Time synchronization of protection and SCADA components in power utility systems

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Abstract

Rising digitization and consistent use of IEC 61850 requires a network-based communication in electrical energy systems. The use of network components as well as intelligent and automated functions increases the relevance of time synchronization for system operators. [1] In the following, the demand is explained with reference to process bus communication and the differential protection systems. In particular the use of IEC 61850-9-2 communication, sampled values (SV), required high temporal accuracy in comparison to the requirements of the previously used functions.

At present, the high precision time synchronization has been greatly neglected. Only a local synchronization with GPS or DCF77 is currently used. A continuous strategy for time synchronization in substations has not been required so far and is therefore not available. [2] Because of the high requirements from for example the SV and the sensitivity of differential protection functions or other automated distributed functions, a strategy will be needed in the future. Therefore, different synchronization methods are considered and evaluated about their operational capability in power utility systems. This paper describes a concept for continuous time synchronization in substations which is also usable in the whole distribution grid.

1 Introduction

The conventional measurements in power utility systems are performed by the same devices that need the values. Due to the consistent use of the IEC 61850, the measured values are recorded by means of merging units and then transmitted to the processing devices, like protection devices, by means of network communication.

The devices are connected by networks which have variable time delays. Time synchronization is therefore necessary in order to avoid errors, for example within differential protection functions. In future, the relevance of a time synchronisation also rises for the SCADA components, such as remote terminal units. Within the control functions increasingly automated functions are used, they must ensure that decisions are made only on current values and not on, through network delays, obsolete values.
A system in which different DSO or TSO equipment operates is also worth mentioning. In such substations, all operators need to synchronize to a common time source. Only with a common time standard, data can be transferred, compared and used from every one. [3]

2 Situation specification

The measurements in conventional power utility systems are performed by the same devices that need the values. Separate current and voltage measuring transformers, which are connected directly to the protection or control devices, are used for protection and control functions.
The consistent use of a process bus, which uses the communication protocol IEC 61850 will dissolved this structure. The measurement data is transmitted by telegrams and can be used by various devices. The recording and processing is carried out in different devices. [1]

2.1 Example: protection function in the process bus

The upper part of the figure 1 shows that up to now a direct analogue connection existed between the measuring transformer and the processing device. The analogue measurement and the digital processing of these values are currently done in one device. In the future, with the process bus, the analogue measurement and the processing will be split in different devices. In figure 1 the measurement of the necessary values is done in two different merging units (MU). The processing is carried out in another device.

Perspective the conventional measuring transformer and MU can also be substituted with non-conventional converters. These own a direct-connected processing unity in the same unit and enter directly the digital values in the SV format on the process bus. [4]
In figure 1 a transformer differential protection is illustrated. This compares the measured values of the current over a transformer. At an excessively high imbalance between the values, the protection function switches off the switch gears to protect the transformer. [5]

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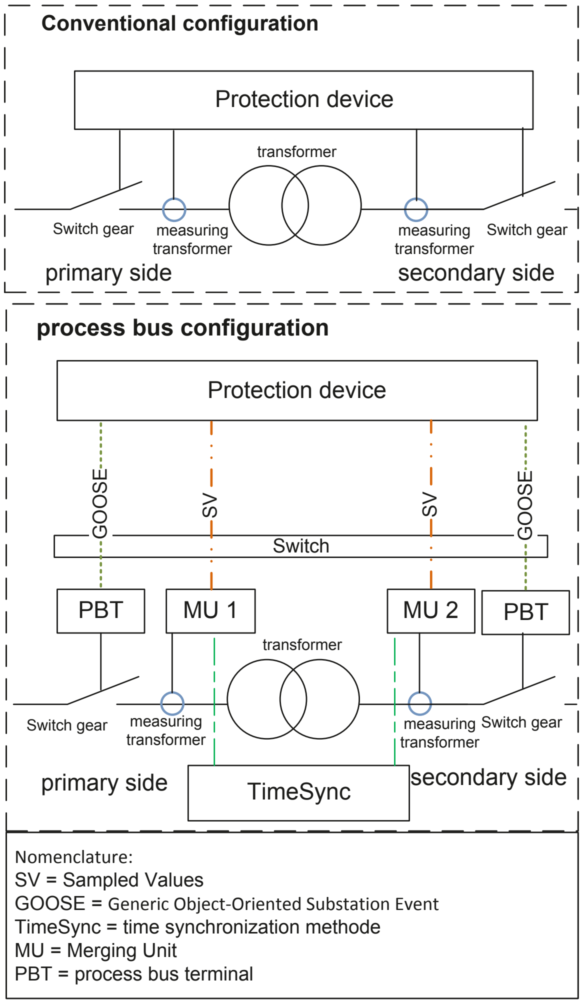

figure 1 Example transformer differential protection in conventional and process bus configuration

2.2 New Situation by sampled values acquisition

The digital measured values, sampled values, are recorded, for example, by merging units. Within a SV message different measured values can be included. The time of the measured value recording is only defined by a sample value counter, which is set by the merging unit. The sample counter within the merging unit is set to zero by a synchronization impulse. In the free run this impulse is generated by the internal oscillator. With external time synchronization this is given, for example, by a pulses-pro-second signal.

Considering a transformer differential protection two merging units are required (lower and upper voltage level at transformer). The split of the measurement in two different devices, here merging unit 1 (MU1) and merging unit 2 (MU2), leads to the fact that these must take up the SVs at the same time or within a low tolerance.
In case the merging units are not synchronized to each other, the situation in figure 2 is possible.

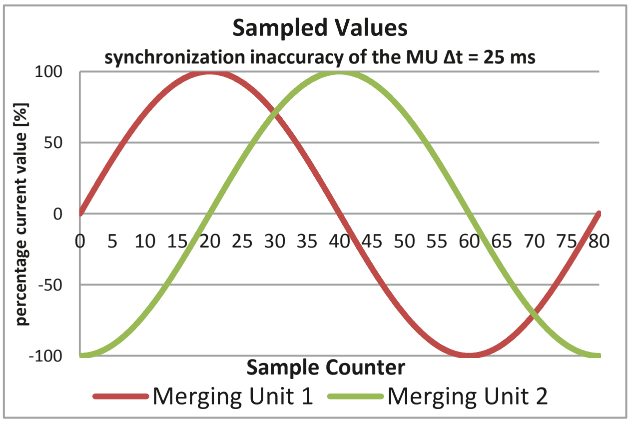

figure 2 Example free running merging units

With an inaccurate synchronization or in the free run it is possible that the used merging units set the sample counter to zero at different times. [7] figure 2 shows one possible signal course which can be measured in the free run at normal operation. The worst case would be that the SV with the counter 0 are so different that it is not possible anymore to process them anymore in combination without a correction.

A maximum difference of 141.42% between the Sampled Value on the primary side of the transformer and on the secondary side occurs, when the synchronization impulse between the Merging Units is shifted by 25 ms.

The transformer differential protection would react immediately when getting such values, because of value differences about more than 30% [6]. The transformer would erroneously disconnect from the power grid. Also other protective functions as well as calculations cannot be performed with measured values having such a difference. Time synchronization is therefore essential.

The Merging Units which generate Sampled Values must be synchronized with each other at highest precision. For the protective function of the transformer differential protection a local time standard, that is valid in the substation, is sufficient.
The function only requires measuring values which are taken up inside the substation.

Synchronization between substations is not required for the transformer differential protection. Other protective functions compare the Sampled Values which are measured at different points in the power grid, one example for that is the line differential protection.
The line differential protection considers sampled values, which are measured in different substations (see figure 3). Therefore, it is necessary that the substations, in which the SVs are measured, are synchronized to the same time standard with a high accuracy.
Another reason why precise time synchronization is especially necessary for a safe use of protection functions.

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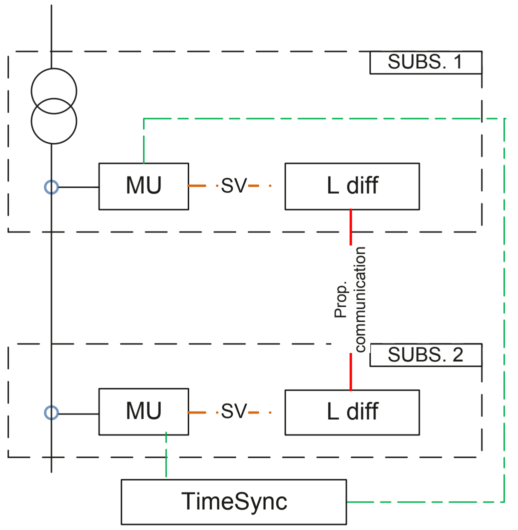

figure 3 Example synchronization of line differential protection

In the future the relevance of a time synchronisation also rises for the SCADA components, like remote terminal units.
The application of automated functions in smart grids leads to an increasing relevance of the time synchronisation. The used functions, especially distributed functions, have to assign the required values to the right time. Otherwise, for example, commands could be rejected erroneously because of a supposedly incorrect timestamp.

3 REQUIREMENTS

To avoid errors in protection and SCADA functions (see chapter 2), requirements are set up. This must be considered when the measurement is done by merging units and SVs, because this required a high accuracy. [8]

The class numbers shown for which applications the accuracy can be used. The performance class 1 is based on distributed functions with low requirements. For ordinary transfer fields performance class 2 shall be considered. The performance class 3 applies for transfer fields where high synchronization in the time behaviour is required, such as in differential functions.

table 1 Example synchronization of line differential protection

data type / class number (x)		for protection P(x)	for metering M(x)
		U und I	U und I
class 1	Rate	480	1500
	Accuracy	±25	±4
class 2	Rate	960	4000
	Accuracy	±4	±1
class 3	Rate	1920	12000
	Accuracy	±1	±1

Rate in [Samples/s] ; Accuracy in [µs]

Regarding IEC 61850-5, within class 2 of Sampled Value recording the requirement of accuracy from ±4 µs is made for protection. For protection functions only a sampling frequency of 960 Hz is required. Currently on the market available devices, also fulfil the metering standards of class 2, therefore the sampling rate is 4000 samples per second and an accuracy from ±1 µs. [8]

To comply with the total accuracy requirement, the requirement to the external time source has to be lower. The derivation of the requirements for the external time source is represented in the “Implementation Guideline for digital Interface to instrument transformers using IEC 61850-9-2”.
Time sources for synchronization must work with an accuracy of ±1 µs (see figure 4). A maximum inaccuracy of ±3 µs may therefor arise from the MU. The accuracy must be observed in sum over the processing of the synchronization signal and the sampling. [9]

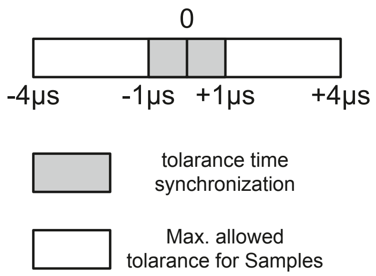

figure 4 Accuracy of synchronization

The other applications, which have requirements on the accuracy of the time synchronization in power utility systems, have lower requirements. Therefore, when using SVs, the synchronization accuracy requirement of ±1 µs by the external time source and accuracy over all of ±4 µs is observed.

4 SYNCHRONIZATION

In Chapter III the requirements for the time synchronization were defined and described. The used synchronization methods have to fulfil at least these requirements. In the following section therefor different synchronization methods are listed, which might fulfil these requirements. Afterwards the different concepts of time synchronization methods are considered. The term external time source is used to refer to systems, which feed a global time in the system. Time server protocols distribute the time or impulses for the synchronization within the system.

4.1 Synchronization methods

Some protection functions need a common time standard in the substations (see chapter 2.2), therefore all substations and power utility system components should be synchronized to a common time standard. The system-wide synchronization has to be even more beneficial, not only has the fulfillment of requirements for protection func-

tions, for example the reconstruction of error sequences or system-wide consistent data. The application of an external time source is therefore required. For an autonomous solution, from the offered external time sources, only the satellite systems are suitable for the synchronization accuracy, because these show the highest exactness.
While the European system Galileo is not completely established, the American system NAVSTAR GPS should be used. This time source shows a typical accuracy of about 1 µs and is the most exact global time source.
A centralized solution can lead to a higher accuracy in the complete power utility system. It can only be achieved by a synchronization from the SCADA central system and a high precision time protocol, but the accuracy of this variant depends on various factors. Among other things, all devices must support the time protocol and only produce low inaccuracy in the synchronization.

Different possibilities are available for the distribution of the time synchronization within the substation.
For power utility systems this would mean, that the SCADA central system acts as a time source. All subordinate systems, like remote terminal units, have to be synchronized to the time standard of the SCADA central system. For this application variant the IEC 61850-9-3 or C37.238 can be demanded. These specifies the maintained accuracy and algorithms.

Currently mainly the Pulse-Per-Second (PPS) signal is used for time synchronization. The average accuracy of about ≥100 µs is sufficient for the protection and control functions at this time, because the measurement and processing is implemented within one device. The present requirements on the station bus fix a time accuracy of about 5 ms.
Distributed protective functions currently communicate about proprietary protocols on separate communication lines, so these functions are not synchronised by a PPS signal. In this case the accuracy requirements of the protection function are not relevant for the synchronization method.

By introducing the process bus with a communication over IEC 61850-9-2 other requirements are needed. That is why the accuracy of PPS is no longer sufficient to fulfil the requirements (see table 1 and table 2).

table 2 Considered time protocols

protocol	average accuracy
IRIG-B	1 ms
1-PPS	≥100 µs
NTP	1-10 ms
IEC61588v1 Hardware sol.	100 ns
IEC61588v2 Hardware sol.	100 ns
IEC 61588 Software sol.	5 – 50 µs

In table 2 the considered time protocols are listed, which have been contemplated for the implementation of the new requirements. It can be seen that only the protocol defined in the IEC 61588 in the hardware solution can comply with the requirements.

Within the IEC 61588 the Precision Time Protocol (PTP) is defined. This was first described in the IEEE 1588, the international electrotechnical commission took over the complete standard into their standard IEC 61588. Also other properties of the protocol show that it is suitable for usage.

4.2 Specification of the IEC 61588 for power utility systems

The standard IEC 61588 defines different algorithms. Some of those allow the measurement of the symmetrical time delay, this time delay can be considered automatically.
This ensures that a high accuracy of time synchronization is achieved. One device, which fulfils the IEC 61588, is not necessarily compatible with other devices that comply with this standard. The incompatibility is caused by degrees of freedom in the standard. For example, not all algorithms, described in the standard, must be implemented and some of them are not compatible with each other.

Consequently, before using PTP, it must be ensured that different devices are compatible. So a requirement is also a selected set of algorithms. For power utility systems, specification of the protocol has already been developed, C37.238 and IEC 61850-9-3. However, both specifications can’t be used in one system. Because the best master clock algorithms have different effects.
In the selection of devices for future synchronization by the PTP, it should be ensured that they have in addition to the standard conformity to the IEC 61588 the conformance to standard IEC 61850-9-3. This ensures that the devices are compatible with each other and the requirements of the synchronization in power utility systems can be fulfilled. The IEC 61850-9-3 limits the set of algorithms and the permissible delay times are defined by the individual components types. [10-12]

4.3 Synchronization concept

In order to fulfil the future requirements, for the accurate measurement of values and the growing automation, protection and control devices should be synchronized with the SCADA central system. The central system receives the time standard via GPS (figure 5)

Subordinate network elements, protection and control devices are synchronized with the PTP from the SCADA central system. Given by the hierarchically layer, devices appear towards the lower-level units as PTP Master. The lower-level units have the PTP mode slave, normally, or passive, if a communication line with a better accuracy is in use.
Once all used devices can fulfil the hardware solution of the IEC 61588 and the specification IEC 61850-9-3, the

synchronization via PTP can be used. A high accuracy can be ensured. [13]

For the system, shown in figure 5, an accuracy of ±1 µs is possible, if the devices comply with the IEC 61850-9-3. The standard specifies that after crossing of 15 transparent clocks (TC) or 3 boundary clocks (BC) the accuracy of ±1 µs is to comply.

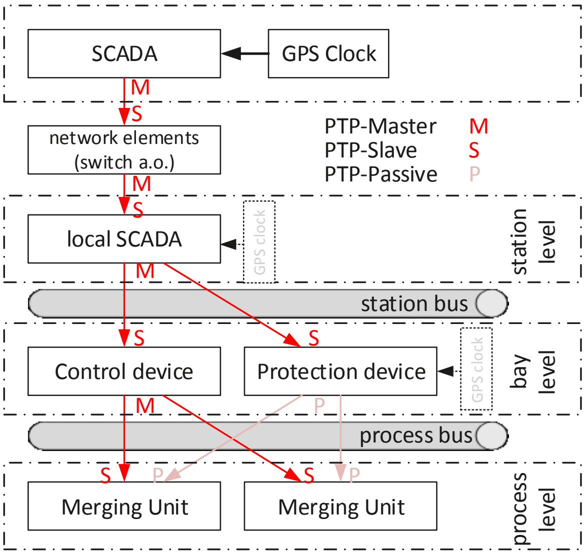

figure 5 Considered time protocols

The network elements, like switch and gateway, are transparent clocks. The devices for protection and control functions are boundary or ordinary clocks (OC). In sum the accuracy does comply. But if more hierarchically layers are implemented, the accuracy must be checked. Because of the complex and extensive structure of most energy systems a complete conversion to PTP is complicated and expensive. Therefore, a gradual introduction can be performed.

First the substations which devices are communicating via IEC 61850 are used to synchronize with a local GPS receiver. Within the process bus and optional in the station bus the synchronization carried out by PTP. Initially only PTP-capable devices within the process bus are needed. These devices have to fulfil the requirements which are named in chapter B. For the applications with the lower accuracy requirement other synchronization possibilities e.g. via the Network Time Protocol (NTP) or PPS should be offered.

The precision time synchronization can expand, in the context of changes from devices, on the station bus and on communication lines to the SCADA central system. If all devices on the communication route do comply with PTP, the time synchronization can use the time standard from the central system. The system structure must take into account that only few crossings over boundary clocks and transparent clocks are allowed for a high accuracy.

Important for this evolution towards a highly accurate synchronized system, is that the demand for PTP-enabled devices increases, especially for products for power utility systems. Otherwise the manufacturer of protection and control devices are not integrating this synchronization option in their devices. So far, the number of available devices on the market is limited.

5 CONCLUSION

With the increasing technical progress the meaning of the time synchronization rises. New technologies and intelligent functions are used in the previously existing power utility system. With the help of sampled values and their use in differential protection functions, the need of time synchronization can be clearly shown. Also other functions, such as automation functions, require precise time synchronization.
In this context may be mentioned in particular distributed functions and various control algorithms. To fulfil these high requirements, which also apply at a higher system level in the future, a new synchronization concept is required.

A time synchronization concept, based on IEC 61588 and IEC 61850-9-3, is described in this paper. This allows a large number of devices to be synchronized to the same time standard. Currently the implementation of a complete synchronization in power utility systems is difficult. Therefore the concept also considers a local synchronization which can be later integrated into a global synchronized network.
Due to the lack of demand only a few manufacturers of protection and control devices have implement the option to synchronize with the PTP according to the standards IEC 61588 and IEC 61850-9-3.

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