31 May 2024

FINAL REPORT

110kV Pernoonkoski Digital Substation Final Report

Contents

1. Document Organisation

1.1. Table of revision

Issue	Date	Issuer	Description
00	15.02.2022	Stefan Weilguni	Initial release - draft
01	27th Apr 2022	Stefan Weilguni	Review after Fingrid comments
02	31.5.2024	Fingrid Oyj	Public release

1.2. Organizations

Fingrid
Empower / Enersense since 2021
Sprecher

1.3. Important note to the following report

All the following descriptions and statements made, correspond to the technical status of used equipment and knowledge of involved engineers at the time of the tests and evaluations. We reserve the right for later functional extensions, test options, product, or tool improvements of Sprecher and third-party products.

Any changes, improvements and extensions since the test phase have not been considered in this document and are subject to change.

2. Abbreviations

BFP … Breaker Failure Protection
CCP … Colour Control Panel
DAN … Double Attached Node
CCT … Conventional Current Transformer
CVT …Conventional Voltage Transformer
EM … Energy Meter
GOOSE …Generic Object-Oriented Substation Events
LE … Light Edition
LC … Lucent Connector (for fibre optic cables)
MMS …Manufacturing Messaging Specification
MU … Merging Unit
NCIT … Non-Conventional Instrument Transformer
NTP … Network Time Protocol
PB ...PRP Process bus (GOOSE & SV), based on IEC 61850-9-2 LE (Ed.2.1) & IEC 61850-8-1
BCU …Bay Control Unit
PRP … Parallel Redundancy Protocol
PTP … Precision Time Protocol
PU … Protection Unit
REP … Resilient Ethernet Protocol
RSTP … Rapid Spanning Tree Protocol
SAMU …Stand Alone Merging Unit
SAN … Single Attached Node
SAN …Single Attached Node
SAS … Substation Automation and Protection System
SCU … Switchgear Control Unit
SNMPv3 … Simplified Network Management Protocol version 3
SPRECON … Sprecher Control (SAS)
SV … Sampled Values
TPU … Tele Protection Unit
VLAN …Virtual Local Area Network

3. General and background

Already in the mid-1990s the work on a new standard called IEC61850 has been started. The goal was to create a standard for power systems, protection and control that covers and describes the whole substation. The result was a standard gaining more possibilities on interoperability and reliability. Fingrid started therefor a pilot station of a digital substation with implementation of IEC61850 using SV and GOOSE messages on process bus. Fingrid's goal was to get familiar with the new technology.

Based on the results and experience of this pilot station, Fingrid is able to decide on future applications for the IEC61850 process bus technology. In general, not only the IEC61850 process bus should be integrated but also different devices from different vendors to test the interoperability. Also new technologies like non-conventional current transformer or IoT should be integrated to gain more experience on the different parts and to get knowledge about reliability and performance.

The above-mentioned points like enhanced interoperability for Intelligent Electronic Devices (IEDs) from various vendors, increased test possibilities, reduced installation times – and thus shorter outage times are always highlighted as big advantages of the standard but exclude problems and risks with this new technology.

Exactly these problems and risks should be tested and explored in the pilot station and with it the maturity of available device.

Most used devices from different vendors have already experience with operation of IEC61850 or parts of it. Nevertheless, the combination of the different devices always contains risks and challenges. This is an essential part of the executed project. This should be achieved by the installation of the digital substation for two line-bays in parallel to the renewed conventional system.

A big focus was put on the IT security topic which is an essential part of the system. Not only in digital substations the importance of cyber security is becoming a bigger part in substation automation systems. Experience of internationally cases have shown that any digital system is a potential subject of hacking and cyberattacks. In digital substation the communication based on Ethernet technology and external access to the system for testing and maintenance is extensively used and makes it a vulnerable component of the whole system.

In chapter 6 the results and finding as well as the limitation of the system are described (technical state during testing and evaluation phase). In most cases no fixed solution or answer is available. Many of them are depending on future improvements of the used equipment. And some other are design decisions for future station or for devices to avoid problems and limitations with simpler system architecture.

In addition, suggestions for future digital substation are made.

4. Pilot Project concept

To get in touch with next generation of substation automation system which promises a smarter and more efficient power transmission system, Fingrid launched a pilot project in the beginning of 2019. The intention was to operate and test a Digital Substation Automation system that includes new technologies like PTP, or process bus communication based on IEC61850-9-2. Therefore, a system was built for two live 110 kV line bays at Pernoonkoski substation in Kotka. The system operates in parallel to the existing renewed conventional control system.

4.1. Concept and scope

The Digital Substation Automation System was realised to gain experience and knowledge concerning the whole concept and to get familiar with the technologies.

The individual integration of IEC 61850 in the different devices from different vendors is advanced. But in interaction with other devices, it is a different story. It was also one task in the execution of the project to verify the interoperability of the system and to evaluate the current state of IEC61850 integration and technological level.

To enable Fingrid to get a clearer view of IEC 61850-9-2 process bus and their integration in the system, it is required to gain more information and knowledge about the reliability and performance of the system. Based on that information Fingrid should have the possibility to decide if the IEC 61850-9-2 process bus should be integrated in future stations and if it can co-exist with existing communication, infrastructure, and primary equipment.

The big challenge is that the pilot installation is not a test of single components, but a whole integrated system.

The Pilot is connected to 110 kV AE05 Tehtaanmäki and AE06 Koria in a redundant way. Means both bays are built up twice to gain experience of interoperability between different manufacturers. The redundant systems are called System A and System B. The main components of the Pilot are IEC 61850-9-2 process bus, IEC 61850 station bus, IEDs, NCITs and gateways. The digital substation is operating in parallel to conventional system. The digital system is connected to the live signals of the substation. Commands and trips can be operated but can also be separated from live substation.

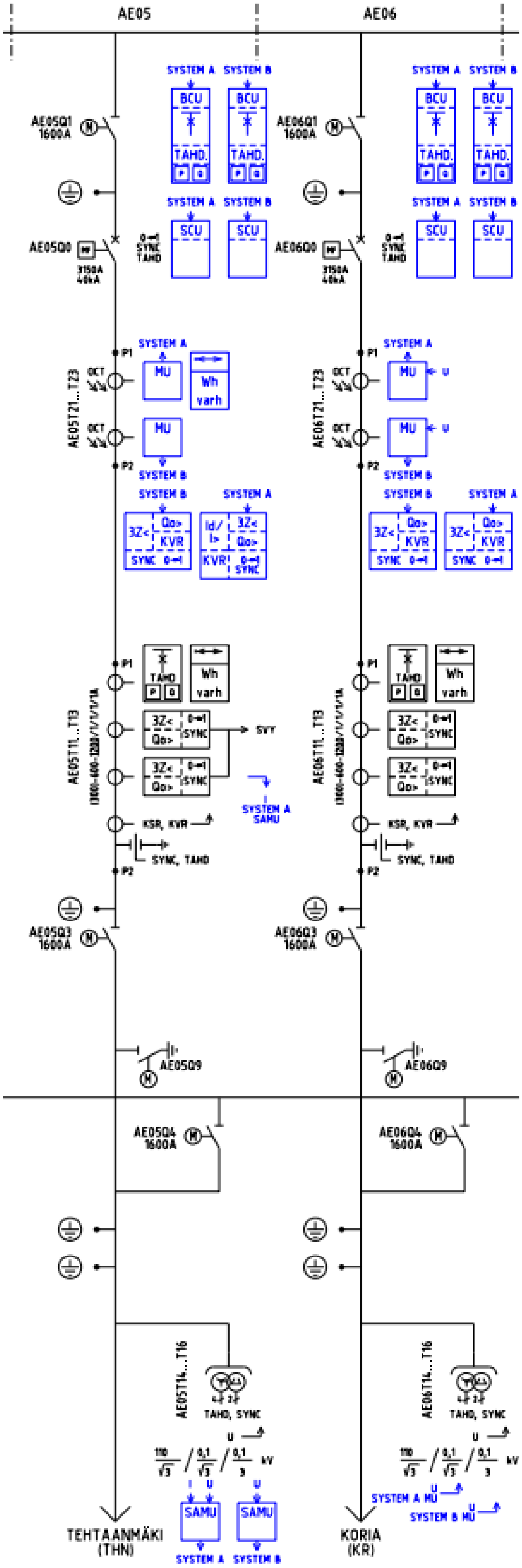

Fig. 1: Single line diagram of lines

4.2. Description of technical solution

The project was executed according to the technical specification document "PRN1A031", which was agreed between Fingrid, Empower and Sprecher. It was the basis for the engineering process.

The approach in this project was to combine different manufactures. System A consists of Condis EPU for current measurements, Arteche SAMU, Arteche SDO-MU and SPRECON-SCU on the process level. On the station level ABB protection relays, SPRECON-E-C BCUs, SPRECON-E-C Gateways are in operation. As local HMI SPRECON-E-V460 is used. In System B the same process level IEDs are used, but in combination with SPRECON-E-P protections.

One of the main challenges in building up Digital Substation Automation System is to reach the same level on reliability and availability that is known from conventional systems. This goal is reached with redundant system architectures on the process- and station-bus, based on Parallel Redundancy Protocol (PRP) network redundancy technology, as shown in Fig. 2 below. Devices that are not supporting PRP have a singular connection to the system (e.g., Energy meter or the Maintenance and Engineering server).

Another essential topic with using process bus (PB) application, is a high accuracy time synchronisation. In the DSAS this is solved with two-time sources, GMC1 and GMC2, using the Precision Time Protocol (PTP) v2 power profile to ensure 1 µs accuracy.
The clocks themselves are connected via two connection each to the process-bus. That means that each IED has access to four time-instances. On the station-bus NTP is used as time service. The NTP sources are connected via PRP to the station bus.

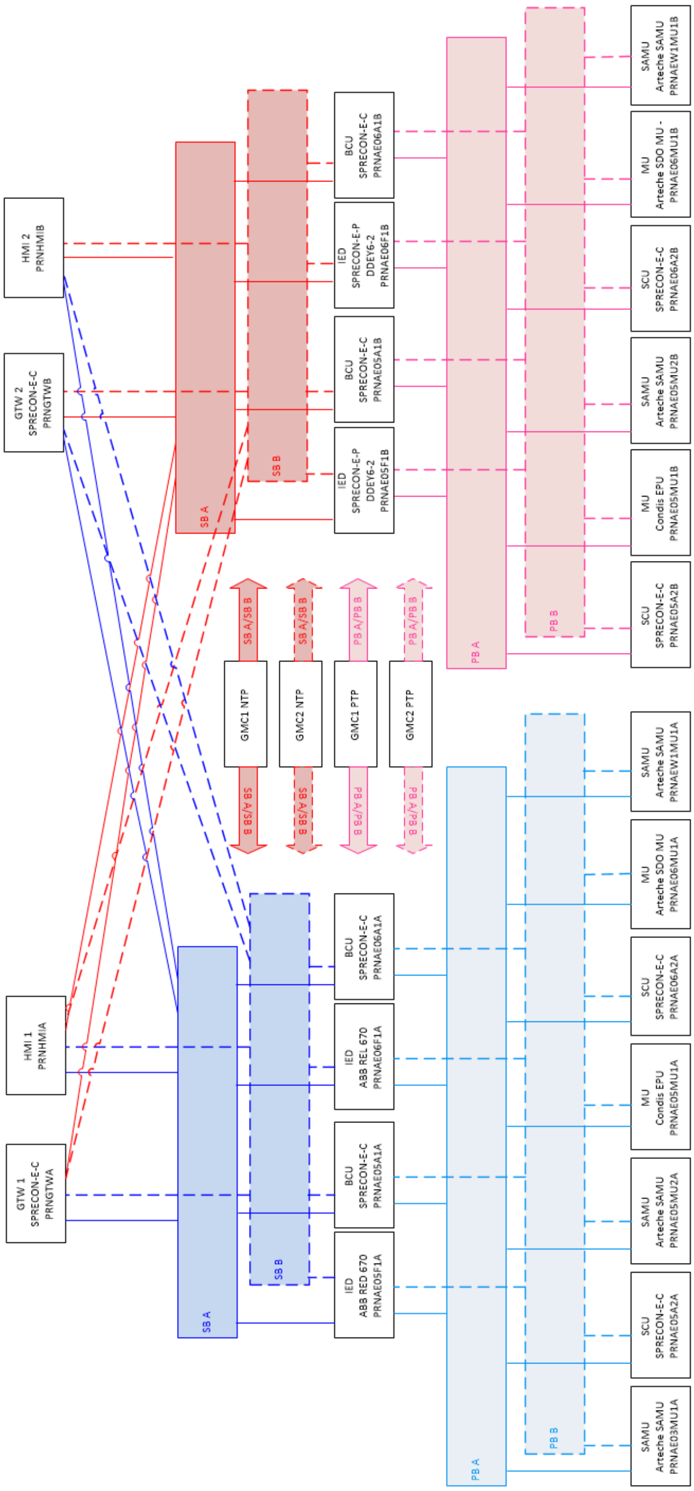

Fig. 2: Pilot project topology (simplified)

The Stand-Alone-Merging-Units and Merging-units are measuring the voltages and currents in the live transmission lines and busbar. Also, the SCUs are connected to the real lines with a separator switch to open the command circuits. SV streams according to IEC61850-9-2LE with 80 samples per cycle are used for metering, protection, and control functions.

Another challenge are the SV streams for protection devices. The distance protections need voltage as well as current values to function correctly. It is essential that these values have the same time stamp for the PROT to operate. In the pilot station the voltages and currents come from two different sources in Bay AE05 (MU for currents and SAMU for voltages). A mismatch of time signal between the measurements causes a protection malfunction. Special attention was put on this matter. In addition, the differential protection IED in System A bay AE05 is also subscribed to third SV stream source (SAMU) to receive currents from the bus coupler bay AE03 as well. This allows the differential protection to be active when the bus coupler bay AE03 is in use instead of bay AE05. The selection of the right current source for the differential protection is done automatically by the IED.

On process LAN only sampled value- and GOOSE-service is transferred.

The station LAN is a PRP network as well. Only MMS communication is available in station LAN. Process-bus devices are connected to the station bus for service and maintenance too. Depending on the support of the IEDs, this link is established as singular or redundant PRP connection.

4.2.1. Vendors

Equipment from several manufacturers were used and integrated in the DSAS system. This enables the possibility on evaluating the fundamental aspects like capabilities and technological readiness level of IEDs. Problems with interoperability or level of IEC61850 integration between specific devices can be detected and verified too. Vendors represented in the pilot installation were ABB, Arteche, Condis, Ruggedcom, Landis & Gyr, Meinberg, Omicron, GE, and Sprecher.

5. Project execution

5.1. Organisation

With the Kick-off meeting in Helsinki in February 2019 the project execution began. From the tendering phase the basic concept was available. But a lot of conceptual decisions, hardware types and implemented functionalities were needed. To solve all these topics, workstream meetings were introduced.

- Management checks: Administration topics, procurement status, schedule
- Work stream 1: Topics regarding the control system in general and communication
- Work stream 2: Protection topics, concepts
- Work stream 3: Software solution, network topics, cyber security

The Work stream meetings were held regularly.

During the first phase of clarification and creation of technical specification, a lot of discussion and research was going on. There are many device types that have never been used in such constellation and therefor meetings with internal experts and specialists from vendors were necessary. This is also the reason of many adaptions and workarounds in the system. This clarification and back and forth approach, delayed the start of the engineering phase and extended the test and in house test phase. The results of interoperability tests (as soon as the devices arrived) made some changes in the technical specification necessary too.

Non-technical issues had a very deep impact on the project too. Because of the evolving COVID situation we cancelled the planned FAT in Linz scheduled for Q1/2020. Work was continued after lock-down and relaxing of the situation. Together with EMPOWER we continued tests during summer and re-scheduled the FAT for Q3/2020. Again, COVID made it impossible for FINGRID and EMPOWER to come to Linz. The FAT was re-scheduled again.

Since there was no improvement of the situation in sight. Fingrid, Empower and Sprecher agreed on an online virtual-FAT (vFAT). Again, we were pioneers in this field. We created a concept, organised the technical equipment. Finally, the virtual-FAT could be performed in week 51/2020. The FAT was successful. After implementation of open points, discovered during vFAT, the station equipment was shipped on site.

5.2. Control and protection

The pilot project has successfully implemented an operational protection and control system using the sampled values and process bus technology as defined in the IEC61850-9-2 standard. During the whole execution phase, from test phase until the commissioning phase a lot of valuable experience and knowledge had been gained. This delivered important information for future application for all parties.

IEC61850 is partly a very open standard that leaves a great part for interpretations and implementations to the vendor. Vendors implement the standard on different levels and from different perspectives. This fact caused some main challenges related to the interoperability and functionality separation (which device is covering which functions). Special focus was put on the communication switches (first use in DSAS for Sprecher) and the whole technical specification for the pilot station. All these mentioned points leave room for improvements.

The Ruggedcom RST2228 is a switch designed especially for the operation in digital substation. It was the first use of Ruggedcom in digital substations, and the first use of this type at all for Sprecher. The configuration was not straightforward. This created some challenges, and obviously requires a thorough understanding of the many features available.

The PTP time synchronisation is an essential part of a digital substation. All devices connected to the process bus support PTP time-service, but the diagnostic and monitoring function are poor for most of the devices. Only the availability of any PTP time source is monitored. There is no information offered by the IED on quality, or the actual PTP instance that is used. Many of these information was gained on applicational level and took long time to find a possibility, integrate it in the system, and test it.

Inside each Meinberg clock there are 4 PTP-time modules supporting the power profile. The power profile does not support PRP (power profile is a layer 2 multicast service without IP-address). Hence in each process bus segment there are four PTP sources available (two from GMC1 and two from GMC2). Each IED makes the decision on PTP source on its own. That leads to numerous switch overs.

In general, for extensions, service, diagnostics, and maintenance of the system a very deep knowledge of all parts of the system is necessary. This included the device functionality for control and protection, the knowledge of IEC 61850 and other used standards, and network technology. For the above-mentioned topics, several software is used to be able to find malfunctions.

The complexity of the system always caused troubles. There are five redundancies interconnected to each other. This includes:

- Redundant system A and B
- PRP Redundancy of both process busses and both station busses
- Redundant Gateways with connection to both system A and system B (interconnecting system A and B); Redundancy link between GTWA and GTWB
- Data point redundancy combining the indication of system A and system B for the dispatch center
- Redundant local HMIs with connection to both system A and system B; redundancy link between HMIA and HMIB

As result the system is very difficult to handle, and special knowledge is necessary.

5.3. Switchgear monitoring

In the system a switchgear monitoring system is implemented. The initial concept of using an already available AX-measuring module, was overturned. The concept was adapted several times. The AX-2670 module, especially designed for DC-measurements, was developed, and used. Together with external sensors it is now possible to measure the motor currents, save them together with switchgear indications, and other signals to a Comtrade File. This file can be transferred via Webserver or WebDAV Service. Comtrade records are collected automatically by using the SDM600 software.

5.4. Testing

Testing was a very special topic in this project. To understand the behaviour of the system as result of the combination of different manufacturers, redundancies, and simulation options was very challenging, and caused troubles. The topic becomes even more special when it comes to protection testing. The test procedures were defined. An according OCC file was created by EMPOWER based on the test requirements and test plans provided by FINGRID and then supplied to Sprecher. The OCC file was very extensive and would mean a big effort already in conventional systems. But in the digital substation environment, the tests according to the file were very challenging and time consuming. Following points must be considered:

5.4.1. Test Equipment

Software and hardware of Omicron test devices such as the CMC850, the Daneo400, and the StationScout have themselves limitations (as to our knowledge and technical information at time of testing). They don’t support PRP-networks, so test devices just have a singular connection to the system. The availability during testing is lower than during normal operation.

The test equipment can handle only one IP-address. They can be connected to one system only. If you want to change the systems, a re-configuration of test set is necessary.

Behaviour of test equipment: When importing a GOOSE configuration to CMC devices when using Test Universe, it started automatically to publish all GOOSE without test- or simulation-flag. This overwrites the valid system indication and causes toggling of indication and malfunction. Special attention must be put on this behaviour.
This problem was present during the IHT phase after applying a GOOSE or SV configuration, but was solved on site by updating Test Universe from vesion 3.20 to version 4.20. In version 4.20 the default setting for publishing GOOSE messages was set to be „Simulation/Test“ and for publishing SVs „Simulation“ .

5.4.2. IEC61850 Test- and simulation-mode

All used devices support the IEC61850 test- and simulation-mode. The IEC61850 leaves space for interpretation here as well. Not all device work in the same way or have the modes fully integrated (some functions are not mandatory). The discovering of the different behaviour of the single devices, was difficult enough, but was again exceeded, when a combination of different devices was involved (e.g., Protection relay – SCU, BCU – SCU, PROT – BCU).

6. Conclusion and improvements Sprecher Automation

Even though the single IEDs support IEC61850 and all services for digital substations, it is a completely different situation when this IED from different vendor must interact. Many constellations and interactions between the single IEDs led to unpredicted behaviours.

6.1. Improvements

The architecture of the system must be re-thought for future digital substation. The complexity apart from the actual digital substation pilot is far too high. This led to challenges independent from the actual DSAS topic.
Some improvements could be:

- Reduced redundancy concept
- Strict separation of system A and system B without interconnections
- No PRP-network on the station level. There is no time critical transmission, a rapid spanning tree or similar topologies might be suitable.
- Less time sources on the network. Reducing the number of PTP sources in the process bus to two. Now there are four sources, because of the energy profile, no IP addresses and hence no PRP is available.
  A reduction of time sources will reduce the number of switchovers between them and the risk of time deviations between the individual devices (e.g., MUs for split measurements)
- Reducing the test scenarios and test files (OCC)
- Voltage and Currents measurements should be provided from one SAMU or MU only. This reduces the risk of time deviations between the SV stream of voltages and currents and prevents malfunction on the Distance-protection IEDs

6.2. Limitations

During the project execution, we detected limitations of the used equipment.

NOTE: The described limitations are according to our state of knowledge and technical information at the time of testing. There might be improvements, or functional extensions available

- The number of subscribed SV in the IEDs is limited. For Sprecon the maximum number was increased with firmware optimizations.
- The number of external measurement channels for Sprecher Protection devices (in case of Sprecon Protection) is limited to eight (the same as for conventional wired Protection, 4x currents and 4x voltages).

- Test equipment from Omicron does not support PRP. Only singular connection to one of the PRP networks is available
- Network settings for test equipment is limited (Daneo, CMC850 and StationScout). A change from system A to B means a re-configuration of the devices.
- Strange behaviours of test equipment. After an import of GOOSE configuration, CMC devices using Test Universe started immediately to publish them (problem of toggling indication and malfunction). This behaviour was solved during the commissioning phase with an update from Test Universe 3.20 to 4.20
- Process-bus level cannot be represented in IED's data model. A lot of manual re-configuration in the SCD files is necessary to achieve a complete SCD file.
- The interface files (SCD, ICD) between the IEDs must be manually adjusted because of preceding point. ABB export file must be adjusted to import and map them to the Sprecon configuration and vice versa.
- Missing monitoring functions for PTP inside the IEDs.
- PTP monitoring functions on the Meinbergs are limited → PTP failure is not detected by clock itself but from all connected IEDs.
- During IHT phase Condis EPUs lost one sample of published SV-stream when receiving a PTP telegram. This occurred appx. all 3min. This has no effect on operation of the PROT or BCUs. Behaviour was corrected in week 6/2022 by changing the IEC61850 boards and updating the firmwares of the CONDIS devices. (Problem or behaviour was corrected in week 6/2022 by changing the IEC61850 boards and updating the firmwares.)

7. Conclusion and improvements Fingrid

7.1 Abstract

A couple of years ago different transmission system operators were very interested in digital substations. Nowadays when some projects have been reached and they have had various difficulties the hype has calmed down. The hype got started from different consults and standard developers. They kept presentations and demonstrated why digitalisation will change the substation environment.

In digital substations the biggest material savings come from copper cable because it is only needed for the auxiliary voltage of the devices. Measurements and controls use GOOSE and sampled value protocols. Devices which use these protocols are connected each other with optical fibres. That sounds pretty good but after this project we have knowledge of many problems that must be fixed and thought again before system like this can be used in a real process. The key idea is really great and, in the future, when devices are developing this could be good solution instead of the conventional substation.

7.2 Improvements

GOOSE and sampled value protocols use process bus in message sending. All the process bus devices are married to each other and that causes challenges/rethinking for the following things:

- setting changes, device additions, testing, troubleshooting
- part of process bus faults remains not tested because not enough knowledge how to teste or issues can't be tested.
- in the conventional system we know exactly how breaking down of each device effects to the system. These effects are limited, and device repairing is straightforward. Fingrid's protection philosophy is based on this. We don't want to change this to the worse direction. The process bus devices are in the product development phase, and it is not known how long their life cycle is going to be and how they are going to operate in a real difficult network faults.

Test philosophy and way of working are also different if compared with conventional testing. The digital system includes much more instruments which needs programming. This increases the amount of programming work. You must create many different test modes and testing in live system it is necessary that the test equipment sends only test signals. At the same time, you must pick up those signals but also confirm that test signals don't go into the real process to devices which are part of the real process. The conventional system relays and bay control units can be disconnected from process one by one just opening their terminal blocks and tested or replaced and tested one device at the time.

The system FAT and SAT testing were painful and whole system testing in same time was very difficult or even impossible. Because of that some functions were not tested.

Test equipments were not able to simulate all needed SV-streams for one bay to make complete functional tests. The system is very complicated and test devices are difficult to switch to the system. Additionally, there are some artificial interfaces which made testing more difficult. Therefore, it should be a priority one that the system is transparent without different interfaces.

Maintenance is also a very important thing, and this should be user friendly. The whole system maintenance is very difficult because there is no single place where you can get all the information about the system. In the process bus has been many errors and faults and you don’t find them in one concentrated place. Here we come to the fact that self-monitoring of the system is at a quite low level. It must be possible to reset remotely in the future all the digital substation devices. This is not possible at the Pernoonkoski.

Nowadays all station maintenance staff have trained for a conventional substation. With their current knowledge they cannot do much on digital substation. This is the one fundamental problem. Fingrid’s maintenance service providers don’t have employees who knows about the operation of the digital substation. And contractors have the same problem. The key point is how we build a new digital substation if we don’t have enough know-how for more simple station bus implementations where IEC61850 standard are used.

More conclusions and observations which came up during the project:

- The process bus will need also more advanced IED’s which have developed to operate with SV-measurements. The relays what were used in this project are today used also for conventional protection.
- We have seen problems which originate from time synchronisation. When the synchronisation is lost - it is necessary that some backup protection still is working. Now it is possible when the time synchronisation is lost all protection functions are blocked. Overcurrent protection doesn’t need the precise angles.
- Relays give also too less information of what is the reason for fault or problem related to SV measurements for example a differential protection becomes blocked. In the future more advanced relays could give more information what is the reason for fault and block only the protection functions which are necessary.
- In the future digital substation pilot project it is fundamental that all parties need to work together until the end of the project.
- In the project bidding phase it is very important that supplier selection isn’t made only based on presentation documents – some sort of small scale type approval needed for main IED:s.
- It’s important that SCD file is prepared at the beginning of the project.

7.3 Conclusion and next steps

How reliable process bus system can be today. There are mainly only pilot projects where transmission system operator and manufacturer have used a lot of resources and effort. Not much has been told which kind of problems or challenges in details they have encountered during the projects. We need much more research results if we want to switch to process bus system. The system must be much more simple that testing and maintenance would be easier, and time for configuration and testing would be shorter.

The transmission system operator cannot make change to trial solutions which could reduce transmission reliability. Technology must be reliable and tested and risks must be handled before using new solutions in the transmission system.

This project has provided improvements for the next secondary system type approval, utilizing of tools and project organization knowledge of the system.

Now we try to keep system running with current devices as good as possible and collect data regarding system operating in normal condition and during network faults - keep analysing those. At the moment it is clear that most of devices are not suitable for production use. There are too many independent IED-devices to make it feasible.
Next step after trial run should be started within one year and goal there is to reduce amount of IED:s to minimum – one IED should include BCU, SCU, Protection and SAMU/MU functionalities and process bus network should be simplified. To see how mature latest technology is and developing knowledge.

8. Conclusion and improvements Enersense

8.1. Challenges:

The project required a lot of innovation and adaptation, as there were no established practices or templates to follow. This made it difficult to estimate the time needed especially for the testing.

The system was complex and dynamic, and it changed and improved throughout the project. This meant that the testing had to be flexible and responsive to the system updates, and that the test methods and entities had to be constantly revised and refined.

The system involved various types of equipment, communication protocols, and configuration files, which increased the risk of errors and inconsistencies. The testing had to ensure that the system components were compatible and functioning properly, and that the communication signals were correct and reliable.

The testing was time-consuming and tedious, as it involved many steps and procedures, such as making changes to the SCD file, updating the configuration, checking the communication cables, running the Omicron devices, and verifying the results. The testing also had to be repeated after any changes or updates, which added to the workload and duration of the project.

The problem solving was challenging and slow, as it required identifying and isolating the possible sources of errors, such as the SCD file, the communication switches, the secondary devices, the Omicron devices, or the communication cables. The problem solving also had to take into account the interdependencies and interactions of the system components, and the impact of any changes or updates on the system performance.

8.2. Improvements

The design of the substation automation system needs to be revised for future digital substations. Focus on one thing or a few main areas at a time and test them thoroughly, so that new technologies or solutions could be implemented in production someday. The project identified the importance of diagnostic tools especially during testing to see the state of the system components and the system itself and to identify the root cause of different faults or abnormal behaviors. The more user-friendly the implementation is, the less devices and software are needed to understand the system state.

In addition to already mentioned improvements in this report:

- Type Approval process before the actual substation implementations. In this way, for multi-vendor deliveries, the device usage possibilities would be identified and known in advance, and it would be more likely to avoid situations where the implementation does not fully match the vision, wishes or requirements.

- For common systems, separate IED devices should be used instead of combined ones, for example, for busbar switching devices and for bus coupler switching devices. In the case of Pernoonkoski, this was a design-technical compromise to integrate these to other devices.
- To ensure configurability of secondary devices according to IEC61850, minimizing manual xml-code editing, minimizing the number of available tools and creating a design process /workflow to ensure design, editing, version control and maintainability.
- Software tools must support efficient engineering, testing and maintenance
- To eliminate excess redundancy. The implemented system is highly segmented and isolated. This makes it hard to maintain and supervise, e.g. a comprehensive overview of the system cannot be seen from one place, but it would be highly beneficial, if this would be possible.
- It should also be possible to easily attached external diagnostic and test devices to the system.
- Test plans and test documentation for digital substation to be specified
- The type of testing devices and the type of testing arrangements to be specified.
- Testing process should not vary for any devices that are the same kind.

8.3. Conclusion

Pilot gave a lot of experience, increased competence and understanding of both the devices used and above all the possibilities of the digital substation in production use and development needs, both on the device and software side, as described in this document.

To utilize the digital substation more easily in future projects, a Type Approval process is needed, where device variants, device features and interoperability of devices from different manufacturers are tested in advance, so that the differences, features and limitations of different products would be as much as possible known beforehand. In addition, removing excess redundancy speeds up design, clarifies the system and makes it easier to understand, design, configure and test.

Suitable and efficient tools for IEC61850 design is needed as well. A simple and straightforward IEC61850 design process is required, using as few tools as possible (there should be no need for multiple or different versions of the scd-file for different devices or manual editing of the scd-file)

The next pilot project should be started from a life cycle perspective. The system should be easily extendable, upgradable and maintainable without the fear of breaking the system. This requires that all devices, software solutions and tools are suitable for the intended use with well described and understandable workflow. The technology adoption is more likely when these conditions are fulfilled.