SP Transmission Plc, Network Innovation Competition
FITNESS – Future Intelligent Transmission Network Substation

FITNESS Close Down Report

Table of Contents

1.0 Project Title 4
2.0 Project Background 4
3.0 Executive summary 5
3.1 Key Learning Points 6
4.0 PROJECT SUMMARY 6
4.1 NETWORK TOPOLOGIES AND INTEROPERABILITY 7
4.1.1 Standards 7
4.1.2 Test set-up and methodology 8
4.1.3 Observations 9
4.1.4 Lessons Learnt 11
4.2 TIME SYNCHRONISATION – AVAILABILITY OF PROCESS BUS AND RELIANCE ON TIME SYNCHRONISATION 12
4.2.1 Standards 12
4.2.2 Test Setup and Methodology 12
4.2.3 Recommendations 12
4.3 LOW POWER INSTRUMENT TRANSFORMER AND ITS DIGITAL INTERFACE 13
4.3.1 Standard 13
4.3.2 Test Setup and Methodology 13
4.3.3 Lessons Learnt 14
4.3.4 Recommendations 15
4.4 SUMMARY 15
5.0 Communication Architecture Overview 15
5.1 Communication Architecture Generalities 15
5.1.1 PRP network topology 15
5.1.2 HSR network topology 16
5.1.3 HSR to PRP Interlink 17
5.1.4 Time Synchronisation Overview 17
5.2 Description of the FITNESS Architecture 18
5.3 System Architecture 19
5.3.1 Levels of architecture 19
5.3.1.1. Station Level: 19

5.3.1.2.	Bay Level:	20
5.3.1.3.	Process level:	22
5.3.1.4.	Bus Voltage Interconnection Ring	27
5.3.2	Architecture Design Considerations	27
5.3.2.1.	Bandwidth and Latency	27
5.3.2.2.	Traffic Segregation	28
5.3.2.3.	Description of data streams	30
5.3.2.4.	Control system Engineering	31
5.3.3	Advantages of the proposed design	35
5.3.4	Design Considerations for future Digital Substation	35
5.4	Protection & Control Implementation	35
5.4.1	General	35
5.4.2	Newarthill 1 Circuit Implementation	36
5.4.3	ABB IED Access Points Configuration	37
5.4.4	ABB 670 series IEDs - Merging Unit Configuration	39
5.4.5	ABB 670 series IEDs – Analogues Configuration	39
5.4.6	ABB 670 series IEDs – Time Synch Configuration	41
5.4.7	IEC 61850-8-1 Engineering	41
5.4.8	GOOSE Engineering using the IET600 as an SCT Tool	44
5.4.9	MicroSCADA Engineering	47
5.4.10	Substation Overview	47
5.4.11	Supervision	48
5.4.12	Feeders	48
5.4.13	DAR and Sychronising	51
5.5	Testing and Commissioning	52
5.5.1	Testing in digital substations – Challenges and differences to conventional substations	52
5.5.2	Network communication testing	52
5.5.3	IEC 61850 System Verification	53
5.5.4	Network redundancy testing	53
5.5.5	Time synchronization testing	55
5.5.6	Network performance assessment	56
5.5.7	Protection testing	57
5.5.8	Simulation and Test Mode Concept	58

5.5.9 Automation and Control Testing 60

5.5.10 Commissioning and site acceptance testing 61

5.5.11 Cyber Security and functional monitoring 65

5.5.12 Conclusions and lessons learnt for testing 66

5.6 Wide-Area Monitoring and Control 66

5.6.1 Infrastructure 67

5.6.2 Measurement Chain Architecture 67

5.6.3 Phasor Measurement for Wide-Area Monitoring & Control 68

5.6.4 Capture of Fault Behaviour Using Fast Phasor Measurements 69

5.6.5 Power Quality: Harmonics 69

5.6.6 Results of Measurement Chain Performance Comparison 69

5.6.7 Integration with Central Information Infrastructure – WAMS & EMS 72

5.6.8 WAMS-EMS Integration 73

5.6.9 Common Information Model 73

5.6.10 Wide-Area Control Platform 74

5.6.11 Cyber Security 75

5.6.12 Novel Applications Investigated 75

5.6.13 Lessons Learned 78

6.0 Performance compared to the original Project aims, objectives and SDRC 79

7.0 Required modifications to the planned approach during the course of the Project 81

8.0 Project Finances 81

8.1 Variation in Project Costs 82

8.1.1 Labour 82

8.1.2 Equipment and Contractors 82

8.1.3 IT 82

9.0 Updated Business Case and lessons learnt for the Method, Project replication AND Planned implementation 82

9.1 BUSINESS CASE 82

9.2 PROJECT REPLICATION: DIGITAL SUBSTATIONS TRANSITION STRATEGY 83

9.2.1 PROPOSED OUTCOMES OF THE DIGITAL SUBSTATIONS INITIATIVE 84

9.2.2 Gap analysis and Update of specifications, policies and standards requiring update to enable roll-out of digital substations 84

9.2.3 Defining process change enabling efficient transition from conventional to digital substation deployment 85

9.2.4 Training and development of new roles within the organisation 85

9.2.5 Establishment of necessary test facilities and IT processes to support transition to business as usual 86

9.3 PLANNED IMPLEMENTATION 87

10.0 Knowledge Dissemination 88

10.1 Year 2016 & 2017 89

10.2 Year 2018 92

10.3 Year 2019 92

10.3.1 FITNESS Other Technical Visits and training 94

10.4 Year 2020 97

11.0 Contact details 100

1.0 PROJECT TITLE

Future Intelligent Transmission Network Substation (FITNESS)

Leading Licensee: SP Transmission Plc

Project Partners: ABB Ltd, GE Grid Solutions, Synaptec, and The University of Manchester.

2.0 PROJECT BACKGROUND

FITNESS, Future Intelligent Transmission Network Substation was approved and supported by 2015 RIIO-T1 Network Innovation Competition. https://www.ofgem.gov.uk/publications-and-updates/network-innovation-competition-project-direction-fitness.

FITNESS is GB's first multi-vendor digital substation demonstration project using process bus at SP Transmission's (SPT) Wishaw 275kV substation. FITNESS (Future Intelligent Transmission Network Substation) proposed a low outage and low risk approach to substation asset replacement and load related investment by replacing hardwired signalling with digital communication and through provision of an open platform upon which novel and enhanced monitoring, protection and control functions can be built. It enabled faster deployment, greater availability, improved safety and greater controllability with a reduced footprint and lower cost than conventional design. It will also help to defer new build substations and expansions, deriving benefits for transmission and distribution operators and customers.

The new technology that is deployed at SP Transmission's Wishaw 275kV substation is based on modern digital communications with integrated information technology that will help to improve system visibility, diagnostics and operations, resulting in increased reliability and safety. Both vendor 1 and vendor 2 have deployed their optical instrument transformer technology in the selected circuits; Bay 1 (Newarthill 2) & Bay 2 (Newarthill 1).

FITNESS trialled a new substation architecture that significantly reduces the number and length of circuit outages throughout the life cycle of the substation, enables new measurement, monitoring, protection and control applications, and allows integration of low carbon technology into substation design in a standardised and optimum way:

- Measurement using Low Power Instrument Transformers (LPITs) and novel distributed sensor technology, providing increased accuracy, quality and reliability of measurement whilst improving safety and reducing environmental impact. As well as conventional transformer measurements digitised at source by a Merging Unit (MU).
- Digital communications using the IEC 61850 9-2LE Process Bus standard for publishing digital SV and sent over a fibre optic link, to replace analogue signals over copper wiring from switchyard to control building.
- Monitoring of dynamics, fault recording and PQ functions using the digitised data sources, feeding central information and control systems.
- Protection with digital communications in place of hardwired inputs and outputs, reducing physical size, enabling connection with reduced outage, and adaptable to system conditions.
- Control via flexible logic processes applied to incoming data, enabling grid-sensitive constraint and risk management.
- Substation management and integration to central information systems.

The following standards and literature have been used for designing FITNESS architecture

SP Transmission Standards: -

- PROT-01-008 - Requirements for the protection & control application policy to be applied on the 400kV and 275kV transmission systems within the SP Transmission licence area.
- PROT-01-018 – Protection and Control Design Policy.

IEC Standards: -

- IEC 61850 (8-1, 7-4) - Communication networks and systems for power utility automation
- IEC 61850-9-2:2011- Specific communication service mapping (SCSM) - Sampled values over ISOIEC 8802-3
- IEC 61869-9 - Instrument Transformers – Digital interface for Instrument Transformers
- IEC 62439-3 Industrial communication networks – High availability automation networks Part 3: Parallel Redundancy Protocol (PRP) and High-availability Seamless Redundancy (HSR), Edition 3.0 2016-03).
- IEC 61588 / IEC61850-9-3 (POWER PROFILE) - Precision clock synchronization protocol for Networked measurement and control systems IEC 61588:2009(E), IEEE Std. 1588(E): 2008
- IEC61850-9-3 (POWER PROFILE) ™, Edition 2.0 2009-02.

3.0 EXECUTIVE SUMMARY

As one of the international leading demonstration projects, FITNESS is supported by the dedicated electrical Network Innovation Competition mechanism under RIIO-T2 regime by Ofgem, the UK.

This project is aiming to enable GB Transmission Owners (TOs) and Distribution Network Operators (DNOs) to apply a digital substation design approach to future load and non-load related investment. Digital substations are based on concepts of standardisation and interoperability,and enable replacement of many kilometres of copper wiring with digital measurements over a cost effective fibre communications network.

The successful completion of this project, supported by the UK regulator as well as project partners, provided rich evidence and industrial experience to facilitate future roll out of digital substation at both transmission and distribution levels.

The details of the learning and contributions to international standards have been well documented and listed in the main body of this report. Those learnings will enable the fulfilment of our engineering objectives:

- **Digital Communications** - Digital substations are designed with digital communications over fibre optic links instead of analogue signals over copper wires from switchyard to control building. The method relies on the recent International Electrotechnical Commission (IEC) 61850 9 2 ‘Process Bus’ standard for publishing digital SVs. The project trials the fitness-for-purpose of the standard and interoperability of products and integrated systems designed to this standard.
- **Measurement** - The process bus standard enables integration of smaller, lighter and higher quality sensors. The project is intended to prove that NCITs can be integrated with protection, monitoring and control, and that the data quality is sufficient to fulfil the functions of multiple conventional transformers, while reducing footprint and using environmentally benign materials. Trials include substation NCITs fulfilling protection needs (with a voltage NCIT released in 2015), novel distributed sensors applicable to hybrid overhead/underground lines. It has been trialled by remote and local measurements integrated using IEC 61850 9-2,and conventional transformers via merging units to achieve a practical roadmap for introducing the process bus architecture.
- **Protection** - With only digital communications and no analogue hardwiring, protection devices are smaller and can be replaced or reconfigured without any changes to wiring in the switchyard, avoiding circuit outages. The reliability and availability of protection in the new architecture in a live substation is a key outcome, as is the interoperability between multi-vendor protections based on IEC 61850-8-1 and 9-2 standards.
- **Control** - Substation control processes applied in the IEC 61850-8-1 based substation design.
- **Substation management** - The project intends to prove that multi-vendor equipment is interoperable and can be managed in an integrated system and is cyber secure.

Digital Substation Technology will be playing a critical role in the Green Recovery and our transition of a Net Zero energy network. SP Energy Networks, as the leading licensee, are proud about the on time and in budget delivery. There are extensive stakeholder engagement activities during the delivery of this project to ensure that the customers can benefit from this Open Innovation style.

Completion of FITNESS has led to the launch of the SPEN Digital Substations Initiative to build the necessary skills within SPEN, development of utility wide standards, specifications and requirements for successful roll-out of digital substations and, most importantly, to raise awareness regarding the benefits of digital substations. This initiative will enable seamless roll-out of digital substations on the network. The potential sites in RIIO-T2 and RIIO-T3 where digital substations can be implemented are identified. In 2020, the FITNESS Project has undertaken a series of knowledge activities to establish a suitable framework for the digital substation technology, including IEC61850 Global 2019, setup and Operation of replica system and training, and FITNESS Close Down Webinar. Further detail can be found within Section 10.

The project has been executed at the Wishaw 275kV substation in Scotland and was delivered to programme and within budget. With robust project management, SPEN has successfully identified efficiencies in labour, travel & expenses which has helped subsidise IT infrastructure additional contractor support during the Live Trial. This four year project was started in April 2016 and project close down webinar presented in April 2020. A summary of the project is provided in Section 4.

SPT was awarded NIC funding of £8.335M in 2015 to carry out FITNESS with the project commencing in April 2016. A further £0.95M was invested by SPT with some additional contribution, through benefits in kind, from project partners to deliver the project and raised the total project funding to £10.998M. Further detail can be found within Section 8.

Project FITNESS delivered over and above the planned methods and outcomes of the project. The significant changes and/or additions to the planned approach in delivery of project FITNESS are as follows

- Procurement of specialised skills on the onset of the pilot project and subsequent transfer of knowledge to internal engineers. It was identified in the course of project FITNESS delivery that digital substations design and deployment requires specialised skills which every TO and DNO needs to ultimately develop in house through training and hands-on practice. However, in a pilot project with trial of innovative concepts it was deemed necessary to acquire specialised support such as that from standard bodies for successful execution of the project. This knowledge was subsequently transferred to internal engineers through over 30 different training and hands-on workshop sessions.
- Procurement of additional engineering design and testing tools. Project FITNESS identified the significant and crucial need for right engineering design and testing tools for successful engineering, testing and commissioning of digital substations. As digital substations signify a paradigm shift from hardwired to communication network based critical protection, control and monitoring applications, the need to have and make use of the greater visibility of the data traffic and streams is of paramount significance to the ultimate reliability, availability and maintainability of digital substations

3.1 Key Learning Points

Key learning points are as follows:

Architecture: From an operational, maintenance and testing perspective, it was observed that it is the network redundancy that needs some consideration

Implementation: Regardless of the selected network architecture, the protection and control system needs to fulfil the requirements of main protection redundancy (main 1 and main 2 from two different suppliers) as in any conventional protection systems, plus backup protection and bay control unit.

Testing Methodologies: Testing digital bays involves – besides the classical tests expected on any protection and control IEDs - network and time synchronisation tests. As these elements are key for the overall performance of a digital bay, special consideration must be given.

Further details of learning points can be found in Section 4

4.0 PROJECT SUMMARY

In FITNESS, two bays from Wishaw 275kV were considered for equipment from two main vendors. The digital substation solution is deployed in parallel with the conventional system and is live with the exception of actual interaction with the plant (the tripping sequence ends at the Switching Control Unit (SCU) situated in the Bay Marshalling Kiosk (BMK)).

- FITNESS demonstrates digital substation technology with a combination of LPITs, associated merging units (MUs) and standalone merging units (SAMU) publishing sampled value streams to the process bus for protection and control IEDs based on the IEC 61850 edition 2 standards. The project aims to demonstrate that the designed architecture is capable of supporting all the application needs of a protection, automation and control (PAC) system.

One of the main objectives of this project was to test and prove multi-vendor interoperability at the station, bay and process bus level. Interoperability:

For IEC 61850, interoperability can be defined as the ability for equipment and systems from one or more vendors to exchange information and interpret it to use the information for their own functions. The infrastructure must be proven to support interoperability and functionality at the station and process bus level.

- Interchangeability:

  Interchangeability refers to the capability of any two pieces of equipment to be used in the place of each other for the same functions. In an IEC 61850-based digital substation, it can be appreciated that interchangeability may be more readily achieved for equipment's such as ethernet switches, clock sources and merging units (MUs) (that are either passive or required to output predefined messages).

- Redundancy:

  The interoperability must also encompass the redundancy of the ethernet communication links that are used to achieve the increased reliability and availability of a digital substation. In the FITNESS project, both High-availability Seamless Redundancy (HSR) and Parallel Redundancy Protocol (PRP) standards for redundancy are tested and used to enable a practical live substation environment comparison, not just theoretically but also operationally.

4.1 NETWORK TOPOLOGIES AND INTEROPERABILITY

4.1.1 Standards

The FITNESS architecture (see Figure 1) uses ethernet based network as the backbone. It implements the IEC61850 Edition 2 unifying communication standards to facilitate information sharing and interoperability. IEC 61850-8-1 is used for exchanging digital information over station bus and process bus. Analogue information is transmitted from field devices at process level to the respective IED's using IEC 61850-9-2LE sampled values. The protection IEDs use 80 samples per cycle. Time critical information is exchanged via GOOSE and there is a need to ensure that this information is transferred reliably within a specified time frame. This is addressed by the IEC62439-3 standard which defines two protocols HSR and PRP. These two protocols provide the required network redundancy with zero recovery time. Precise time synchronisation is required in substations for accurate protection, control, global analysis, and data acquisition.

In FITNESS two bays are considered as depicted in Figure 1. Bay 1 (Newarthill 2) is based on HSR architecture, whilst Bay 2 (Newarthill1) is based on PRP. The individual bay architectures consist of three levels namely station level, bay level and process level. There is also a dedicated check synchronisation bus ring carrying the voltage required for the check synchronisation. This information is shared between the two bays.

[redacted]

Figure 1: System Architecture for FITNESS project

The IEC 61850 standard does not make any recommendation for any specific architecture, therefore one of the biggest decisions when designing an IEC 61850-based digital substation is the network architecture. The basic requirements of an architecture serving the protection and control functionalities include the following:

- The scope and criticality of the distributed functionality (reliability and availability)
- Sampled Values subscription location
- Avoiding single points of failure (based on architecture and/or system design)
- Maintenance procedures (simulation/isolation and testing)

4.1.2 Test set-up and methodology

In FITNESS the focus has been on testing the robustness of the architecture (Figure 1), stability and performance of the network and, most importantly, reliability and availability of the key protection and control functionalities for the designed system. Extensive offsite testing using state of the art software and testing tools has been performed on the FITNESS setup. This ensures minimal to no unidentified issues during commissioning on site and achieves maximum efficiency through deployment of digital substations.

The test procedure is categorised into three major aspects

- Overall system testing including positive and negative tests for
  Reliability and availability tests for both redundant architectures (HSR and PRP) Figure **2**, Figure 3
  - **Figure 2**Figure 3
  - SV, GOOSE and MMS interoperability between multi-vendor IEDs and SCADA systems. Figure 4 Figure 5
  - Edition 2 test and simulation mode

- Time synchronisation refer to section 4.2
- Network performance testing Figure 5
- System configuration file (.scd) verification Figure 6

- **Figure 6**Protection and control functionality testing
  - Main protection (Line differential and Distance) Figure 7
  - Backup protection (Overcurrent, Earth Fault and Circuit Breaker (CB) Fail) Figure 5
  - Common control functions (synchronising and delayed auto reclose (DAR))
- Substation supervision and data acquisition (SCADA) system test
  - Supervision and Control
  - Alarm/Indications
  - Measurements

4.1.3 Observations

Following are selected observations from FITNESS offsite testing.

Figure **2** and Figure 3 show the results for HSR and PRP performance.

Figure **2** is under steady condition and Figure 3 shows GOOSE availability on PRP at different locations with changes in network availability.

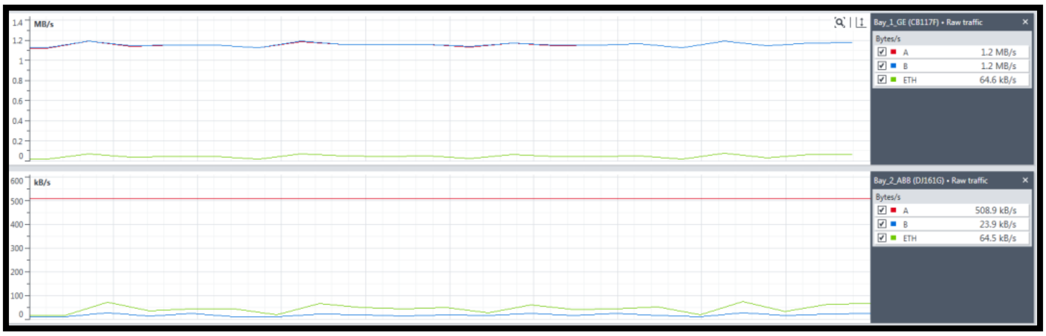


Figure 2: Network Load – Network Load for PRP and HSR bay

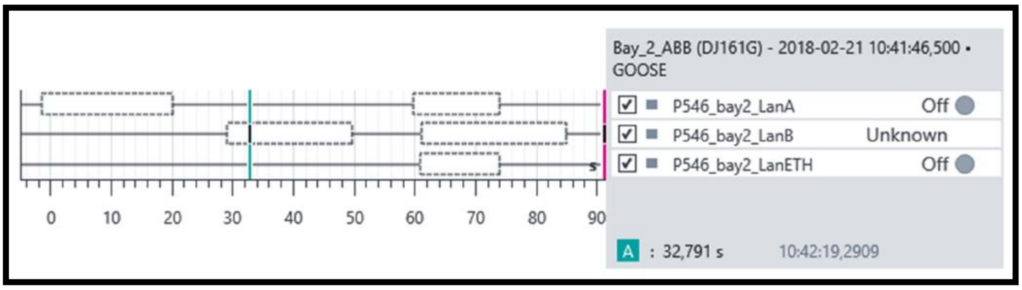


Figure 3: PRP bay - GOOSE communication during single point failure on PRP bay

Figure 4 shows multi-vendor interoperability and availability of SV streams and GOOSE in the HSR bay during current differential operation.

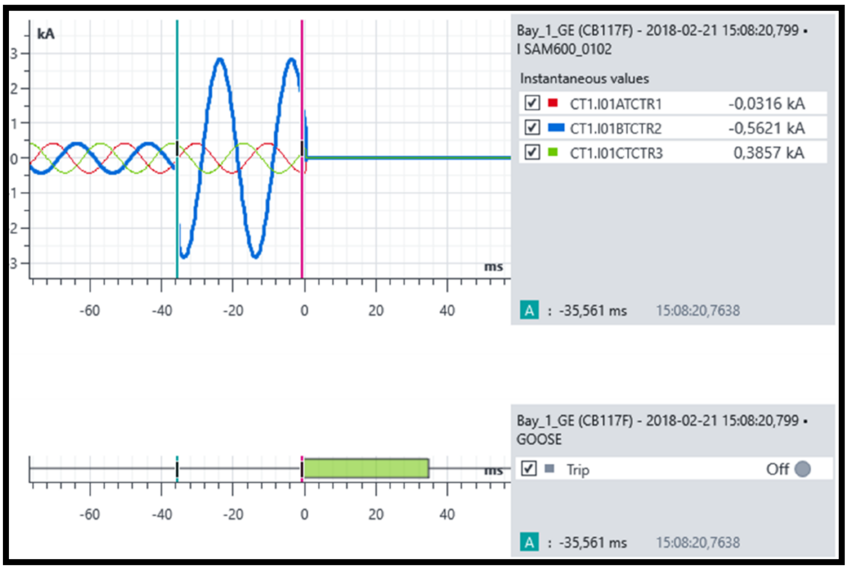


Figure 4: HSR Bay – SV streams from Vendor A MUand associated Trip GOOSE from Vendor B Differential relay

The inter-bay communication from PRP to HSR bay and the associated GOOSE propagation delay was measured and is shown in Figure 5. It is to be noted that the GOOSE propagation delay is in micro-seconds. This proves multi-topology interconnection is robust and interoperable between different redundancy architectures and vendor devices in digital substations.

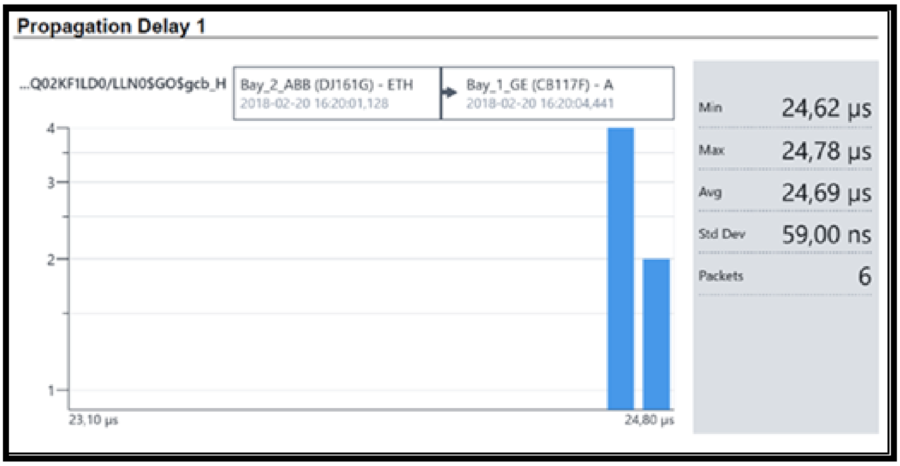


Figure 5: GOOSE Propogation delay of CBF measured between LAN A of PRP Bay to LAN A of HSR Bay and GOOSE Interoperability

The overall configuration of the substation is done using a .scd (substation configuration description) file. It is important to validate this file and fix any discrepancies (between the system configuration and the actual data) in the network found before functionality and system testing as shown in
Figure **6**.

Figure 7 proves that the standard protection functions have the same reliability and performance in a digital substation based on SV measurement streams and GOOSE tripping sequence as compared to conventional substations. The automated test sequence created during offsite testing phase can be re-used in all phases of the project (offsite, site and operation and maintenance testing).

IED	Server	GOOSE & SV	Result
CNEWHAR1	✓	✓	✓
SCU1NH1	✓	✓	✓
SCU2NH1	⚠	✓	⚠
AA1D1Q02FN1	✓	⚠	⚠
R841BUP	✓	✓	✓
AA1D1Q02KF2	✓	✓	✓
R546FPFM	✓	✓	✓
AA1D1Q02KF3	✓	–	✓
AA1D1Q02FN2	✓	✓	✓
AA1D1Q02KF1	✓	⚠	⚠
RREDFPSM	✓	✓	✓
GTWM	⚠	–	⚠
OISERVM	✓	–	✓
MER1UNIT320	–	⚠	⚠
SAM600	–	✓	✓
MERUNIT320	–	✓	✓

Figure 6: System verification to validate .scd file and to identify configuration errors

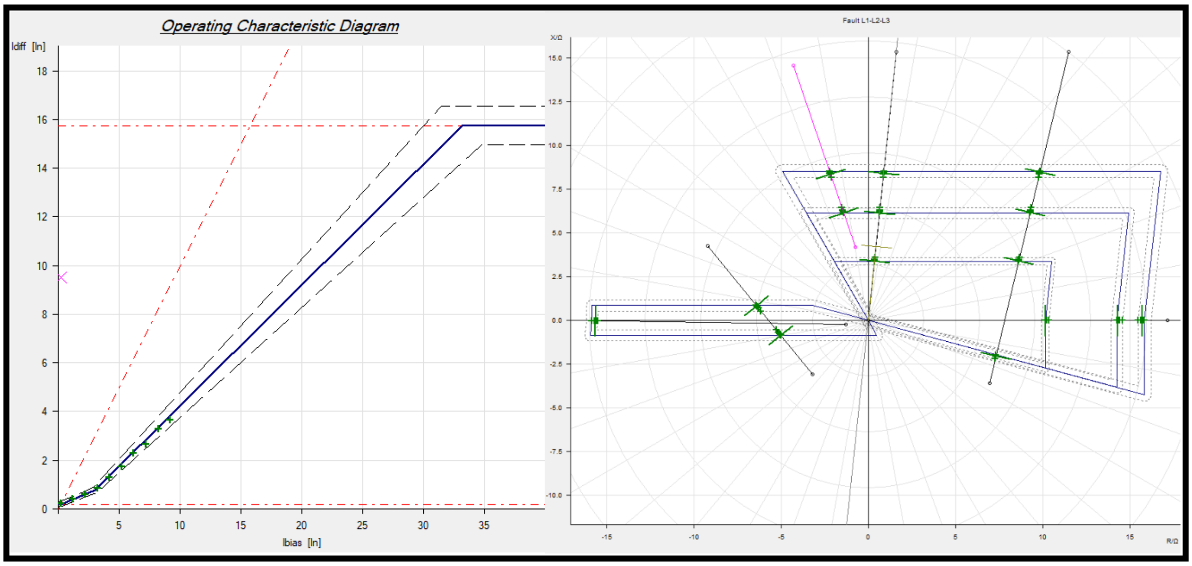


Figure 7: Current differential and distance protection tests on Bay 1 with vendor A MU SV stream and vendor B protection IED

4.1.4 Lessons Learnt

1. Architecture: HSR and PRP
   From an operational, maintenance and testing perspective, it was observed that it is the network redundancy that needs some considerations. Whilst the HSR type of network seems to align itself better to the concept of sharing data in a unified format, i.e. GOOSE, MMS and SV on the same network with 1 GBPS network bandwidth used to cater for the network load, the PRP type of network on the station / bay level and completely segregated process buses on the process level offers a clear demarcation between station data and critical process data - more in line with the concept of segregation of station functions from the critical process related data, as in any conventional systems. The PRP option seems to enable an easier harmonisation of utilities operational procedures when it comes to testing and isolation. Going forward, a mixture of both PRP and HSR might be the way to implement redundancy in protection and control systems.
2. Implementation
   Regardless of the selected network architecture, the protection and control system need to fulfil the requirements of main protection redundancy (main 1 and main 2 from two different suppliers) as in any conventional protection systems, plus backup protection and bay control unit. This can be easily achieved with the present protection and control IEDs. However, a fully digital bay solution lends itself to some special considerations regarding the number of IEDs within a bay at both bay and process level. As such, subject to utilities acceptance, the number of IEDs can be reduced by integrating the backup protection into both main 1 and main 2 protections and the functionality of the bay control unit can be migrated into one of the two switching control unit (SCU). This would simplify the architecture whilst retaining the requirements for main / backup / control as in any conventional systems.
3. Testing Methodologies

Testing digital bays involves – besides the classical tests expected on any protection and control IEDs - network and time synchronisation tests. As these elements are key for the overall performance of a digital bay, special consideration must be given. As such, protection performance, availability and reliability tests must be conducted in conjunction with network and time synchronisation. These tests require specialised test equipment that allows the system integrators to visualise, debug and test the protection and control system as a whole. Automated test sequences are desirable in the context of a digital bay. Once all the information needed for testing is made available in an IEC61850 format, it is a simple procedure to start building up test routines for all conceivable testing scenarios. Extensive functional tests on protection and control panels can thus be conducted in a fully repeatable, traceable and succinct manner. These test routines can be re-utilised and fine-tuned during the next project execution, thus enabling a consistent approach to testing from one project to another.

4.2 TIME SYNCHRONISATION – AVAILABILITY OF PROCESS BUS AND RELIANCE ON TIME SYNCHRONISATION

4.2.1 Standards

Time synchronisation is of paramount importance for maintaining reliability and availability of the process bus and sampled values, and consequently, the availability of critical protection and control functions in a digital substation. Depending on the regulations, utilities may not accept loss of protection functionalities for more than 1-3 secs, and such loss cannot be a frequent occurrence. In the FITNESS project time synchronisation is achieved predominantly by application of the IEC 61850-9-3 standard. IEC 61850-9-3 (2016) part of IEC 61850 standard specifies a precision time protocol (PTP) power utility profile which allows compliance with the highest synchronization classes of IEC 61850-5 and IEC 61869-9. The standard defines three different kinds of clocks; master/ordinary clocks (MCs) which can be configured as grandmaster only or in grandmaster capable, boundary clocks (BCs) with grandmaster capability and transparent clocks (TCs) with PTP frames forwarding capability. The standard requires all clocks to support the best master clock algorithm defined in IEC 61588:2009 | IEEE Std 1588-2008.

4.2.2 Test Setup and Methodology

In FITNESS the time synchronisation architecture comprises of two GPS based MCs, acting as grandmasters, directly connected to the two station LAN switches on PRP, configured to act as TCs**Error! Reference source not found.**. From s tation level, the PTP signals are distributed to the bay level switches and IEDs. These devices participate in selecting the best master clock and could act as master clocks if no better clocks are detected. Once synchronised, the bay 2 merging units can provide multiple time synchronisation signal outputs in pulse per second (PPS) format, as this may be required by some devices that are not yet compatible with IEC61850-9-3 PTP time synchronisation protocol.Observations

Once all devices have been configured and connected**Error! Reference source not found.**, a series of test cases were run t o demonstrate time synchronisation under following conditions:

- Clocks change over whilst in GPS mode (Clock class 6)
- Clocks change over whilst in holdover mode (Clock class 7 - system running on local oscillators).
- Clocks availability during LANs failure combined with loss of one or both GM clocks.

The observed behaviour of the system was as follows:

- The best-known clock on the system became the Best Grand Master Clock (BGMC).
- The other MC clock went into passive mode.
- All devices (IEDs, switches and Merging Unit) had the same time as the BGMC.
- All (IEDs, switches and Merging Units) shown a synch locked indication.
- All IEDs, switches and Merging Units) shown the Grandmaster identity (the same BGMC).
- When the current grandmaster clock went down, the passive clock was elected and became the new grandmaster.

The behaviour of the overall system was in line with the IEC61850-9-3 standard - the switching between the two Grand Master Clocks was seamless under both test scenarios (GPS and non-GPS conditions). The Merging Units – the most demanding device when it comes to PTP synchronisation - exhibited a much better holdover time than the one specified in the standard (minimum 5 sec).
A software tool was used to sniff the network. This allowed us to detect abnormalities in the network traffic and automatically log all events with the corresponding detailed information.

4.2.3 Recommendations

1. It should be noted that - as in any protection related matters - it's quite difficult to get the right balance between scheme security and availability under various Sample Value synchronisation conditions. The definition in IEC61850-9-3 for

steady state as 30 s after a single master starts to send synchronization messages and 16 s after a change of master, with no change to the environment temperature, indirectly implies that MUs may not be in a steady state for 16 s during a changeover. This may not be acceptable to utilities for system critical functions. Another solution could be to increase availability of MUs, for example, vendors could allow MUs to holdover for 30s for protection applications instead of 10s as required for metering applications. Vendors currently tend to put a strong emphasis on scheme security - although robust enough, under certain re-synchronisation conditions, the Merging Unit was blocked, and thus unable to provide Sample Values to the protection and control IEDs. On the other-hand, utilities put more emphasis on scheme availability, whilst expecting to maintain security at an acceptable level.

2. It was observed that even a slight mismatch in power profiles and configurations in both MCs increased the negotiation time in the best master clock algorithm. In order to avoid this both MCs were set to power utility profile and associated configurations were exactly matched and a significant improvement was observed in the performance of the best master clock algorithm. Our recommendation is to clearly specify the requirement to match the profiles in the standard.

4.3 LOW POWER INSTRUMENT TRANSFORMER AND ITS DIGITAL INTERFACE

4.3.1 Standard

IEC 61869-6 defines the additional general requirement for Low Power Instrument Transformer (LPIT). The digital interface format of IEC 61869-6 is covered by IEC 61869-9 and IEC 61850-9-2. To support the fast-growing market and to further clarify uncertainty with respect to interoperability of the standard, a subset of the standard was developed by experts, named as Implementation Guideline for Digital Interface to Instrument Transformers Using IEC 61850-9-2, generally known as IEC 61850-9-2LE (Light Edition). Through these definitions, the receiver from different vendors can interpret the sample value streams. The implementation of IEC 61850-9-2LE is widely used ever since its publication and is the version used in FITNESS.

4.3.2 Test Setup and Methodology

The test setup includes the following equipment Figure 8 Figure 9:

- Current/voltage source simulators: to simulate the current/voltage.
- The sensor: current/voltage sensors
- MU: receives the proprietary signals from the sensors and publishes IEC 61850-9-2LE streams
- Accuracy Measurement Unit: calculate the accuracy of the sensor under test for protection and metering applications
- Visualization Tool (PC): to provide control and visual measurement results.
- Time Synch: Synchronize all the devices in the setup to avoid the inaccuracy caused by out of synchronization.

Within the accuracy measurement unit, the piece of hardware with high calibration accuracy samples the current/voltage and uses it as the reference. The unit then compares the reference current/voltage with the incoming IEC 61850-9-2 LE signal stream and calculates the magnitude and phase error

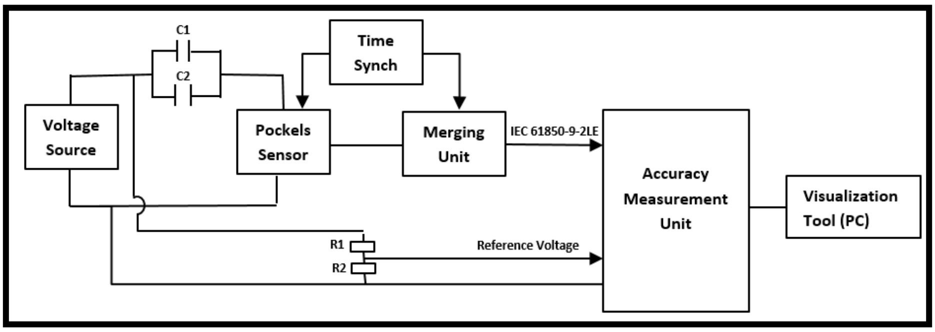


Figure 8: Optical VT offline test setup

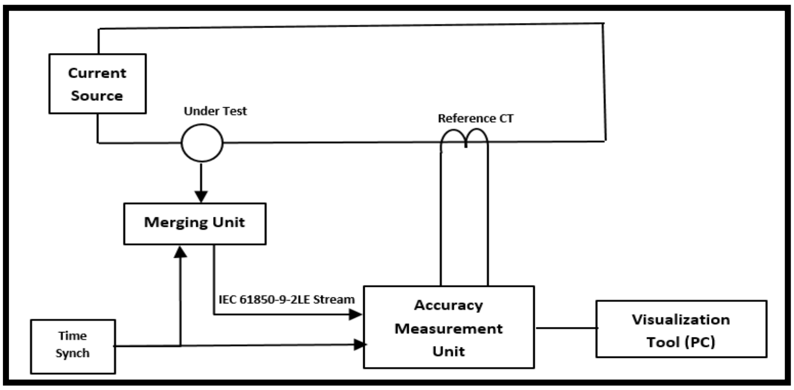


Figure 9: Optical CT offline test setup

4.3.3 Lessons Learnt

In FITNESS LPITs from two vendors have been deployed proving multi-vendor interoperability at process level for protection and control applications as per architecture shown in Figure 1. The same accuracy class level as for a conventional instrument transformer has been applied to LPITs to meet utility specifications for protection and metering purposes. The general applied accuracy class level is 0.2s. For protective current transformer (CT), the typical accuracy level is 5P. For protective voltage transformer (VT), the typical accuracy level is 3P.Accuracy tests were performed at ambient temperature for the accuracy limits class 0.2S according to IEC 60044-8 and 11, Sub. cl. 9.4. Measurements were carried out at 1%, 5%, 20%, 100% and 120% of rated current (2.5 kA) with the extended current factor (1.2). The errors are plotted in two separate graphs, as shown in Figure 10, Figure 11: As it can be seen from the graphs, the sensor head along with its merging unit is compliant with the IEC accuracy class 0.2S for metering and protection applications, according to IEC 60044-8 at a rated current of 2.5 kA and rated frequency 50 Hz.

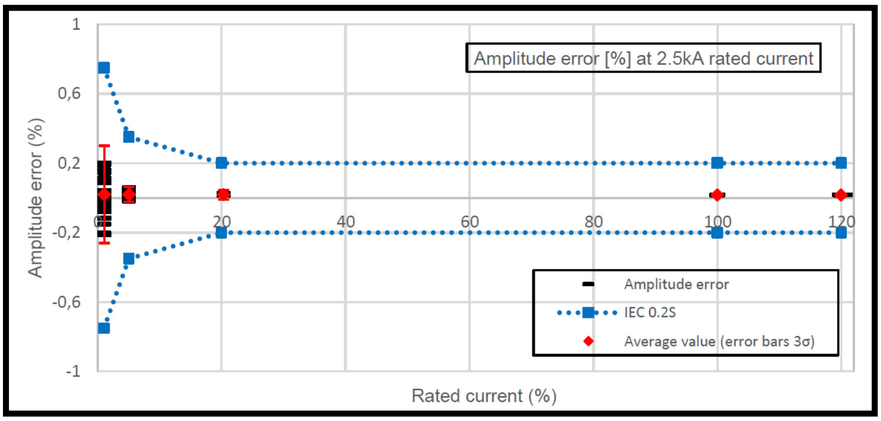


Figure 10: Vendor B Sensor Head Amplitude Error

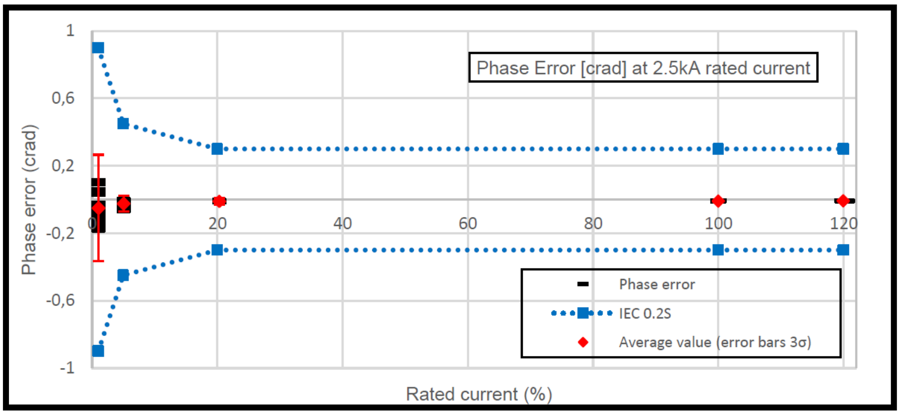


Figure 11: Vendor B Phase Error

4.3.4 Recommendations

Compared with conventional CT/VT, the LPIT is generally composed by two parts – the sensor and the MU. The standards define the measurement accuracy and interface while treat them as a whole. It is noted that the interface between the sensor and the MU is not defined. Thus, generally a specific sensor needs a specific MU compatible with it presently from the same vendor.

4.4 SUMMARY

FITNESS proves that interoperability issues related to SVs, GOOSE and MMS between the chosen vendors have been minimal to none. The only interoperability issues identified are related to integration of different IEDs to the two SCADA systems. The protection performance tests must be conducted in conjunction with network and time synchronisation tests to prove reliability, availability and robustness of the entire system. These tests require specialised test equipment and software tools enabling automated test sequences which are desirable in the context of a digital bay. Once all the information needed for testing is made available in an IEC61850 format, it is a simple procedure to start building up test routines for all conceivable testing scenarios.

The interchangeability in FITNESS has been proven through use of two manufacturer's clocks and integration of vendor A MUs with vendor B IEDs and vice-versa. The redundancy aspects have been tested with PRP and HSR architectures to ensure maximum availability of the entire system.

FITNESS demonstrates that the digital substation technology is ready to be deployed on a larger scale in substations across the world, given right level of collaboration between vendors, utilities and standard bodies exists to timely resolve any issues identified.

5.0 COMMUNICATION ARCHITECTURE OVERVIEW

5.1 Communication Architecture Generalities

As the IEC 61850 standard does not specify what kind of redundancy is required for P&C systems, engineers studied parts of the IEC standard, namely at the IEC 62439 series which deals with "Industrial communication networks – High availability automation networks". IEC Working Group 10 adopted IEC 62439-3 for Parallel Redundancy Protocol (PRP) and High-availability Seamless Redundancy (HSR) as the redundancy method for demanding substation automation networks operating on layer 2 networks, according to IEC 61850-8-1 and IEC 61850-9-2LE. The IEC 62439 specifies two redundancy protocols designed to provide seamless recovery in case of single failure of an inter-bridge link or bridge in the network, which are based on the same scheme - parallel transmission of duplicated information. These are HSR and PRP redundancy protocols. The choice of HSR or PRP, or a combination of both for a substation application depends on the network characteristics and the relative benefits of each protocol.
In the FITNESS project, the architecture is designed with the combination of PRP-HSR, PRP-PRP, HSR-HSR and its merits and demerits were analysed.

5.1.1 PRP network topology

PRP networks can have any topology; for the FITNESS project, a star topology has been selected. The two PRP networks, including the Ethernet switches, must be completely independent: they cannot be connected or bridged together in any way, and they should have separate power supplies as shown in Fig 13. Standard Ethernet switches are used within each PRP network – they are not required to be "PRP-aware" switches.
This redundancy protocol implements redundancy in the nodes rather than in the network using Dual Attached Nodes (DANP). A DANP is attached to two independent Local Area Networks (LANs) of similar topology, named LAN A and LAN B, which operate in parallel. A DANP source (i.e. an IED) sends the same frame over both LANs and a destination DANP receives it from both LANs within a certain time, uses the first frame and discards the duplicate frame. However, a frame could - in exceptional situations - be wrongly rejected as duplicate. Therefore, a mechanism to age out frames is introduced. This ageing mechanism causes in seldom cases that both duplicates are accepted. The duplicate must then be filtered out by the transport layer (e.g. TCP) or tolerated by the application. This is normal, since a LAN does not guarantee absence of duplicates. The ageing mechanism considers both the maximum repetition rate of the frames and the worst-case difference in propagation delay.
A DANP has the same MAC address on both ports and has only one set of IP addresses assigned to that MAC address.

The two LANs can be organised in any kind of topology (tree, ring or meshed), have no connection between them and are assumed to be fail-independent - redundancy can be defeated by single points of failure, such as a common power supply or a direct connection whose failure affects both LANs.

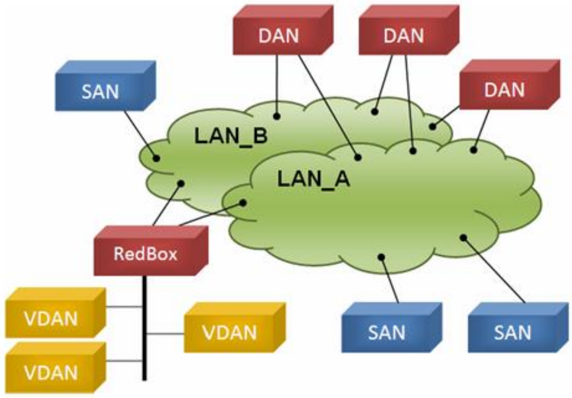


Figure 12. PRP LANs with ring topology according to IEC 62439-3 standard

When designing a PRP based architecture, the following aspects have been considered: -

- The two LANs must have similar properties, i.e. each one is able to carry the traffic that would exist in the absence of redundancy.
- DANP shall be connected to both LANs.
- Single Attached Nodes (SANs) that need to communicate with one another shall be connected to both LANs via a RedBox.
- The two LANs shall use cables distinctly identified as A and B.
- For unicast, both ports A and B of a DANP shall be configured with the same MAC address. This MAC address shall be unique in the network.
- For multicast, all nodes in the network shall be configured to operate with the same multicast address for the purpose of network supervision.
- IP addresses of any node or bridge shall be unique within the whole network (LAN A and LAN B) - uniqueness applies to all IP addresses of a device.
- A DANP shall have the same IP addresses when seen from either LAN A or LAN B.

5.1.2 HSR network topology

HSR networks have a ring topology. Each device is connected to the two immediately adjacent devices only, and so on until a ring is completed as shown in Fig 14 below. An advantage of HSR networks is that Ethernet switches are not required, although having at least one switch may be beneficial for network management and data monitoring. In principle, a simple HSR network consists of dual attached bridging nodes, each having two ring ports, interconnected by full-duplex links, as shown below. A source DANH sends a frame passed from its upper layers ("C" frame), prefixes it by an HSR tag to identify frame duplicates and sends the frame over each port ("A"-frame and "B"-frame). A destination DANH receives two identical frames from each port within a certain interval, removes the HSR tag of the first frame before passing it to its upper layers ("D"-frame) and discards any duplicate. The nodes forward frames from one port to the other, according to the following four rules:

1. A node will not forward a frame that it injected into the ring or mesh.
2. A node will not forward a frame for which it is the unique destination (except for special applications such as redundancy supervision).
3. A port will not send a frame that is a duplicate of a frame that it already sent into that same direction.
4. A port will (optionally) refrain from sending a frame that is a duplicate of a frame that it already received from the opposite direction (except for supervision and timing frames).

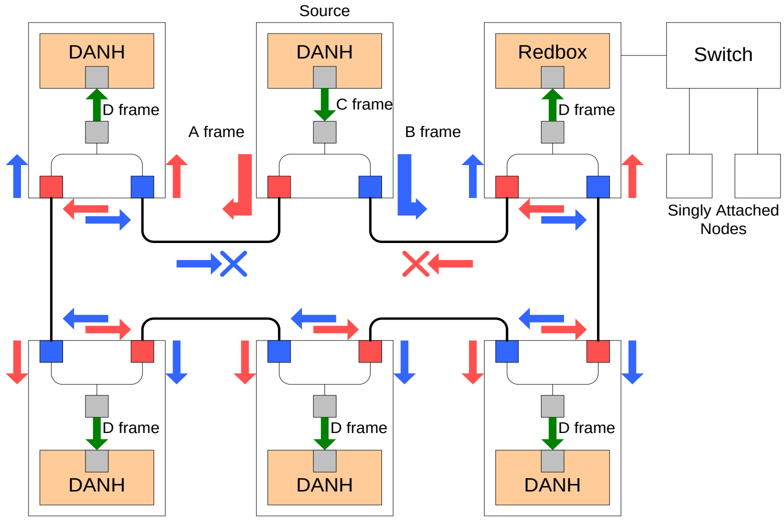


Figure 13. HSR example of ring configuration for multicast traffic according to IEC 62439-3 standard

There are some guidelines for HSR networks provided by the IEC 62439-3 Standard. In brief, these are as follows: -

- All nodes in the ring must be DANH nodes.
- LAN switches cannot be inserted in the ring, as they are a Single Attached Node device.
- Non-HSR devices can be connected only to an HSR ring by using a RedBox / QuadBox, as appropriate.

5.1.3 HSR to PRP Interlink

HSR to PRP interlink is required to convert the HSR frames into PRP network. Interlink redbox converts the HSR frames to PRP as shown in Fig 15. Two interlink boxes are used, one for LAN A and the other for LAN B of the PRP network.

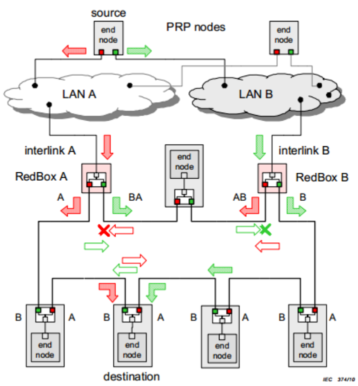


Figure 14. HSR to PRP architecture

5.1.4 Time Synchronisation Overview

Time synchronisation is of paramount importance for the correct operation of all devices on the network. The most demanding network is to be found at process bus level where accuracies as low as 1 microsecond are expected. Going up in the hierarchy of the SAS, the bay level requires accuracies in the range of milliseconds and the station in the range of tens/hundred milliseconds.
Like other important areas within Substation Automation Systems, time synchronisation has developed over the years from a standalone system using its own infrastructure to time sources that send the clock signal directly over the Ethernet network. By doing so, time synchronisation has benefited from a significant reduction of cabling.

The architecture for FITNESS project uses the IEC61850-9-3 (POWER PROFILE) Precision Time Protocol (PTP) - power profile. In PTP networks there must be only one recognised active clock at a time, called the Best Master Clock. If there are two Grandmaster capable clocks on the network (as it is the case in FITNESS project) then a Best Master Clock algorithm ensures that all client devices will synchronise to the same time source. One Grandmaster capable clock will be selected as the Best Master Clock, the other will not send synchronization packets and will takeover in the event the current grandmaster clock fails.

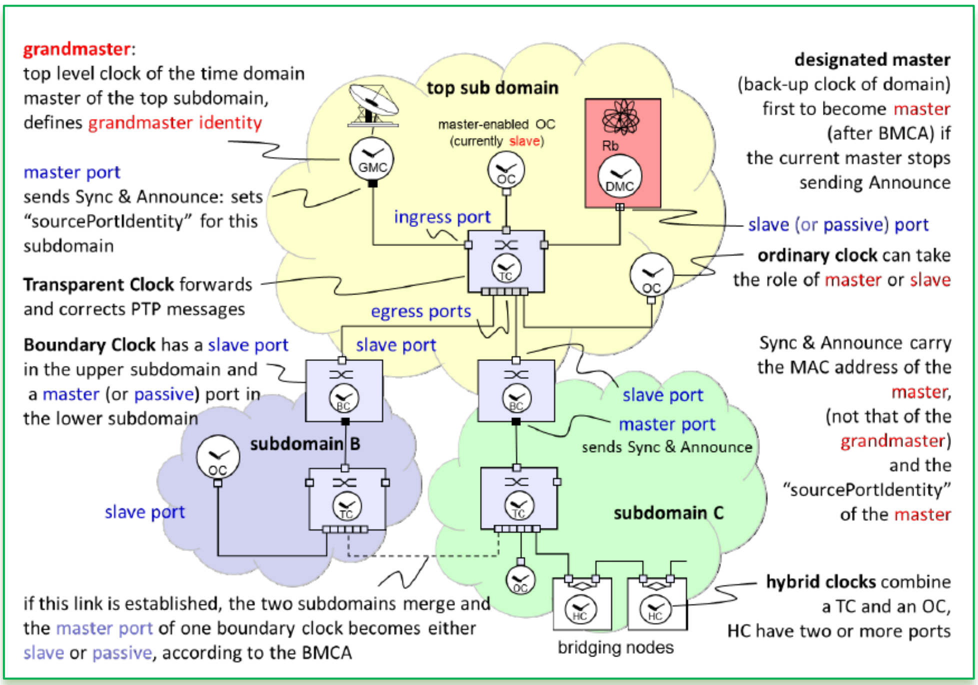


Figure 15. Time Synchronisation Principle according to IEC61850-9-3 (POWER PROFILE)

All components play a role in a PTP network by directly influence the level of accuracy that can be achieved by the clients. Asymmetric network connections degrade the accuracy, therefore classic layer 2 and 3 Ethernet switches with their "store and forward" technology are not suitable for PTP networks and should be avoided.

PTP synchronisation is LAN (Layer 2 Ethernet Mapping) based, multicast addressing using peer-to-peer delay measurement. An important requirement for PTP based systems is that switches (at both station and process bus levels) and IEDs must be able to act as Transparent Clocks (TC) and as Boundary Clock (BC) respectively.

A **Transparent Clock (TC)** is capable of measuring the time taken by a PTP message from the ingress port to the egress port and to add the measured time value to a correction cell in the message. In this way, any delays/asymmetry that the device could introduce in the transfer of PTP messages are corrected. Typically, network switches will act as Transparent Clocks in a network. A TC shall introduce less than 50 ns of time inaccuracy, measured between the applied synchronization messages at any ingress port and the produced synchronization messages at any egress port, provided that it is in steady state.

A **Boundary Clock (BC)** is a multiport device that synchronizes to the reference time provided by a master clock on one port and delivers time on one or more ports. Switches, Redboxes and some IEDs belong to this category. A BC shall introduce less than 200 ns of time inaccuracy between the port in the SLAVE state and any port in the MASTER state, provided that it is in steady state.

An **Ordinary Clock (OC)** is a clock that has a single Precision Time Protocol (PTP) port in a domain and maintains the timescale used in the domain. It may serve as a source of time, i.e., be a master clock, or may synchronize to another clock, i.e., be a slave clock. IEC 62439-3 allows 2 for Ordinary Clocks that are doubly attached. When the OC is the best clock of its subdomain, it becomes the **Grandmaster Clock (GMC).** Its port is in the MASTER state and sends Sync messages to synchronize all slave clocks. Otherwise, its port is in the SLAVE (or PASSIVE) state and it receives synchronization messages.

Hybrid clocks (HC) combine a transparent clock (TC) and an ordinary clock (OC).

5.2 Description of the FITNESS Architecture

As described in the IEC 61850 standards, there are three main communication categories utilised in a digital substation: MMS (Manufacturing Message Specification), GOOSE (Generic Object-Oriented Substation Event) and SV (Sample Values). The MMS is based on client-server communication principle and it covers operational related information, such as control, alarms, indications, etc.

GOOSE and SV are based on publishing-subscribing principle and are used for time critical missions, such as trip commands and analogue data (volts and amps) used by the protection system. In the proposed architecture, at station bus level (LAN "A" and LAN "B") MMS service is utilised, whereas at process bus level SV and GOOSE services are utilised. Elements of power system protection as requested by customer's spec, combined with modern communication technologies enables a robust system architecture organised on three vertical levels, starting from the process level, up to the station / control room level, as described in the next subsections.

Apart from the IEC 61850 the architecture also constitutes PMUs which acquires data on SV but delivers the PMU traffic on C37.118 protocol. The network is combined with IEC 61850 traffic and also C37.118 traffic. Bandwidth calculation played a vital role in defining the architecture.

5.3 System Architecture

The architecture uses Ethernet as the backbone. It implements the IEC 61850 Edition 2 unifying communication standard to facilitate information sharing and interoperability. IEC 61850-8-1 is used for exchanging digital and analogue information over station bus and process bus. Analogue information is transmitted from field devices at process level to the respective IED's using IEC 61850-9-2LE sampled values. The protection IED's use 80 samples per cycle whereas PMU/measurement processes will be based on 80 samples per cycle as well as 256 samples per cycle for comparison and experimentation.

After a series of discussions, ABB adopts PRP topology for Newarthill Circuit 1 and GE adopts HSR topology for Newarthill circuit 2 to establish multi-topology architecture in the interest of innovation. As such, ABB presented the architecture with redundant station bus star-connected at bay level and independent process bus at process bus level whilst GE presented a single ring architecture, connecting all components (IEDs, MUs, SCUs, etc) into one single ring. This is very much in the spirit of this innovation project and SPEN welcomed the idea of trying different bay level architectures. A full Bill of Material (BOM) was presented and agreed that each vendor shall provide the necessary hardware to demonstrate. It was also agreed that regardless of the proposed system architecture, it shall be possible to extend the substation in terms of number of future bays, scalability being an important factor that needs to be considered when designing a system architecture. Once both vendors have completed their preferred system architecture and the associated report, these were assessed by both University of Manchester and 3rd party consultants.
Respective Bay's BMK will be placed in the field, close to the primary apparatus and designed to provide the necessary environmental protection class to all sensitive equipment that it houses inside, as listed in the table below.

5.3.1 Levels of architecture

The architecture is divided into three levels namely Station level, Bay level and Process level.

5.3.1.1. Station Level:

The station level consists of the Human Machine Interfaces (HMI), Communication gateway (GTW), Phasor Controller, station level switches & Grandmaster Clocks. Following tabled the station level equipment.

Device	Function	Type	Manufacturer	Quantity
SAS	DS Agile SCADA system	DS Agile	GE	1
SAS	MicroSCADA system	MicroSCADA	ABB	1
LAN "A"	Station LAN "A"	S2024G	GE	1
LAN "B"	Station LAN "B"	AFS670	ABB	1
CLK1	Station Clock 1	RT430	GE	1
MUL	PPS & IRIG-B Multiplexer	RT411	GE	2
CLK2	Station Clock 2	Meinberg	Meinberg	1
PDC	Phasor Data Concentrator	GE	GE	1

Table 1. Station Level Bill of Material

[redacted]

Figure 16.: FITNESS Station Bus Architecture

5.3.1.2. Bay Level:

Newarthill Circuit 1:

All Protection and Control IEDs, Phasor Measurement Units (PMU) and Ethernet Switches/Redbox at bay level are physically housed in conventional protection and control cubicles and installed in a panel enclosure. The proposed design allows for future bays extension. The bay level for Newarthill 1 circuit consists of:

- First Main protection IED FPFM from ABB (RED670) & Second Main protection IED FPSM GE (MiCOM Agile P546)
- Bay controllers from ABB (REC670) with integrated back-up overcurrent, circuit breaker fail (CBF) and delayed auto-reclose (DAR). There is also a dedicated check synch bus carrying the voltage required for the check-synchronisation.
- 2x Disturbance recorder central unit GE (RPV311). One high sampling rate PMU & Harmonics and one with standard Phasor Measurement Unit (PMU).
- Network switches and RedBox for conversion of SAN to DANP for the devices which doesn't support PRP.

Device	Function	Type	Manufacturer	Quantity
FPFM	Feeder Protection First Main	RED670	ABB	1
FPSM	Feeder Protection Second Main	MiCOM P546	GE	1
BCU	Bay Controller Unit	REC670	ABB	1
LAN "A"	PRP LAN "A"	AFS670	ABB	1
LAN "B"	PRP LAN "B"	AFS670	ABB	1
PMU-1	Fast Phasor measurement Unit & Harmonics	RPV311	GE	1
PMU-2	Phasor Measurement Unit	RPV311	GE	1
Daneo	Network Analyser	DANEO	Omicron	1
DA-INT	Synaptec Interrogator		Synaptec	1

Table 2 Newarthill Circuit 1 Bay Level Bill of Material

[redacted]

Figure 17 - Newarthill Circuit 1 Bay level architecture

Newarthill Circuit 2:

All Protection and Control IEDs, Phasor Measurement Units (PMU) and Ethernet Switches/Redbox at bay level are physically housed in conventional protection and control cubicles and installed in a panel enclosure. The proposed design allows for future bays extension.

The bay level for Newarthill 2 circuit consists of:

- First Main protection IED FPFM from GE (MiCOM Agile P546) & Second Main protection IED FPSM ABB (RED670)
- Dedicated Backup IED GE (MiCOM Agile P841) for overcurrent, circuit breaker fails (CBF) and delayed auto-reclose (DAR).
- Bay controllers from GE (C264)
- 2x Disturbance recorder central unit GE (RPV311). One high sampling rate PMU & Harmonics and one with standard Phasor Measurement Unit (PMU).
- 1x Disturbance recorder unit ABB (RES670) acting as PMU
- Network switches and RedBox for conversion of SAN to DANH for the devices which doesn't support HSR.
- Quadbox for coupling HSR-HSR coupling for sharing the bus voltage to multiple bays including provision for future expansion.

Device	Function	Type	Manufacturer	Quantity
FPFM	Feeder Protection First Main	MiCOM P546	GE	1
FPSM	Feeder Protection Second Main	RED670	ABB	1
BU	Backup Protection Unit	P841	GE	1
BCU	Bay Controller Unit	C264	GE	1

Redbox	SAN-DAN Redbox	H49	GE	4
Redbox	Interlink Redbox (HSR-PRP)	H49	GE	2
Redbox	Quadbox (HSR-HSR)	H49	GE	1
PMU-1	Fast Phasor measurement Unit & Harmonics	RPV311	GE	1
PMU-2	Phasor Measurement Unit	RPV311	GE	1
PMU-3	Phasor Measurement Unit	RES670	ABB	1
Daneo	Network Analyser	DANEO	Omicron	1
DA-INT	Synaptec Interrogator		Synaptec	1

Table 3 Newarthill Circuit 2 Bay level Bill of Material

[redacted]

Figure 18 - **Newarthill Circuit 2 Bay level architecture**

5.3.1.3. <u>Process level:</u>

The process level consists of the:

- Switchgear Control Units (SCU) from ABB on bay 1 & GE on Bay 2,
- ABB LPIT Merging units SAM600TS, SAM600CT and SAM600VT
- LPIT, Standalone Merging Unit GE Stand Alone Merging Unit (SAMU; MU320) on one bay and a GE merging unit (XMU320) interfacing with non-conventional CT and VT (CTO and VTO),
- Optical distributed measurement units from Synaptec,
- GE RA331 which is the high rate acquisition unit for conventional CT/VT and processed by for the RPV311.

In Newarthill Circuit 1, GE has deployed 2 sets of 3 Phase Low Power Instrument Transformer (LPIT) one for CT & the other LPIT for VT. Armoured Fibre optic cable layed through the cable trench and is used as the medium of connectivity between LPIT and the XMU860 Merging unit. The XMU860 is housed in Bay marshalling Kiosk (BMK) of Newarthill 1 circuit. XMU860 generates the IEC 61850-9-2LE. Merging unit utilises PTP time synchronisation additionally PPS if necessary.

In addition to the LPIT solution, conventional CT, VT merging unit is also housed in the BMK through which acquires the Current & Volts from the conventional CT & VT in turn the Merging unit delivers the IEC 61850-9-2LE. Whilst LPIT is GE manufactured, ABB manufactured Standalone Merging Unit is used for conventional measurements. Hence delivering 2 independent SV streams from different sources. The utilisation of these streams is discussed in Bay Level section.

Device	Function	Type	Manufacturer	Quantity
MU1	Optical CT & VT Merging Unit - Protection	XMU860	GE	1
MU2	Optical CT & VT Merging Unit - Measurement	XMU860	GE	1
MU3	Stand Alone Merging Unit	SAM600TS	ABB	1
MU4	Stand Alone Merging Unit - CT	SAM600CT	ABB	1
MU5	Stand Alone Merging Unit - VT	SAM600VT	ABB	1
SCU1	Switchgear Control Unit 1	REC670	ABB	1
SCU2	Switchgear Control Unit 2	REC670	ABB	1
DA	PMU Data Acquisition Unit	RA331	GE	1
SU	Sensor Unit		SYNAPTEC	1

Table 4 Newarthill 2 Process level Bill of Material

[redacted]

Figure 19– Newarthill Circuit 1 Process level architecture

In Newarthill Circuit 2, Low Power Instrument Transformer (LPIT) were used to digitally connect them to the IEDs via Merging Units. ABB UK has deployed its FOCS optical CT technologies, connected via fibre-optic to the Optoelectronic Module (OEM), housed in the Bay Marshalling Kiosk (BMK). A Voltage Transformer (conventional VT from a measuring principle point of view) is installed on the line side of the circuit. Its output is hardwired into the SAM600VT merging unit housed in the same BMK. It is here where the final IEC 61850-9-2 LE stream is generated, by merging the measurements provided by the OEM unit (for current) and SAM600VT unit (for voltage) via SAM600TS unit. The SAM600TS unit is also responsible for time synchronising the whole chain of merging units and providing, where necessary, the PPS signal.

Same alike Newarthill Circuit 1, in addition to the LPIT solution, measurements from conventional CT & VT is acquired by Standalone Merging Unit (SAMU). In Circuit 2 GE manufactured Standalone Merging unit-MU320 is used. The MU320 can accommodate 3 Phase CT & 3 Phase VT and thus, generates the IEC 61850-9-2LE streams for protection. MU320 is also time synchronised on PTP.

Device	Function	Type	Manufacturer	Quantity
MU1	Optical CT - Optoelectronic Module	OEM	ABB	1
MU2	Stand Alone Merging Unit - VT	SAM600VT	ABB	1
MU3	Stand Alone Merging Unit – Time Synch	SAM600TS	ABB	1
MU4	Stand Alone Merging Unit - CT & VT	MU320	GE	1
SCU1	Switchgear Control Unit 1	C264	GE	1
SCU2	Switchgear Control Unit 2	C264	GE	1
DA	PMU Data Acquisition Unit	RA331	GE	1
SU	Sensor Unit		SYNAPTEC	1

Table 5. Newarthill 1 Process level Bill of Material

[redacted]

Figure 20– Newarthill Circuit 2 Process level architecture

[redacted]

Figure 21. Primary Equipment Interaction with Secondary Equipment on Newarthill 1 circuit

[redacted]

Figure 22. Primary Equipment Interaction with Secondary Equipment on Newarthill 2 circuit

5.3.1.4. Bus Voltage Interconnection Ring

In order to share the selected bus voltage across both Newarthill circuit 1 & 2 a dedicated Standalone Merging unit (GE MU320) is housed in wallbox cabinet. This MU320 generates a single SV stream for both bus voltages. The selection of bus voltage is computed at the IED.

To share the bus voltage SV streams across both bays and to extend the provision for future extension of bays, the architecture provides an additional & independent 100Mbps High availability seamless redundancy ring which is interlinked with the existing architecture for both Newarthill Circuit 1 & Circuit 2.

For Newarthill 1 circuit the Redbox converts the HSR to a single attached node (SAN) and connects to the Process bus switch (PB2) feeding sampled values to the control IEDs

Circuit 2 being 1 Gbps HSR, it additionally interconnects this 100 Mbps HSR by Quadbox. The Quadbox couples both HSR rings of different bandwidth and shares the bus voltage sampled value streams in circuit 1 control IED for synchronisation.

[redacted]

Figure 23. Bus Voltage Interconnection Architecture Circuit 1 & 2

5.3.2 Architecture Design Considerations

5.3.2.1. Bandwidth and Latency

A digital substation requires a robust and reliable design of the communication network to be used for schemes based on IEC 61850. This requires the consideration of bandwidth requirements and latencies caused by various network elements.

An IEC 61850 GOOSE message has a typical size between 92 bytes to 250 bytes. One GOOSE application in an IED generates about 1 Kbit/s in steady state and 1 Mbit/s during bursts. An SV frame with a sampling rate of 80 samples per cycle transmitted at 4.0 kHz (for a 50 Hz grid) has an approximate size of 140 bytes, consuming a bandwidth of approximately 5 Mbit/s per source IED per SV stream. PTP as defined for power system applications (in C37.238 or 9-3) publishes once per second and has a bandwidth comparable to steady state GOOSE messages.

The FITNESS system architecture is designed for data transfer latency requirements in IEC 61850-90-4 Technical Report to meet the substation automation functional requirements. For example, the most time critical messages, the trip and blocking signals from the protection function category, need to meet the 3ms transfer time for adequate performance.

In FITNESS, the station bus switches are capable of handling 1Gbit/s traffic. Due to adequate traffic segregation on the process bus, switches PB1 and PB2 in the PRP bay can use 100Mbit/s communication network links as this speed is adequate to handle the network traffic.

The HSR ring has no physical traffic segregation and handles 3x 80 samples/cycle and 3x 256 samples/cycle SV streams, leading to a constant bandwidth requirement of 60 Mbit/s, primarily from SVs. In order to avoid network traffic overload and ensure the required level of performance of critical protection and control functions a 1 Gbit/s link was deployed. The 100Mbit/s communication port interface available on various process bus compliant IEDs in the market posed a serious limitation to this approach, a Redbox per IED was required to convert the 1Gb data stream to 100Mb data stream. These redboxes are configured as multicast boundaries enabling filtering of SV streams to prevent unintended multicast traffic beyond specific recipients for optimal network performance. As newer IED's are released with 1 Gbit/s HSR ports, this Redbox will not be required.

5.3.2.2. Traffic Segregation

Physical Segregation

In FITNESS, communication network traffic segregation is applied between bays, with each bay separable from the station bus switches and the corresponding bay level connections ILA and ILB in the Newarthill circuit 2 and PRP–A and PRP-B in the Newarthill circuit 1. There is also physical traffic segregation between the bay level and process bus level traffic in the PRP bay through use of redundant bay level switches PRP-A and PRP-B and process bus level switches PB-1 and PB-2. The HSR bay is designed as combined bay and process level hence physical traffic segregation is not envisaged between the bay and process level.

VLAN Filtering

VLAN is adopted to segregate the traffic that share the medium. VLAN reduces the traffic on edge links so that subscribing IEDs are not flooded with messages which are on blocked VLAN. To support VLANs, the IEEE 802.3 frames carry a header, called the VLAN tag according to IEEE 802.1Q, which has two functions: prioritization of traffic and logical segregation of the traffic. In FITNESS VLAN filtering is primarily used in the HSR ring to separate GOOSE and SV streams onto different virtual LANs at the Redbox 100Mbit/s link single attached nodes connecting to IEDs which doesn't support 1 Gbps interface. VLAN filtering is also used at bay level switches ILA, ILB, PRP-A and PRP-B switches on both bays to allow transmission of inter-bay GOOSE and filter out any bay specific GOOSE.

Multicast Filtering

Multicast address filters limit the distribution of multicast addressed frames (GOOSE, SV & PTP) to the subscriber ports that require the data, rather than simply transmitting the frame to all ports. This was achieved through static filtering, defined through the management interface of network devices. In FITNESS, each SV stream and GOOSE control block were defined with unique Multicast addresses which were used to classify the availability of these frames on dedicated interfaces. Multicast filtering is primarily used in the HSR ring to only filter through the SV stream subscribed by the connected IED at the 100MB interface of Redbox.

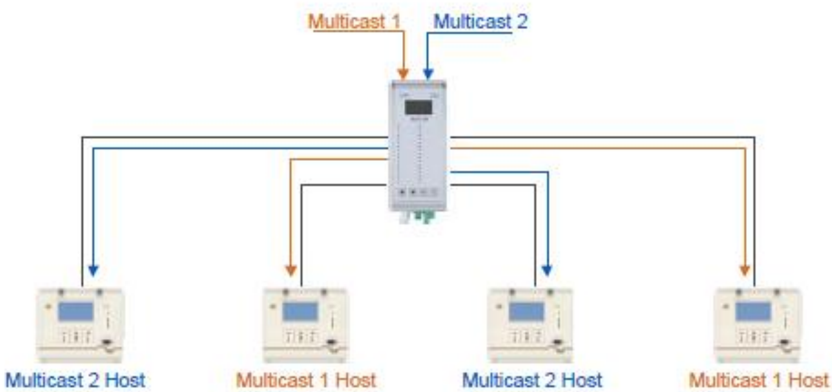


Figure 24. Multicast Filtering

As a best practice, two levels of traffic segregation are recommended. The first is through the use of VLAN filtering (802.1Q) to prioritise the protocols and their application, and the second level is to use multicast address filtering (802.1D) to limit the flow of information within the particular VLAN. Some VLANs may not require any multicast filtering, in which case multicast frames will be handled as if they were broadcast frames but restricted to that VLAN. This approach is consistent with the draft Network Engineering Guidelines that has been published as IEC TR 61850-90-4.

Time Synchronisation

For the FITNESS project, the time synch architecture comprises two GPS based Master Clocks (one GE and one Meinberg), acting as Grandmaster Clocks, directly connected to the two station LAN switches on PRP, configured to act as Transparent Clocks as shown in figure 26. From station level, the clock signal is transferred to the bay level switches, configured as Boundary Clocks.

These devices participate in selecting the best master clock and can act as the master clock if no better clocks are detected. The boundary clock mitigates the number of network hops and results in packet delay variations in the packet network between the Grandmaster and Slave. This enables the synchronisation of SCUs & Merging units present in Process level.

In order to ensure availability and reliability of the time synchronisation throughout the architecture,

1. Both GE & Meinberg GMC acquire time from GPS & GLONASS.
2. Both the GMC are connected on PRP

The time synchronisation is designed to operate as follows:

- ✓ The best-known clock on the system became the Best Grandmaster Clock (BGMC).
- ✓ The other MC clock went into passive mode.
- ✓ All devices (IEDs, switches and Merging Unit) had the same time as the BGMC.
- ✓ All (IEDs, switches and Merging Units) shown a synch locked indication.
- ✓ All (IEDs, switches and Merging Units) shown the Grandmaster identity (the same BGMC).
- ✓ When the current grandmaster clock went down, the passive clock was elected and became the new grandmaster.

The behaviour of the overall system was in line with the IEC61850-9-3 standard - the switching between the two Grand Master Clocks was seamless under multiple failover test scenarios (GPS and non-GPS conditions). The Merging Units – the most demanding device when it comes to PTP synchronisation - exhibited a much better holdover time than the one specified in the standard (minimum 5 sec).

The combined architecture for FITNESS project has been updated to classify the Boundary clock (BC) and transparent clock (TC) respectively based on the following:

1. The H49 units used for the Interlinks, marked “IL-GE” on the drawing should be a BC as per the recommendation for a PRP/HSR interface in the IEC 62439-3 standard.
2. Rest all IEDs/switches/Redbox can be a TC
3. Process Level switches at Newarthill circuit 1 “NS-ABB (PB1)” and “NS-ABB (PB2)” should certainly both be TC, as they are connected directly to grandmaster clocks.
4. Bay level switches at Newarthill circuit 1 “NS-ABB (PRP ‘A’)” and “NS-ABB (PRP ‘B’)” could be either BC or TC. However, it is recommended that they are TCs, as this means that the other switches and IEDs below in the PRP network of Circuit 1 will get their sync directly from the grandmaster and this will facilitate the accuracy. The argument for using BC here is that it would reduce the multicast traffic on the PRP network, but in this small network it is not a significant gain.
5. While connecting a RedBox (HSR/PRP) to SAN, then the recommendation is to configure as a TC.

[redacted]

Figure 25. Time Synchronisation for Newarthill circuit 1 & 2 circuit covering station and process bus

5.3.2.3. Description of data streams

The following data streams are passed around the architecture. Summarised descriptions of each stream are given below.

IEC61850-8-1: GOOSE messages are used to exchange status information in addition to protection trips and controls to plant equipment. Field devices will perform the acquisition and send fast information typically SPS (Single Point Status) and DPS (Double Point Status) to bay level IEDs. Bay level IEDs will send trip GOOSE and command GOOSE messages to field IEDS. Bays IEDs can also exchange GOOSE messages for any automation purpose such as CBF initiation or auto-reclose blocking.

IEC61850-9-2LE: The bay level IED's receive the voltage and current information from the conventional and non-conventional CT's and VT's by sample values from the merging units at 80 and 256 samples per cycle. Protection relays are using 80 samples per cycle whereas 256 samples per cycle are used for Power quality features.

IEEE C37.118: These messages are used for wide area monitoring and control application located at station level or higher level. PMU frame are generated by the RPV311. RPV 311 will read sample values from MUs or SAMU and convert it to IEEE C37.118 to exchange phasor information between the station level and bay level measurement IED's.

IEC61850-9-3 (POWER PROFILE): GE's RT430, RT431 and Meinberg GPS at the station level are connected to the individual GPS antennas. GPS clocks convert the timing information into the IEC61850-9-3 (POWER PROFILE) format and transmit this over the Ethernet on the station bus and process bus. This information is used by IED's for sampled value and event time synchronisation.

1PPS: One pulse per second signal is available for the sampled value synchronisation and differential function.

IRIG-B: IRIG-B signal is available for synchronisation of GE PMUs (RPV311).

The figures below show the simplified version of how the data streams are passed around the architecture on Newarthill 1 & 2 circuits.

Newarthill 1 Circuit

[redacted]

Figure 26. Process Bus Subscriptions for Newarthill Circuit 1

Newarthill 2 Circuit

[redacted]

Figure 27. Process Bus Subscriptions for Newarthill Circuit 2

5.3.2.4. Control system Engineering

Multi-vendor interoperability is extended to SCADA system. The project is designed to facilitate realtime monitoring & control of primary & secondary electronic equipment (IEDs) and field equipment of both circuits proving interoperability at the control system hierarchy with DS Agile SCADA from GE & ABB's Microscada operating in parallel.

DS Agile gateway facilitates IEC 60870-5-101 & IEC 60870-5-104 communication to the remote-control centres as per SPEN protocol requirements. The gateway communicates on IEC 61850 Edition 2 from all IEDs of Newharthill 1 & 2 and provides data to the remote-control centres utilising the above tele-control protocols. Gateway communications are tested locally using a Master simulator.

The IEDs support for multiple IEC 61850 clients are used to report independent RCB to both SCADA system & DS Agile Gateway.
The following mimics illustrate the capabilities and level of interoperability achieved from DS Agile control system.

Substation System Overview

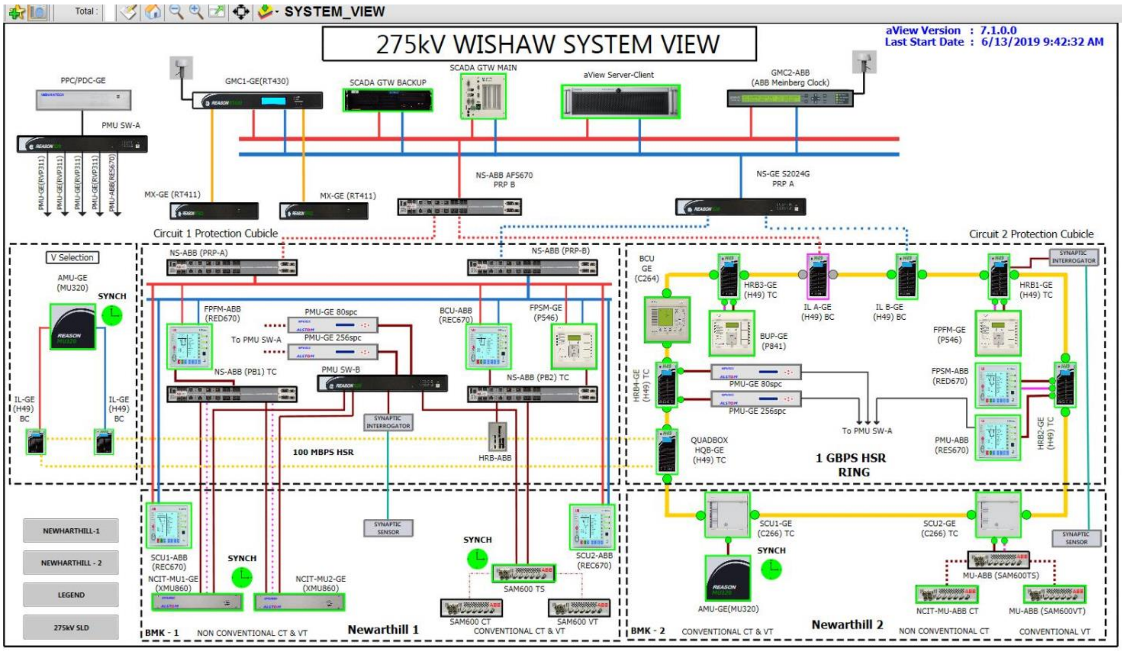


Figure 28. Overall System Overview on DS Agile SCADA system Newarthill circuit 1 & 2

Newharthill 1 Circuit detailed view

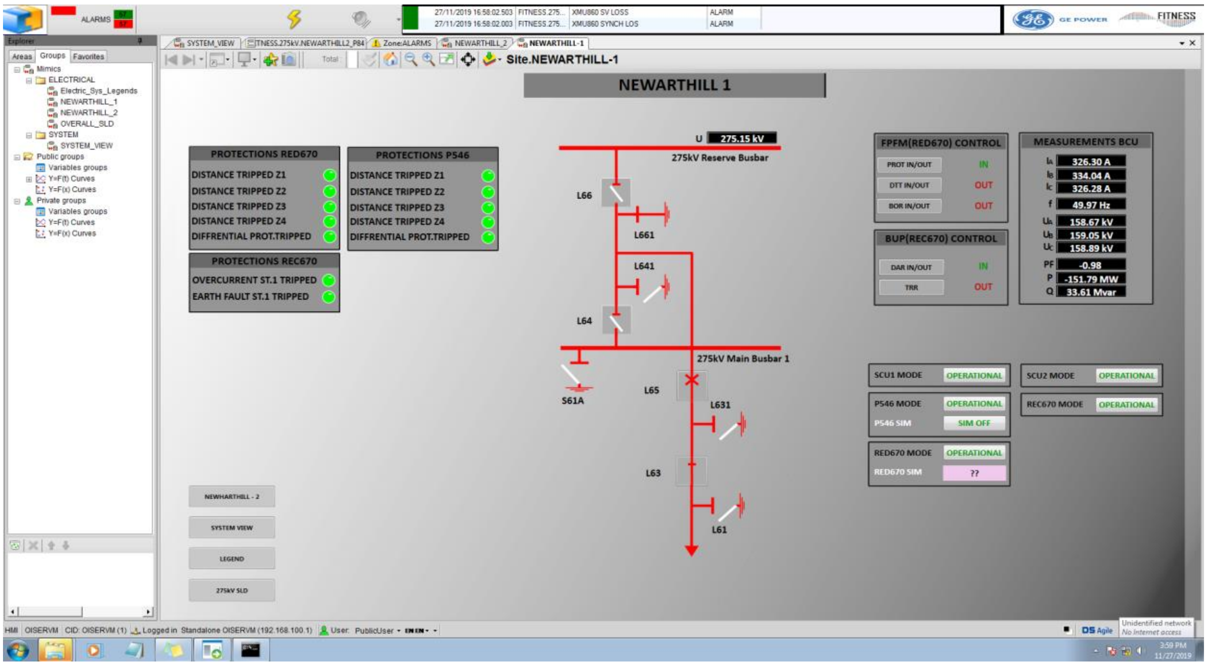


Figure 29.

Detailed Bay view of Newarthill circuit 1

Newharthill 2 Circuit detailed view

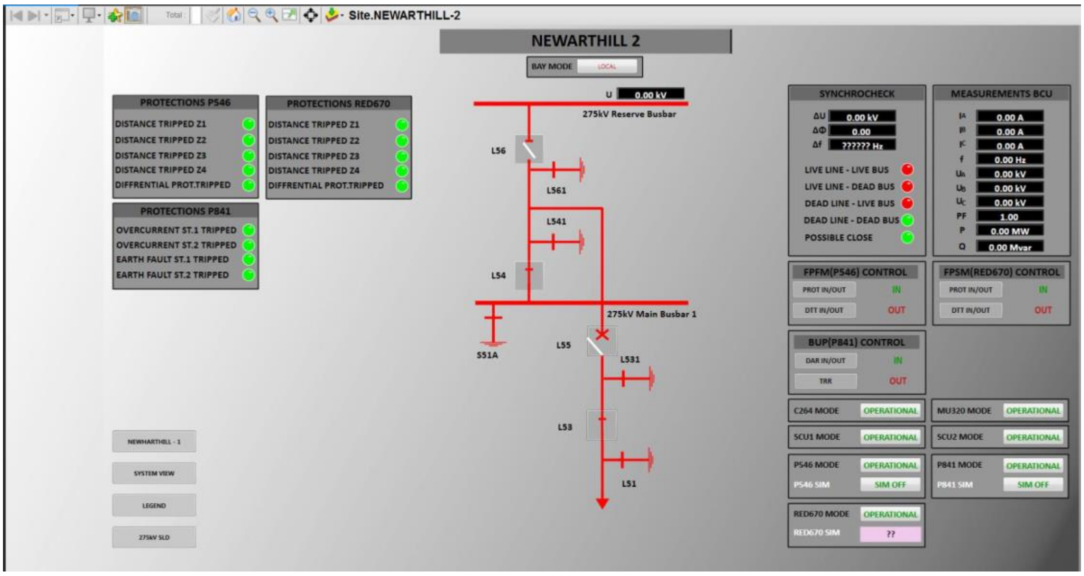


Figure 30. Detailed Bay view of Newarthill circuit 2

Event & State View

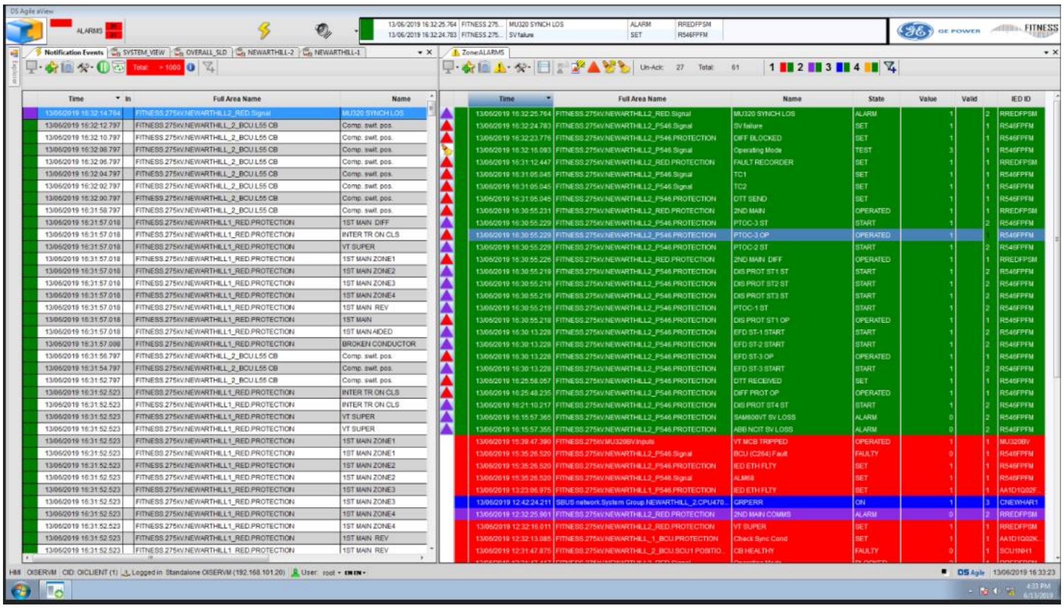


Figure 31. Events, Stated & Alarm view of Example Circuit

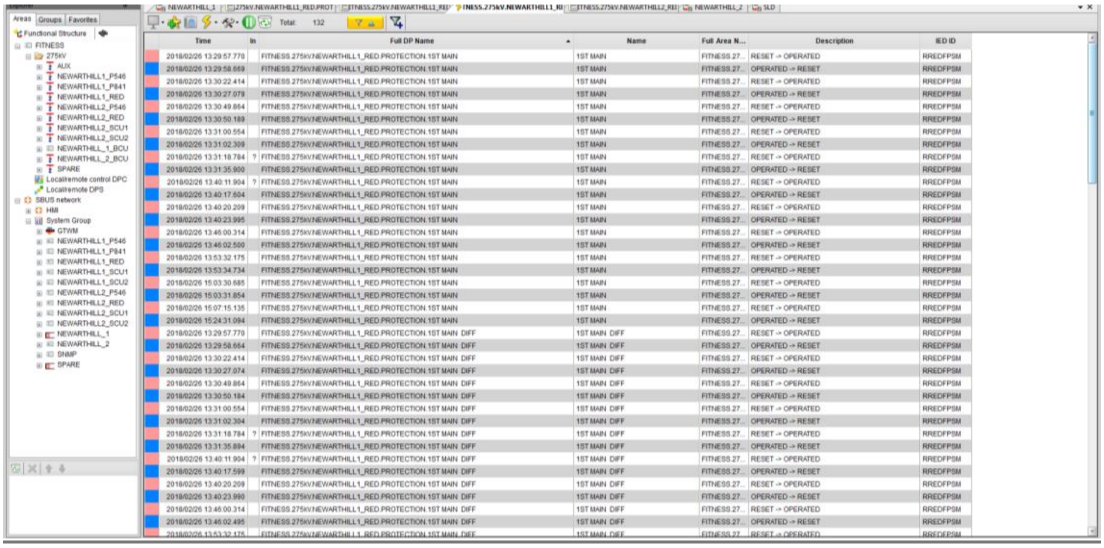


Figure 32. Realtime Events view of Example IED

Gateway Configuration

The architecture is designed with two DS Agile Gateways acting on Hot-Hot redundant mode, each of these Gateways will have IEC 60870-5-101 ports & IEC 60870-5-104 ports (OCC Main and OCC Standby). At any given time, only one of the Gateways is "ACTIVE". Only the ACTIVE gateway responds to any T101 & T104 interrogations on either of its ports. The port it is communicating on is determined by the Master station, hence the reason for the comms splitters on each channel. The PASSIVE Gateway, whilst operational on the station bus and communicating with the ACTIVE for updates etc, is silent in terms on tele-control protocols, it's listening but not responding whilst in the PASSIVE state. Only when it becomes ACTIVE will it respond to IEC 60870 interrogations. It can only become ACTIVE if we choose it to be ACTIVE or if the previously ACTIVE Gateway fails in its critical functions (failure to communicate with IED's etc).

A single queue should be maintained not only across the Dual IEC 60870 ports on an individual Gateway, but also across the Dual ports on the Dual Gateways. Currently, the system we have demonstrated has the ACTIVE Gateway determined by the IEC 60870 communications activity.

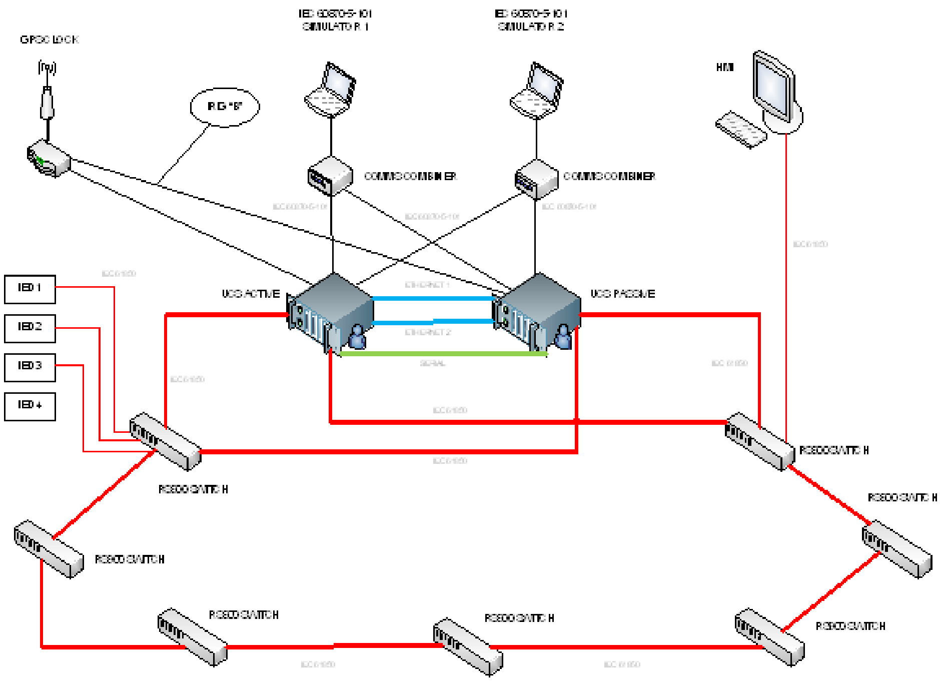


Figure 33. Gateway Topology as per SPEN specification.

5.3.3 Advantages of the proposed design

There is a standard configuration for each IED, including standard protection, control and monitoring logical nodes, and pre-processing function blocks. Subject to the application (conventional or non-conventional instrument transformers), the application engineer would need to map the analogue signals to either the built-in Analogue to Digital Measurement (ADM) card or to the external Merging Unit. The advantages of a complete fibre-based P&C system over a conventional system are:

- Simplified and standardised bay / station design.
- Elimination of copper-based interface, for both plant as well as station related signals.
- Much faster installation, testing and commissioning, thus well fitted for short outages.
- Increased health and safety to personnel, as the open CTs risk is no longer an issue to fibre-based systems.

IEC61850 requires a good understanding of system engineering. Both ABB and GE carried out system engineering within their own bays, integrating their own IEDs, as well as 3rd party IEDs. Right from the onset both vendors exchanged .icd files. System exchange description files (.sed file) were used to integrate the two bays into the station (.scd file).

5.3.4 Design Considerations for future Digital Substation

Intensive and several phases of testing were performed throughout the phase of project where we could gather many lessons learnt. Few are discussed as follows.

1. SV are tagged in accordance to the level of GPS synchronisation on per sample basis and are not frequency tracked. The merging units do not store a record of the sampled values published on to the network. Furthermore, the IED's may not record the raw SV data. Hence, tagging or other information in the SV frame may be lost. Therefore, it may be considered necessary to have an independent network monitoring/acquisition device to store the raw network traffic to enable detailed analysis if required.
2. Considering the above point Omicron DANEO could able to function as the network analyser which were permanently deployed one in Newarthill Circuit 1 & 2
3. HSR being a ring topology optimizes the installation time, as fewer fibre optic connections and less Ethernet switches are required compared with PRP. However, availability of the HSR for the designed bandwidth will be a key aspect. The increased number of Redboxes, increases the points of failure on the communication.
4. The 100Mbit/s communication port interface available on various process bus compliant IEDs in the market posed a serious limitation to this approach requiring a Redbox per IED converting the 1Gb data stream to 100Mb data stream.
5. In PRP networks, failure of an IED or the addition of new IED's has minimal impact on other IED's and the redundancy of the network; all other IEDs still send and receive data on two different network paths. However, more fibres and connections are necessary to extend a PRP network than an HSR network.
6. Regardless of PRP or HSR topology, implementation of suitable filtering mechanisms will optimise the traffic on the network.
7. Bandwidth estimation also plays a major role on architectural design.

5.4 Protection & Control Implementation

5.4.1 General

Local end (Wishaw Substation):

As described in the Communication Architecture and Design section, the architecture proposed for Newarthill 1 circuit encompasses ABB and GE IEDs. The ABB IEDs were connected to non-conventional GE CTs/VTs via GE merging units, whilst GE IEDs were connected to conventional CTs/VTs via ABB hardwired merging units. The architecture proposed for Newarthill 2 circuit (see Figure 24) encompasses ABB IEDs (Redbox 670) and GE IEDs (Micom P546). GE IEDs were connected to non-conventional ABB CTs/VTs via ABB merging units, whilst ABB IEDs were connected to conventional CTs/VTs via GE hardwired merging units. Switchgear controls, alarms and indications at bay level were handled directly by the two Switching Control Units (SCUs). On Newarthill 1 circuit, the two SCUs were provided by ABB, whilst on the 2nd cct, the SCUs were provided by GE. The scope of this mixed arrangement was to demonstrate the interoperability at various levels: process bus level, bay station level, SCADA level.

Remote end (Newarthill Substation):

At Newarthill end, on both circuits, ABB and GE IEDs derive their analogue quantities from conventional CTs/VTs. At Wishaw end, ABB provided 2 panels, whilst at Newarthill end ABB provided one panel for both FPFM and FPSM. CT summation was employed at Newarthill end (summating Newarthill phase currents with Coatbridge phase currents which were available at Newarthill end). Both FPFM and FPSM were hardwired into the existing conventional CTs / VTs. Unfortunately, at Newarthill end Wishaw 2 cct there are no VTs, therefore, the distance protection within FPFM/FPSM was not provided at Newarthill end, but at Wishaw end only.

5.4.2 Newarthill 1 Circuit Implementation

Once the architecture was agreed, the implementation of the protection and control was carried out in line with current SPEN specifications. Protection and control functions were allocated to each device, as depicted in the tables below:

BUP & BCU REC670 (ABB) - Technical Key: AA1D1Q02KF1 – IP Address: [redacted]		
SPEN Function	**Logical Node**	**Selection**
Backup O/C Protection (note 3)	OC4PTOC:1	Yes
Backup E/F Protection (note 3)	EF4PTOC:1	Yes
Delayed Auto Reclose	SMBRREC:1	Yes
Check and System Synchronising	SESRSYN:1	Yes
Voltage Selection	N/A (Logic)	Yes
Trip Relay Reset	N/A (Logic)	Yes
Bay Control	SXCBR:1, SCSWI:1-9, SXSWI:1-8	Yes
1st Trip Circuit Supervision		No*
2nd Trip Circuit Supervision		No*
Phase Unbalance/Open Circuit Detection	BRCPTOC:1	No**
Analogue telemetering	CVMMXN:1, CMMXU:1, VNMXU:1	Yes
Disturbance Recording and Oscillography	DRPRDRE:1	Yes
CB Fail Protection	CCRBRF:1	Yes
VT Supervision (FUSE Failure)	FUFSPVC:1	Yes
FPM1 RED670 (ABB) – Technical Key: AA1D1Q02FN1 – IP Address: [redacted]		
SPEN Function	**Logical Node**	**Selection**
Main Protection 1 Differential	L6CPDIF:1	Yes
Main Protection 1 Distance	ZMFPDIS:1	Yes
Protection Signalling	ZC1PPSCH:1	No
1st Intertrip	via LDCM 305	Yes
1st Trip Circuit Supervision (note 1)	N/A*	No
Phase Unbalance/Open Circuit Detection (note 2)	BRCPTOC:1	Yes
Backup O/C Protection 1 (note 3)	OC4PTOC:1	No
Backup E/F Protection 1 (note 3)	EF4PTOC:1	No
STUB Bus Protection	STBPTOC:1	Yes
Disturbance Recording and Oscillography	DRPRDRE:1	Yes
SOTF Protection	ZCVPSOF:1	Yes
VT Supervision (FUSE Failure)	FUFSPVC:1	Yes
Fault Locator	LMBRFLO:1	Yes
VT Supervision (FUSE Failure)	FUFSPVC:1	Yes

Table 6 List of Functions BCPU

Note 1: Not included in FITNESS design. However, some possible solutions were discussed.

Note 2: Phases Unbalanced duplicated in FPM1 and FPM2

Note 3: BU O/C and E/F protection configured in both FPM1 and FPM2as well as in BCU. However, it is the BCU where BU O/C and E/F functions are actually enabled.

FPM2 P546 (GE) – Technical Key: AA1D1Q02FN2 – IP Address: [redacted]		
SPEN Function	**Logical Node**	**Selection**
Main Protection 1 Differential	DifPDIF1	Yes
Main Protection 1 Distance	DisPDIS1	Yes
Protection Signalling	GosGGIO2/ind27	No
1st Intertrip	GosGGIO2/ind15	Yes
1st Trip Circuit Supervision (note 1)	N/A	No
Phase Unbalance/Open Circuit Detection (note 2)	GosGGIO2/ind19	Yes
Backup O/C Protection 1 (note 3)	OcpPTOC1	No
Backup E/F Protection 1 (note 3)	EfdPTOC1	No
STUB Bus Protection	GosGGIO2/ind13	Yes
Disturbance Recording and Oscillography	GosGGIO2/ind20	Yes
SOTF Protection	GosGGIO2/ind26	Yes
VT Supervision (FUSE Failure)	GosGGIO2/ind29	Yes
Fault Locator	GosGGIO2/ind27	Yes

Table 7 List of Functions FPM1

5.4.3 ABB IED Access Points Configuration

An access point is an Ethernet communication interface for single or redundant station communication. Two physical Ethernet ports were allocated for station bus where redundant communication was enabled, whilst a single port was utilised for the process bus. The access points are also used for time synchronization using Precision Time Protocol (PTP). The settings for the access points are configured using the Ethernet configuration tool (ECT) in PCM600. The access point is activated if the *Operation checkbox* is checked for the respective access point and a partial or common write to IED is performed. To increase security, it is recommended to deactivate the access point when it is not in use.

Redundancy and PTP cannot be set for the front port (Access point 0) as redundant communication and PTP are only available for the rear optical Ethernet ports. Subnetwork shows the SCL subnetwork to which the access point is connected. This column shows the SCL subnetworks available in the PCM600 project. SCL subnetworks can be created/deleted in the Subnetworks tab of IEC 61850 Configuration tool in PCM600. When saving the ECT configuration after selecting a subnetwork, ECT creates the access point in the SCL model. Unselecting the subnetwork removes the access point from the SCL model. This column is editable for IEC61850 Ed2 IEDs and not editable for IEC61850 Ed1 IEDs because in IEC61850 Ed1 only one access point can be modelled in SCL. The IP address can be set in IP address column. The ECT validates the value; therefore, the access points have to be on separate subnetworks.

The subnetwork mask can be set in Subnet mask. This field has been updated to the SCL model based on the Subnetwork selection. To select which communication protocols can be run on the respective access points, check or uncheck the check box for the relevant protocol. The protocols are not activated/deactivated in ECT, only filtered for the specific access point. On the station bus, both MMS and GOOSE services were selected, whilst on the process bus port, only GOOSE (in addition to the default SV service).
Redundant communication is configured with the Ethernet configuration tool in PCM600. This is activated when the parameter is set to either PRP-0, PRP-1 or HSR. The settings for the next access point will be hidden and PhyPortB will show the second port information. Redundant communication is activated after a common write to IED is done.

PRP-1 should be used primarily, as PRP-0 is intended only for use in existing PRP-networks. PRP-1 and HSR can be combined in a mixed network. If the access point is not taken into operation, the write option in Ethernet Configuration Tool can be used to activate the access point.

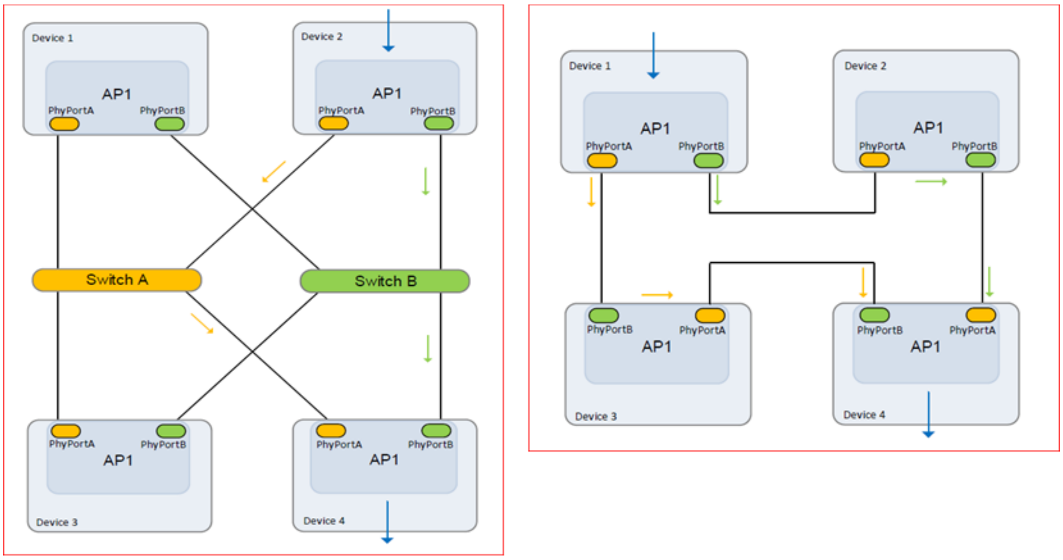


Figure 34 Signal Communication between IEDs

REC670 - BCU - Ethernet Configuration

Access points | Merging units | Routes

Access point	Description	Operation	Redundancy	Physical port A	Physical port B	Subnetwork	IP address	Subnet mask	Default gateway	PCM600 access	MMS	GOOSE
0	FrontPort	✓	None	ETH_Front		None	[redacted]	255.255.255.0	10.1.150.1	✓	✓	✓
1	Station Bus	✓	PRP-1	SFP_301	SFP_302	AA1WF1	[redacted]	255.255.255.0	10.1.150.1	✓	✓	✓
3	Process Bus	✓	None	SFP_303		WA2	[redacted]	255.255.255.0	0.0.0.0	✓		✓
4	Accesspoint 4		None	SFP_304		None	[redacted]	255.255.255.0	0.0.0.0	✓		

Figure 35 BCU Access Points Configuration

RED670 - FMP1 - Ethernet Configuration

Access points | Merging units | Routes

Access point	Description	Operation	Redundancy	Physical port A	Physical port B	Subnetwork	IP address	Subnet mask	Default gateway	PCM600 access	MMS	GOOSE
0	FrontPort	✓	None	ETH_Front		None	[redacted]	255.255.255.0	10.1.150.1	✓	✓	✓
1	Station Bus	✓	PRP-1	SFP_301	SFP_302	AA1WF1	[redacted]	255.255.255.0	0.0.0.0	✓	✓	✓
3	Process Bus	✓	None	SFP_303		WA2	[redacted]	255.255.255.0	0.0.0.0	✓		✓
4	Accesspoint 4	✓	None	SFP_304		None	[redacted]	255.255.255.0	0.0.0.0	✓		

Figure 36 FPM1 Access Points Configuration

REC670 - SCU1 - Ethernet Configuration

Access points | Merging units | Routes

Access point	Description	Operation	Redundancy	Physical port A	Physical port B	Subnetwork	IP address	Subnet mask	Default gateway	PCM600 access	MMS	GOOSE
0	FrontPort	☑	None	ETH_Front		None	[redacted]	255.255.255.0	10.1.150.1	☑	☑	☑
1	Station Bus	☑	PRP-1	SFP_301	SFP_302	AA1WF1	[redacted]	255.255.255.0	10.1.150.1	☑	☑	☑
3	Process Bus	☑	None	SFP_303		WA2	[redacted]	255.255.255.0	0.0.0.0	☑	☐	☑
4	Accesspoint 4	☐	None	SFP_304		None	[redacted]	255.255.255.0	0.0.0.0	☑	☐	☐

Figure 37 SCU1/SCU2 Access Points Configuration

5.4.4 ABB 670 series IEDs - Merging Unit Configuration

The IEC/UCA 61850-9-2LE process bus communication protocol enables an IED to communicate with devices providing measured values in digital format, commonly known as Merging Units (MU). The merging units are called so because they can gather analog values from one or more measuring transformers, sample the data and send the data over process bus to other clients (or subscribers) in the system.

Some Merging Units are able to get data from conventional measuring transformers (the so-called Standalone Merging Units), and some others from non-conventional measuring transducers. IED's rear access point AP3 was configured for handling Sample Value from various sources in the bay. The IEC/UCA 61850-9-2LE standard does not specify the quality of the sampled values. Thus, the accuracy of the current and voltage inputs to the merging unit and the inaccuracy added by the merging unit must be coordinated with the requirement for the actual type of protection function. Factors influencing the accuracy of the sampled values from the merging unit are, for example, anti-aliasing filters, frequency range, step response, truncating, A/D conversion inaccuracy, time tagging accuracy etc. In principle, the accuracy of the current and voltage transformers, together with the merging unit, will have the same quality as the direct input of currents and voltages.

REC670 - BCU - Ethernet Configuration

Access points | Merging units | Routes

MU	Name	AP connection	Sample Value ID
9201	MU1	AP3:Process Bus	SAM600MU0101
9202	MU2	AP3:Process Bus	MER1UNIT320
9203	MU3	None	ABBMU0103
9204	MU4	None	ABBMU0104
9205	MU5	None	ABBMU0105
9206	MU6	None	ABBMU0106
9207	MU7	None	ABBMU0107
9208	MU8	None	ABBMU0108

RED670 - FMP1 - Ethernet Configuration

Access points | Merging units | Routes

MU	Name	AP connection	Sample Value ID
9201	MU1	AP3:Process Bus	GELPIT_WISH0101
9202	MU2	None	ABB_MU0102
9203	MU3	None	ABB_MU0103
9204	MU4	None	ABB_MU0104
9205	MU5	None	ABB_MU0105
9206	MU6	None	ABB_MU0106
9207	MU7	None	ABB_MU0107
9208	MU8	None	ABB_MU0108

Figure 38 ABB BCU REC670 and FPM1 RED670 Merging Unit Configuration

Note: As it can be seen from above's screen shots, the client IEDs must have the Sample Value ID (SVID) configured identically to the SVID associated with the LPIT / Standalone Merging Unit, the actual source of the analogue data.

5.4.5 ABB 670 series IEDs – Analogues Configuration

Subject to the application (conventional or non-conventional instrument transformers), the application engineer had to map the analogue signals to either the built-in Transformer Module (TRM) card or to the external Merging Unit (MU).

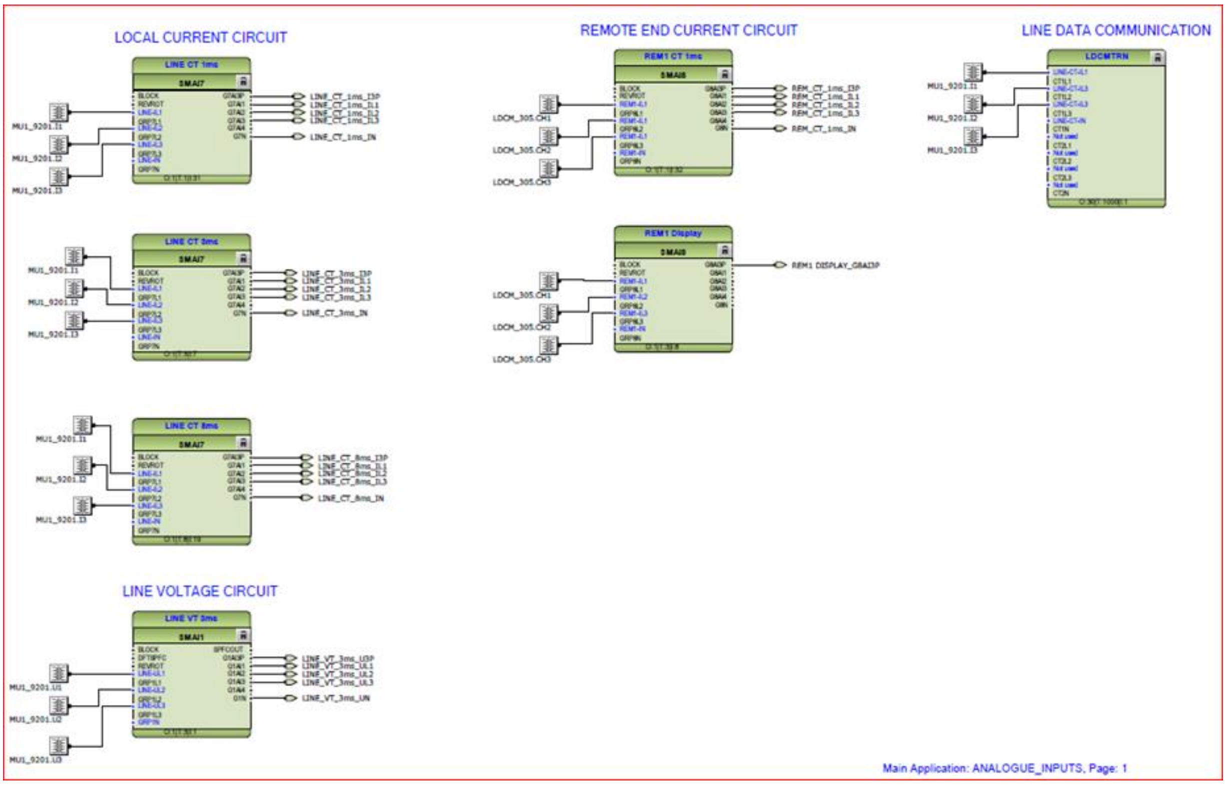


Figure 39 Analogue data handling for Wishaw substation RED670 IED using Merging Unit (digital substation):

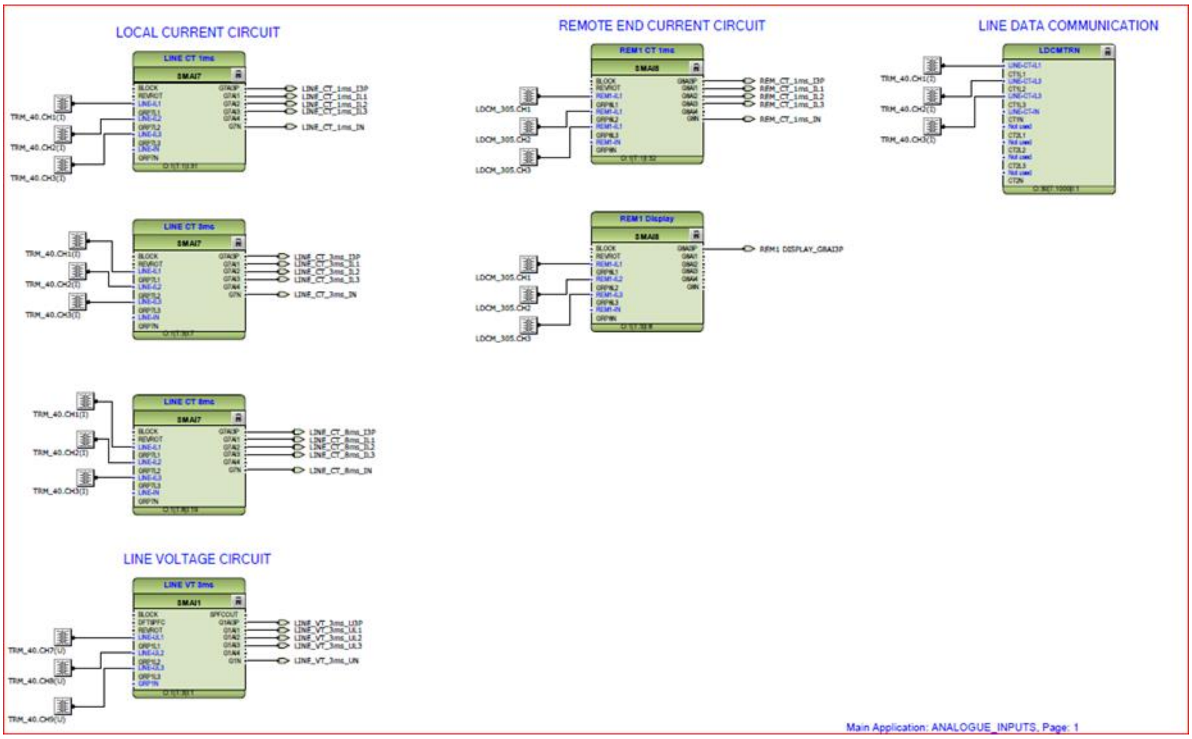


Figure 40 Analogue data handling for remote substation RED670 IED using conventional CTs:

5.4.6 ABB 670 series IEDs – Time Synch Configuration

The IED and the Merging Units (MU) should use the same time reference, especially if analog data is used from several sources, for example from an internal TRM and a MU, or if several physical MUs are used. Having the same time reference is important to correlate data so that channels from different sources refer to the correct phase angle, especially if used for line differential protection. Therefore, an external time synch source can be used to synchronize both the IEDs and the MU. It is also possible to use the MU as a clock master to synchronize the IEDs. When using an external clock, it is possible to set the IEDs to be synchronized via PPS, IRIG-B or PTP. It is also possible to use an internal GPS receiver in the IED (if the external clock is using GPS). In FITNESS, the PTP time synch is derived from the best grand master clock on the network, which acts as time server.

Settings on the local HMI under Main menu/Configuration/Time/Synchronization/TIMESYNCHGEN:1/IEC61850-9-2, as shown below:

- *HwSyncSrc*: is not used as both the software and hardware time are connected with each other due to PTP
- *SyncLostMode*: set to
    - ***Block,*** in order to block protection functions if time synchronization is lost (no clock class 6 or 7 available)
    - ***BlockOnLostUTC*** in order to block protection functions when global common synchronization is lost (clock class 6)
- *SyncAccLevel:* Synch accuracy level can be set to:
    - T5 - 1µs: this corresponds to a maximum phase angle error of 0.018 degrees at 50Hz. This is recommended setting for RED670 line differential protection.
    - T4 - 4µs: this corresponds to a maximum phase angle error of 0.072 degrees at 50Hz. This is recommended setting for REC670 back up protection.

IEC61850-9-2					
HWSyncSrc		Off			
SyncLostMode		Block			
SyncAccLevel		Class T5 (1us)			

Figure 41 670 series IEDs IEC61850-9-2 time synchronisation

Settings on the local HMI under Main menu/Configuration/Communication/Ethernet configuration/Access point/AP_X:

- Operation: On
- PTP: On

Two status monitoring signals are available:

- SYNCH signal on the MUx function block indicates that protection functions are blocked due to loss of internal time synchronization to the IED.
- MUSYNCH signal on the MUx function block monitors the synchronization flag smpSynch in the datastream and IED hardware time synchronization.

5.4.7 IEC 61850-8-1 Engineering

IEC 61850-8-1 communication protocol allows both vertical communication to clients as well as horizontal communication between two or more IEDs from one or several vendors – in this case between ABB's 670 series IEDs and GE's MiCOM IEDs. In order to engineer the IEC61850 system, a system integration tool called IET600 was used within the ABB bay.

For an efficient IEC61850 system engineering, it is recomended to generate either a table or a block diagram depicting what signals are to be sent from one device to the other(s). The same concept can be extended to any bay type. The block diagram shown below is based on the customer application and - to some extent - it replaces the conventional block diagram used in protection & control applications.

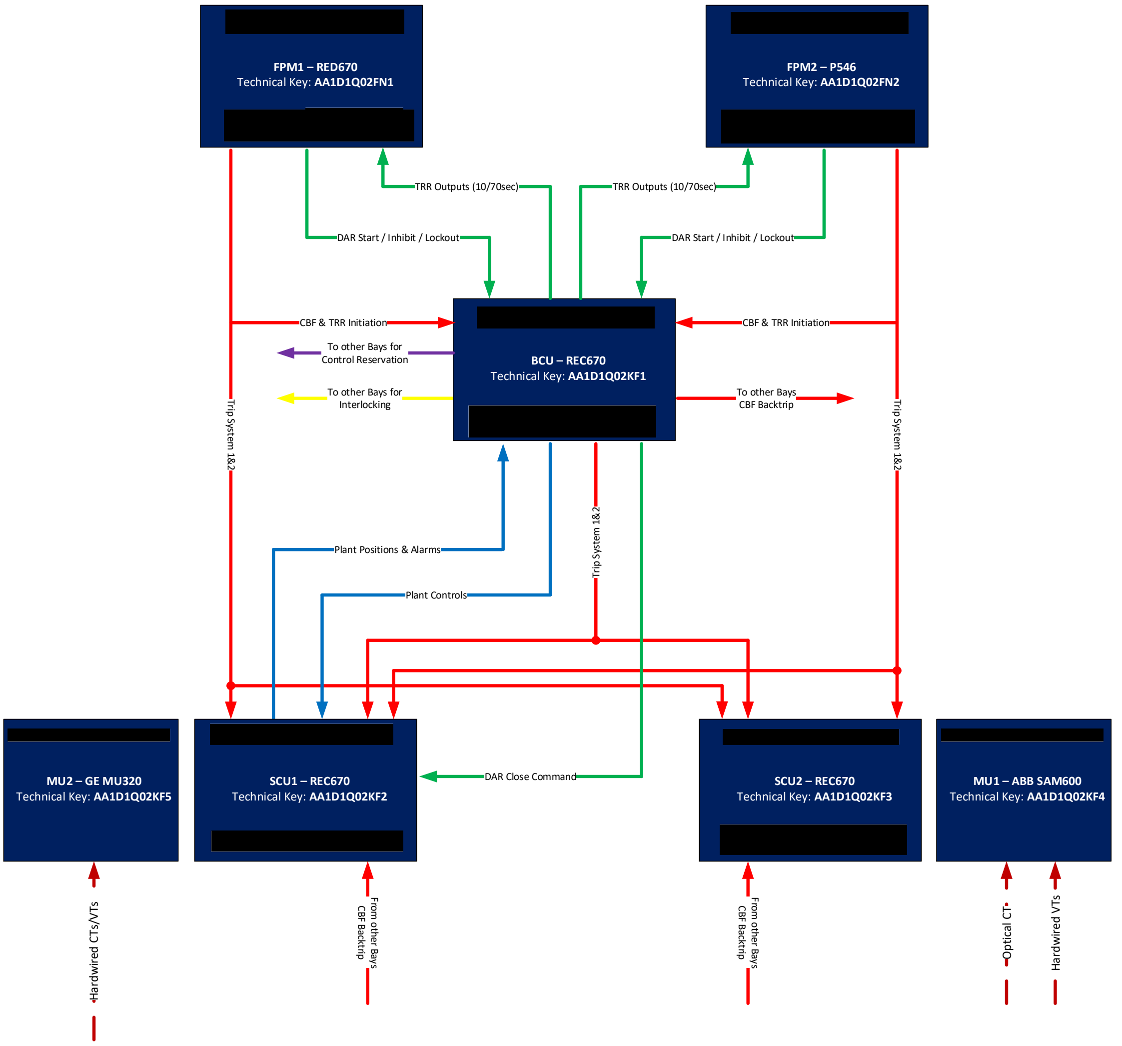


Figure 42: Block diagram for a full digital feeder bay

In order to proceed with all IEC61850 system engineering, the IEDs were fully configured in terms of internal logic and the following documentation is available:

System Engineering Input	
Document Title	**Attachment**
System Architecture Diagram	
Equipment Technical Key and IP Address list	FITNESS IP Addressing_rev2.xls
REC670 BCU signal list	Bay 2 - REC670-BCU = IEC61850 SignalList

RED670 FPM1 signal list	Bay 2 - RED670-FPM1 = IEC61850 SignalList
REC670 SCU1 signal list	Bay 2 - REC670-SCU1 = IEC61850 SignalList
REC670 SCU2 signal list	Bay 2 - REC670-SCU2 = IEC61850 SignalList

Table 8 List of Engineering Documents for FITNESS

GOOSE data exchange

The IEC 61850 protocol supports a method to directly exchange data between two or more IEDs, based on sending a multicast message over the Ethernet. A GOOSE signal includes the actual value and its quality. In the opposite direction, the IEC61850 standard only defines the IED as a subscriber of the GOOSE message. The result is an SCD file generated by the System Configuration Tool. The input data must be connected to a GOOSE receive function block (GOOSEBINRCV) in the Signal Matrix Tool (SMT).

Engineering of vertical and horizontal communication in IET600

For IEC 61850 engineering, a separate system configuration tool was needed, along the PCM600 IED Configuration Tool (ICT). The tool is called IET600 and it acts as a System Configuration Tool (SCT). The procedure for engineering using IET600 was as follows:

- Created a project within the IET600;
- Imported the SCD file generated from PCM600;

- For vertical communication:
    - Configure the required data sets.
    - Configure report control blocks for each data set used in vertical communication. Preconfigured IEDs include predefined report control blocks which can be reconfigured. If additional control blocks are needed, it is possible to add them according to requirements. Up to 8 vertical clients can be configured.
    - Connect the report control blocks to vertical clients. The vertical client must belong to the same sub-network as the IEDs.
- For horizontal communication:
    - Create GOOSE data sets for the sending IED. Define the content of the data set according to the requirements. The data set for GOOSE contains signals on the data attribute or FCDA levels. The latter is also known as structured GOOSE. Data for one signal can only be included in one GOOSE data set. The data set for GOOSE cannot be empty.
    - Create a GOOSE control block and connect it to the GOOSE data set. Check parameters for GOOSE control block, for example MinTime and MaxTime, and update as required.
    - Connect the GOOSE control block to receiving IEDs that subscribe GOOSE data.
- Export the SCD file.

Note 1:
All data sets, report control blocks and GOOSE control blocks must be located at LD0/LLN0. There are limitations regarding the maximum number of data sets, number of entries in a data set and the number of report control blocks that can be used.
Note 2:
The above-mentioned engineering process is called “bottom up”.

5.4.8 GOOSE Engineering using the IET600 as an SCT Tool

Drag a column header here to group by that column.

IED	LD	LN	Dataset	Related Control Blocks	Status
AA1D1Q02FN1	LD0	LLN0	FPM1_STUB_BUS		Manually configured
AA1D1Q02FN1	LD0	LLN0	FPM1_DAR_SIGNALS	gcb_A	Manually configured
AA1D1Q02FN1	LD0	LLN0	FPM1_DIFF_TRIP	gcb_B, gcb_D	Manually configured
AA1D1Q02FN1	LD0	LLN0	FPM1_GEN_TRIP	gcb_C, gcb_E	Manually configured
AA1D1Q02FN1	LD0	LLN0	FPM1_DIST_TRIP	gcb_F	Manually configured
AA1D1Q02FN1	LD0	LLN0	FPM1_BROKEN_COND	gcb_G	Manually configured
AA1D1Q02FN1	LD0	LLN0	FPM1_BUOC_EF	gcb_H	Manually configured
AA1D1Q02FN1	LD0	LLN0	FPM1_FUSE_FAIL	gcb_I	Manually configured
AA1D1Q02FN1	LD0	LLN0	FPM1_IT_SIGNALS	gcb_J	Manually configured
AA1D1Q02FN1	LD0	LLN0	FPM1_SOTF	gcb_K	Manually configured
AA1D1Q02FN1	LD0	LLN0	StatUrgA	rcb_A	Generated by rule
AA1D1Q02FN1	LD0	LLN0	StatNrmlA	rcb_B	Generated by rule
AA1D1Q02FN1	LD0	LLN0	StatNrmlB	rcb_C	Generated by rule
AA1D1Q02FN1	LD0	LLN0	StatIedA	rcb_D	Generated by rule

AA1D1Q02FN1 : 260 entries
FPM1_DIST_TRI... 7 entries (110 allowed)
30 attributes

Dataset Entries	FC	Attr.
ZMF_1.ZMFPDIS1.Op	ST	6
Value: general, phsA, phsB, phsC, q, t		
ZMF_1.ZMFPDIS2.Op	ST	6
ZMF_1.ZMFPDIS3.Op	ST	3
ZMF_1.ZMFPDIS4.Op	ST	3
ZMF_1.ZMFPDIS5.Op	ST	3
ZMF_1.ZMFPDIS6.Op	ST	3
ZMF_1.ZMFPTRC1.Op	ST	6

IED	LD	LN	GCB	Status	Attached Dataset	t(min) (ms)	t(max) (ms)	Conf.Rev.	GCB Typ	MAC Address	APP-ID	VLAN-ID	VLAN Priority
AA1D1Q02FN1	LD0	LLN0	gcb_A	Manually configured	FPM1_DAR_SIGNALS	4	4000	100	GOOSE	01-0C-CD-01-05-01	3001	000	4
AA1D1Q02FN1	LD0	LLN0	gcb_B	Manually configured	FPM1_DIFF_TRIP	4	4000	100	GOOSE	01-0C-CD-01-05-02	3002	000	4
AA1D1Q02FN1	LD0	LLN0	gcb_C	Manually configured	FPM1_GEN_TRIP	4	4000	100	GOOSE	01-0C-CD-01-05-03	3003	000	4
AA1D1Q02FN1	LD0	LLN0	gcb_D	Manually configured	FPM1_DIFF_TRIP	4	4000	100	GOOSE	01-0C-CD-01-05-04	3004	000	4
AA1D1Q02FN1	LD0	LLN0	gcb_E	Manually configured	FPM1_GEN_TRIP	4	4000	100	GOOSE	01-0C-CD-01-05-05	3005	000	4
AA1D1Q02FN1	LD0	LLN0	gcb_F	Manually configured	FPM1_DIST_TRIP	4	4000	100	GOOSE	01-0C-CD-01-05-06	3006	000	4
AA1D1Q02FN1	LD0	LLN0	gcb_G	Manually configured	FPM1_BROKEN_COND	4	4000	200	GOOSE	01-0C-CD-01-05-07	3007	000	4
AA1D1Q02FN1	LD0	LLN0	gcb_H	Manually configured	FPM1_BUOC_EF	4	4000	100	GOOSE	01-0C-CD-01-05-08	3008	000	4
AA1D1Q02FN1	LD0	LLN0	gcb_I	Manually configured	FPM1_FUSE_FAIL	4	4000	200	GOOSE	01-0C-CD-01-05-09	3009	000	4
AA1D1Q02FN1	LD0	LLN0	gcb_J	Manually configured	FPM1_IT_SIGNALS	4	4000	100	GOOSE	01-0C-CD-01-05-11	3011	000	4
AA1D1Q02FN1	LD0	LLN0	gcb_K	Manually configured	FPM1_SOTF	4	4000	100	GOOSE	01-0C-CD-01-05-12	3012	000	4

Figure 43. FPM1 RED670 - GOOSE Control Block Engineering

IED Name	LD	LN	GCB	Attached Dataset	AA1D1Q02FN1 (S1)	AA1D1Q02FN2 (AP1)	AA1D1Q02KF1 (S1)	AA1D1Q02KF2 (S1)	AA1D1Q02KF3 (S1)	CNEWHAR1 (AP1)	OMICRON (S1)	R546FPFM (AP1)	R841BUP (AP1)	RREDFPSM (S1)	SCU1NH1 (AP1)	SCU2NH1 (AP1)	AA1D1Q02FN1 (S3)	AA1D1Q02KF1 (S3)	AA1D1Q02KF2 (S3)	AA1D1Q02KF3 (S3)	OMICRON (S3)	RREDFPSM (S3)	SCU1NH1 (AP2)	SCU2NH1 (AP2)
AA1D1Q02FN1	LD0	LLN0	gcb_A	FPM1_DAR_SIGNALS			x																	
AA1D1Q02FN1	LD0	LLN0	gcb_B	FPM1_DIFF_TRIP																				
AA1D1Q02FN1	LD0	LLN0	gcb_C	FPM1_GEN_TRIP			x																	
AA1D1Q02FN1	LD0	LLN0	gcb_D	FPM1_DIFF_TRIP															x	x				
AA1D1Q02FN1	LD0	LLN0	gcb_E	FPM1_GEN_TRIP															x	x				
AA1D1Q02FN1	LD0	LLN0	gcb_F	FPM1_DIST_TRIP																				
AA1D1Q02FN1	LD0	LLN0	gcb_G	FPM1_BROKEN_COND																				
AA1D1Q02FN1	LD0	LLN0	gcb_H	FPM1_BUOC_EF																				
AA1D1Q02FN1	LD0	LLN0	gcb_I	FPM1_FUSE_FAIL																				
AA1D1Q02FN1	LD0	LLN0	gcb_J	FPM1_IT_SIGNALS																				
AA1D1Q02FN1	LD0	LLN0	gcb_K	FPM1_SOTF																				

Figure 44. FPM1 RED670 - GOOSE Client Engineering

Note:

In order to enable testing, certain datasets attached to individual FPM1 GCBs have been generated. OMICRON test set will act as their client.

Drag a column header here to group by that column.

IED	LD	LN	Dataset	Related Control Blocks	Status
AA1D1Q02FN2	System	LLN0	OPTO	brcbA, brcbC, brcbE, brcbG	IED-defined, configurable
AA1D1Q02FN2	System	LLN0	PROTECTION	brcbB, brcbD, brcbF, brcbH	IED-defined, configurable
AA1D1Q02FN2	System	LLN0	GOSGGIO2	gcb01	IED-defined, configurable
AA1D1Q02FN2	System	LLN0	MEASURMENTS	urcbA, urcbB, urcbC, urcbD	IED-defined, configurable

AA1D1Q02FN2 : 216 entries
└ GOSGGIO2 : 128 entries (allowed)
128 attributes

Dataset Entries	FC	Attr.
System.GosGGIO2.Ind1.stVal	ST	1
System.GosGGIO2.Ind1.q	ST	1
System.GosGGIO2.Ind2.stVal	ST	1
System.GosGGIO2.Ind2.q	ST	1
System.GosGGIO2.Ind3.stVal	ST	1
System.GosGGIO2.Ind3.q	ST	1
System.GosGGIO2.Ind4.stVal	ST	1
System.GosGGIO2.Ind4.q	ST	1
System.GosGGIO2.Ind5.stVal	ST	1
System.GosGGIO2.Ind5.q	ST	1
System.GosGGIO2.Ind6.stVal	ST	1
System.GosGGIO2.Ind6.q	ST	1
System.GosGGIO2.Ind7.stVal	ST	1
System.GosGGIO2.Ind7.q	ST	1
System.GosGGIO2.Ind8.stVal	ST	1

Figure 45. FPM2 P546 - Typical Goose Data Sets Engineering

IED	LD	LN	GCB	Status	Attached Dataset	t(min) (ms)	t(max) (ms)	Conf.Rev.	GCB Typ	MAC Address	APP-ID	VLAN-ID	VLAN Priority
AA1D1Q02FN2	System	LLN0	gcb01	IED-defined, configurable	GOSGGIO2	10	4000	1	GOOSE	01-0C-CD-01-05-21	3021	000	4
AA1D1Q02FN2	System	LLN0	gcb02	IED-defined, configurable		20	1000	0	GOOSE	01-0C-CD-01-00-00	0000	000	4
AA1D1Q02FN2	System	LLN0	gcb03	IED-defined, configurable		20	1000	0	GOOSE	01-0C-CD-01-00-00	0000	000	4
AA1D1Q02FN2	System	LLN0	gcb04	IED-defined, configurable		20	1000	0	GOOSE	01-0C-CD-01-00-00	0000	000	4
AA1D1Q02FN2	System	LLN0	gcb05	IED-defined, configurable		20	1000	0	GOOSE	01-0C-CD-01-00-00	0000	000	4
AA1D1Q02FN2	System	LLN0	gcb06	IED-defined, configurable		20	1000	0	GOOSE	01-0C-CD-01-00-00	0000	000	4
AA1D1Q02FN2	System	LLN0	gcb07	IED-defined, configurable		20	1000	0	GOOSE	01-0C-CD-01-00-00	0000	000	4
AA1D1Q02FN2	System	LLN0	gcb08	IED-defined, configurable		20	1000	0	GOOSE	01-0C-CD-01-00-00	0000	000	4

Figure 46. FPM2 P546 - Typical GOOSE Control Block Engineering

IED Name	LD	LN	GCB	Attached Dataset	AA1D1Q02FN1 (S1)	AA1D1Q02FN2 (AP1)	AA1D1Q02KF1 (S1)	AA1D1Q02KF2 (S1)	AA1D1Q02KF3 (S1)	CNEWHAR1 (AP1)	OMICRON (S1)	R546FPFM (AP1)	R841BUP (AP1)	RREDFPSM (S1)	SCU1NH1 (AP1)	SCU2NH1 (AP1)	AA1D1Q02FN1 (S3)	AA1D1Q02KF1 (S3)	AA1D1Q02KF2 (S3)	AA1D1Q02KF3 (S3)	OMICRON (S3)	RREDFPSM (S3)	SCU1NH1 (AP2)	SCU2NH1 (AP2)
AA1D1Q02FN2	System	LLN0	gcb01	GOSGGIO2	x		x	x	x															
AA1D1Q02FN2	System	LLN0	gcb02																					
AA1D1Q02FN2	System	LLN0	gcb03																					
AA1D1Q02FN2	System	LLN0	gcb04																					
AA1D1Q02FN2	System	LLN0	gcb05																					
AA1D1Q02FN2	System	LLN0	gcb06																					
AA1D1Q02FN2	System	LLN0	gcb07																					
AA1D1Q02FN2	System	LLN0	gcb08																					

Figure 47. FPM2 P546 - GOOSE Client Engineering

Drag a column header here to group by that column.

IED	LD	LN	Dataset	Related Control Blocks	Status
AA1D1Q02KF1	LD0	LLN0	BCU_CB_FAIL_BACKTRIP_...	gcb_A	Manually configured
AA1D1Q02KF1	LD0	LLN0	BCU_GEN_TRIP_PB	gcb_B	Manually configured
AA1D1Q02KF1	LD0	LLN0	BCU_PLANT_CTRLs	gcb_C	Manually configured
AA1D1Q02KF1	LD0	LLN0	BCU_TRR_OUTPUTS	gcb_D	Manually configured
AA1D1Q02KF1	LD0	LLN0	BCU_DAR_CLS_CMD	gcb_E	Manually configured
AA1D1Q02KF1	LD0	LLN0	BCU_GEN_TRIP_SB	gcb_F	Manually configured
AA1D1Q02KF1	LD0	LLN0	BCU_DAR_SIGNALS	gcb_G	Manually configured
AA1D1Q02KF1	LD0	LLN0	P546_SWITCHING	gcb_H	Manually configured
AA1D1Q02KF1	LD0	LLN0	BCU_CBF_BTRIP_SEND	gcb_I	Manually configured
AA1D1Q02KF1	LD0	LLN0	BCU_SYNCH_SIGNALS	gcb_J	Manually configured
AA1D1Q02KF1	LD0	LLN0	BCU_FUSE_FAILURE	gcb_K	Manually configured
AA1D1Q02KF1	LD0	LLN0	BCU_BU_OCEF	gcb_M	Manually configured

AA1D1Q02KF1 : 412 entries
└ BCU_CB_FAIL_B... 2 entries (110 allowed)
2 attributes

Dataset Entries	FC	Attr.
PROT.CCRBRF1.OpEx.general	ST	1
PROT.CCRBRF1.OpEx.q	ST	1

Figure 48. BCU REC670 – Typical Goose Data Sets Engineering

IED	LD	LN	GCB	Status	Attached Dataset	t(min) (ms)	t(max) (ms)	Conf.Rev.	GCB Typ	MAC Address	APP-ID	VLAN-ID	VLAN Priority
AA1D1Q02KF1	LD0	LLN0	gcb_A	Manually configured	BCU_CB_FAIL_BACKT...	4	4000	200	GOOSE	01-0C-CD-01-05-31	3031	000	4
AA1D1Q02KF1	LD0	LLN0	gcb_B	Manually configured	BCU_GEN_TRIP_PB	4	4000	200	GOOSE	01-0C-CD-01-05-32	3032	000	4
AA1D1Q02KF1	LD0	LLN0	gcb_C	Manually configured	BCU_PLANT_CTRLs	4	4000	200	GOOSE	01-0C-CD-01-05-33	3033	000	4
AA1D1Q02KF1	LD0	LLN0	gcb_D	Manually configured	BCU_TRR_OUTPUTS	4	4000	100	GOOSE	01-0C-CD-01-05-34	3034	000	4
AA1D1Q02KF1	LD0	LLN0	gcb_E	Manually configured	BCU_DAR_CLS_CMD	4	4000	100	GOOSE	01-0C-CD-01-05-35	3035	000	4
AA1D1Q02KF1	LD0	LLN0	gcb_F	Manually configured	BCU_GEN_TRIP_SB	4	4000	100	GOOSE	01-0C-CD-01-05-36	3036	000	4
AA1D1Q02KF1	LD0	LLN0	gcb_G	Manually configured	BCU_DAR_SIGNALS	4	4000	100	GOOSE	01-0C-CD-01-05-37	3037	000	4
AA1D1Q02KF1	LD0	LLN0	gcb_H	Manually configured	P546_SWITCHING	4	4000	200	GOOSE	01-0C-CD-01-05-38	3038	000	4
AA1D1Q02KF1	LD0	LLN0	gcb_I	Manually configured	BCU_CBF_BTRIP_SEND	4	4000	200	GOOSE	01-0C-CD-01-05-39	3039	000	4
AA1D1Q02KF1	LD0	LLN0	gcb_J	Manually configured	BCU_SYNCH_SIGNALS	4	4000	100	GOOSE	01-0C-CD-01-05-40	3040	000	4
AA1D1Q02KF1	LD0	LLN0	gcb_K	Manually configured	BCU_FUSE_FAILURE	4	4000	100	GOOSE	01-0C-CD-01-05-41	3041	000	4
AA1D1Q02KF1	LD0	LLN0	gcb_M	Manually configured	BCU_BU_OCEF	4	4000	200	GOOSE	01-0C-CD-01-05-43	3043	000	4

Figure 49. BCU REC670 - Typical GOOSE Control Block Engineering

IED Name	LD	LN	GCB	Attached Dataset	AA1D1Q02FN1 (S1)	AA1D1Q02FN2 (AP1)	AA1D1Q02KF1 (S1)	AA1D1Q02KF2 (S1)	AA1D1Q02KF3 (S1)	CNEWHAR1 (AP1)	OMICRON (S1)	R546FPFM (AP1)	R841BUP (AP1)	RREDFPSM (S1)	SCU1NH1 (AP1)	SCU2NH1 (AP1)	AA1D1Q02FN1 (S3)	AA1D1Q02KF1 (S3)	AA1D1Q02KF2 (S3)	AA1D1Q02KF3 (S3)	OMICRON (S3)	RREDFPSM (S3)	SCU1NH1 (AP2)	SCU2NH1 (AP2)
AA1D1Q02KF1	LD0	LLN0	gcb_A	BCU_CB_FAIL_BACKTRIP...																				
AA1D1Q02KF1	LD0	LLN0	gcb_B	BCU_GEN_TRIP_PB															x	x				
AA1D1Q02KF1	LD0	LLN0	gcb_C	BCU_PLANT_CTRLs				x																
AA1D1Q02KF1	LD0	LLN0	gcb_D	BCU_TRR_OUTPUTS	x																			
AA1D1Q02KF1	LD0	LLN0	gcb_E	BCU_DAR_CLS_CMD																				
AA1D1Q02KF1	LD0	LLN0	gcb_F	BCU_GEN_TRIP_SB																				
AA1D1Q02KF1	LD0	LLN0	gcb_G	BCU_DAR_SIGNALS																				
AA1D1Q02KF1	LD0	LLN0	gcb_H	P546_SWITCHING																				
AA1D1Q02KF1	LD0	LLN0	gcb_I	BCU_CBF_BTRIP_SEND						x						x								
AA1D1Q02KF1	LD0	LLN0	gcb_J	BCU_SYNCH_SIGNALS																				
AA1D1Q02KF1	LD0	LLN0	gcb_K	BCU_FUSE_FAILURE																				
AA1D1Q02KF1	LD0	LLN0	gcb_M	BCU_BU_OCEF																				

Figure 50. BCU REC670 - Typical GOOSE Client Engineering

Note:

In order to enable testing, certain datasets attached to individual BCU GCBs had to be generated; the OMICRON test set acts as their client.

Drag a column header here to group by that column.

IED	LD	LN	Dataset	Related Control Blocks	Status
AA1D1Q02KF2	LD0	LLN0	SCU1_PLANT_POS	gcb_A	Manually configured
AA1D1Q02KF2	LD0	LLN0	SCU1_CB_POS	gcb_B	Manually configured
AA1D1Q02KF2	LD0	LLN0	SCU1_ALARMS_1	gcb_C	Manually configured
AA1D1Q02KF2	LD0	LLN0	SCU1_ALARMS_2	gcb_D	Manually configured
AA1D1Q02KF2	LD0	LLN0	SCU1_OMICRON	gcb_E	Manually configured
AA1D1Q02KF2	LD0	LLN0	EXPERIMENT_1	gcb_F	Manually configured
AA1D1Q02KF2	LD0	LLN0	ELIA_VISIT	gcb_G	Manually configured
AA1D1Q02KF2	LD0	LLN0	StatUrgA	rcb_A	Generated by rule
AA1D1Q02KF2	LD0	LLN0	StatNrmlA	rcb_B	Generated by rule
AA1D1Q02KF2	LD0	LLN0	StatIedA	rcb_C	Generated by rule
AA1D1Q02KF2	LD0	LLN0	SecurityA	rcb_D	Generated by rule

AA1D1Q02KF2 : 261 entries
└ SCU1_PLANT_P... 13 entries (110 allowed)
39 attributes

Dataset Entries	FC	Attr.
CTRL.DPGAPC1.DPCSO1	ST	3
CTRL.DPGAPC2.DPCSO1	ST	3
CTRL.DPGAPC3.DPCSO1	ST	3
CTRL.DPGAPC4.DPCSO1	ST	3
CTRL.DPGAPC5.DPCSO1	ST	3
CTRL.DPGAPC6.DPCSO1	ST	3
CTRL.DPGAPC7.DPCSO1	ST	3
CTRL.DPGAPC8.DPCSO1	ST	3
CTRL.DPGAPC9.DPCSO1	ST	3
MON.SP16GAPC17.Ind1	ST	3
MON.SP16GAPC17.Ind2	ST	3
MON.SP16GAPC17.Ind3	ST	3
MON.SP16GAPC17.Ind4	ST	3

Figure 51. SCU1/2 – Typical Goose Data Sets Engineering

IED	LD	LN	GCB	Status	Attached Dataset	t(min) (ms)	t(max) (ms)	Conf.Rev.	GCB Typ	MAC Address	APP-ID	VLAN-ID	VLAN Priority
AA1D1Q02KF2	LD0	LLN0	gcb_A	Manually configured	SCU1_PLANT_POS	4	4000	300	GOOSE	01-0C-CD-01-05-51	3051	000	4
AA1D1Q02KF2	LD0	LLN0	gcb_B	Manually configured	SCU1_CB_POS	4	4000	200	GOOSE	01-0C-CD-01-05-52	3052	000	4
AA1D1Q02KF2	LD0	LLN0	gcb_C	Manually configured	SCU1_ALARMS_1	4	4000	100	GOOSE	01-0C-CD-01-05-53	3053	000	4
AA1D1Q02KF2	LD0	LLN0	gcb_D	Manually configured	SCU1_ALARMS_2	4	4000	100	GOOSE	01-0C-CD-01-05-54	3054	000	4
AA1D1Q02KF2	LD0	LLN0	gcb_E	Manually configured	SCU1_OMICRON	4	10	400	GOOSE	01-0C-CD-01-05-55	3055	000	4
AA1D1Q02KF2	LD0	LLN0	gcb_F	Manually configured	EXPERIMENT_1	4	4000	100	GOOSE	01-0C-CD-01-05-56	3056	000	4
AA1D1Q02KF2	LD0	LLN0	gcb_G	Manually configured	ELIA_VISIT	4	4000	100	GOOSE	01-0C-CD-01-05-57	3057	000	4

Figure 52. SCU1/2 – Typical Goose Control Block Engineering

IED Name	LD	LN	GCB	Attached Dataset	AA1D1Q02FN1 (S1)	AA1D1Q02FN2 (AP1)	AA1D1Q02KF1 (S1)	AA1D1Q02KF2 (S1)	AA1D1Q02KF3 (S1)	CNEWHAR1 (AP1)	OMICRON (S1)	R546FPFM (AP1)	R841BUP (AP1)	RREDFPSM (S1)	SCU1NH1 (AP1)	SCU2NH1 (AP1)	AA1D1Q02FN1 (S3)	AA1D1Q02KF1 (S3)	AA1D1Q02KF2 (S3)	AA1D1Q02KF3 (S3)	OMICRON (S3)	RREDFPSM (S3)	SCU1NH1 (AP2)	SCU2NH1 (AP2)
AA1D1Q02KF2	LD0	LLN0	gcb_A	SCU1_PLANT_POS	x		x																	
AA1D1Q02KF2	LD0	LLN0	gcb_B	SCU1_CB_POS																				
AA1D1Q02KF2	LD0	LLN0	gcb_C	SCU1_ALARMS_1			x																	
AA1D1Q02KF2	LD0	LLN0	gcb_D	SCU1_ALARMS_2			x																	
AA1D1Q02KF2	LD0	LLN0	gcb_E	SCU1_OMICRON																				
AA1D1Q02KF2	LD0	LLN0	gcb_F	EXPERIMENT_1			x																	
AA1D1Q02KF2	LD0	LLN0	gcb_G	ELIA_VISIT			x																	

Figure 53. SCU1/2 – Typical Goose Control Block Engineering

<u>Note:</u>

In order to enable DAR testing, certain signals i.e. external inhibit or lockout conditions had to be generated in a GOOSE format. This is achieved by using a dedicated GOOSE Control Block (GCB_E).

5.4.9 MicroSCADA Engineering

ABB's MicroSCADA has been engineered to offer a complete functionality for realtime monitoring and control of primary and secondary equipment for both Newarthill 1 and Newarthill 2 circuits. Proving interoperability at various level was deemed to be of paramount importance in FITNESS project. Therefore - albeit very unusual - two control systems have been employed to prove interoperability: ABB's MicroSCADA and GE's Control System. The next section contains a brief description of ABB's MicroSCADA system.

5.4.10 Substation Overview

Figure 54. MicroSCADA Display

This process screen contains the actual single line diagram (SLD) of the substation – in this case limited to the two Newarthill 1 and Newarthill 2 circuits. The SLD was based on the approved SPEN's SLD, and it contains the associated switchgears (circuit breaker, disconnectors and earthing switches), measurement screens and local/station/maintenance/remote control options for the operator.

5.4.11 Supervision

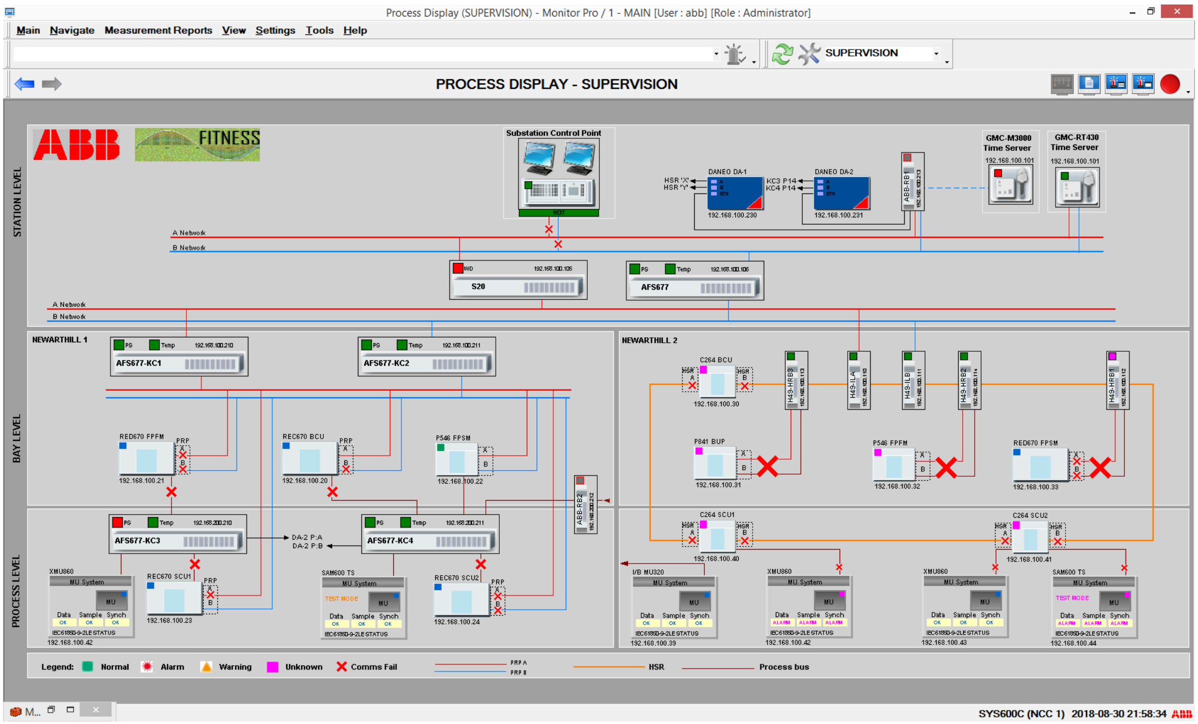


Figure 55. SCADA Port-Supervision

The supervision screen displays the status of all protection and control IEDs, Merging Units, Switching Control Units, comms switches, clocks, RedBoxes, SCS computers and comms links. In addition, for testing during FAT, SAT, as well as during site monitoring, two OMICRON DANEO 400 units were included in the overall architecture.

The equipment is horizontally grouped in process level, bay level and station level. Both PRP and HSR networks are monitored through the connected equipment. The status of each of the equipment is displayed in a little box coloured green if healthy, red if in alarm or an amber triangle if in warning mode. Each comms link failure is represented by a red flashing X cross in the supervision screen, as well as on each individual circuit (feeder) screen.

5.4.12 Feeders

Two feeder screens have been engineered for both Newarthill circuits. These contains circuit SLD, measurements, IED supervision, IED comms supervision, bay alarms, protection and DAR IN/OUT switching.

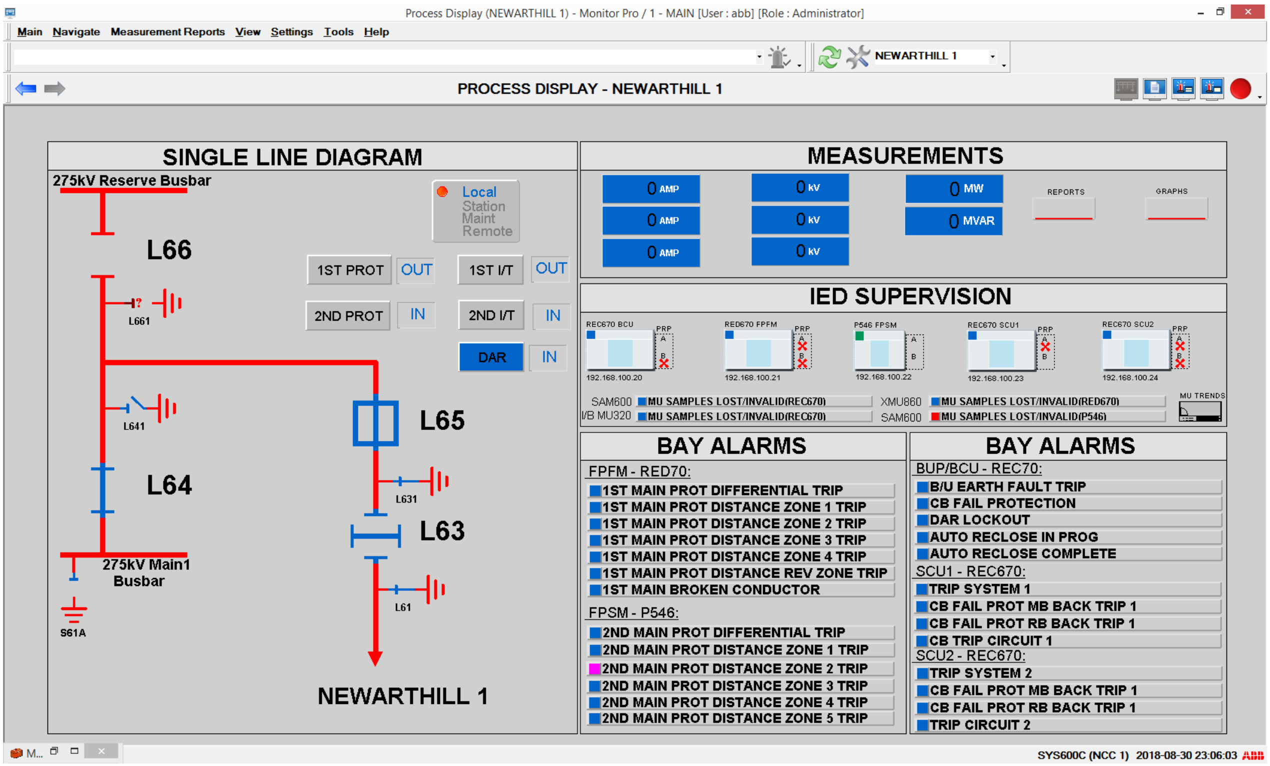


Figure 56. SCADA Bay Views-1

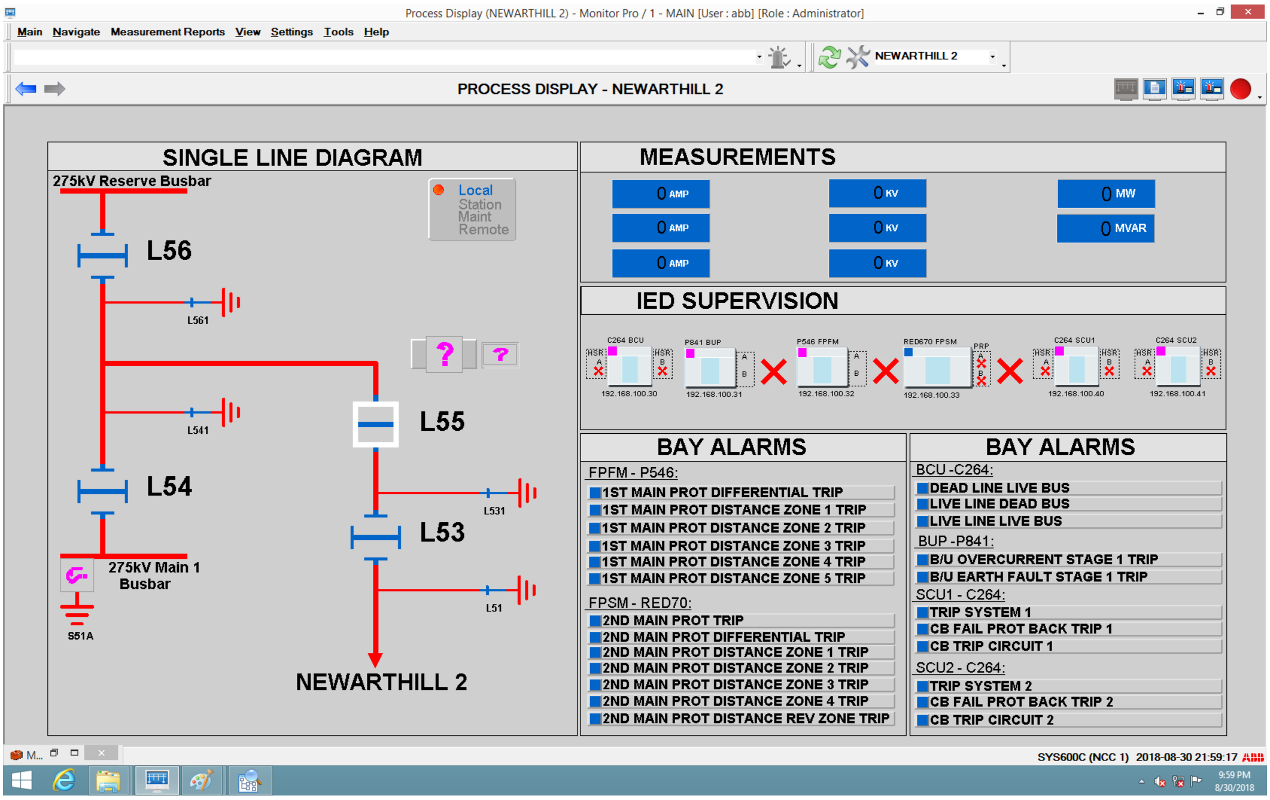


Figure 57. SCADA Bay Views-2

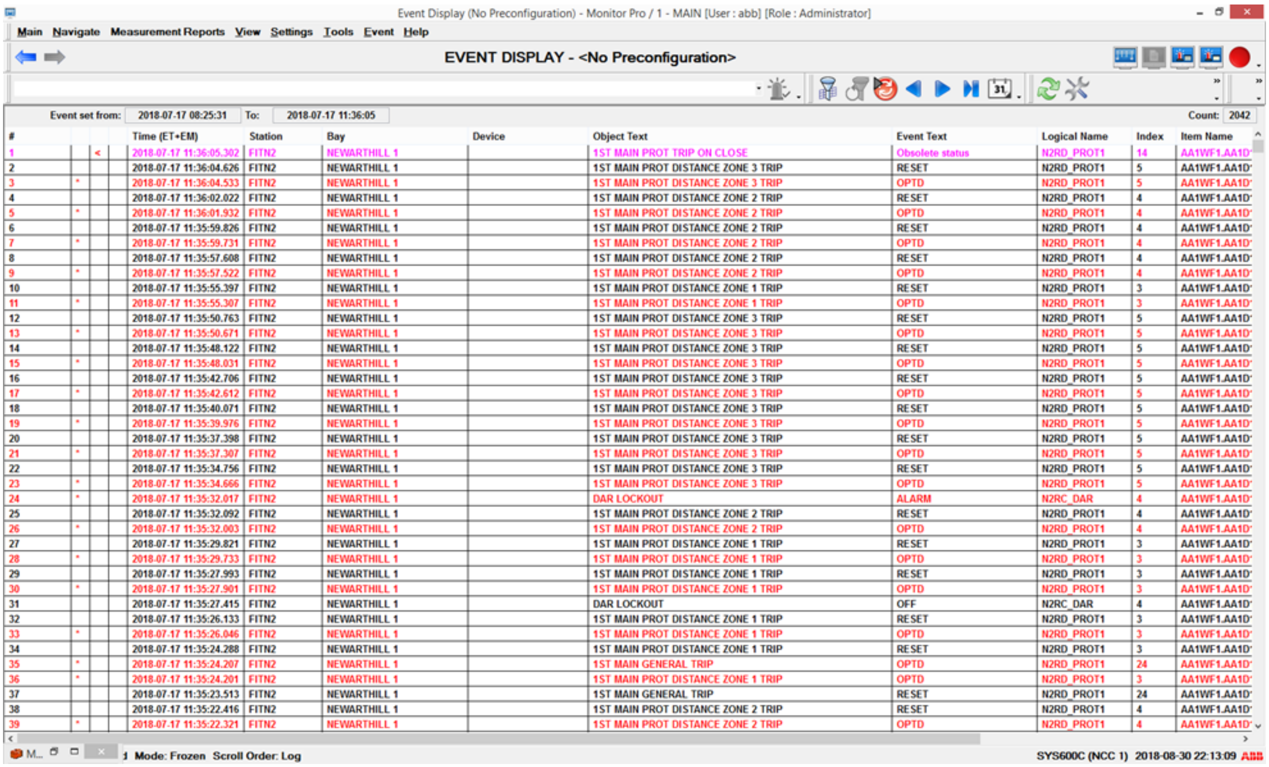


Figure 58. SCADA Events List

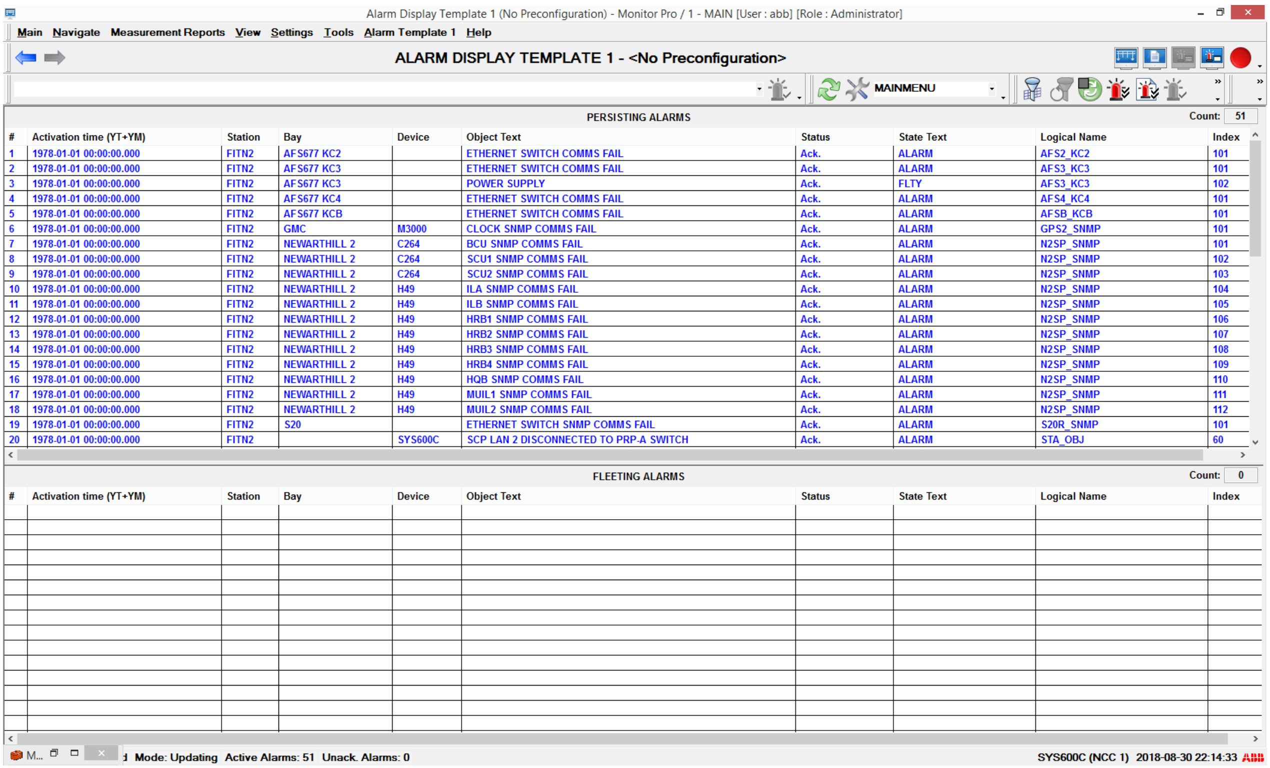


Figure 59. SCADA Alarm List

5.4.13 DAR and Sychronising

The DAR function is implemented in the REC670 BCU and the P841. Its main function is to allow an automatic reclosure, following a transient fault. The DAR is primed by DAR required trip commands, such as line differential, distance zone 1, distance aided trip and I/T Received trips. It is temporarily inhibited during the TRR time (10 seconds) and locked out by DAR not required trips such as distance zone 2, 3 or reverse, backup protection, busbar protection, CB fail or persistent I/T (>60 seconds) or system split.

By settings, the DAR could be performed under one of the following line and bus conditions:

- Dead line charge.
- Dead bus charge.
- Check synch.

The DAR will never be permitted under dead-line dead-bus conditions.

In order to perform the actual closure under the scenarios presented above, the DAR needs to interact with the synchronising function block.

SPEN do not use busbar VT's, they use a check synchronising scheme which replicates the main/reserve bus voltages. In FITNESS, the synch function block is fed with the incoming volts derived from line VT, whereas the running volts (Main Bus Volts and Reserve Bus Volts) are derived from Wishaw substation synchronising buswires via GE's MU320 stand-alone merging unit. The digitised data is presented to the REC670 process bus switch, along with its own line voltage. Based on the main/reserve bar isolator position, the synch function makes the correct running volts selection and compares it against the incoming volts. In other words, REC670 BCU and P841 subscribe to multiple SV streams that allow measurement of main/reserve bar volts and the incoming line volts. Once these are mapped to the relevant pre-processing function block, the rest of the scheme is identical to any conventional systems.

REC670 - BCU - Ethernet Configuration

Access points | Merging units | Routes

MU	Name	AP connection	Sample Value ID
9201	MU1	AP3:Process Bus	SAM600MU0101
9202	MU2	AP3:Process Bus	MER1UNIT320
9203	MU3	None	ABBMU0103
9204	MU4	None	ABBMU0104
9205	MU5	None	ABBMU0105
9206	MU6	None	ABBMU0106
9207	MU7	None	ABBMU0107
9208	MU8	None	ABBMU0108

Figure 60. SV ID configuration for BCU

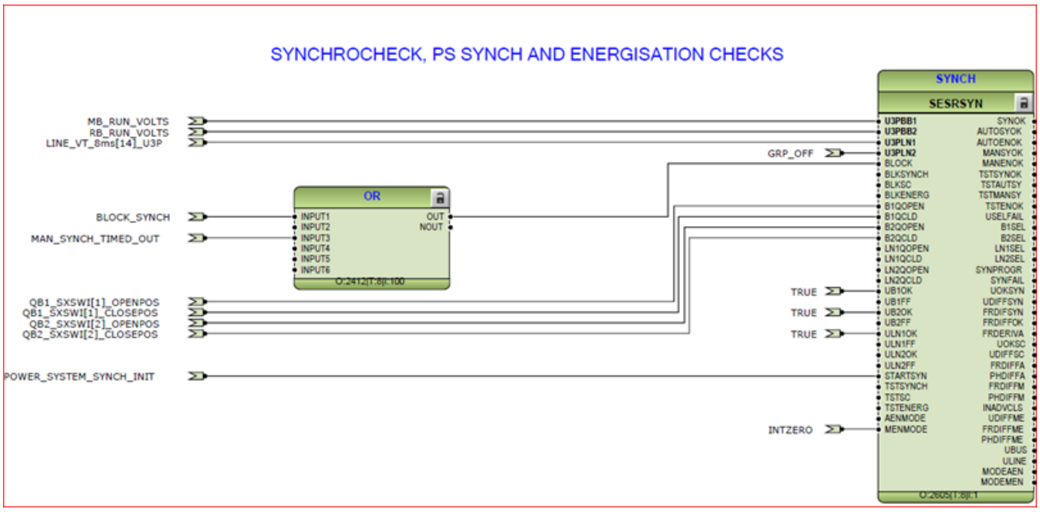


Figure 61. Synch Function Block configuration

5.5 Testing and Commissioning

The testing formed a key part in the FITNESS digital substation pilot project. Having performed extensive offsite tests in the vendors' factories at ABB in Stone and GE in Stafford, the commissioning and onsite testing of the two bays at Wishaw 275kV substation was carried out in two phases.

In this close-down report, the most relevant tests of the FITNESS project are briefly explained. All tests and their detailed test results are available as attachments to the FITNESS SDRC report.

Some of the main challenges for testing in digital substations and differences compared with conventional substations are listed here. At the end of this section the lessons learnt for testing in digital substations are summarized as a conclusion.

5.5.1 Testing in digital substations – Challenges and differences to conventional substations

One of the biggest challenges in testing digital substations is that the new technologies require also new testing tools. It is somehow clear to everybody that we can easily measure values with a multimeter in a conventional substation but how can we get this kind of information out of the bits and bytes on the digital substation network. The engineers require according new tools for that. Additional it is also often necessary that engineers get training for the new skills. More collaboration and a close teamwork of Protection, Automation & Control, and IT engineers is needed in digital substations.

A major difference to conventional substations is that the communication network is now an integral part of the overall system and testing of it is required. Also, the cyber security aspects need to be considered for the communication network. There are new connections to the primary equipment in digital substations. The instrument transformers have a MU out in the field and there are only fibre connections into the relay room.

The protection system is using GOOSE and SV instead of conventional wirings. There is the Simulation and Test mode concept defined in the IEC 61850 standard which allows isolation of the test scope without physical disconnections and therefore allow outage-less testing and maintenance of the system. And there are more possibilities for automation and control systems which require also automated testing as already available and common for protection systems.

5.5.2 Network communication testing

Communication networks are of paramount importance for the overall performance and operation of the fully digital substation. Analogue data (SV) and binary data (GOOSE), as well as time synchronisation messages (PTP) are sent via the communication network. The following network tests have been performed in the FITNESS project.

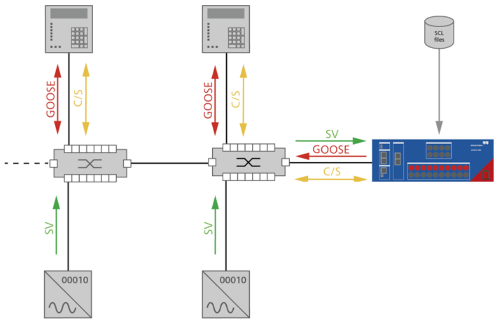
5.5.3 IEC 61850 System Verification

The IEC 61850 communication is a mission critical part of the protection automation and control system. The description of the FITNESS communication system in the standardized IEC 61850 substation configuration language (SCL) format serves as the basis for the verification.

This test verified that the IEC 61850 server of all IEDs are available and the substation network traffic is present on the communication network as defined. As devices are put into operation one by one during commissioning, the verification can be performed incrementally without re-executing all the checks for all devices already verified.

The network analyser devices were connected to the substation network so that all kind of IEC 61850 messages are received and all IED servers are reachable. The DANEO in bay 1 was connected with port A to PB1, port B to PB2, and ETH port to one bay level network switch (e.g. PRP A). The DANEO in bay 2 was connected with ports A/B in TAP mode into an HSR link and with the ETH port to the testing RedBox. The test PC with DANEO software was also connected to the testing RedBox.

In the figure below an example result of a system verification is shown. If devices do not perform as desired, detailed information is provided for further investigation and debugging. There are different reasons why an IED verification can fail. It is possible that there is an error is in the engineering file, the IED configuration, or even in the network configuration.



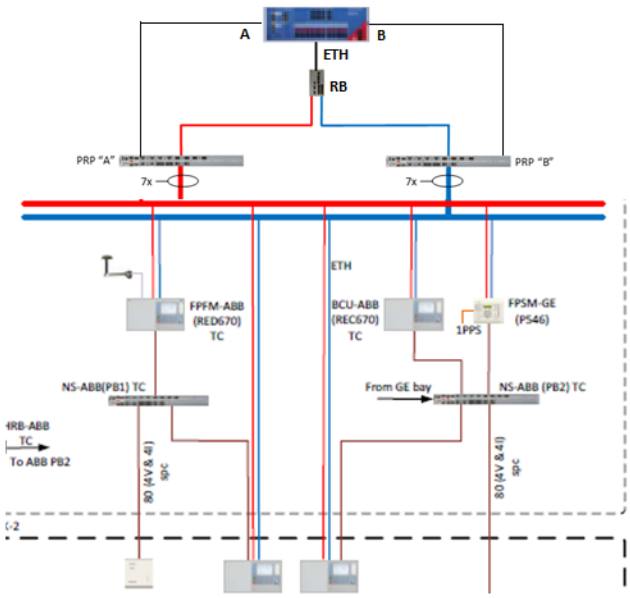
IED	Server	GOOSE & SV	Result
CNEWHAR1	✓	✓	✓
SCU1NH1	✓	✓	✓
SCU2NH1	⚠	✓	⚠
AA1D1Q02FN1	✓	⚠	⚠
R841BUP	✓	✓	✓
AA1D1Q02KF2	✓	✓	✓
R546FPFM	✓	✓	✓
AA1D1Q02KF3	✓	–	✓
AA1D1Q02FN2	✓	✓	✓
AA1D1Q02KF1	✓	⚠	⚠
RREDFPSM	✓	✓	✓
GTWM	⚠	–	⚠
OISERVM	✓	–	✓
MER1UNIT320	–	⚠	⚠
SAM600	–	✓	✓
MERUNIT320	–	✓	✓

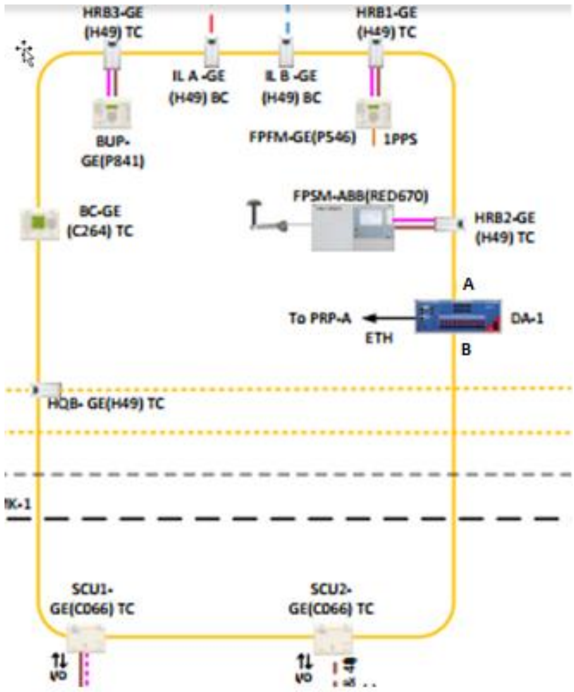
Figure 62. System Verification

The overall system verification test result was passed after all single IEDs have passed. Some differences in GOOSE messages and SV streams were detected but changes in configurations and engineering files solved all issues. When the engineering files were corrected and completed the system verification test passed and no orphan elements were found in the system.

5.5.4 Network redundancy testing

For the network communication in the FITNESS project a redundancy with zero convergence time is required. In bay 1 there is a PRP network architecture and in bay 2 there is an HSR ring. In the figure below there is the connection of the test set shown for both bays. The network on station level is also designed as a PRP network. In such redundancy networks, packets are sent out on both links of the DAN and are evaluated by the receiving node. The receiving node accepts the first received frame and discards the second.





PRP network redundancy in bay 1 **HSR network redundancy in bay 2**

Figure 63. System Redundancy Tests

The following redundancy tests are negative tests which detect the missing of packets on the network ports of the test device in case of broken network links or network components at one and both ports of the device under test.

The DANEO network analyser shows the GOOSE and SV data values of the IEDs. There is an overview of the three device ports showing if packets are received or not. The traffic statistics on each network port provides details about communication timeouts and the number of missed packets. In the example below, the GOOSE was not received on LAN B of PRP but it was still received on LAN A and also on station level which was here port ETH.

G R546FPFMSystem/LLN0GOgcb01

Details

Statistics

	A	B	ETH
Receive time	2018-04-13 11:08:14,725	2018-04-13 11:06:57,896	2018-04-13 11:08:14,725
Packet count	122	55	131
Status changes seen	2	2	2
Status changes missed	0	0	0
Retransmissions missed	9	0	0
Duplicates seen	0	0	0
Time to live expired	False	True	False
Time to live expired count	2	2	1
Packet delay:			
Minimum	-637,45 ms	-637,45 ms	-637,45 ms
Maximum	-632,66 ms	-632,66 ms	-632,66 ms
Average	-635,06 ms	-635,06 ms	-635,06 ms

DataSet - R546FPFMSystem/LLN0$OPGOOSEDataset

Name	Type	Value	Ports
DA CB1PTRC1.Tr.general	Boolean	True	A B ETH
DA CB1PTRC1.Tr.q	Quality	Good	A B ETH

Figure 64. System Redundancy Tests-1

For reporting of the test results a GOOSE or SV timeout event was used to trigger the recording of the PCAPs and the time signals on all three network ports (A, B, and ETH). In figure below an example network redundancy test report is shown for a GOOSE message of a protection IED.

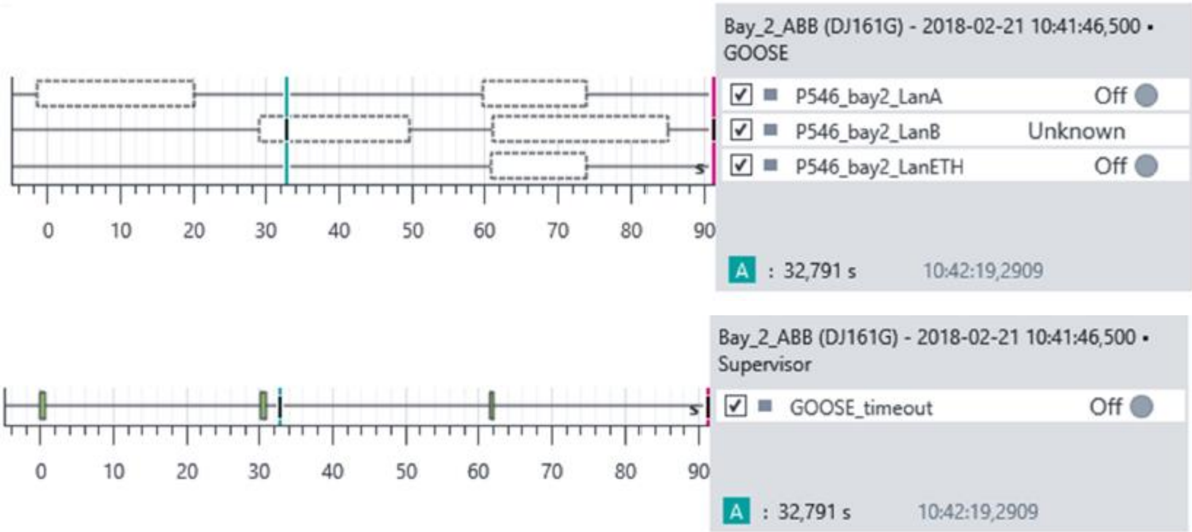


Figure 65. System Redundancy Tests-II

In the tests the redundancy in HRS and PRP bay was proofed. We have always checked the system and IED behaviour during the tests. Troubleshooting of issues was easily possible with all the details and recordings by the test set.

An additional test case we have performed was the power cycling test of IEDs. The purpose of this test was to verify the power-down / power-up cycle of any IED connected to the PRP and HSR network. There was no unexpected disruption on the other IEDs and there was no reconfiguration of any device in the system required.

5.5.5 Time synchronization testing

The time synchronization architecture in FITNESS comprises two GPS based grandmaster clocks as shown below.

Both Meinberg and GE grandmaster clocks were synchronized via GPS / GLONASS and set to the same priority. The best GM became the grandmaster according to the BMCA.
The successful synchronization of all devices was checked by analysing the network traffic and verification of the synchronization status of all IEDs and network switches.

The PTP network sniffer in the network analyser listed all PTP grandmaster clocks on the network and its details as shown below.

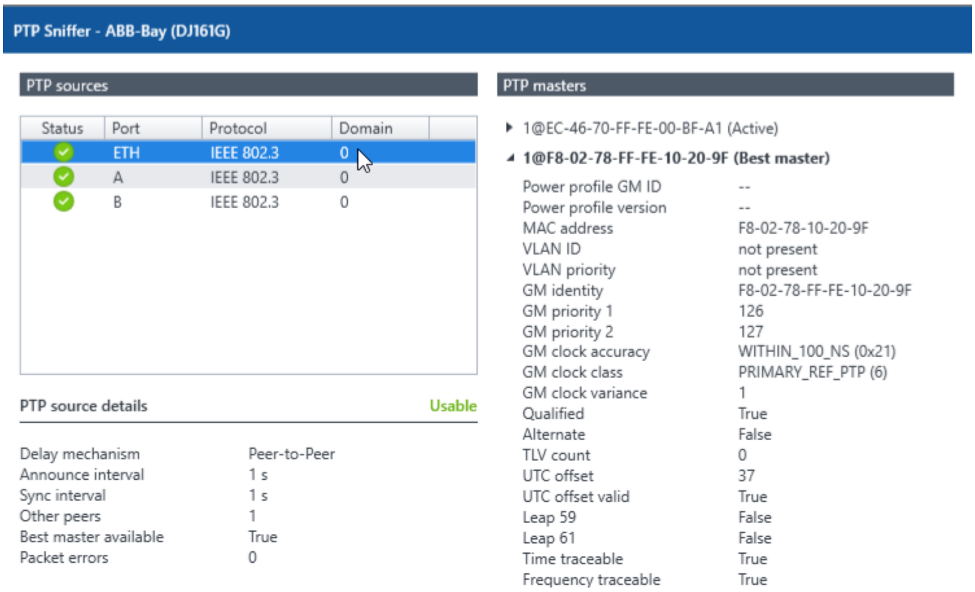


Figure 66. Time Synchronisation Tests

We tested the BMCA and measured switchover and holdover times with negative testing of GPS loss and network failures. Also, here we always checked the overall system and IED behaviour during the testing.

5.5.6 Network performance assessment

The correct design of the communication network is an essential precondition for a digital substation. Consequently, the performance and load of the communication network needs to be tested and assessed.

Network Bandwidth Load

This test verified that there the network load is not overloaded and there is enough reserve bandwidth for situations with increased amount of traffic (e.g. protection trip, control commands, testing with additional simulated data, downloading of fault records).

The network analyser was connected to different locations of the substation network. For each location, the traffic signal (bytes/s and packets/s) are measured. At the network switches a mirror port is required for this test. The test set even shows the values for the different kind of substation traffic (GOOSE, SV, IP).

Bytes/s		Packets/s	
A-GOOSE	13,7 kB/s	A-GOOSE	29,2 P/s
A-SV	3,3 MB/s	A-SV	17,6 kP/s
A-IPv4	14,3 kB/s	A-IPv4	117 P/s
A-Total	3,3 MB/s	A-Total	17,8 kP/s

Figure 67. Network Bandwidth Tests

For testing of the situations with increased traffic the network analyser shows the traffic signals on the timeline to detect the maximum bandwidth load during such a test execution. In case of a bandwidth load issue a report of the recorded traffic signals can be attached to the test report.

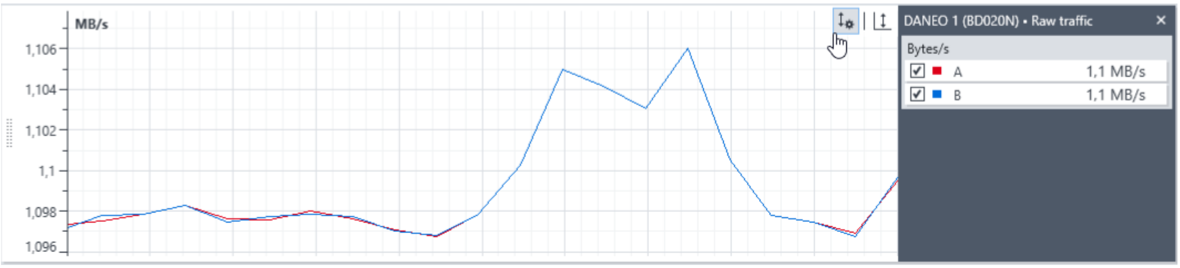


Figure 68. Network Loading Tests

The bandwidth loads were measured at all different network locations and documented in the test report. After fixing some filter configurations in the network all values were as expected and tests were marked as passed.

Packet Propagation Delay Measurement

There are performance requirements to be fulfilled for GOOSE and SV transfer times. The transfer time consist of data processing time in the IEDs and the network time.

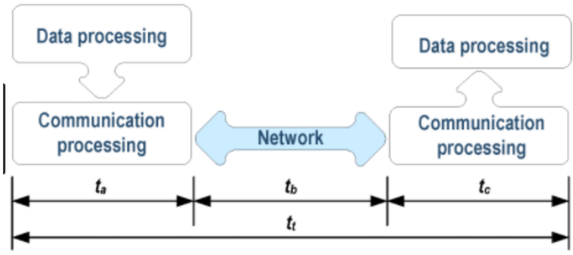


Figure 69. Propagation Delay

The network analyser test set was used to measure and assess the network time of any network packets (GOOSE, SV, IP).

In figure 71 below, an example propagation delay measurement result is shown for the inter-bay GOOSE message. The inter-bay propagation delay was measured with traffic recordings in bay 1 and bay 2. Here we have the statistics with min, max, average, and standard deviation shown for the GOOSE packets.

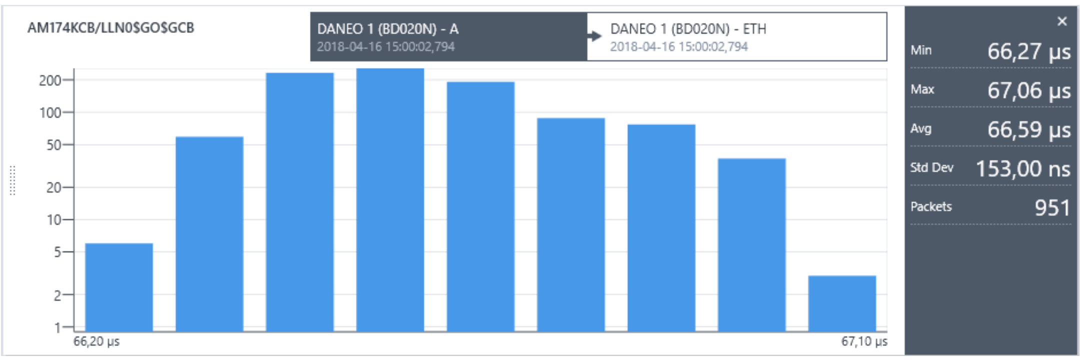


Figure 70. Propagation Delay Measurement

It is important to make such performance tests also with worst case scenarios with the highest network load.

5.5.7 Protection testing

We started to define automated test procedures for protection testing during the FAT. The efforts for creating these test procedures payed off very quickly because of reusing them multiple times during the testing in the different phases of the project. The test sequences included both main 1 and main 2 protection, as well as the back up protection and circuit breaker failure protection. We have added some instructions so that the execution of the test proecedure is also easily possilbe for engineers who were not part of the project and its test template creation.

The correct operation of the protection system was confirmed not only via the automated test sequences executed with the OMICRON CMC test set, but also with the MicroSCADA events lists and the IEDs HMI LEDs. All OMICRON OCC files have been stored on the dedicated test laptop in the system. They can be re-run at any time, thus proving the concept of repeatability and traceability of test sequences. It should be noted that the protection was tested as a completed system with simulated SVs and GOOSE. For this purpose, certain preparation had to be carried out at IEDs level as explained in the next section.

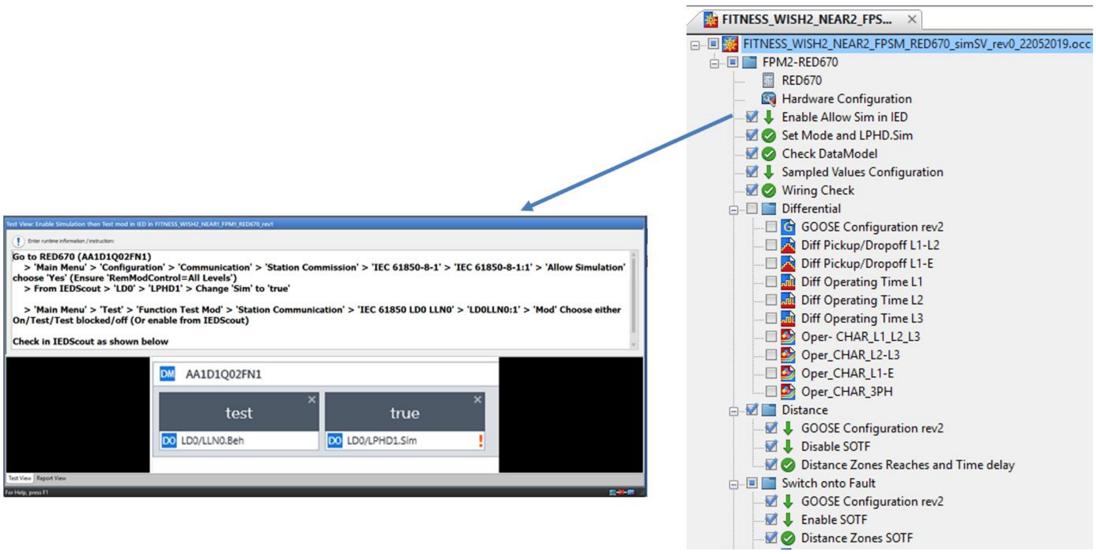


Figure 71. Automated Protection Testing

5.5.8 Simulation and Test Mode Concept

This aim of this test was to prove that testing with simulated data is possible according to IEC 61850 edition 2. This feature is very useful to test the protection in a live system without physically changing any wiring.

The IEC 61850 Simulation and Test mode concept provides enhanced testing capabilities for IEC 61850 protection systems. Operator commands can configure the IEC 61850 **Mod** parameter which determines the behaviour**Beh** of the according functions. For IEDs, the mode can be configured in the device menu or remotely from an IEC 61850 client, for example the SCADA system or a dedicated test tool. The IEC 61850-7-4 standard gives a detailed overview over all aspects of the test mode and the resulting behaviours.

In the testing we have used following test and simulation features and proved the concept in a real substation environment during the site acceptance testing.

- An individual IED is set into Mod = test
- A control service and data attributes within a GOOSE message are characterised with test flags
- The ability to subscribe to simulated GOOSE or SV messages from a test set

The simulation and test mode sequence used in the FITNESS project is described and shown in figure 73 below. The protection IED with MOD=ON is still subscribing to the SV stream from the MU and working normally, only the protection IED with in Test and Simulation subscribes to the test set SV stream.

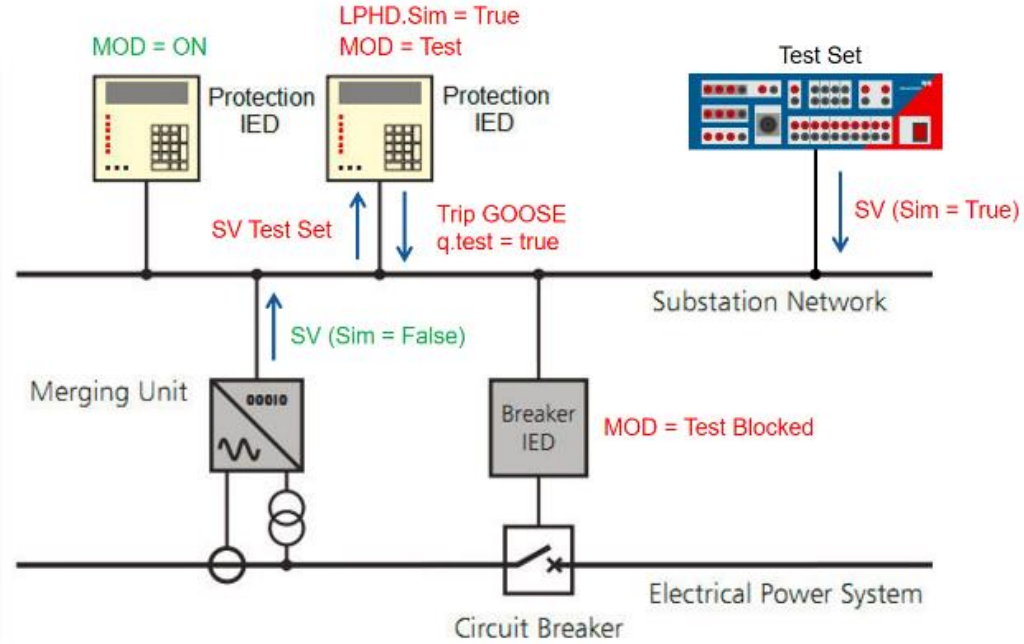


Figure 72. Simulation Flag and Test Mode

Operation on simulation and test mode

The SV stream from the CMC test set has the simulation flag equal to TRUE and the data values marked as test in the quality attributes. The protection IED must be configured to simulation mode LPHD.Sim = TRUE so that it processes the simulated SV stream from the test set. Once the simulated messages are received, the corresponding 'real' messages from the MU are ignored until the simulation mode is disabled. Additionally, the protection IED is set into Test mode. The data in the trip GOOSE is marked as Test in the quality attributes and will be processed by the Breaker IED depending on its configured mode.

The REC670 BCU with its built-in plant simulator feature (nothing to do with IEC 61850 simulation mode was enabled to allow simulation of plant positions during the test. The simulation (LPHD.Sim) and test (MOD) mode of the IED under test was set to true and we verified this with the IEDScout test tool, as shown below.

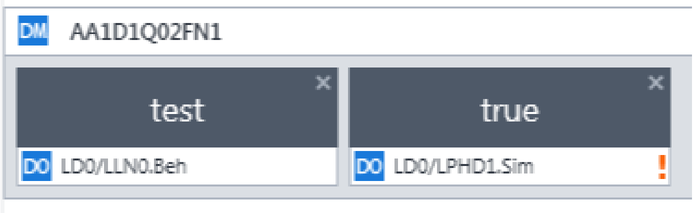


Figure 73. IED under test set LPHD.sim to 'True' and Beh to 'Test'

Any IEDs in the sequence was in Mod = Test. The plant interfacing IED has to be set to Mod = test-blocked if trip signals are mapped to the circuit breaker (CB). In FITNESS project there was no physical connection to the actual plant, other than indications. GOOSE messages that are intended to trip the plant were supervised and recorded by the Switching Control Units (SCUs).

The OMICRON test set SV publisher was globally synchronized, and the simulation flag was set to 'true' to indicate the SV streams are being published by a test device. The SV stream was monitored on the process bus. The quality of the stream was good with no samples missed as shown below.

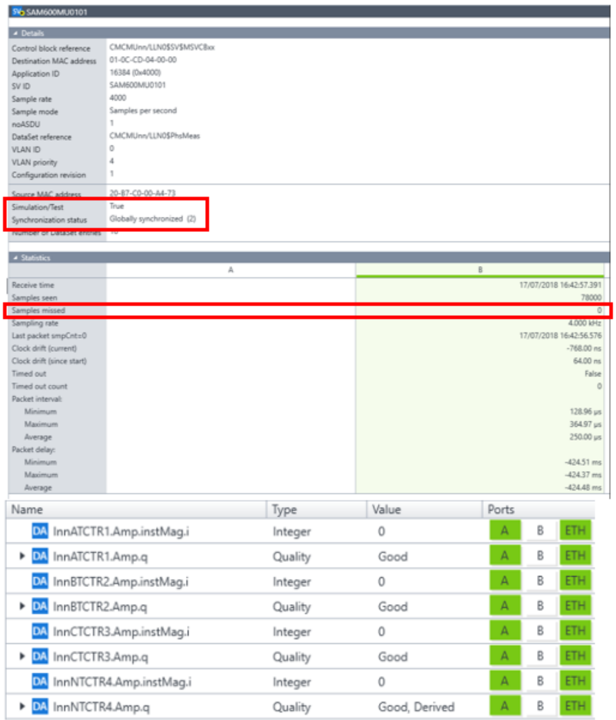


Figure 74. SV stream details monitored with the DANEO network analyser

The test set was configured to subscribed to the GOOSE messages from the protection IED. The trip signal of the IED in test mode was published with the quality test bit set to 'true'. Any IED in the sequence set to test mode will process this operation. Other IEDs in Mod = on ignored the trip signal. The SCU in Mod = test-blocked with the plant interface accepted the trip signal and simulated the plant position but did not trip the actual plant CB. After completion of test sequence all IEDs were set to Mod = on again and the simulation mode on the protection IED was reset back to false.

With the simulation and test mode concept, there is no need to disconnect any fibre optic associated with the MUs. Also, there is no need to change any SVID in the real MU, in the IED or in the test tool. The same SVID as the real one is used in the setup and the only difference is the value of the simulation flag. This concept can also be applied easily when it comes to onsite maintenance. No physical interaction is required with the IED, allowing testing whist in service, without operating the plant, or requiring outages. With a remote connection to the substation also remote testing is even possible. In the redundancy system when testing Main 1 protection, it is expected Main 2 will not be in simulation mode to continue to provide full protection. Once Main 1 protection is tested and put in 'On' mode again, the same procedure above is repeated for Main 2 protection.

5.5.9 Automation and Control Testing

Tests were carried out to verify the automation and control functionalities together with the communication between different devices within the substation. Using the SCL engineering file which contains all the signal mapping we could easily trace how signals propagate through the substation network. The StationScout test tool was used here to graphically display the point-to-point communication for reports and see all the GOOSE messages being published and subscribed.

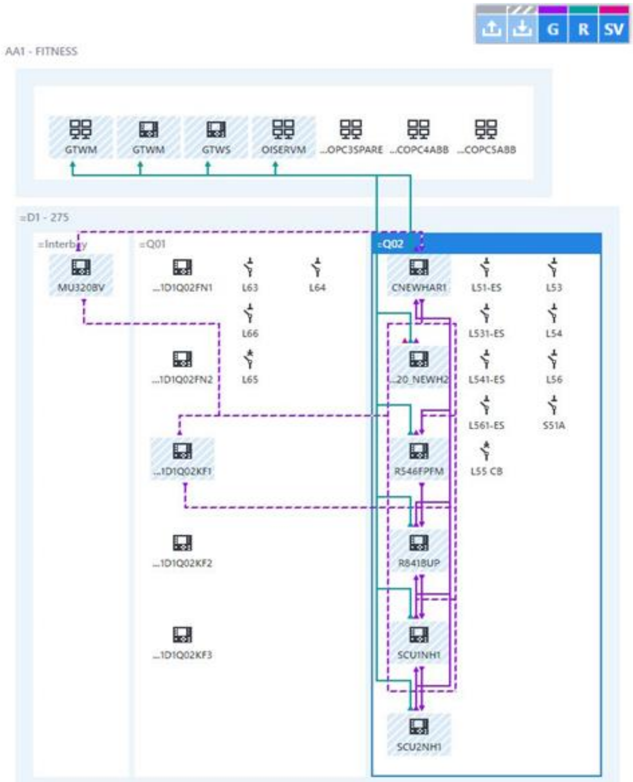


Figure 75. Network Testing With Station Scout

Testing like this allowed us to efficiently test the system. Having an overview like this we move from testing of a single device to testing of the entire system.

During FAT and commissioning we needed to simulate missing IEDs and some signals. Having a fully defined SCL file made it possible to verify the communication configuration even when not all devices or bays were yet installed.

5.5.10 Commissioning and site acceptance testing

There are some tests which are not possible under laboratory conditions during the factory acceptance testing. These tests were the focus during our commissioning and site acceptance testing work (i.e. primary injection and end-to-end testing using SPEN communication channels and IEDs installed in different geographic locations).

Primary Injection Tests

Primary injection tests were conducted to prove the whole chain of equipment: from Merging Units (XMU860 and SAM600) to process bus switches, IEDs and SCADA HMI. An OMICRON CPC primary injection test set was used to simultaneously inject both the conventional instrument transformer (CIT) and the non-conventional instrument transformer (LPIT). The two sets of results facilitate comparison/analysis to be carried out between the two instrument transformer technologies.

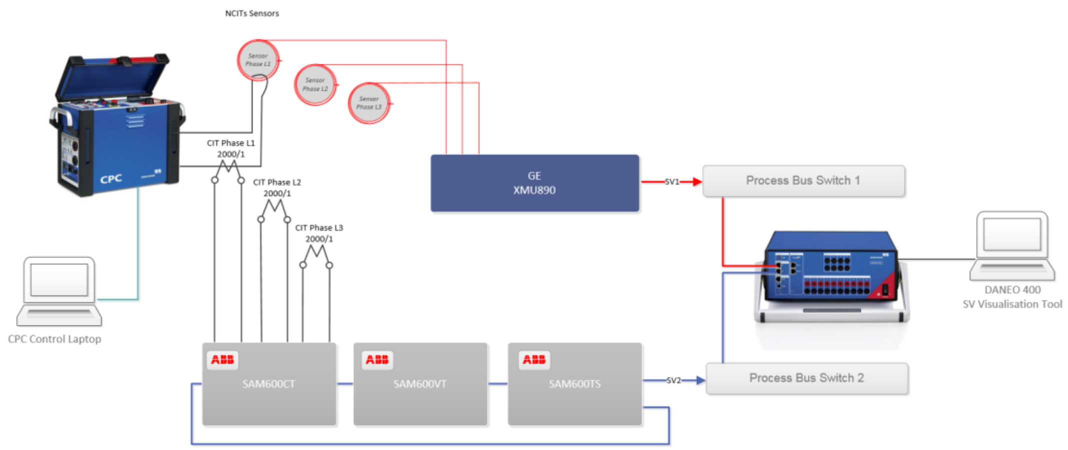


Figure 76. FITNESS Primary Injection Set-Up

We injected different voltages and currents levels to the instrument transformers. A comparison with the values in the SV streams from the MUs was easily possible with the test result diagrams. Both CIT and LPIT have an acceptable level of performance for the IEDs. Primary current injection was carried out in increments of 0A, 20A, 50A, 100A, 200A, RMS measurement of both technologies was within acceptable accuracy. Readings were taken from the DANEO 400 visualization tool and confirmed by both the SCADA HMI and the relevant IEDs: RED670 and REC670 for SVs derived from the LPITs and P546 for SVs derived from the CITs via SAM600. The same tests were repeated for phase L2 and phase L3, as well as in pairs (L1-L2, L2-L3, L3-L1) with identical results.

A similar test was carried out with the voltage transformers. It should be noted that the primary injection test set was unable to generate more than 2kV primary. However, this proved to be sufficient to demonstrate that all fiber optic connections, phasing and – ultimately - the quality of the associated SVs was within accepted IEDs tolerances.

A closer look at lower current magnitude measurements shows that the LPITs sensor technology provides much better accuracy and quality of measurements, compared with their conventional counterparts.

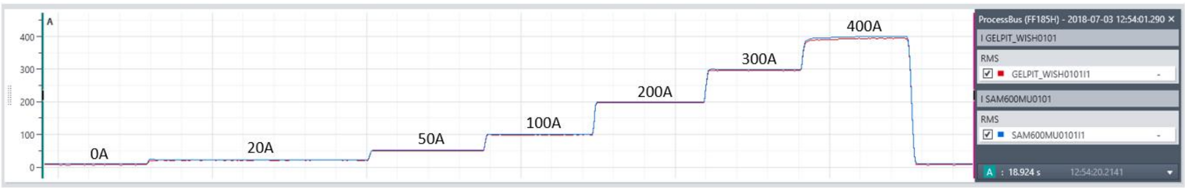


Figure 77. RMS values, LPIT in red, CIT in blue

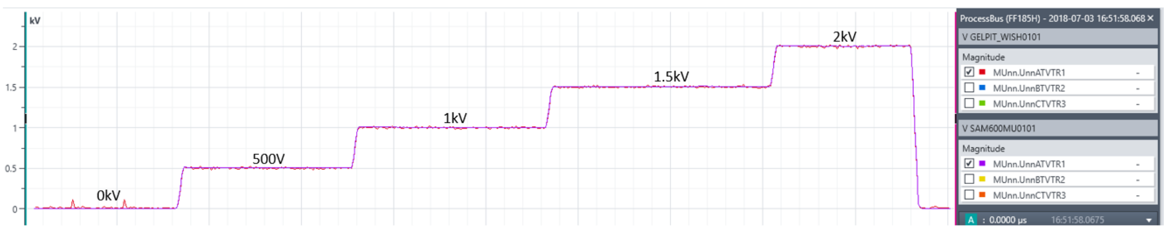


Figure 78.Voltage Magnitude, LPIT in red, CIT in blue

The test results show that the LPITs accurately reproduce all harmonics content, whereas the CIT only picks up the fundamental frequency. This behaviour was observed for both current and voltage transformers.

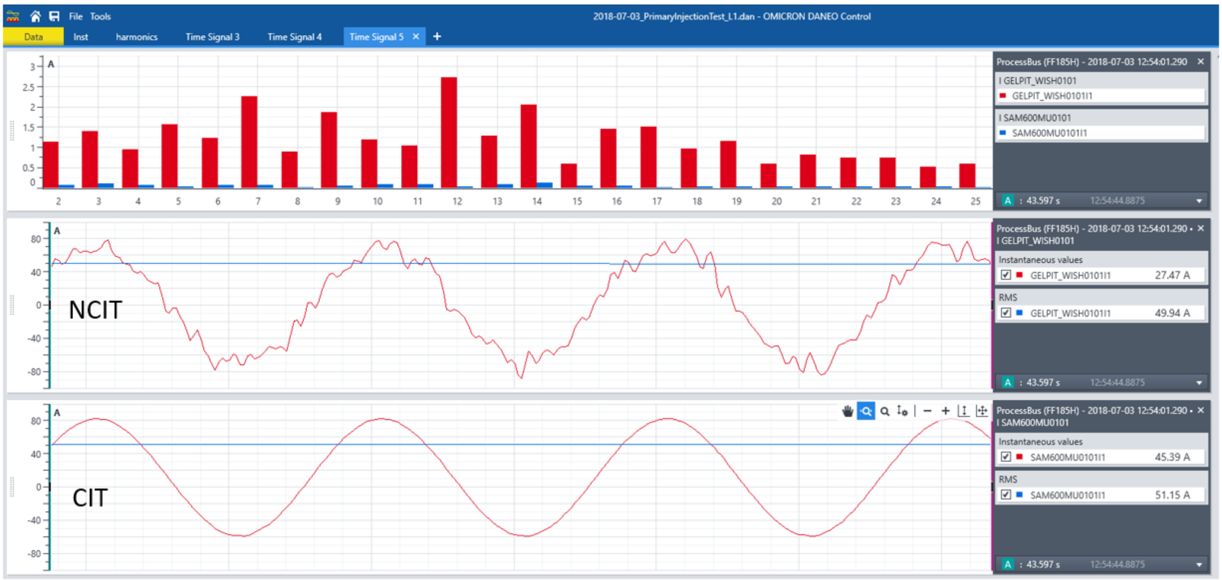


Figure 79. LPIT has higher accuracy measurements at lower magnitude levels

The tests proved the interoperability between MUs and protection IEDs as a chain in a substation environment. Additionally, the quality and correct subscription of SVs was verified. We proved the correct phasing for all primary and secondary equipment, CT and VT ratios. We discovered and fixed an issue related to OVT phase L3 which needed some adjustment on the comms attenuation to finally be validated as good quality SV by the subscribing IEDs.

End-to-end Testing

To comply with SP Energy Networks policy when it comes to main protection, duplicated line differential protections are used in FITNESS. Although for any conventional system, line differential protection site testing activities would have been limited to just pick up, drop off and operating time tests, to give the assurance that the system is correctly configured in terms of CT ratios, CT star points, phasing, wiring, setting, etc., it was decided to utilise a more modern end-to-end testing methodology, as supported by the OMICRON CMC test set.

Primarily, the aim of this test was to verify the stability and the tripping performance of the line differential protection as a system (including site comms) and to prove that the performance of the differential protection is not affected by the mixture of technologies, i.e. with the local end IED fed with analogue data derived from merging units and the remote end IED fed with analogue data derived from conventional CTs. During the end-to-end testing, synchronous fault conditions were simulated by injection at both ends to verify that the IEDs operate correct.

As in FITNESS project the local end is based on non-conventional technology, an OMICRON injection test set with process bus capabilities was used to publish SVs and subscribe to GOOSE messages, whilst at the remote end, a second OMICRON test set was hardwired to the IED for both the analogue signals and trip contact, as shown below.

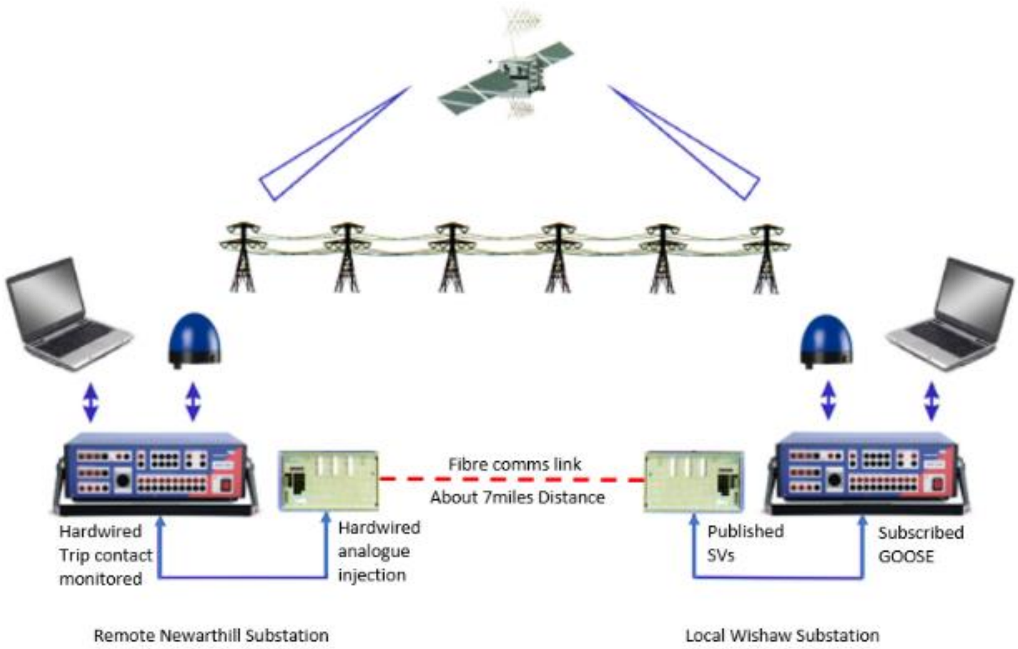


Figure 80. End to end testing of line differential protection

The end-to-end testing provided the final assurance in terms of differential stability and in zone faults. The end-to-end test results showed the plotting of the operating characteristic. This test also ensured that CT ratios and polarities are correctly configured. The automatic assessment offers easy analysis and troubleshooting in case of any issue. Such end-to-end test does not depend on any protection device.

5.5.11 Cyber Security and functional monitoring

After commissioning the digital substation, it is recommended to make a permanent monitoring during the operation phase. This includes cyber security aspects with an intrusion detection system as well as the monitoring of functions and network communication.

Network traffic supervision

A network traffic analyser was connected into the system as a network TAP and installed permanently in the rack onsite as shown in figure 82 below. In the FITNESS project we already detected a few occasional problems like GOOSE, SV, or PTP time synchronization issues during testing. The troubleshooting and solving was possible with the triggered recordings of signals and related PCAP files of the network analyser.

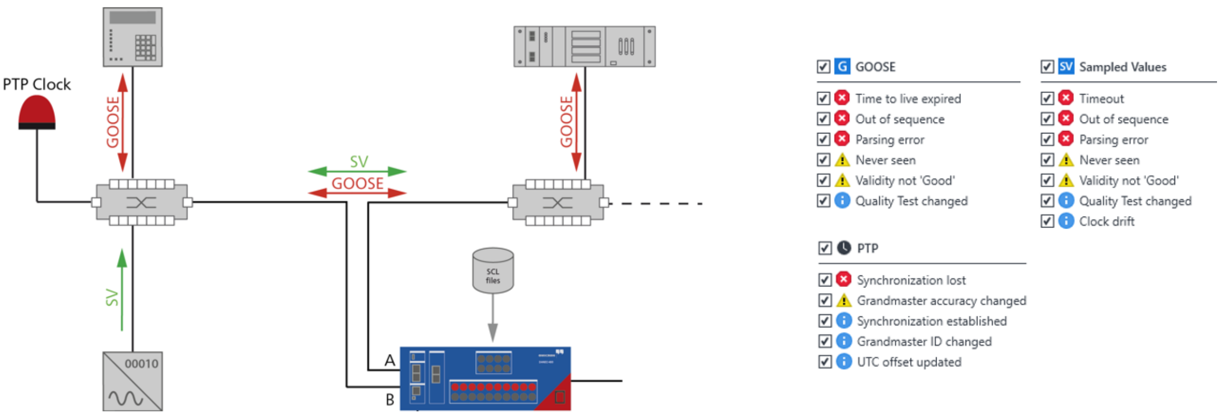


Figure 81. Cyber security intrusion detection

An Intrusion detection and functional monitoring system was used to analyse all network traffic to detect cyber security intrusions and equipment malfunctions. A prototype of the StationGuard product was used because it was still under development at this time. The tool is using the knowledge about the substation automation system (SAS) and information about the power system and its assets to determine which behaviour is safe or unsafe. StationGuard retrieves this information from the SCD engineering file of the substation. A whitelist approach is used, this means that each communication and each event which does not fit to the system model of the substation will trigger an alarm.

StationGuard was connected to the station bus and before the SCL files are loaded all devices sniffed on the network were highlighted in 'red', indicating unknown traffic as shown in figure 83.

Figure 82. Errors Identified in Cyber Security Testing

The SCD files from GE and ABB were loaded and all devices defined in the SCD files were arranged in a logical a zero-line diagram in 'grey'. Unknown traffic was still identified as 'unknown devices' in red, consisting of equipment such as merging units, test sets, test and engineering PCs which were not defined in the SCD files. We added them into the 'known devices' manually by classifying them based on predefined roles within the SAS.

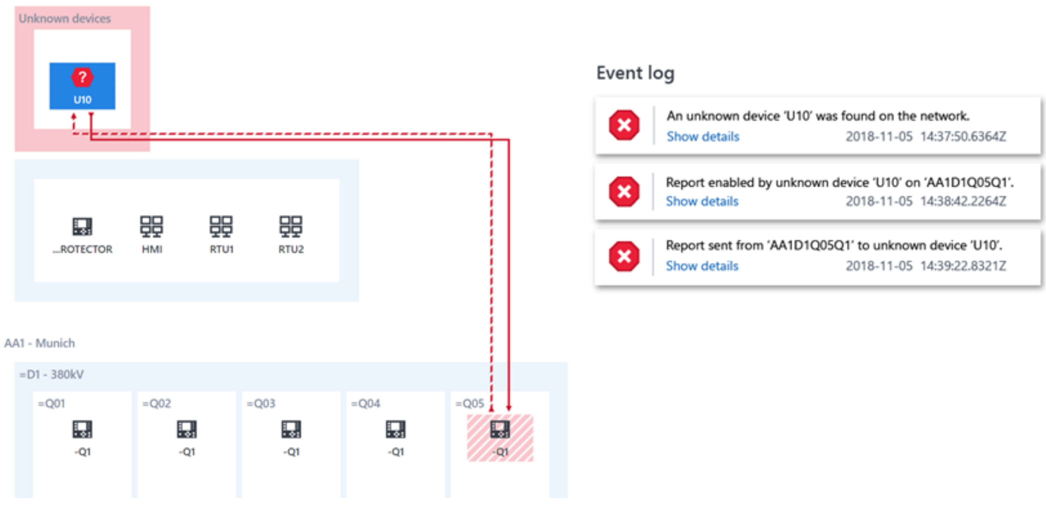


Figure 83. StationGuard intrusion detection system with alarms in event log

The configuration of StationGuard was easily possible because there is no detailed IT-security or IEC 61850 knowledge required. The Alarms and indications could also be integrated into the SCADA and existing security systems. It is possible to configure also binary outputs from StationGuard to provide alarm signals to the system operator utilizing RTUs/Gateways.

5.5.12 Conclusions and lessons learnt for testing

The testing in the FITNESS pilot project was challenging for the team members as well for the used testing tools. Here are some of the main lessons learnt for testing during the project work.

- Consider **testing concept** already in design phase
- Quality and versioning of the **SCL engineering files** is essential
- Setting up **test lab** helps to gain knowledge
- Perform **network communication tests** before PAC testing
- Detailed offsite testing **reduces onsite time** significantly
- **Automated test procedures** are recommended and pay off quickly
- Consider also **cyber security** and define measures

5.6 Wide-Area Monitoring and Control

The core objectives of the FITNESS project with respect to Wide-Area Monitoring and Control (WAMC) are listed below, and the related SDRCs and evidences are listed within Section 6.

- Demonstrate that the Digital Substation can support existing needs, specifically in the areas of PMU-based Wide-Area Monitoring and Control, Fault capture and analysis, and harmonics monitoring.
- Assess measurement quality and confirm interoperability of the different measurement chains.
- Explore new applications that could be supported by the measurements used in FITNESS, including fast PMU data for fault analysis and real-time harmonics monitoring.
- Assess cybersecurity requirements and capabilities, including a comparison of PMU data exchange protocols.

In pursuit of these objectives, the following work was undertaken, which is described in more detail later in this chapter, along with key lessons learned:

- Infrastructure demonstrated and evaluated:
  - Primary and secondary measurement chains: conventional, nonconventional and hybrid
  - Measurement functions: Phasor Measurement Unit, Fault capture & analysis, Harmonics
- Wide-Area Monitoring & Control aspects reviewed:
  - Integration with central information infrastructure: WAMS and EMS
  - Wide-Area Control Platform
  - Cybersecurity
- Novel applications investigated
  - Fault analysis: location and system-wide behaviour
  - Real-time harmonics monitoring
  - Topology & measurement validation

5.6.1 Infrastructure

This section describes the various conventional, non-conventional and hybrid measurement chains deployed in the FITNESS project, the measurement functions utilised in evaluating their performance, and the findings of that evaluation.

The monitoring elements of FITNESS focus on some of the most demanding system monitoring application areas in terms of measurement performance, some key requirements of which are detailed in the following subsections:

- **Wide-area monitoring & control** using synchronised phasor measurements from Phasor Measurement Units (PMUs) at 50fps.
- **Capture & analysis of fault behaviour** (including impedance-based fault location) using fast (200Hz) phasor measurements
- Power Quality monitoring – in particular **harmonics**.

In FITNESS, these functions are all performed by a single model of device – the GE RPV311 multifunction recorder - with 4 devices in total covering all measurement chains across the two circuits. The RPV311s receive measurement signals from both the IEC 61850-9-2 process bus and from their own conventional analogue acquisition modules – which are connected to their respective RPV311 via a point-to-point fibre connection.

Fault oscillography data is stored locally on each device, and phasor measurements and harmonic information are streamed via the IEEE C37.118 protocol to a local GE Phasor Data Concentrator (PDC) in the FITNESS substation, where they are stored. In addition to providing local storage for the PMU and harmonics data, the PDC provides local visualisation of measurements and the capability to export in COMTRADE or CSV format for event analysis.

5.6.2 Measurement Chain Architecture

The FITNESS measurement chain architecture is illustrated in Figure 84. It can be seen that digital, conventional and hybrid measurement chains are monitored. Furthermore, a mixed-vendor approach has been taken across both bays and each level.

At the primary plant level, the mix of components includes:

- Non-conventional voltage & current transformers
- Conventional Capacitor Voltage Transformers (CVTs) and inductive Current Transformers (CTs)
- Specialised transducers retrofitted to conventional CVTs to provide a signal suitable for harmonic measurement

At the secondary measurement level, components include:

- Novel fibre-distributed optical current transducers

- IEC 61850-9-2 analogue Merging Units operating at 80 and 256 samples/cycle, following the “IEC 61850-9-2 LE” guideline
- Conventional analogue measurement acquisition directly by the multifunction recorder devices used for FITNESS monitoring, sampled at 256 samples/cycle.

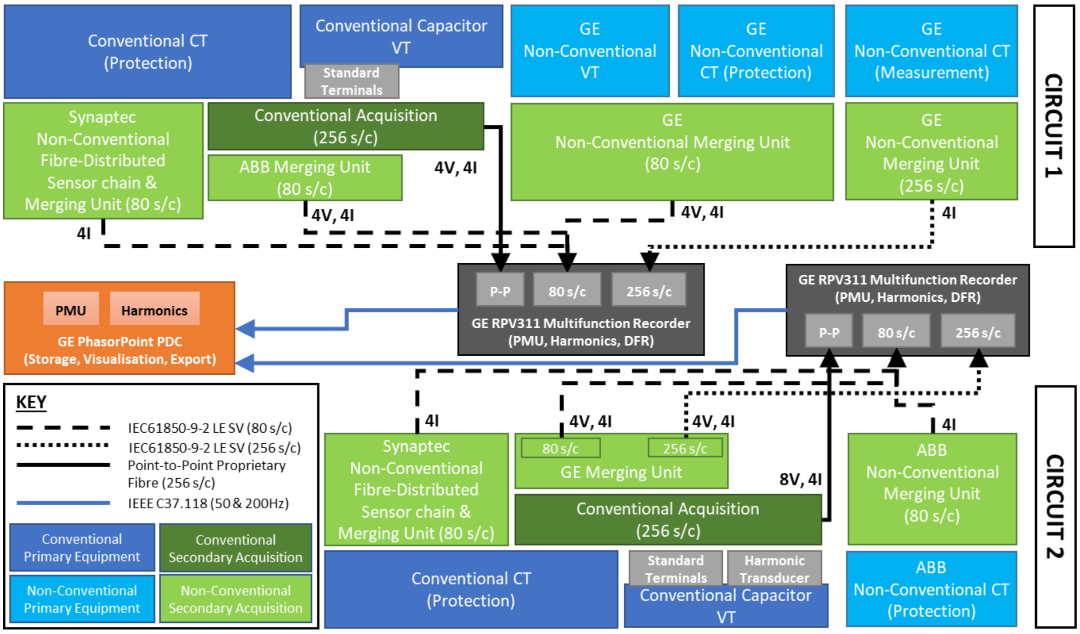


Figure 84: Architecture diagram illustrating the various measurement chains implemented across the two circuits incorporated in the FITNESS substation. Protection & Control systems are not shown

5.6.3 Phasor Measurement for Wide-Area Monitoring & Control

A Phasor Measurement Unit (PMU) provides measurement of the magnitude and phase angle of voltage and current waveforms in a power system, streamed continuously in real-time over a communications network. These measurements are reported typically up to once per mains cycle, and are accurately synchronised within microseconds to a UTC (Universal Coordinated Time) reference. In contrast to un-synchronised measurements from the conventional Supervisory Control & Data Acquisition system (SCADA), PMUs provide advantages in two key areas:

- The synchronised nature of PMU measurements enables comparison of phase angle across the power system. This gives a direct measure of the system state - which is otherwise approximated in the Energy Management System (EMS) through model-driven numerical estimation using asynchronous SCADA sweeps of measurements and switch/breaker states. This direct measurement of system state is valuable in areas such as awareness of network constraints and stress, oscillatory interaction, disturbance analysis and management of islanding and resynchronisation.
- The fast update rate provides continuous, wide-area visibility of system dynamic behaviour such as oscillations and disturbances. This enables solutions such as management of oscillatory stability, system model validation and response and analysis of system events.

The IEEE C37.118 standard defines both the measurement performance and application-layer communication protocol for synchronised phasor (“synchrophasor”) measurement. Calculation of phasors and frequency by a PMU will typically employ windows covering multiple cycles of the 50/60Hz waveform – a shorter window will provide a faster, higher-frequency bandwidth response at the cost of accuracy. The standard specifies performance in aspects such as measurement latency, accuracy, the capture of dynamic behaviour within a certain frequency range, rejection of higher frequencies that would cause interference in the reported measurements, and capture of grid disturbances.

With regard to impact of the measurement chain performance on PMU measurements, phase shift and latency are key. These affect the accuracy of phasor angle measurements, and of timing of disturbances in grid quantities such as during generator disconnections. Both are critical in many wide area monitoring and control applications. It is therefore critical that timestamping is accurately managed throughout the measurement chain, and that delays due to analog or digital signal conditioning and transmission are accounted and compensated for.

5.6.4 Capture of Fault Behaviour Using Fast Phasor Measurements

Fast phasors are calculated at update rates higher than nominal frequency, using shorter windows e.g. a single cycle of the 50Hz waveform. The faster update rate and shorter calculation window provides better visibility of fast transient behaviour such as transmission system faults, at the cost of reduced accuracy and greater susceptibility to noise.

Standard phasor measurements are updated up to once per cycle and can employ calculation windows several cycles in length. Thus, fast electromagnetic transients such as transmission system faults will often occur and be cleared entirely within a single phasor calculation window and will coincide with only a few phasor samples. Employing fast phasors with a shorter calculation window and more frequent update rate means that transient behaviour is captured more accurately (e.g. peak fault current) and more fully (e.g. fault duration).

With regard to measurement chain performance requirements for Fault analysis, measurement phase shift and latency are also key, as is magnitude accuracy. This is particularly true in impedance-based estimation of fault location, which relies on combined analysis of voltage and current phasors, sometimes from multiple sites. Accurate operation over a wide range is also crucial – in particular for current, which can reach significantly higher levels during fault conditions. These requirements are also relevant to protection systems.

5.6.5 Power Quality: Harmonics

The GE RPV311 performs local recording of harmonics, with each harmonic up to the 50th calculated and averaged every 3s, according to the IEC 61000-4-7 standard. Under FITNESS, the RPV311 has been augmented with the capability to stream these harmonic values in real time, time-multiplexed as part of the standard (50fps) PMU stream.

For measurement of harmonics, the critical performance aspect is the spectral bandwidth accurately passed by the measurement chain, with visibility up to the 25th or 50th harmonic a typical requirement. This represents a challenge for both primary and secondary plant.

Regarding the primary level, the Capacitor Voltage Transformers (CVTs) typically employed at high voltage tend to attenuate content above the 16-34th harmonic, as well as distorting harmonic amplitudes at lower orders. One solution to this limitation has been to retrofit specialised transducers within the secondary wiring of the CVT, which re-construct a wider-bandwidth signal. New non-conventional instrument transformers take advantage of overall different primary and secondary measurement principles and architectures to address the issue.

At the secondary level, harmonic visibility is constrained not only by sampling rate but also the analog and digital filtering employed in measurement acquisition units – typically, an 80 samples/cycle stream may provide visibility to ~20th harmonic, and 256 samples/cycle the ~60th.

It may be noted that recent industry recommendations have indicated that management of harmonics up to the 100th order is now advisable, given the proliferation of power electronic equipment and evidence of adverse effects. Visibility of this range places even more onerous requirements on measurement chains, including those potentially not feasible using IEC 61850-9-2 LE streams at 256 samples/cycle. It may be that higher rates are required, such as the 14.4kHz rate supported by IEC 61869-9, discussed in Section 5. Whilst the FITNESS project equipment and analysis has focussed on visibility up to the 50th harmonic, follow-up work may well examine performance up to the 100th.

5.6.6 Results of Measurement Chain Performance Comparison

This section outlines the key observations from the measurement chain performance comparison conducted during the FITNESS project. More details results are available in FITNESS Report # 26 - Measurement Chain Performance.

Analog merging units from GE and ABB both show good performance, across the measurement functions evaluated – appearing to reliably capture and convey measurements consistent with those from conventional acquisition.

Optical CTs from GE and ABB, and the Optical VT from GE, show comparable performance relative to conventional measurements in terms of voltage and current magnitude and phase, during steady-state and disturbed conditions. These measurements do differ more from conventional measurements than those from the analog merging units, however this is to be expected given that they are from separate physical high voltage devices, employing different signal conversion technology.

Regarding harmonics, the Optical CTs demonstrate similar performance to conventional acquisition, which is in line with expectations – conventional CTs being considered to capture harmonics reliably. The Optical VT captures qualitatively similar harmonic behaviour – i.e. similar “fingerprint” harmonic patterns are observed – but reports larger or smaller amplitudes relative to conventional measurements. This is expected, given the known distortion of harmonic amplitudes by conventional Capacitor VTs.

The Optical VT shows comparable performance on magnitude & phase relative to conventional measurements. On harmonics, it shows a different level of attenuation of certain harmonic ranges than the conventional measurements – which is to be expected, given the known issues with accurate harmonic representation from conventional Capacitor VTs. Later analysis including a known reliable PQsensor transducer will enable a conclusion to be drawn on harmonic accuracy.

The Synaptec distributed current sensors show reasonable measurement performance at medium-to-high line loading levels, with increased noise at lower loading. This is unsurprising given the intended use of these sensors in cases where conventional CTs and VTs are not practical, and the prototype nature of their deployment in FITNESS. Thus, whilst their reliability at present seems limited for precise analytical or monitoring applications such as power quality, oscillation & disturbance monitoring, and analysis of low-impedance and/or complex faults, they do seem applicable to coarse measurement and analysis of low-impedance (i.e. medium-high current) faults.

Some sample analysis results are presented the remainder of this subsection. For reasons of confidentiality, charts have been anonymised to remove sensitive numerical scales and vendor identification, and some results that could be linked to any one particular vendor have not been presented.

Figure 85 compares voltage magnitude measured from a CVT by a standalone Merging Unit with that from conventional acquisition of the CVT output, over a 24h period. It can be seen that variation between the two is low, <0.03%.

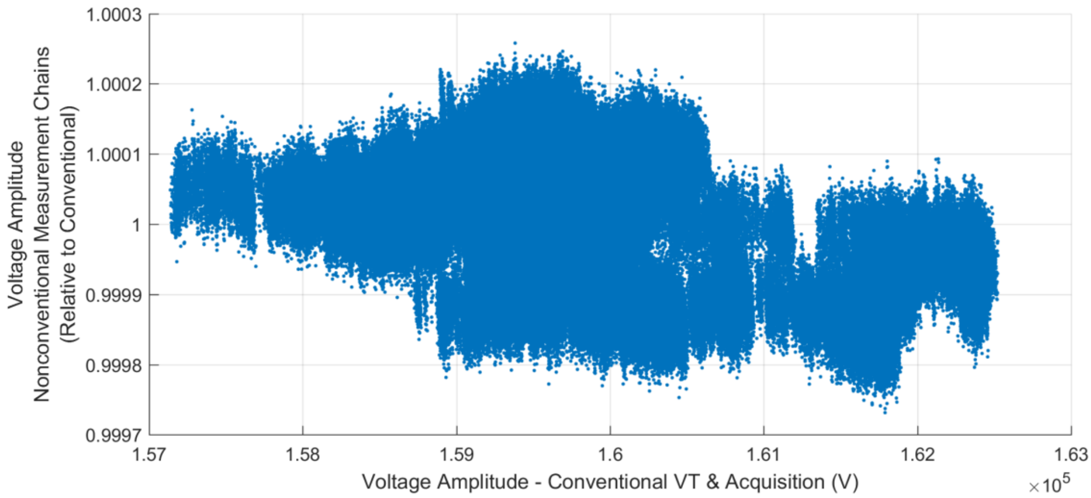


Figure 85: Comparison of voltage phasor magnitude from conventional CVT via standalone Merging Unit, relative to conventional acquisition of CVT output, taken over a 24h period

Figure compares current magnitude reported by non-conventional measurement chains, normalised to the current reported by the conventional CT and acquisition, over a 24h period. It can be seen that the measurements show similar behaviour. CT rated current for the circuit in question is approximately 3kA.

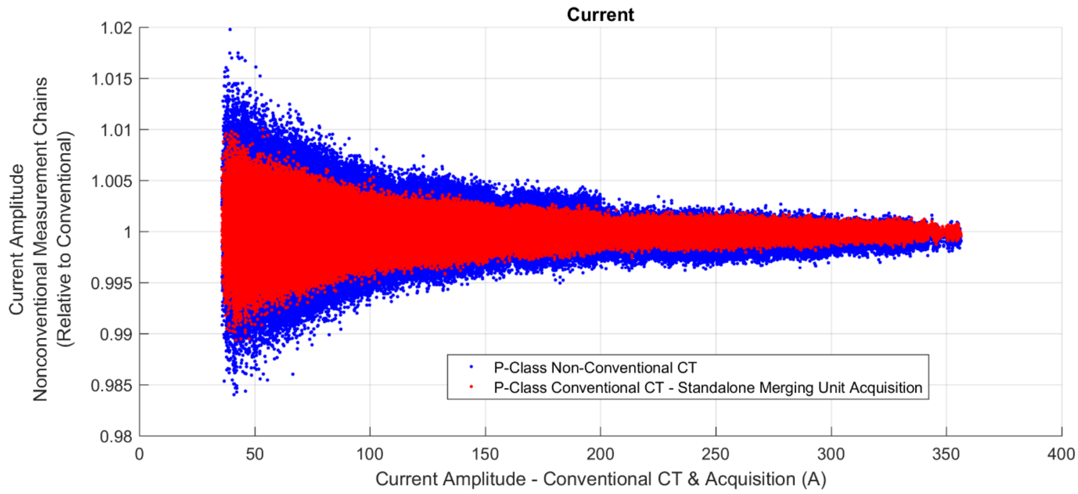


Figure 87 Comparison of current phasor magnitude from nonconventional measurement chains, relative to conventional CT and acquisition, taken over a 24h period

Examination of angle behaviour suggests good alignment of the different measurement chains. Angle measurements from the same primary source (instrument transformer) were observed to be within 0.01º of each other for voltage and 0.1º for current, and measurements from different primary sources within 0.15º for voltage and 0.3º for current. For the period examined, current was at ~10% rated value.

Three measurements chains for current are compared in the diagram on the right of Figure 86 – a conventional CT serving a standalone Merging Unit and conventional acquisition, and a non-conventional CT. All three are relatively consistent, which is in line with expectations given the frequency response characteristics of a conventional CT.

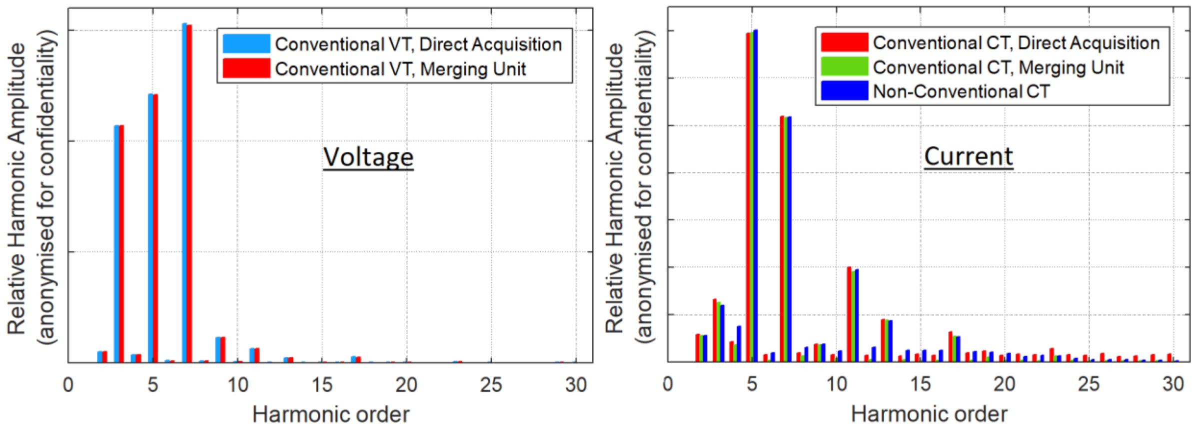


Figure 86: Observed harmonic amplitudes over a 24h period – voltage (left) from a Capacitor VT with conventional and Merging Unit acquisition; current (right) from a conventional CT & secondary acquisition, conventional CT via Merging Unit, and a nonconventional CT.

Regarding voltage, it was observed that in the case of conventional (Capacitor VT) primary acquisition, similar results were obtained from the standalone Merging Unit and conventional measurement acquisition – illustrated on the left of ***Figure 86***.

Results from the non-conventional VT were notably different from the CVT – sharing the same general signature (higher 3rd, 5th, 7th harmonic) but with relative gain / attenuation in certain regions. This is to be expected given the known uneven frequency response of CVTs.

5.6.7 Integration with Central Information Infrastructure – WAMS & EMS

As part of FITNESS, a report was prepared outlining the information infrastructure associated with the Wide-Area Monitoring & Control elements deployed in the FITNESS substation, illustrated in Figure 87. This report, FITNESS Report #6 on Central Information Infrastructure, discussed the infrastructure itself, the potential applications enabled by integration of WAMS data with the control room Energy Management System (EMS), and the use of the Common Information Model (CIM) in integrating WAMS data with other systems.

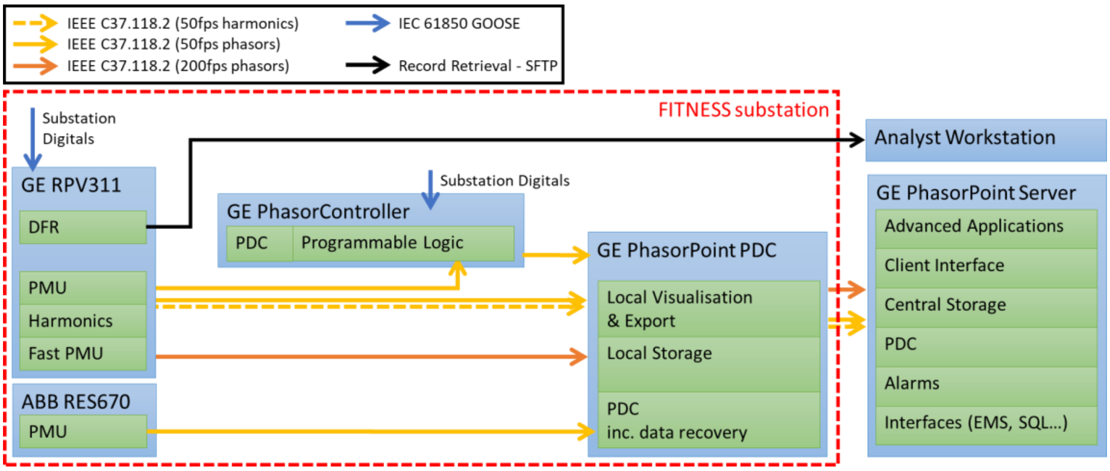


Figure 87: FITNESS WAMC Information Infrastructure

The FITNESS Information Infrastructure begins at the substation, where derived measurement data is received from the substation measurement IEDs (GE RPV311 and ABB RES670), and ends with data streams that can be sent to the Central WAMS server in the SPEN Operational Control Centre. This infrastructure **Error! Reference source not found.**includes:

- **Substation** Phasor Data Concentrator (PDC) **–** employing GE's PDC software. This receives, via the IEEE C37.118.2 protocol, the 50fps standard PMU streams (including multiplexed harmonics data) from the FITNESS substation PMUs. It also directly receives 200fps "Fast PMU" streams from the GE RPV311 devices in the FITNESS substation. The Substation PDC provides:
  - Aggregation of the data streams from the FITNESS substation PMUs and forwarding to the Central WAMS server.
  - Local buffering of data to enable recovery in the event of a break in the connection to the Central WAMS Server. This also provides a local data store for short-term historical data review.
  - Local basic live and historical visualisation of raw IEEE C37.118 data, for purposes such as commissioning and debugging.
  - Local export of data in CSV and COMTRADE formats, to support commissioning and studies.
- **PhasorController** – GE's platform for wide-area phasor-based control. This receives standard 50fps PMU streams via the IEEE C37.118.2 protocol from the FITNESS substation PMUs and incorporates a flexible programmable logic platform capable of receiving, processing and sending IEEE C37.118 and IEC 61850 GOOSE data.
- **Central WAMS Server** running GE's PhasorPoint software, already deployed at the SPEN control centre. The functions of the Central WAMS Server relevant to FITNESS include:
  - A Phasor Data Concentrator (for 50fps standard and 200fps "Fast PMU" data rates)
  - Centralised long-term storage (for standard and 200fps data rates)
  - Analytics: e.g. oscillatory stability (for standard PMU data rates)
  - Custom calculation engine, used for FITNESS to demultiplex harmonics data (for standard PMU data rates)
  - Flexible live and historical visualisation of raw IEEE C37.118 data and derived data (e.g. symmetrical components, demultiplexed harmonics) (for 50fps and 200fps data rates)
  - Export of raw IEEE C37.118 data to CSV (Comma Separated Value) and IEEE C37.111 COMTRADE formats, export of IEEE C37.118 CSV data and derived data via SQL (Structured Query Language) interface. (standard and 200fps data rates)

- **Analyst workstation** representing any computer, which can be used to retrieve Digital Fault Records and other data from the GE RPV311 Multifunction Recorders, via the SFTP protocol.

It may be noted that whilst external communications from the FITNESS substation and Central WAMS server were not implemented for the site deployment, the full end-to-end chain was tested at the factory stage, and the same exchanges of PMU and DFR data with SPEN central servers already occur with several SPEN conventional substations as part of normal business operation.

5.6.8 WAMS-EMS Integration

From the Central WAMS Server, connection to further systems, such as the EMS, is possible. Integration of WAMS data within the EMS can be made in a number of applications – these were outlined in the report and are summarised in this subsection.

Hybrid State Estimation is one of the most obvious instances of WAMS-EMS integration. The inclusion of accurate, time-synchronised measurements, including voltage angle, within the EMS State Estimator alongside the usual asynchronous SCADA magnitude and power flow measurements can lead to faster, more reliable mathematical convergence to a solution estimating the state of the power system.

Another "low hanging fruit" is the presentation of WAMS measurements, analytics and alarms in EMS displays. Examples include simple validation and backup of power flow and voltage measurements already provided by SCADA, voltage angle differences across the grid which are a good summary indicator of system stress, and analytics detecting and identifying the source unstable power oscillations. Such integration can take place in conventional EMS displays, or more recently developed "Situational Awareness" displays designed to combine a variety of information such as weather, power system and geographical data.

A more advanced class of hybrid applications is emerging, which combine the accuracy, synchronisation and measurement-based analysis of WAMS with the extended visibility and the model- and topology-supported analyses of the EMS. One such example is in islanding, resynchronisation and blackstart management – WAMS provides measurement-based detection and clustering of islands that form from a system separation or blackstart scenario, independent of any topology (breaker position) information. The EMS topology and generator information can then be used, in combination with the WAMS visibility of the stability, frequency and angle of each island, to redispatch the right generation to stabilise, align, and then resynchronise the system across the optimal transmission lines.

5.6.9 Common Information Model

By their nature, applications integrating WAMS and EMS information rely on integration of WAMS data points with the model of power system assets and measurements used in the EMS. This can easily involve hundreds of data point mappings from measurement to model. The robustness and effort associated with deploying and maintaining such applications therefore depends heavily on the compatibility of the information and data models used.

To this end, the FITNESS project explored the use of the Common Information Model (CIM) standard in mapping of WAMS data. CIM comprises a series of IEC standards and has achieved a high level of maturity – now being deployed as a best practice approach to achieve data interoperability. Although the CIM series of standards was originally focused on SCADA/EMS, the development of the CIM continues – with WAMS being one key area of interest.

FITNESS Report #6 on Central Information Infrastructure reviewed the rationale, concepts and provided an overview of CIM; discussed the relevance to WAMS and proposed some extensions to CIM in order to accommodate WAMS.

The CIM is an abstract and generic model that represents all the major objects in an electric utility enterprise (originally in an EMS information model) that can be used by multiple applications. CIM is designed be compatible with any application used in the power system industry, and to support custom extensions to accommodate the specific individual application needs, without affecting the standard core format. Represented in Unified Modelling Language, (UML), CIM defines object-oriented data models defining classes of objects (e.g. transformer, circuit breaker, transmission line), their attributes (e.g. impedance) and relationships.

An initial proposal for the extension of CIM to incorporate WAMS was included in the report. Extensions to CIM included the creation of PMU, Phasor Measurement, Analog/Digital converter and Clock CIM object classes. Further aspects were discussed, including security of sensitive information such as device IP addresses, and the relevance of different "Profiles" (model subsets) to different users such as academia, operational technology departments, and power system analysts.

5.6.10 Wide-Area Control Platform

Under the FITNESS project, a flexible Wide-Area Control Platform – GE's PhasorController, shown in Figure 88 – was deployed within the FITNESS substation. The combined FITNESS Report #27/28, on Flexible Phasor-Based Control Platform and Smart Frequency Control Use Case, describes the PhasorController and proposed a control scheme to be demonstrated in the FITNESS substation as an illustration of Wide-Area Control functionality implemented within a Digital Substation environment.

Figure 88: ***GE PhasorController***

The PhasorController is a GE-developed hardware and software platform, that is expected to be deployed within a power grid as a key component of Wide-Area Monitoring, Protection and Control (WAMPAC) applications. In such applications, PhasorControllers will typically analyse PMU measurements from across multiple locations, together with other measurements such as IEC 61850 GOOSE status information, to produce one or more binary trip or analogue control signals.

The PhasorController is designed to be highly flexible, extensible and scalable in its deployment:

- Stand-alone or in groups
- Co-located or distributed across a suitable IP network.
- Autonomous or collaborative to manage a specific aspect of grid behaviour.

Given this flexibility, such a platform is suited to a number of present and potential future use cases:

- Special Protection / System Integrity Protection / Remedial Action schemes designed to take fast specific action to protect overall system security – such as shedding of specific generation or load in response to loss of a specific transmission line.
- Wide-Area Control schemes such as those designed to incorporate synchronised measurements from across a power system before and during an event and take proportional action in the correct location to ensure overall system security. A typical feature of such schemes is the use of wide-area frequency and voltage angle information to not only detect a contingency event but rapidly characterise the event and the response of the system to it, informing the action to be triggered. Notable examples include the Smart Frequency Control scheme demonstrated in the UK under the National Grid NIC project of the same name, and Wide-Area Defence schemes in the Icelandic power grid, some of which were featured in the European Horizon 2020 MIGRATE project.
- Local Control schemes such as out-of-step and loss of mains detection, microgrid islanded detection & operation or black-start, and slower rate-of-change of frequency based generation or load response (implementing such responses too fast based on only local measures can have a destabilising effect on the wider grid).

A number of PhasorController devices have been deployed in the FITNESS substation and configured to receive certain PMU measurements and GOOSE status information from within the substation. Whilst some basic passive schemes have been implemented on these PhasorControllers to demonstrate successful platform operation & integration, the report proposes a more complex control scheme to be demonstrated that would also incorporate wide-area measurements.

5.6.11 Cyber Security

Reliable and secure operation is a critical requirement of power grids, and wide-area monitoring and control systems are playing an increasing role in ensuring this – particularly as grids decarbonise. However, as reliance on wide-area measurements for informing decision-making and taking automatic control action grows, it becomes vital that they are secured against cyber-attack.

Combined FITNESS Report #35 / 36 on Cybersecurity for WAMC Infrastructure highlights the cybersecurity issues involved in WAMC implementation, and measures that can be taken to mitigate risk. It also discusses and compares the existing IEEE C37.118.2 protocol for WAMC data exchange and the relatively new IEC 61850-90-5 protocol, with a focus on cybersecurity aspects. Some key elements discussed within the report are outlined in this subsection.

The cyber-security management of WAMC must be holistic, considering components including PMUs, communications networks, PDCs, end-user applications, and interfaces to other systems such as the Energy Management System. Measures should include pro-active mechanisms to secure communications, system access and modification; and re-active mechanisms to detect and mitigate attacks when they occur. Measures to deliver this include:

- Robust encryption and authentication of information exchanges.
- Cyber-secure infrastructure design to isolate critical systems, protect them from attack, and ensure performance and availability.
- Robust authentication, authorisation, credential management and access control systems to restrict access to and modification of critical systems.
- Intrusion Detection Systems to detect and respond to attacks based on unusual activity that may occur at an infrastructure level (e.g. DoS attack), user level (e.g. compromised credentials) or application level (e.g. sophisticated data manipulation).

The two main standards for exchange of WAMC information, IEEE C37.118.2 and IEC 61850-90-5, take differing approaches to cybersecurity. The former specifies only the application layer protocol and leaves aspects such as encryption and authentication to other network layers. Such solutions are available, including VPN or TLS. IEC 61850-90-5 incorporates many cybersecurity capabilities, however their implementation is flexible. Neither approach can be said to have "plug & play" fully cyber-secure solutions readily available on the market – nor can either be said to be inherently incapable of implementation in a cyber-secure environment. Careful implementation and appropriate supporting ICT infrastructure (such as key management) is required in each case.

5.6.12 Novel Applications Investigated

This section outlines the novel applications explored under the FITNESS project. The first two applications, relating to fault analysis and wide-area real-time monitoring of harmonics, were investigated under feasibility studies. The third application, a "validating PDC", was implemented and tested on the GE PhasorController platform.

Fault Analysis: Location & Wide-Area Current Contribution

This application, discussed in FITNESS Report #7 on Applications Exercising Data Quality, concerns the use of 200fps "fast" phasor measurements in the analysis and management of power system disturbances or "faults". Specifically, the application involves the detection and location of disturbances; and characterisation both in a local context (e.g. classification, duration, local indices) and a wide-area context (e.g. fault current distribution).

The report reviewed fault analysis and location approaches, including travelling wave fault location, and impedance-based fault location using DFR data from one or multiple terminals of a transmission line. The report also discussed existing software applications for analysis and presentation of fault information. This included SPEN's internal PSDIAGNOSIS system which performs automated characterisation of system events utilising available SCADA and DFR data, and SPEN's PhasorPoint WAMS application for automated detection, analysis and reporting of system disturbances utilising PMU data.

The potential for the use of fast phasor measurements in Fault analysis was discussed, including the differing requirements for fast phasor measurement compared to standard PMUs - such as shorter calculation window and elimination of the decaying DC components associated with faults. Tests were performed to validate that these requirements could be met.

An assessment was made of the PMU and/or DFR measurements required to determine fault parameters such as type, element, line location, peak current, clearance time, pole spread and system impact. This indicated that the majority of parameters (save for pole spread) could be determined with fast phasor measurements, though DFR measurements could add accuracy and time precision in most cases. One of the principle advantages of fast phasors lay in capturing whole-system response to a fault, and not only that of the faulted element.

Finally, a proposed architecture and application functional descriptions were outlined for a system to gather fast phasor information and utilise it for fault analysis. The architecture suggested incorporated some key fast measurements being continuously streamed to the Central WAMS Server, with the majority of measurements maintained at site in a rolling buffer, and transferred to the Central WAMS server in the event of a fault or other system disturbance. In this way, communications bandwidths and storage requirements would be minimised.

The application proposed covered several aspects. Firstly, to automatically gather and analyse fast PMU data in the event of a fault, characterising the fault itself in terms such as type, element, line distance, current and timings. Integration with SCADA and DFR data retrieval systems was also recommended. A second aspect of the application was to assess the impact of the event on the wider system, including mapping the contribution of fault current from monitored circuits and generation. An illustration of one of the proposed displays is shown in Figure 89. This would support validation of models and plant behaviour under fault conditions – particularly relevant as the generation mix shifts to power electronic connected plant.

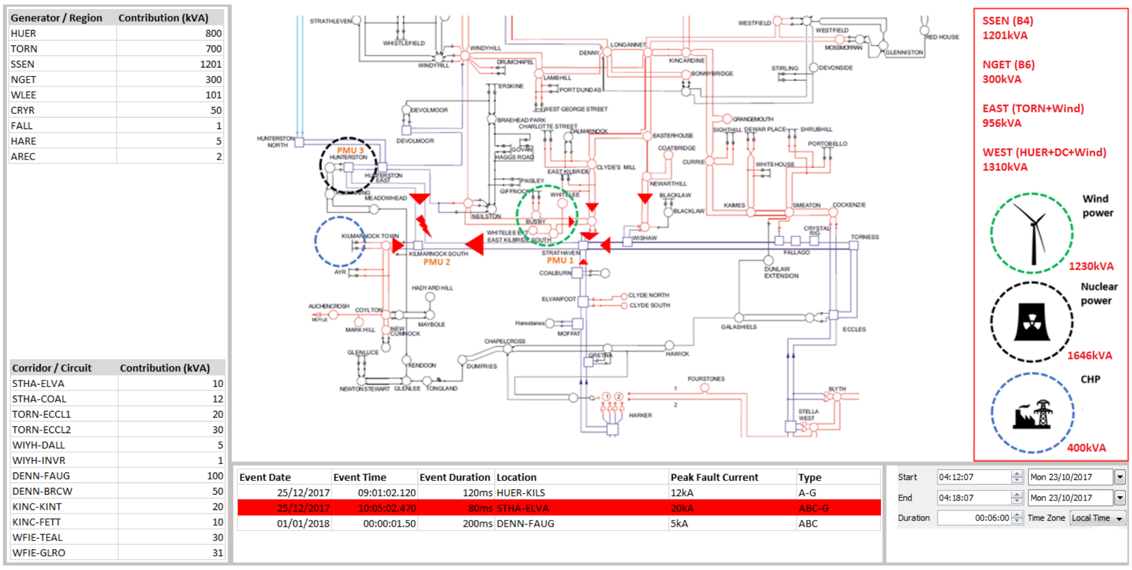


Figure 89: Example fault current contribution display

Real-Time Wide-Area Monitoring of Harmonics

This application, discussed in FITNESS Report #7 on Applications Exercising Data Quality, involves the reception of real-time harmonic measurements from power quality recorders; application of alarm thresholds; and aggregating, summarising and presenting this data in a way that is useful and comprehendible to users.

The report reviewed the principles, components, requirements, processes and standards around management of harmonics. This included the measurement principles and performance of conventional and nonconventional instrument transformer technologies with regard to harmonics. Standards and existing practices for the monitoring and management of harmonics on electricity networks were described, along with future challenges. Three existing systems for real-time monitoring of harmonics were also presented – from New Zealand, the United States of America, and Turkey.

Finally, a functional specification was presented describing an application for real-time wide-area monitoring of harmonics, including approaches for effectively aggregating and presenting harmonics information to users in a comprehensible manner. The specified application would incorporate not only real-time harmonic data from PMUs as demonstrated under the FITNESS project, but also offline recorded harmonic measurements from power quality monitors.

Topology & Measurement Validation

One of the benefits of a Digital Substation architecture lies in the straightforward and non-disruptive exchange of substation status and measurement data between devices. Coupled with advances in substation computational and programmable logic platforms, this encourages the use of mechanisms within a substation to validate and aggregate measurement information – for example, the determination of representative busbar voltages and the identification of inconsistent measurement or status data.

Performing such processing at the substation level rather than a centralised system can:

- Increase the information available to the validation process.
- Reduce the computational loading on the central system.
- Increase the reliability and speed with which measurement inconsistencies can be identified.

To this end, two applications of this nature were demonstrated under the FITNESS project – Local Topology Processing & Hybrid State Estimation, and a Validating PDC.

The first, the Local Topology Processor & Hybrid State Estimator, is illustrated in Figure 90. It determines the set of "true" topology (switch and breaker states) and transformer tap positions most consistent with the measurements and states reported by the substation control system – and in the process, identifying any inconsistencies in reported states. The application then performs a local state estimation based on phasor and analog measurements within the substation, together with the now-validated topology and tap positions – again, highlighting any inconsistent reported measurements. The result is a high-confidence snapshot of the substation state: power flows, voltages, topology and tap positions, which can be provided to the central State Estimator and in turn support a more reliable, faster converging overall system State Estimate.

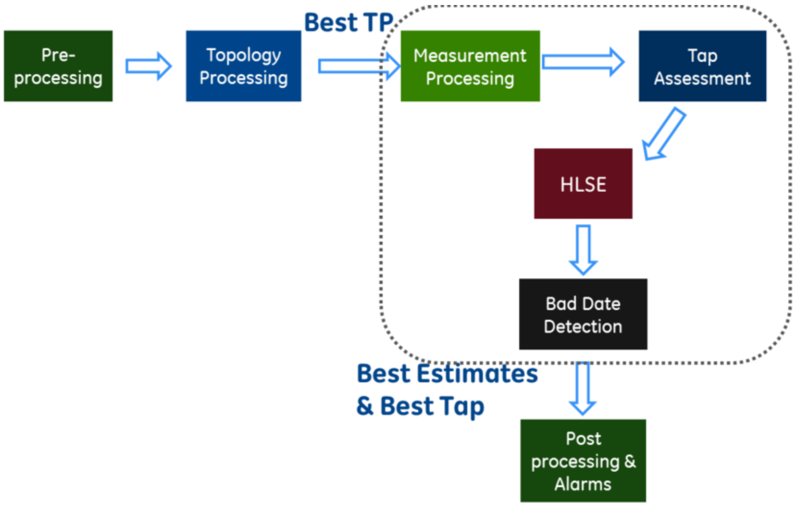


Figure 90: Local Topology Processor & Hybrid State Estimator

The second application, the Validating PDC, focuses on the reliable determination of representative busbar voltage phasors for a substation.

Some protection and control mechanisms require a voltage signal representative of the substation busbar – for example, synchronism-check devices which prevent a feeder circuit breaker being closed when there are unsuitably large electrical differences (e.g. voltage angle) between the line side and substation side. Some Transmission Network Owners such as SPEN do not measure busbar voltage directly but derive a representative busbar voltage signal by means of a voltage selection wiring scheme - electrically combining feeder voltage measurements using switches linked to the states of the real circuit breakers.

The Validating PDC, illustrated in Figure 91, performs a similar function in real-time at the synchrophasor measurement level, as well as identifying any inconsistencies in the feeder voltage measurements or in the topology information provided by the substation control system. First, clusters of mutually consistent measured feeder voltage phasors are identified (i.e. phasors appearing to be connected to the same bus, based on their magnitude and phase), and topology information is used to assign the identified clusters to a busbar. As with the Local Topology Processor and Hybrid State Estimator, inconsistent measurements or status information are highlighted for investigation.

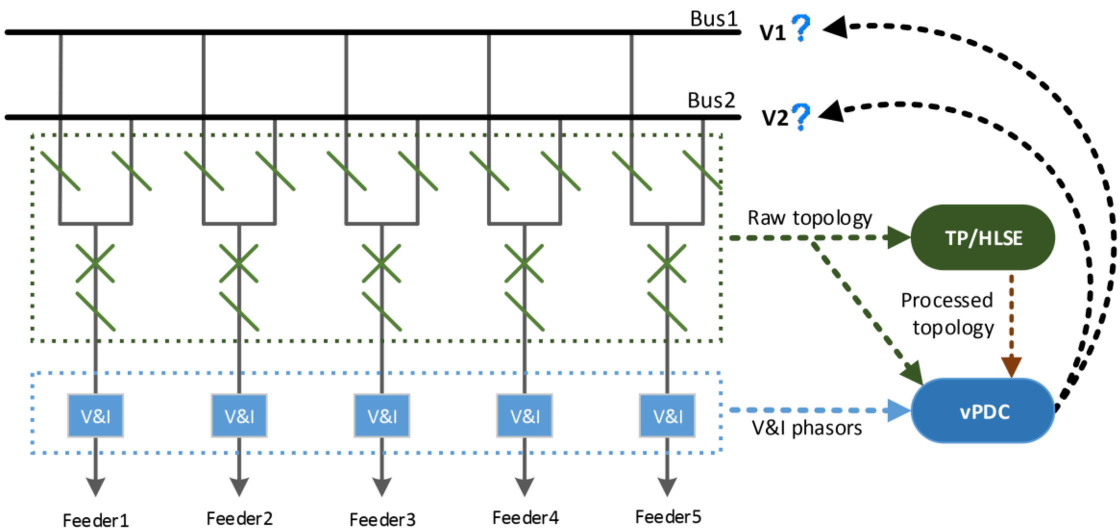


Figure 91: ***The Validating PDC***

Both applications have been tested under various scenarios – details of which are presented, together with more detailed discussion of the applications themselves, in FITNESS Report #23 on Topology & Measurement Validation of Substation-to-System Information. Additionally, the Validating PDC was tested on the PhasorController hardware platform

5.6.13 Lessons Learned

This section outlines some of the key lessons learned relevant to the Wide-Area Monitoring and Control elements of the project.

Propagation of IEC 61850-9-2 Status & Quality Information to Measurement Applications

During early testing near the start of the project, some issues were identified around how the quality flag information from IEC 61850-9-2 Sampled Value streams were propagated to measurement applications – for example, an invalid and unsynchronised Sampled Value stream should lead to the PMU measurement for that signal (which uses that SV stream) being also marked as invalid and unsynchronised. This was found to not always be the case in the tested version of PMU firmware, and fixes were implemented to correct this.

Similar situations can arise in user front panel and software displays, where the absence of an SV stream (due to a communications network issue) can appear as a zero measurement – i.e. implying that the transmission circuit is switched out of service. As Digital Substations enter more common use, it will be important that user interfaces and status information adapts to make clear the distinction between electrical out-of-service (i.e. line dead) and communications out-of-service (no SV stream received). This includes indication of dropped Sampled Value packets, for example.

Tools for Easy Netowrk Traffic (especially Sampled Value Stream) Inspection

Commissioning of some FITNESS equipment was made more challenging on a few occasions by the difficulty in determining whether the correct network traffic (in particular Sampled Value streams) was reaching the device (e.g. a PMU) being commissioned. In an analog world, such checks are quickly and simply achieved through the use of a multimeter or voltage / current tester on the appropriate wire terminals at the rear of the device. However, this is more complex in a Digital Substation. Network observations from Omicron DANEO devices in the substation, and from network switches, were helpful, but in some cases troubleshooting required connection of a laptop directly to the network port of the device being commissioned – in order to determine whether the problem lay with the communications network or with the device.

The development of small and easy-to-use tools for performing such checks would greatly reduce the effort in both commissioning and later maintaining Digital Substation equipment.

Interoperability of Small Form Factor Pluggable (SFP) modules for Fibre-Optic Ethernet Connections

Another challenge during commissioning of some FITNESS equipment lay in compatibility restrictions between the various Intelligent Electronic Devices (IEDs) deployed in the substation such as PMUs, network switches and computing platforms, and the Small Form-factor Pluggable (SFP) modules used to connect them to the Fibre-Optic Ethernet communications network. These SFPs are small modules that fit into a universal electronic socket on a device and incorporate a specific type of Fibre-Optic connector (e.g. LC) designed to operate at a specific wavelength. However, the specification of these devices can vary not only in the Fibre-Optic connector used but also in the wavelength of light and data bandwidth supported. A further complication lies in the compatibility with the host device – many device manufacturers, for reasons including commercial, compatibility and quality control, will only accept SFPs of a certain vendor and model. This is checked via an electronic exchange between the two devices – from a user perspective, a "trial and error" approach must often be taken, though many manufacturers will list supported SFP models in their user documentation.

Thus, in order for a Fibre-Optic Ethernet connection to be successful between two devices, not only must each SFP be compatible with the device is plugged into, but also the two SFPs on either end of the connection must be compatible in aspects such as light wavelength used.

In reality, this means that at the device, substation and/or engineer level, multiple spare SFPs must be available if repairs and troubleshooting are to be conducted efficiently.

6.0 PERFORMANCE COMPARED TO THE ORIGINAL PROJECT AIMS, OBJECTIVES AND SDRC

Project FITNESS delivered and performed over and above the set SDRCs at the beginning of the project. Project FITNESS met all its SDRCs and proved digital substations to be viable technology to be rolled-out in RIIO-T2. Project FITNESS is acknowledged internationally as a landmark project which created a roadmap for roll-out of digital substations internationally for various utilities and vendors across the globe.

	SDRC Description	***Comments***
	Evidence (WP1)	
1	**1. Contracts with project partners (June 2016)**	Completed
2	**2. Report on architecture & design of substation secondary system (August 2016)**	Completed
3	**3. Report on reliability/availability analysis (Nov 2016)**	Completed
4	**4. Report on bay selection, site survey, engineering feasibility (August 2016)**	Completed
5	**5. Engineering design for LPIT & MU installation (July 2016)**	Completed
6	**6. Letter confirming agreement with contractors/subcontractors for site works. (Dec 2016)**	Completed
	Evidence (WP2, 2.1)	Completed
7	**1. Report on Functionality & Interoperability Tests (Lab tests), including description of (April 2017)**	Completed
	a. Test Plan	Completed
	b. Test Environment	Completed
8	**2. Report on Low voltage secondary systems testing results.(Nov 2017)**	Completed
9	**3. Report on Functionality & Interoperability Tests (High Voltage tests), including description of (Nov 2017)**	Completed
	a. Test Plan	Completed
	b. Test Environment	Completed
10	**4. Report on High voltage secondary systems testing results.(Jan 2018)**	Completed
11	**5. Report on diagnosis of outstanding issues, and plan for resolution (Mar 2018)**	Completed
	Evidence (WP2, 2.2 & 2.3)	Completed
12	**1. Bay #1 Site Test Report (Jun 2018)**	Completed
13	**2. Bay #1 Installation & commissioning Report (Nov 2018)**	Completed
14	**3. Bay #1 Distributed Optical Sensor integration & test (July 2018)**	Completed
15	**4. Bay #2 Site Test Report (Jun 2019)**	Completed
16	**5. Bay #2 Installation & commissioning Report (Nov 2019)**	Completed

17	6. Bay #2 Distributed Optical Sensor integration & test (July 2019)	Completed
	Evidence (WP2 2.2, 2.3, 2.4)	Completed
18	1. Report on Bay #1 piggy-back trial phase (Feb 2019)	Completed
19	2. Report on Bay #1 live operation trial phase (July 2019)	Completed
20	3. Report on Bay #2 live operation trial phase (Nov 2019)	Completed
21	4. Report on Extended Live Performance Trials (Mar 2020)	Completed
	Evidence (WP3, 3.1)	Completed
22	1. Report on implementing and testing LPIT/MU to PMU/DFR/harmonics measurement chain (including data quality) (March 2017)	Completed
23	2. Report on topology & measurement validation of substation-to-system information (May 2017)	Completed
24	3. Report on central information infrastructure integration and enhancement (August 2017)	Completed
	a. Standard EMS/WAMS integration	Completed
	b. New WAMS data types	Completed
	c. Applying CIM to data referencing	Completed
25	4. Report on applications exercising data quality (October 2017)	Completed
	a. Fault information mgt	Completed
	b. Harmonics management	Completed
26	5. Include experience from Bay #1 & Bay #2 performance trials, once available (Revisions Nov 2018, Nov 2019)	Completed
	Evidence (WP3, 3.2)	Completed
27	1. Report on flexible phasor-based control platform & interfaces (Mar 2018)	Completed
28	2. Report on EFCC use case and associated substation-to-system interaction (May 2018)	Completed
29	3. Report on feasibility of wide area voltage stability (July 2018)	Completed
30	4. Report on adaptive protection central logic and substation-to-system interaction (Oct 2018)	Completed
	Evidence (WP4, 4.1)	Completed
31	1. Report on cyber security measures in the substation (Dec 2016)	Completed
32	2. Risk assessment for the FITNESS substation (May 2019)	Completed
33	3. Demo remote access, data transfer and security measures (Mar 2018)	Completed
34	4. Demo remote access, data transfer and security measures –(Mar 2019)	Completed
35	5. Investigate/compare IEEE C37.118 and IEC 61850 90-5 with respect t0 cyber security (Aug 2019)	Completed
36	6. Report on cyber security for Wide Area Control infrastructure (Nov 2019)	Completed
	Evidence (WP5, 5.1)	Completed
37	1. Training & Workshop plan for TOs and DNOs.(Dec 2016)	Completed
38	2. Report on on-going training & workshop sessions delivered (June 2017, Dec 2017,June 2018, Dec 2018, June 2019, Dec 2019, Mar 2020)	Completed
39	3. Report on Cigre B5 working group participation & contributions to standards bodies (August 2017, Mar 2018, Jul 2018, Nov 2018, Mar 2019, Jul 2019, Nov 2019)	Completed
40	4. GB Stakeholder and Dissemination Events organised (August 2017,2018,2019)	Completed

.

Table 9 FITNESS SDRC and Relevant Project knowledge dissemination documents

7.0 REQUIRED MODIFICATIONS TO THE PLANNED APPROACH DURING THE COURSE OF THE PROJECT

Project FITNESS delivered over and above the planned methods and outcomes of the project. The significant changes and/or additions to the planned approach in delivery of project FITNESS are as follows

- Procurement of specialised skills on the onset of the pilot project and subsequent transfer of knowledge to internal engineers. It was identified in the course of project FITNESS delivery that digital substations design and deployment requires specialised skills which every TO and DNO needs to ultimately develop in house through training and hands-on practice. However, in a pilot project with trial of innovative concepts it was deemed necessary to acquire specialised support such as that from standard bodies for successful execution of the project. This knowledge was subsequently transferred to internal engineers through over 30 different training and hands-on workshop sessions.
- Procurement of additional engineering design and testing tools. Project FITNESS identified the significant and crucial need for right engineering design and testing tools for successful engineering, testing and commissioning of digital substations. As digital substations signify a paradigm shift from hardwired to communication network based critical protection, control and monitoring applications, the need to have and make use of the greater visibility of the data traffic and streams is of paramount significance to the ultimate reliability, availability and maintainability of digital substations. Thus, following tools were procured during the FITNESS project delivery
    - Helinks STS – Engineering Design Tool
    - Kalkitech – SCL Manager – Engineering Design Tool
    - OMICRON – Test Universe, IED Scout, StationScout and DANEO 400

8.0 PROJECT FINANCES

Project FITNESS delivery cost variance as compared to the original project cost estimation is shown in the table below.

[redacted]

Table 10 FITNESS Project Costs Variance

8.1 Variation in Project Costs

An shortfall in the expected interest has lead to an overspend of £63k, which SPEN are happy to absorb as part of the successfully delivery of this innovative project.

8.1.1 Labour

Project FITNESS labour costs are [redacted] lower than that anticipated at the beginning of the project. The explanation for this variation is requirement for specialised skills to complete design, testing and specification work in the project that needed to be largely outsourced externally. Digital substations deployment requires specialised skills which SP Transmission is currently building within the organisation for future roll-out of digital substations. In order to de-risk the project specialised skills were outsourced followed by internal training of staff to build knowledge for future roll-out.

8.1.2 Equipment and Contractors

The equipment manufacturers ABB Ltd. and GE Grid Solutions were also the main sub-contractors on the project. Thus, the majority of equipment costs were covered through fixed price contractor costs with ABB and GE. The additional variance of 37% in the contractor costs as compared to the initial submission is the additional need for specialised knowledge and skillset on project FITNESS. We required additional support from ABB and GE with regards to engineering design and testing during the course of the project.

8.1.3 IT

Project FITNESS highlighted the need of specialised tools for engineering and testing. These tools were instrumental to the success of the project. They provided significant understanding and visibility of communication on the substation network LAN and thus enabled our engineers to better test and commission digital substations. The lack of tools in previous IEC61850 deployments had already highlighted issues with the technology. SP Transmission Plc. worked with OMICRON Electronics GMBH to procure additional tools and IT support for testing and commissioning of digital substations.

9.0 UPDATED BUSINESS CASE AND LESSONS LEARNT FOR THE METHOD, PROJECT REPLICATION AND PLANNED IMPLEMENTATION

9.1 BUSINESS CASE

SP Transmission's (SPT) Network Innovation Competition (NIC) project Future Intelligent Transmission Network Substation (FITNESS) demonstrates a reduced outage and low risk approach to future substation secondary design through implementation of a fully digital multi-vendor feeder bay protection solution. Digital substations deliver benefits such as faster deployment, greater availability, improved safety and greater controllability with a reduced footprint and lower cost as compared to conventional design. The solutions enabled by FITNESS facilitate reduced network costs and constraints feeding through to significant benefits for GB customers. The international standards bodies and the supplier base have been driving the technology roadmap for digital substations and there is a variety of commercially available solutions developed in the last decade. Utilities across the globe in France, Australia, China and India already have live and operational digital substations.

The business as usual adoption of fully digital substation design approach in RIIO-T2 load and non-load related projects will result in significant benefits in CAPEX and OPEX investment. Digital substations are based on concepts of standardisation and interoperability and enable replacement of many kilometres of copper wiring with digital measurements over a cost-effective fibre communications network, and provide much greater flexibility in building, maintaining, modernising and controlling future substations.

The key benefits of digital substations are highlighted qualitatively in Figure 92

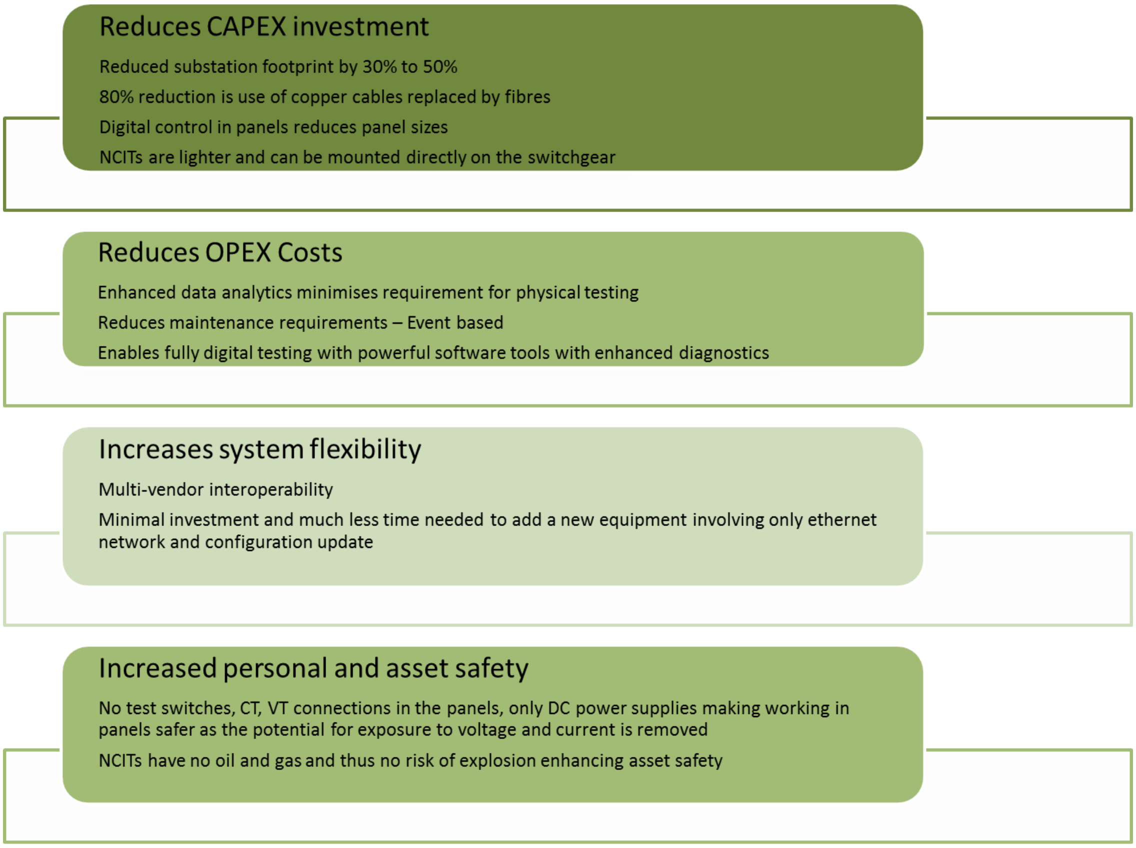


Figure 92 Key Digital Substation Benefits Qualitative Assessment

There is an ongoing business change process within SP Transmission under digital substations initiative to enable implementation of digital substations in RIIO-T2. The key benefits of digital substations as compared to a conventional substation are highlighted in

Benefits Description	Savings
Reduced use of copper in substation	80%
Reduced size of substations (Control Buildings)	60%
Reduction in installation and commissioning time on site (secondary)	40%
Reduction in time required for secondary upgrades and maintenance	60%
Reduction in outage time for secondary upgrades and maintenance	80-100%
Reduction in CAPEX costs for new builds and replacements	5-10%
Reduction in operational costs	40-50%
Enhanced safety	-

Table 10 Key Benefits of Digital Substations

9.2 PROJECT REPLICATION: DIGITAL SUBSTATIONS TRANSITION STRATEGY

The transition from a conventional secondary substation to fully digital substation can be perceived as a significant change to business practices. The different technologies constituting a fully digital substation have been implemented from 2009 onwards in parts in different SP Transmission projects ref: ACACS scheme, Windyhill, Chapelcross and Currie 132kV, wind farm connections 33kV and at Western HVDC Link on both AC and DC side. The **key challenge in transitioning digital substation pilot project into business as usual is that the realisation of the core aspects of digital substation design affects almost every business unit and a combined business strategy is required to facilitate the required changes throughout the business**.

It can be safely stated that digital substations inherently change substation secondary design and any piecemeal approach to upgrading equipment or attempts to adopt conventional practices and design philosophies for digital substations will delay the realisation of benefits and may in cases incur additional cost to the business. By embracing the development process of a fully digital substation and allowing for new design concepts to be introduced ahead, planning for required training and inclusion of new standards, both the transition time and total cost can be reduced. A considerable amount of this development knowledge has already been created by project FITNESS, which has put GB transmission network owners (TOs) and distribution network operators (DNOs) high up in the digital substation curve through development of a technical solution, and in the process addressed multiple technical issues which would have delayed the deployment of the 1st digital substation should it had been tried for the first time by GB TOs and DNOs through existing business practices in a business as usual project.

9.2.1 PROPOSED OUTCOMES OF THE DIGITAL SUBSTATIONS INITIATIVE

A working group within individual TOs and DNOs will produce a case study for digital substations using learning from FITNESS and enabling roll-out of digital substations in RIIO-T2. The digital substations initiative should be empowered to take an objective long view on the most appropriate deployment strategy — allowing it to deviate from conventional standards where necessary and found appropriate — without compromising the reliability, availability and dependability requirements for secondary systems especially protection and control. It should be given the authority and responsibility to design a transition program to be approved by the business change steering group.

Its key role should be to manage the change process required within different business units to enable a full-scale design and implementation of a digital substation from design to operation and maintenance. **The main outcomes of this working group which will ultimately enable roll-out of digital substations within TOs and DNOs business are as follows**:

1. **Gap analysis and Update of specifications, policies and standards requiring update to enable roll-out of digital substations**
2. **Defining process change enabling efficient transition from conventional to digital substation deployment**
3. **Training and development of new roles within the organisation**
4. **Establishment of necessary test facilities and IT processes to support transition to business as usual**

The aforementioned 4 outcomes of the digital substations initiative are crucial to allow for seamless transition to digital substations, avoiding the challenges faced by our organisation in the past deployment of the technology. This strategy in its introduction provides a timeline and proposal for achieving the key steps to enable roll-out of digital substations.

9.2.2 Gap analysis and Update of specifications, policies and standards requiring update to enable roll-out of digital substations

The gap analysis of the specifications, policies and standards are required to ensure we as an organisation are in charge of the solutions we procure from the market and the compatibility of these solutions to our preferred architecture and functional requirements. In order to speed up the process of updating these documents in the digital substations initiative industry experts can support in the definition led by individual engineering standards team.

The three main categories for changes to these specifications as shown in are

- Existing specifications that require update
- New documents that need to be specified for digital substations
- Related documents that need to be re-defined in light of digital substations

The digital substations initiative within SP Transmission is working in conjunction with Iberdrola's global practice group (GPG) will be responsible in definition of next INS for IEC61850 applications for transmission owners in 2021. We currently estimate a timeline of 15 months for completion of definition and approval of the necessary specifications and policies.

9.2.3 Defining process change enabling efficient transition from conventional to digital substation deployment

The most distinctive change required to facilitate the transition to digital substations in an efficient manner which enable realisation of maximum benefits from roll-out of digital substations is the process change required to engineering design, configuration, testing and commissioning process for substation secondary systems within the business. As the conventional procedures operate in silos with handovers between different teams delivering, testing and commissioning substation protection and control, SCADA, telecommunication and system monitoring system if the same is adopted for digital substations they will greatly limit the true benefits of efficiencies that can be generated through digital substations. It will also increase complexity of lifecycle management, operations and maintenance of such systems. We propose the following process for delivery of digital substations in RIIO-T2 which is a step change from conventional process as shown below:

- Project specific IEC61860 specification and pre-qualification of compliant manufacturers
- Complete engineering design, configuration and validation phase to be completed offsite
- Rigorous offsite testing before panel build and comprehensive offsite factory acceptance testing. Digital substations allow 85% of testing to be completed off-site thus greatly reducing commissioning time on site
- Primary interface and 15% of remaining plant and control room interface tests to be completed on site
- 24x7 automatic monitoring and routine maintenance tests for continuous monitoring of system health

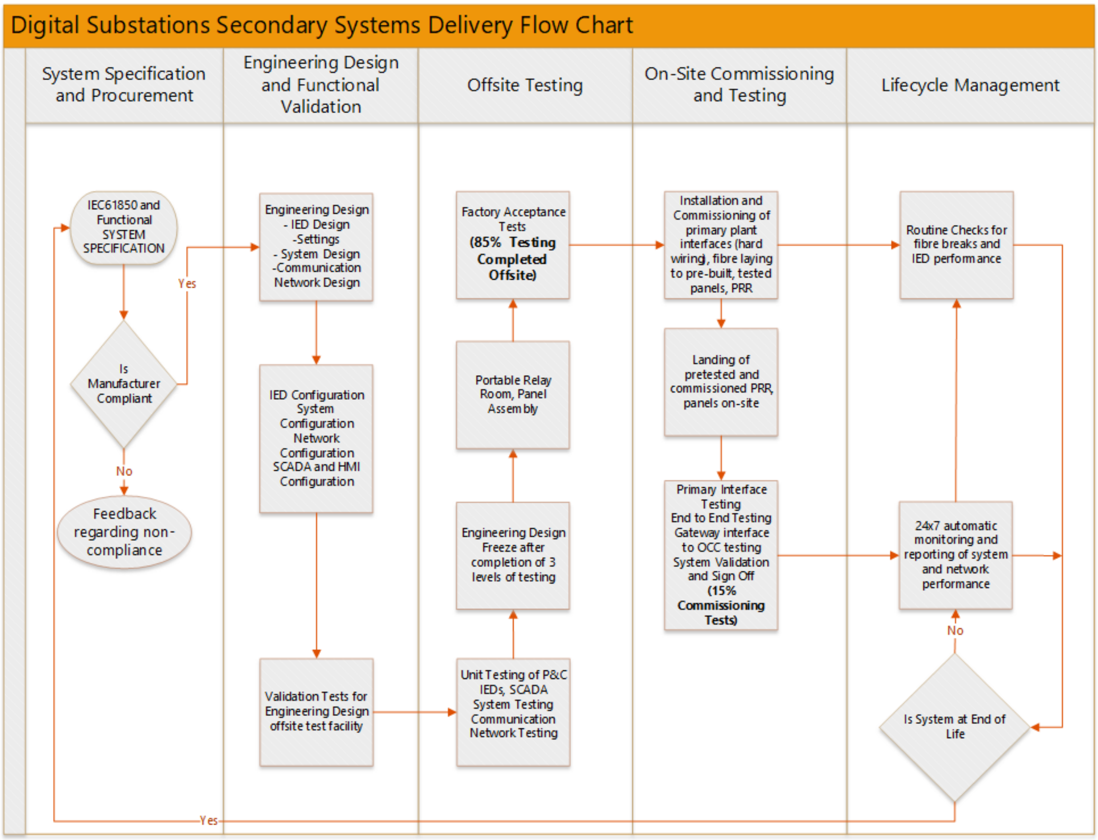


Figure 93 Process Change proposed for roll-out of digital substations

9.2.4 Training and development of new roles within the organisation

The major shift from conventional to digital technologies is increased dependency on communication network and software tools. Whilst these skills inherently exist within our organisation there is requirement for fundamentals and hands-on training required for almost all engineers who will interact with digital substations technology and will need to troubleshoot issues on site during the live operation of the system. The digital skills developed through this training process will be applicable to other areas of design and operations within their day to day activities.

In addition to the general training and hands-on experience to be provided to the engineers there is need for specialist knowledge development and potentially new roles to be defined within the organisation to enable lifecycle management such extension, changes and operation and maintenance of digital substations. The current structure within utilities also has experts who work in silos focussed on their areas. In a digital substation concept this changes to a more integrated approach where the existing experts will need to cover more areas to allow for more integration and new roles will manage overall system integration.

Following specialist knowledge needs to be created within the organisation, along with existing roles of P&C engineer, SCADA engineer and system monitoring engineer as shown in Figure 94.

- System designer - P&C, Monitoring engineering design and IEC61850 configuration
- Communication network engineer – To configure, maintain and manage substations communication network and also responsible for cyber security
- System Integrator – This a new role that will cover and follow through the lifetime of the system from design to operation and maintenance and will bridge the integration gaps between different teams across the organisation.

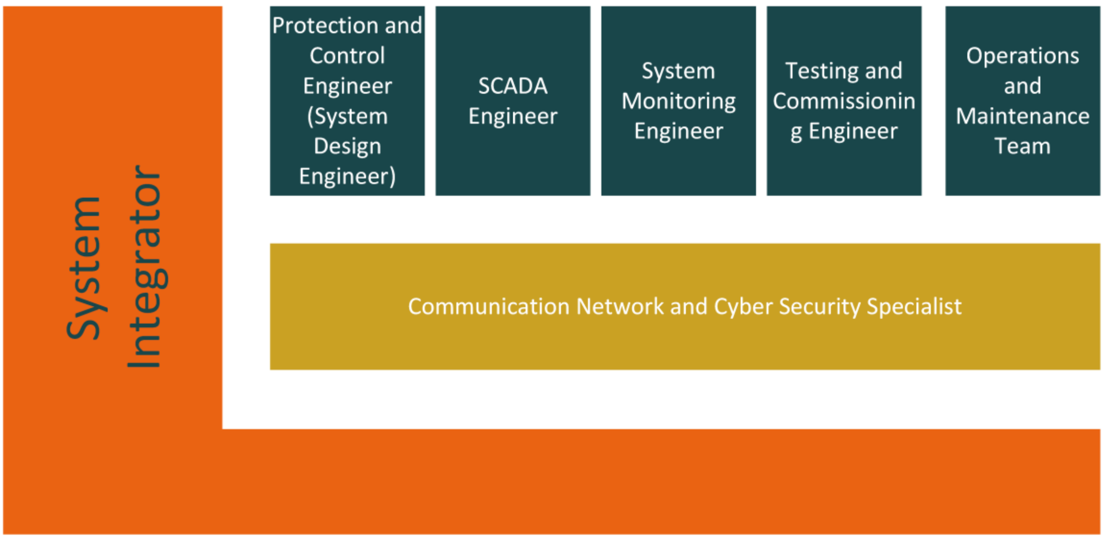


Figure 94 Digital Substation Roles and Responsibilities

9.2.5 Establishment of necessary test facilities and IT processes to support transition to business as usual

The digital substations process change adds additional emphasis to offsite test facilities, requirement for version control and access to software tools. These are important requirements that there is sufficient scope for engineers to design and validate and ensure seamless testing can be performed offsite.

The requirements can be divided into 3 categories

1. **Offsite Test Facility**

A replica system should be set up by utilities for offsite testing for complete template design for any future substation. This offsite test facility needs to be housed in a facility with possibility for future extension with easy access for project engineers, test engineers and system integrator.

Ideally this offsite test facility should also have an outdoor area to land a portable relay room and AC/DC supply boards to enable full-scale offsite testing before landing the pre-tested panels or portable relay room on site.

This is crucial as this test facility will save considerable amount of time on site which currently amounts up to £10-20k in welfare facilities and up to £10k a week for a commissioning engineer. It will also provide a controlled environment to test and prove the system without the pressures on site to meet outage windows.

2. **Version Control**

Digital substations are designed mostly with software tools and thus all configurations, settings and firmware require considerable version control. This is crucial to ensure that future extensions, troubleshooting and replacements are possible without disruption of the live system.

In this regard the business needs to deploy software tools for version control and management of secondary systems. There are many solutions present in the market that enable such version control and the business needs to deploy such solutions in future price controls.

3. **Design and Testing Software Tools**

The need for better design and testing software tools is obvious to roll-out of digital substations. Project FITNESS has already proven and demonstrated usability with various tools that provide design, testing and troubleshooting capabilities. Currently many of our engineers require laptops and/or configuration PCs that have all necessary tools installed on them and also cyber secure in our corporate and operational environment. **The business IT and OT team in conjunction with the engineering team need to define a cyber-secure however flexible way to enable installation and use of design and testing software tools.**

9.3 PLANNED IMPLEMENTATION

SPT's RIIO-T2 plan provides an ideal opportunity to consider digital substations as an alternative to conventional builds in order to achieve the anticipated benefits. However, this requires an integrated approach by all teams in SPEN affected by the shift in paradigm from conventional to digital substations to assess the magnitude of gaps in the technology, processes and skillset to recommend or otherwise the roll-out of digital substation solution demonstrated through FITNESS in RIIO-T2.

The success of project FITNESS has led to the launch of the digital substations initiative to build the necessary skills within our organisation, development of utility wide standards, specifications and requirements for successful roll-out of digital substations and, most importantly, to raise awareness regarding the benefits of digital substations. This, however, is a shift in paradigm and complete change in internal business practices of how we design, build, install and commission secondary systems in our substations. It is also based on the application of an international standard which requires a considerable amount of collaboration among network owners, suppliers and international research bodies for standardisation, validation and implementation. This initiative will enable seamless roll-out of digital substations on the network.

The potential sites in RIIO-T2 where digital substation solution potentially can be rolled out at the following sites

- All new builds, wind farm connections
- Windyhill 275kV GIS (In Business Plan)
- Westfield 275kV (2-Stage Build) (Potentially RIIO-T3)
- Longannet 275kV (Offline AIS Build) (Potentially RIIO-T3)
- Hunterston 132kV GIS (In Business Plan)

10.0 KNOWLEDGE DISSEMINATION

The goal of FITNESS is to enable GB TOs and DNOs to apply a digital substation design approach to future load and non-load related investment after successful demonstration. Digital substations are based on concepts of standardisation and interoperability and enable replacement of many kilometres of copper wiring with digital measurements over a cost-effective fibre communications network, and provide much greater flexibility in building, instrumenting, maintaining, modernising and controlling future substations.

With potential to deliver great financial and environmental benefits, digital substations and the associated technology was trialled through project FITNESS. This however is a shift in paradigm and complete change in our business practices of how we design, build, install and commission secondary systems in our substations. It is also based on application of an international standard which requires considerable amount of collaboration among network owners, suppliers and international research bodies for standardisation, validation and implementation.

Internal and external stakeholder engagement played an important role in making the process of transition to digital substations in building the necessary skills within SP Transmission, development of utility wide standards, specifications and requirements for successful roll-out of digital substations and most importantly to raise awareness regarding the benefits of digital substations. FITNESS has enabled this stakeholder engagement through live demonstration at Wishaw 275kV substation.

Project FITNESS deployed state-of-the art digital substation technologies such as optical current transformers, multi-vendor protection intelligent electronic devices connected over a high-speed fibre-based communication network synchronised by both satellite and oscillator technologies. The project showcases the best and the latest in digital substations technology and has been of interest to other network owners within GB and worldwide, to our regulator and others who see digital substations as a key enabler of future smart grid.

The IEC 61850 Standard has been in development for over a decade and the benefits of this technology are numerous and well established, however the industry has yet to widely deploy. The shift to digital technology represents a step change; replacing longstanding and reliable technology and practices with a completely new suite of technologies and practices of which the industry has very little experience that have been largely limited to off-line trials.

Bringing large‐scale innovations such as FITNESS from demonstration to business‐as‐usual is a challenging feat and, although we have received support from the necessary business areas, the progression into day‐to‐day operations required comprehensive internal stakeholder engagement and through open debates with external parties to ensure all concerns and challenges are addressed.

The fundamental objective of this project was to accelerate the adoption of this technology, which is based on achieving the following two equally important conditions:

1. Technology readiness: achieved by demonstrating the technical operation including multi‐vendor interoperability.
2. Cultural readiness: achieved by instilling sufficient confidence and experience in IEC 61850 implementations.

Knowledge dissemination was fundamental to this project satisfying these conditions; stakeholder events and technical workshops ensure we collect and distribute experience and learning amongst all stakeholders. The key highlights and impact created through stakeholder engagement and knowledge dissemination activities in FITNESS are listed below:

- The first bay under this trial was successfully commissioned in July 2018. Since July 2018 SPEN has organised workshops and site visits at Wishaw for our stakeholders. We have so far hosted Ofgem, Scottish and Southern Electricity Networks, GB, Elia Belgium, Vattenfall Sweden, Hafslund Norway, Kawasaki Japan, Statnett, Norway independent consultants, and our senior management demonstrating application of RIIO NIC innovation funding in practical implementations and our commitment to drive innovation to business as usual.
- We expect through our engagement with our stakeholders we have created a positive outlook for retaining innovation stimulus in future price controls to enable transformational innovation projects such as FITNESS which has received considerable international recognition establishing GB as a global leader in innovation.

- We have mobilised further collaboration among utilities to drive international standards and suppliers for better standardisation of digital substations and driving the market to deliver to meet network owner's needs. It has also led to the digital substations initiative internally to prepare our business for roll-out digital substations in RIIO-T2.

The following sections provide details of year by year knowledge dissemination activities undertaken by project FITNESS.

10.1 Year 2016 & 2017

During the reporting period, the following knowledge activities were undertaken to establish a suitable knowledge dissemination framework to support Project FITNESS to achieve its goals:

- Dedicated key Stakeholder Engagement Event, Glasgow
- Wider stakeholder engagement activities undertaken, including presentations given at:
- LCNI 2016 & 2017 conference, Manchester
- IEC Europe 2016 & 2017 conference, Amsterdam
- GE CEAP Roadshow, Far East
- GE protection training course, Stone
- Article and commentary in industry-renowned PAC World Magazine December 2016
- FITNESS IEC 61850 Training 0 held in Glasgow, March 2017. The training course was hosted by SPEN and delivered by Opal‐RT and FMTP.
- FITNESS IEC 61850 Training 1 held in Glasgow, June 2017, hosted by SPEN and delivered by Opal-RT,FMTP and Helinks.
- FITNESS Helinks system configuration tool training delivered by Helinks in Glasgow, November 2017.
- FITNESS Steering Board meeting attended by key internal and external stakeholders.
- Wider stakeholder engagement activities undertaken, including presentations given at SGTech 2017 conference, Amsterdam.
- Abstract and subsequent full paper submitted to PAC World with presentation to be delivered in June 2017.
- Abstract and subsequent full paper submitted to Cigre conference.
- Abstract and subsequent paper submitted to Eskom.

The first in a series of FITNESS IEC 61850 training course was held in Glasgow in March 2017 hosted by SPEN and delivered by Opal‐RT and FMTP. The course was attended by Network Operators and Vendors from across Great Britain. The course was a great success and received excellent feedback from attendees.

The training course covered a number of topics and in great detail over the course of three days and catered to personnel from various backgrounds from automation to protection systems. Presentation topics included, among others, the following:

- Smart Grid and IEC 61850.
- Substation Automation Protection and Control.
- Time Synchronisation Protocols.
- IEC 61850 Commissioning and Maintenance.

Figure 95 FITNESS IEC61850 Training Session

An online survey was created and all attendees were invited to complete the survey online. The results of the survey are shown on the following page in graphical form. After the survey closed, a meeting was arranged between the parties involved in delivering Training 0 to discuss the results. As Training 1 was hosted by SPEN and again delivered by Opal-RT and FMTP, the feedback was used to inform the Training 1 material and plans arranged to introduce a hands-on training session.

A selection of the comments from the survey are shown below:

Q. What did you like about the training?

- “Very informative, given a real understanding of where it is, how we’re using it and how it will develop in the future.”
- “Getting to hear from industry experts was invaluable. All presenters were very knowledgeable and passionate about the field that made the material more engaging.”
- “High quality of the course content provided by industry experts. Most of the material was presented in good depth and easy to follow thanks to the excellent course material provided. Location and venue were also excellent.”
- “The trainers have excellent knowledge and were able to simplify the concepts to aid people like myself who have no prior knowledge of the subject.”

Q. What could we do to improve the training?

- “Although the training was appropriate to an introduction course, future courses would benefit from increased hands - on practical work.”
- “Allow attendees to participate in practical demonstrations and open up ‘brainstorming’ discussions.”
- “More time for discussion and to take information in, although I know time constraints did not allow for this”.

The feedback highlighted above is consistent with the results of the survey. As previously mentioned, the feedback received has been used to inform the next training course with hands - on sessions included as well as time allocated for feedback and discussions.

The first dedicated knowledge-sharing and stakeholder engagement event was held on 27th October 2016 at the Technology Innovation Centre, Glasgow. Through which, the FITNESS project delivery team shared the detailed objectives and business drivers behind the project to a wide audience of both internal and external stakeholders.

The event was held alongside the WG10 “Power systems management and associated information exchange” meeting to engage with the many key industry experts, and spark valuable debate between standard shapers, technology suppliers and the end users.

Figure 96 FITNESS External Stakeholder Session 2016

Colin Taylor, Director of Engineering Services responsible for the “Future Networks” innovation department at SPEN, opened the event by highlighting the importance of FITNESS in answering essential questions and challenges that prohibit widespread uptake by utilities.

The collective presentations from SPEN, ABB and GE, introduced the fundamental objectives of the pilot project; explaining the business drivers leading to the deployment of two parallel fully-digital multi-vendor solutions at Station and Process Level; the architectures of the proposed solutions; and the mixture of devices supplied to demonstrate interoperability by mirroring the live operation and replicating tripping signals.

In conjunction with demonstrating multi-vendor interoperability and the footprint savings associated with digital-solutions, presentations were given to demonstrate the additional benefits of low power instrument transformers (LPITs) that were supplied by ABB, GE and Synaptec who were able to present their unique distributed sensor technology to a wider audience of GB and international stakeholders. In addition to the IEC 61850-based technology to be trialled, representatives from GE presented how FITNESS seeks to demonstrate the role digital substation technology can play in helping facilitate the future sophisticated network management concepts such as WAMPAC - Wide-Area Monitoring, Control and Protection.

The event was a success in many ways; engaging a wide audience of key internal and external stakeholders to enhancing project awareness, raise valuable questions and, importantly, highlight challenges and areas for development.

10.2 Year 2018

During the reporting period, the following knowledge activities were undertaken to establish a suitable knowledge dissemination framework to support Project FITNESS to achieve its goals:

- FITNESS Steering Board meeting attended by key internal and external stakeholders.
- Wider stakeholder engagement activities undertaken, including paper submissions and presentations at prestigious conferences around the world.
- FITNESS project selected to feature in PAC World magazine.
- DPSP conference in Belfast, March 2018.
- SP Transmission Staff Conference Poster Session in Glasgow, June 2018.
- Cigre, Paris, August 2018- Paper published and contributions made at Cigre Paris Session
- Project presented and ranked best presentation at IEC61850 Global 2018

The second in a series of FITNESS IEC 61850 training course was held in Glasgow in June 2017 hosted by SPEN and delivered by Opal-RT, FMTP and Helinks. The course was attended by Network Operators and Vendors from across Great Britain. The course was a great success and received excellent feedback from attendees. The training course covered a number of topics and in great detail over the course of three days and catered to personnel from various backgrounds from automation to protection systems. Presentation topics included, among others, the following:

- Smart Grid and IEC 61850.
- Substation Automation Protection and Control.
- Time Synchronisation Protocols.
- IEC 61850 Commissioning and Maintenance.

Figure 97 FITNESS IEC61850 Training and Workshop

10.3 Year 2019

During the reporting period, the following knowledge activities have been undertaken to establish a suitable framework to support Project FITNESS to achieve its goals:

- Paper published and presented at PAC World Conference 2019

- Dedicated training organised for testing and commissioning engineers at Glasgow
- Over 25 site visits and workshops organised with delegates from Ofgem, senior management, GB network owners and international utilities

SP Energy Networks has actively participated in the PAC World forum for several years now. PAC World brings together representatives from around the world who specialise in Protection, Automation and Control (PAC), to allow idea exchange, best practice sharing, collaboration and the exploration of new technologies or processes. Having been recognised by PAC for delivering on our innovation ambitions, SPEN recently had the opportunity to play a key role at their annual conference.

Network Planning & Regulation Director at SPEN, Scott Mathieson, during his keynote speech, emphasised that empowering people and creating smart cities is crucial to our future, and he spoke passionately about his personal belief that engineers are key drivers of innovation, especially in the utilities sector. He spoke about the success so far and our future aspirations, highlighting the work we're already doing with our innovation projects like FITNESS and PHOENIX.

Figure 98. FITNESS hosts protection and control engineers from across the globe as part of PAC world technical tour

SP Transmission Director, Pearse Murray, and RIIO T2 Innovation Lead, Priyanka Mohapatra, were happy to welcome representatives from 12 different countries onto our Project FITNESS site in Wishaw as part of the conference technical tour. Some attendees were responsible for the defining of digital substations standards and were delighted to see their work realised at the first multi-vendor digital substation and automation system in Great Britain. Priyanka recognises that attending the PAC World conference a few years ago was a great inspiration to her. She said, “I attended PACWorld 2014 in Zagreb which gave me the idea for Project FITNESS, and 5 years later it is a proud moment for me to be able to present a live demonstration to the delegates and organisers of the same conference.”

Speaking generally about PAC events, Pearse said “I was delighted to witness the real community spirit in the protection and control world and for us to be a key part of an important event in their calendar this year. It’s fantastic to see such drive around the development of digital substations around the globe, and I’m proud of the success our FITNESS project has already delivered.”

10.3.1 FITNESS Other Technical Visits and training

FITNESS hosted over 25 different groups of delegates at the Wishaw 275kV substation between July 2018 – July 2019. The international popularity and success of the project has drawn interested utilities and network owners, delegates, regulators to our installation at the Wishaw substation. We had the pleasure to organise following knowledge sharing sessions over the last year

- ✓ Ofgem senior delegates and project officers
- ✓ SPEN senior management, CEO and Scottishpower CEO
- ✓ Iberdrola senior leadership
- ✓ SSEN
- ✓ Elia Belgium
- ✓ Vattenfall Sweden
- ✓ JFK Steel and Kawasaki Japan
- ✓ SPEN Engineers
- ✓ SPEN graduates
- ✓ PAC World delegates
- ✓ Fibre training course at Wishaw
- ✓ FITNESS testing and commissioning course at Glasgow
- ✓ IEC61850 working group conveners and members

Figure 99. FITNESS presented at PAC world conference Glasgow 2019

Figure 100. FITNESS hosts delegates from Japan who specially visited Scotland to visit the FITNESS set up

Figure 101. FITNESS hosts delegates from Vatenfall Sweden

Figure 102. FITNESS Digital Substations testing and commissioning training

10.4 Year 2020

During the reporting period, the following knowledge activities have been undertaken to establish a suitable framework to support Project FITNESS to achieve its goals:

- IEC61850 Global 2019
- Digital Substations 2019
- Cigre 2020
- Digital substations initiative
- Halfslund Norway FITNESS Visit
- Set up and Operation of replica system and training
- FITNESS Close Down Webinar

In order to promote knowledge dissemination and provide engineers to try the concepts and methodologies developed through project FITNESS an offsite replica system was developed through the project to promote knowledge transfer and skill set building within SP Transmission. This offsite replica system can also be accessed by other TOs and DNOs as and when required for testing through permission of SP Transmission. The offsite replica system extends the type of protection concepts trialled in project FITNESS to other types of feeder bays such as busbar and transformer protection. It also is equipped with test and engineering tools that will enable seamless roll-out of digital substations in RIIO-T2.

Figure 103. FITNESS Offsite Replica Test System

The FITNESS Close Down Webinar event held on the 8th of April 2020 attracted over 300 registrations from over 30 different countries and over 50 different utilities from around the globe. The actual event was attended by 210 attendees and a range of presentations by SP Transmission, ABB Ltd, GE Grid Solutions and OMICRON Electronics. The full webinar was recorded and made available to all attendees along with the slide pack for wider knowledge dissemination. The full webinar recording and slide pack can be accessed at the following links

FITNESS Webinar Slides

FITNESS Webinar Recording

The survey conducted SP Transmission following the event was filled up by 90 attendees. It had the following key comments and observations by the attendees which highlights the value generated through innovation and project FITNESS.

Q2

Customize Save as

How would you rate the overall event?

Answered: 87 Skipped: 3

4.3

average rating

	1	2	3	4	5	TOTAL	WEIGHTED AVERAGE
☆	1.15% 1	1.15% 1	10.34% 9	45.98% 40	41.38% 36	87	4.25

Q3

Customize Save as

How would you rate the knowledge of the presenters?

Answered: 88 Skipped: 2

4.6

average rating

	1	2	3	4	5	TOTAL	WEIGHTED AVERAGE
☆	1.14% 1	0.00% 0	3.41% 3	26.14% 23	69.32% 61	88	4.63

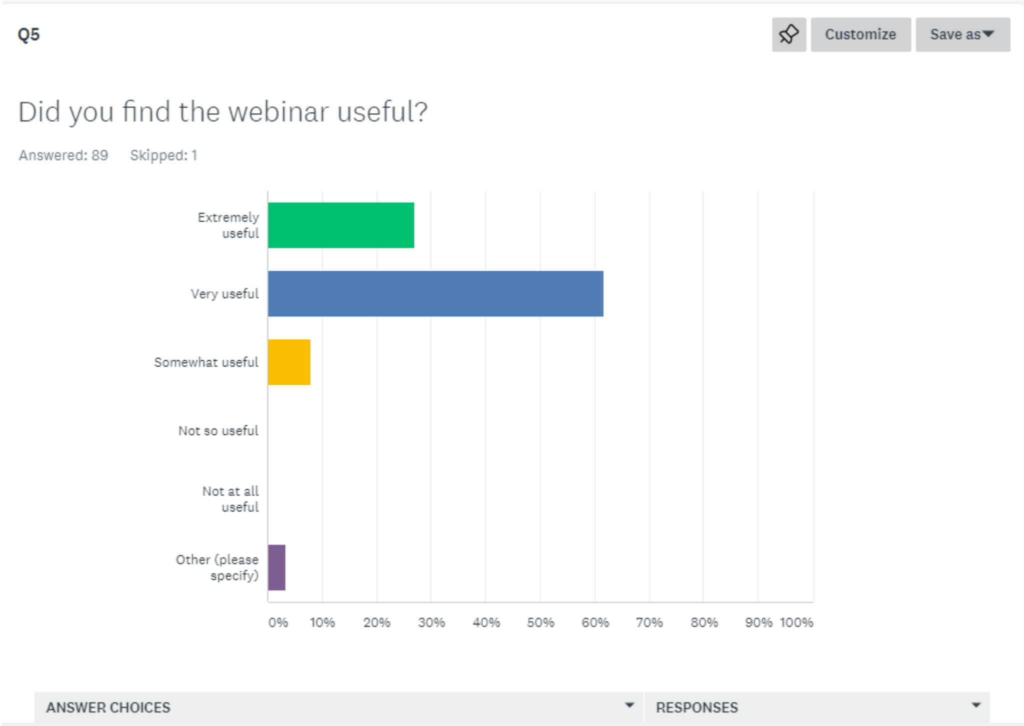


Figure 104. FITNESS Survey Results

What did you find most useful in the webinar?

- That various suppliers came together to implement the project and the suppliers understand the view of utilities typical requirements of redundancy, diversity and segregation.
- The technical challenges of interoperability and SPENs involvement.
- That Digital Substation is business as usual. It’s time to break the norms within utilities & promote it. Thanks to SPEN for taking the lead.
- Testing on Interoperability and the fact that you were able to successfully combine IEDs from different vendors. The testing set up by the presenters from OMICRON, and the testing on time synchronisation was also a good one
- Thank you for taking the effort to organize and hold this meeting. You are doing a super job helping your colleagues at other companies to get first-hand experience.
- Practical presentation of reliability and speed of using digital substation instead of metallic connection of signals.
- Great to hear experiences and learnings with pushing technology and combining vendor systems in implementing a digital substation. The webinar will help our utility's journey and strategy I was very interested in the presentations covering the many aspects of the design, testing/verification/monitoring and lifecycle The responses from you and the other presenters to the questions were relevant and of benefit to me. Very interested to hear about the Line differential protection set up and GPS clocks given the problems we are experiencing with traditional line differential protection and cross site GPS clock synchronisation. I was also very interested in the documentation and operational/maintenance considerations when design and implementing the project.
- The fact that you were able to complete a digital substation design with multi-vendor support, get so many people involved and happy to share your learnings. Awesome.
- Great job! Good to see how you guys collaborated with the vendors and share the information with everyone to move the industry forward

Figure 105. FITNESS Survey Results

11.0 CONTACT DETAILS

[redacted]

12.0 ABBREVIATIONS

Ref	Description
FITNESS	Future Intelligent Transmission Network Substation
RIIO	Revenue= Incentives+Innovation+Outputs
NIC	Network Innovation Competition
AAU	Analogue Acquisition Unit
AMU	Analogue Merging Unit
BC	Boundary Clock
BU	Back-up Overcurrent
BMCA	Best Master Clock Algorithm
BMK	Bay Marshalling Kiosk
CB	Circuit Breaker
CBF	Circuit Breaker Fail
CT	Current Transformer
DAN	Dual Attached Node
DANH	Dual Attached Node HSR
DANP	Dual Attached Node PRP
DAR	Delayed Auto-Reclose
FPFM	Feeder Protection First Main
FPSM	Feeder Protection Second Main
GOOSE	Generic Object Orientated Substation Event
GTW	Gateway
HRB	HSR RedBox
HMI	Human Machine Interface
HQB	HSR Quadbox
HSR	High-availability Seamless Redundancy
IED	Intelligent Electronic Device
IL	HSR and PRP Interlink
LAN	Local Area Network
MU	Merging Unit
LPIT	Non-conventional Instrument Transformer
NS	Network Switch
NTP	Network Time Protocol
PCAP	Packet CAPture
PDC	Phasor Data Concentrator
PMU	Phasor Measurement Unit
PPS	Pulse Per Second
Prot'n	Protection
PRP	Parallel Redundancy Protocol
PRR	Portable Relay Room
PTP	Precision Time Protocol
RedBox	Redundancy Box
SAMU	Stand Alone Merging Unit
SAN	Single Attached Node
SCADA	Supervisory Control And Data Acquisition

SCU	Switchgear Control Unit
SNTP	Simple Network Time Protocol
SV	Sampled Values
TC	Transparent Clock
TCP	Transport Control Protocol
TPSA	Tele-Protection Stand Alone
VDAN	Virtual Dual Attached Node
VT	Voltage Transformer
WACU	Wide Area Control Unit