to edition 1 of the standard. Such an indication was not defined for Sampled Values

2.6 Indication "Simulate" for GOOSE and Sampled Values

With edition 2 of the standard for GOOSE[3] and Sampled Values they come with new information to distinguish between real and simulated signal: A S- ("simulated") information. When the bit S is set, the GOOSE telegram has been issued by a publisher located in a test device and not by the publisher as specified in the configuration file of the device. It is a simulated GOOSE[3]. This is figuratively valid for Sampled Values too. The advantage is that the S-Bit is situated in a defined position in an Ethernet frame. This allows an easy detection or distinction e.g. by a subscribing IED. The mechanism is explained in Figure 1. The entire physical device (!) can be set with a control in the LN describing the physical device (LPHD) to receive simulated GOOSE or simulated Sampled Values instead of real. [5]

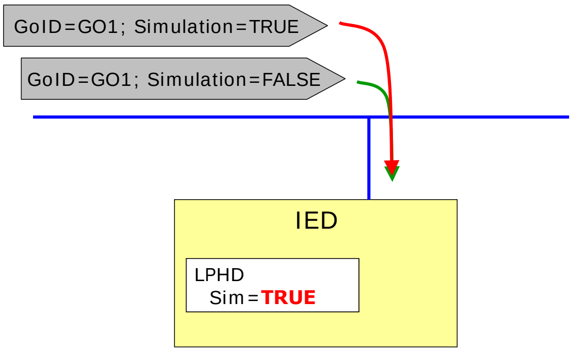

Figure 1 Simulation of a GOOSE message [5]

2.7 Handling of Data with "Test"

As mentioned already edition 2 of the standard first time explains the interaction of the different test-data. This was required, since the huge amount of possibilities confused the customers and more or less impedes the usage of the potentials. The table as defined in appendix of 7-4[4] is shown Figure 2:

Table A.2 – Definition of mode and behaviour

MODE/BEHAVIOUR	on	on-blocked	test	test/blocked	off
Function behind LN	ON	ON	ON	ON	OFF
Output to the Process (Switchgear) via a non-IEC 61850 link for example wire (typical for X...,Y... and GGIO LNs)	YES	NO	YES	NO	NO
Output of FC ST, MX (issued independently from Beh)	value is relevant q is relevant	value is relevant q = operatorBlocked	value is relevant q = test	value is relevant q = test +operator-Blocked	value is irrelevant q = invalid
Response to (Normal) Command from Client (a+ / a- acknowledgement)	a+ pos. ack.	a- neg. ack.	a- neg. ack.	a- neg. ack.	a- neg. ack.
Response to TEST Command from Client (a+ / a- acknowledgement)	a- neg. ack.	a- neg. ack.	a+ pos. ack.	a+ pos. ack.	a- neg. ack.
Incoming data with q=normal	Processed as valid	Processed as valid	Processed as valid	Processed as valid	Not Processed
Incoming data with q=operatorBlocked	Processed as blocked	Processed as blocked	Processed as blocked	Processed as blocked	Not Processed
Incoming data with q=test	Processed as valid	Processed as invalid	Processed as valid	Processed as valid	Not Processed
Incoming data with q=test+operatorBlocked	Processed as invalid	Processed as invalid	Processed as blocked	Processed as blocked	Not Processed
Incoming data with q=invalid	Processed as invalid	Processed as invalid	Processed as invalid	Processed as invalid	Not Processed
Non-IEC 61850 binary (relay, contact) inputs and analogue (instrument transformer) inputs	Processed	Processed	Processed	Processed	Not Processed

NOTE A precondition of the use of different modes (Mod/Beh) is the processing of the quality status (q) of the receiving information.

Figure 2 Mod/Beh [4]

Processed as valid" means that the application should react according to quality and behavior of the LN. So the "Processed as valid" for mode "on" differs to that "processed as valid" in case of the mode "test"- the reaction is as the mode of the IED. Only if the IED is in mode "test" data with identification "test" will be used! The experience of the author as a member of different working groups showed, that this table leaves space for discussions and interpretations and needs further investigations.

2.8 Scenarios

Different scenarios coming from interpreting the standard have been discussed in [5]. The paper used a general IED controlled by a client and subscribing to GOOSE. It was connected to a circuit breaker via wired output (Fig. 3) Different scenarios coming from interpreting the standard have been discussed in [5]. The paper used a general IED controlled by a client and subscribing to GOOSE. It was connected to a circuit breaker via wired output (Figure 3)

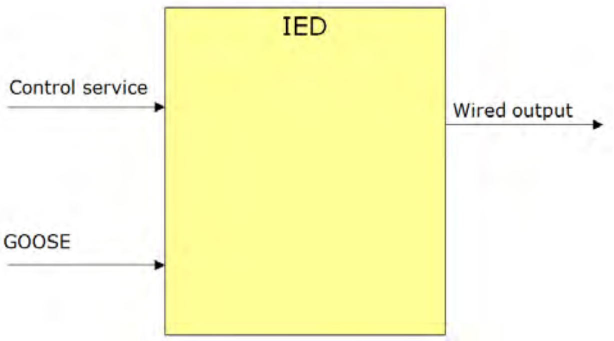

Figure 3 IED with incoming data and output to process [5]

The switching between the modes should only happen as a result of an operator command to the data object Mod so client with the capability to control is needed. Here we only use one example for a mode "test"- the testing mode.

2.9 Test [5]

As mentioned already the logical device, the physical device or even the LN can be set to test mode. In that case only controls or GOOSEs with indication “test” will cause an operation (Figure 4)

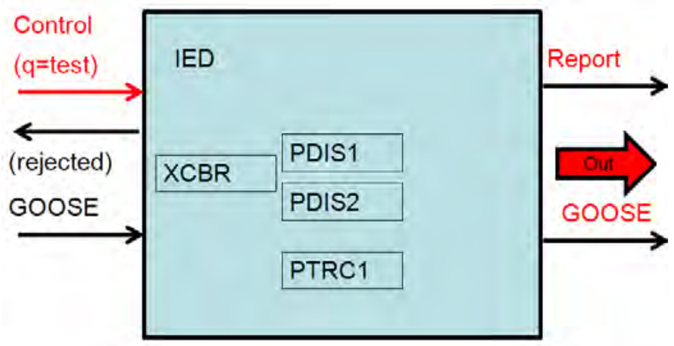

Figure 4 Test

2.10Test/Blocked [5]

To avoid tripping of circuit breakers the mode “test/blocked” will be used (Figure 5)

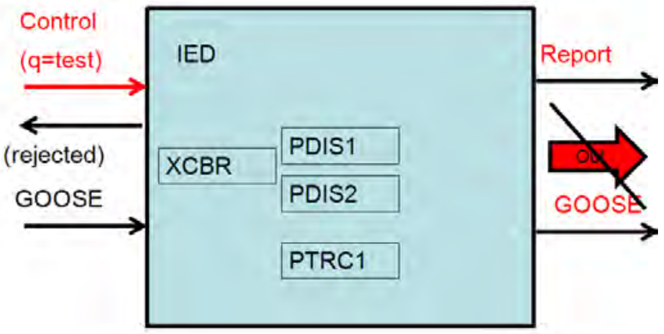

Figure 5 Test/ Test/Blocked

2.11Test of Protection Functions [5]

Conventional test plugs are used to disconnect the process. And secondary signals are injected with a test set. The logical device “protection” is set to mode “test”, to avoid tripping of circuit breakers the XCBR node can be even set to “test/blocked” (if not realized by the test plugs). In case of a trip of the relay the results will be issued by a report (with quality test). The proposal to use the mirroring (e.g. opRcvd= operation received) for a protection test will not work, since this is limited to control data only.

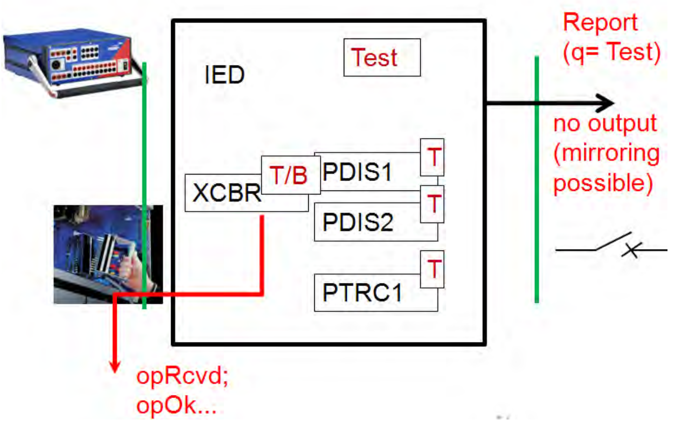

Figure 6 Test of protection function

2.12Functional Testing

CIGRE Work Group B5.32 presented their report "FUNCTIONAL TESTING OF IEC 61850 BASED SYSTEMS" in 2009. This report described already new ways to test performance and functionality of IEC 61850 Substation automation Systems (SAS). The brochure contains a structured method to specify functional tests on systems based on this standard. An object oriented approach was proposed, using UML, text and XML formats. Conformance and interoperability tests are not treated, being already standardized. This document is a good base for further discussions how to test dedicated protection functions or how to embed this into existing protection testing routines. The IEC working group responsible for IEC 61850 is WG 10 and discussing the issues. Due to some personal changes the progress of the ongoing work regarding testing was limited. National activities as described in next chapter shall accelerate the work and will be hopefully accepted as a valuable contribution. IEC 61850, its impact on substation automation and protection are under discussion in Germany for a long time already. First user recommendations [7][8] gave hints also for testing, Figure 7 shows the setup.

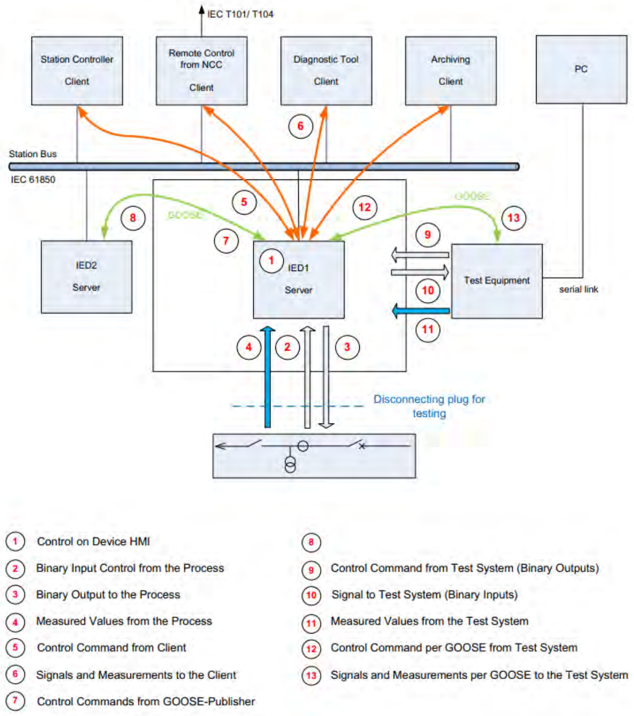

Figure 7 Information flow and test

With the new release of [7] which was published in 2013 [9] it was obvious that further definitions and recommendations will be needed- so [9] refers to the content of next chapter which will be published in 2015.

2.13 Testing Recommendation

The intention of the document to be published is shown in Figure 8.

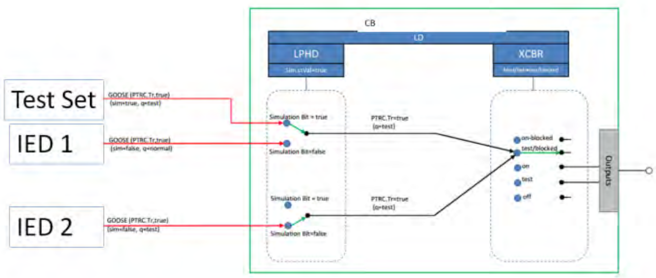

Figure 8 Combination Mod/Beh and Sim

A test set and different protection related IEDs are connected to a circuit-breaker IED. The protections IEDs as well as the test set publish a GOOSE with a DataSet containing the general trip

(PTRC). The circuit breaker (CB) is subscribing this GOOSE. The entire physical device (LPHD) can be set to simulate and will start to react on simulated values if they are available. Now in addition the circuit-breaker functionality (XCBR) needs to be defined and change its mode and behavior. Already this combination shows diversity and possibilities. To embed this in protection testing further discussions are necessary The protection device is now distance protection, backup protection and auto-recloser (green boxes in the middle). They interact with circuit breaker IED in bay (green box right hand side):

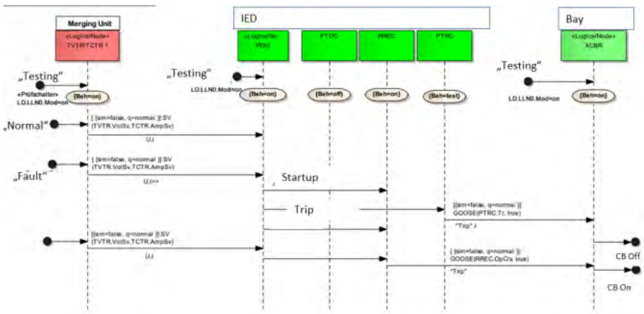

Figure 9 Sequence Diagram

Even in case of normal operation different modes might occur- e.g. backup protection (PTOC) or auto recloser (RREC) can be switched off. This behavior has to be restored after test! During test the IED reacts according the definitions of mode and behavior, the test set injects with simulation indication to allow distinguishing between real and simulated values in case of "Sim". The test set connected needs to check the transmitted quality information of trip for testing.

2.14Performance Testing [10]

With the communication network taking over all the tasks of the formerly hard wired connections, it becomes a mission critical component. The hard wired signal loops become replaced by GOOSE messages, that exchange the information between the protection relays and also towards the now intelligent switch controllers. Sampled Values deliver the data from the instrument transformers to the relays and meters. When all these elements of the so-called digital substation are utilized, a dedicated network for the real time data, often called a process bus, will be present. A measurement method must capture packets with accurate time stamps at different locations in the network and identify and relate them correctly. Since the propagation time is a relative measure, it can be determined without absolute time reference when the packet capturing can be done with a single unit. In distributed scenarios, the different acquisition units need to be synchronized to a common reference, which is typically done via GPS. Besides these synchronization issues, the measurement itself is very similar in local and wide area scenarios.

2.15Measurements in Local Networks

In a local network, such measurements can be relatively easy performed when it is possible to reach all locations from which traffic is to be captured from one single measurement device. The relative timing of the data packets captured with the device is always accurate and no additional time synchronization is required. Figure 10 shows such a measurement setup for a minimal network with two switches S1 and S2 that are connected by a trunk link.

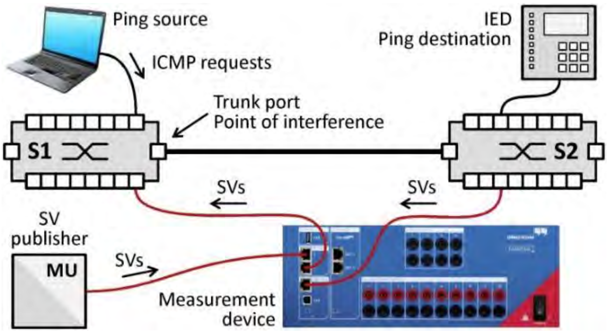

Figure 10 Possible Measurements in LAN

A Sampled Value source (a merging unit) publishes one Sampled Values stream into the network. The measurement device captures the Sampled Values packets coming from the Sampled Values source before they enter the network at switch S1 and then again when they are broadcasted from the other switch S2, after traversing through the network. A PC connected to switch S1 generates load traffic by "pinging" an IED which is connected to switch S2. This forces ICMP messages to be exchanged over the trunk link and therefore interfering with the Sampled Values. The ping utility used for generating this load traffic allows specifying the size and the frequency of the ICMP packets. In the used setup, all Ethernet links, also the trunk link, operated at 100 Mbit/s. The ICMP packets were issued at a rate of about 1000 packets per second. At a packet size of 500 bytes, one ICMP packet occupies the network for 40 µs and the ping packets utilize 4 % of the total bandwidth. The next figure shows the delay time distribution of the Sampled Values under the described conditions.

Figure 11 Delay time distribution with collisions due to network load

The left two bars, that contain most (96 %) of the measured packets represent the delay times between 25 µs and 28 µs. This is the time needed for a packet to traverse the little network undisturbed. The bars to the right, extending to delay times with a maximum of 66 µs, come from packets that got in conflict with one of the ping packets. The maximum is exactly 40 µs (the duration of the ICMP packets) higher than the average value for an undisturbed passage. This result matches perfectly the expectations that can derived from the theoretical examination of the situation. This demonstrates how other traffic can for example influence the transfer times of mission critical information in such networks. A theoretical evaluation of the circumstances will not always be as easy as with this minimal setup with its few and well controlled parameters, but a measurement will always show the actual circumstances in a given installation.

2.16Measurements in Wide Area Networks

When measuring delay times over WAN, the task becomes more complex. Multiple acquisition devices need to be used and they have to be precisely time synchronized (IEEE 1588, PTP) to achieve the required timing accuracy. In the following picture, this is indicated by the GPS receivers connected to the acquisition devices.

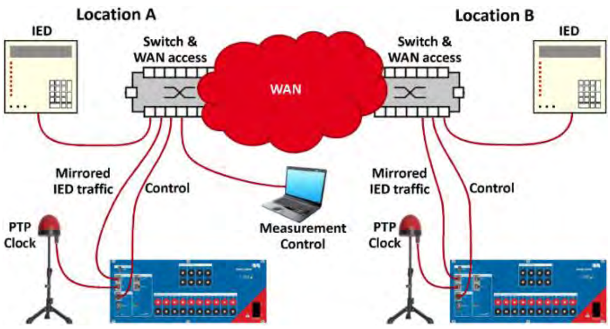

Figure 12 Propagation time measurement over a WAN

But the whole measurement system is still controlled from one single computer, making the operation as easy as possible. The expected range of the measured propagation delays is of course typically one order of magnitude larger than in LANs, but this depends very much on the bandwidth and WAN technology used.

As an example, a measurement was performed between two locations which are connected by a microwave link. The measurement was made by capturing ICMP packets which were generated by "pinging" a device at the remote end.

Figure 13 Delay time distribution over WAN connection.

The base speed of the link is rather fast, the bulk of the delay times lies in the range of 90µs to 180µs. But there are outliers in the range of more than 2ms. There was arbitrary load on the link, probably causing the outliers. If such a communication link was to be used for protection applications, the cause of the outliers needs to be investigated and removed to obtain consistent

3 CONCLUSION

The paper described the challenges and possibilities of testing in IEC 61850 substations. Ongoing standardization and modern test sets allow application.

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