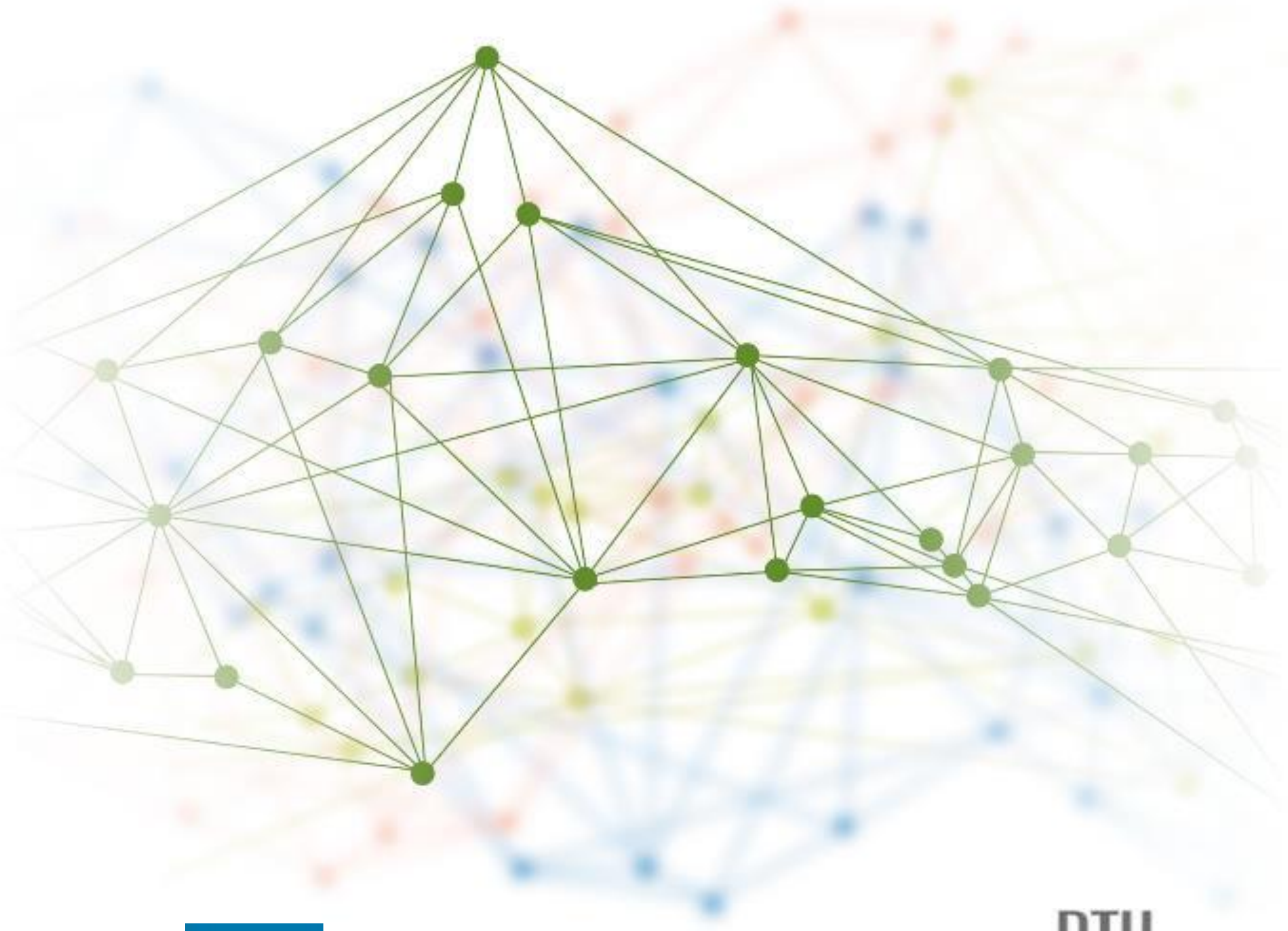
PHOENIX

Project Close Down Report



About Report

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Report History

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Contents

Table of Acronyms and Abbreviations

Abbreviation	Meaning
AVR	Automatic Voltage Regulator
BESS	battery energy storage system
CBA	Cost Benefit Analysis
CWG	Commercial Working Group
DTU	Technical University of Denmark
ECVC	Eccles voltage support and real time rating system
EFCC	Enhanced Frequency Control Capability
FACTS	Flexible AC transmission system
FES	Future Energy Scenarios
FTC	Fast Transients Compensation
GFC	Grid Forming Converter
H-SC	Hybrid Synchronous Condenser
HIL	Hardware In Loop
IBG	Inverter Based Generations
ISM	Inertia Support Maximisation
LoG	Loss of generation
LRM	Loss reduction mode
NGESO	National Grid Electric Systems Operator
NGET	National Grid Electricity Transmission
NIC	Network Innovation Competition
NOA	Network Option Assessment
OEL	Over Excitation Limiter
ORPS	Obligatory Reactive Power Service
PCC	Point of Common Coupling
PLM	Power Loss Minimization
PSS	Power System Stabiliser
RDP	Regional Development Program
RoCoF	Rate of Change of Frequency
SAT	Site Acceptance Tests
SC	Synchronous Condenser
SCAPP	Synchronous Condensers Application in Low Inertia systems
SCL	Short circuit level
SPEN	Scottish power energy networks
SPT	Scottish Power Transmission
STATCOM	Static compensator
SDRC	Successful Delivery Reward Criteria
UoS	University of Strathclyde

1. Introduction

Phoenix is a national flagship innovation project supported under RIIO-T1, NIC mechanism in 2016. This project has aimed to address a number of challenges resulting from the on-going energy transition - a change in the method of electricity generation from conventional fossil fuel-based sources to renewable sources:

- Reduced Network Inertia
- Low Short circuit level (SCL)
- Limited Voltage control

These challenges pose a significant impact on the GB electricity transmission system which drastically changes system dynamics and operational pattern, affecting capacity and consistency of power transmission between regions. To combat these challenges Phoenix looked into sustainable design, deployment and operation of an innovative hybrid co-ordinated control system referred as the Hybrid Synchronous Condenser (H-SC) combined with a static compensator (STATCOM, -a flexible AC transmission system (FACTS) device). The project showcased technical and economic advantages of deploying H-SC over similar technologies with the aim of encouraging future rollout of the H-SC across the GB network. Phoenix demonstrated:

- The first design and deployment of a H-SC in GB,
- The first live trial of an H-SC within the GB Transmission Network,
- Increased the Boundary Transfer Capability from Scotland to England leading to a better distribution of renewable electricity generated in the North.
- A lower carbon footprint than its conventional counterparts.

The timing of Phoenix is really critical. Based on industry's best view set out in t different future energy scenarios and the ten-year statement, there could be 9300 MW of wind and only 635 MW of synchronous generation (pumped storage, CHP, gas, biomass) connected to the SP transmission network by 2030 [1].

The total budget for the project was £17.6m, this was used to:

- coordinate, develop, procure, commission, and operate the first GB-wide H-SC infrastructure and associated applications,
- overcome technical challenges, build confidence in the technology, and ultimately accelerate the uptake of H-SCs within GB.

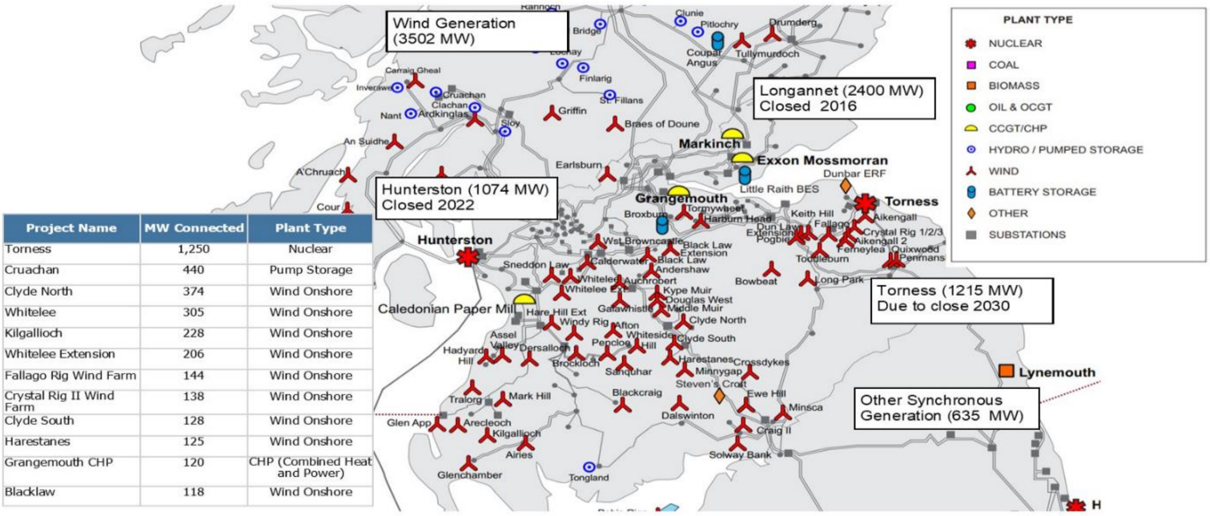
Phoenix is a collaboration project between SPT, National Grid Electricity System Operator (NGESO), ABB/Hitachi Energy, University of Strathclyde (UoS), and the Technical University of Denmark (DTU). Its aim is to develop and showcase an efficient and composite solution to provide dynamic voltage control, network inertia and Short Circuit Level (SCL).

The project team is very delighted that the key purpose of creating a blueprint through this innovation has been fulfilled satisfactorily and in a timely manner. The learnings from the engineering, innovation, commercial challenges and industrial experiences of the project have been properly documented and shared with the international electricity sector. This project has already generated tangible benefits for our electricity customers by informing the roll out of this technology into Business as usual, this includes SPEN's plan for an installation at Eccles before 2026 as well as several other projects across the UK which have been announced recently in April 2022.

2. Executive Summary

2.1. Project Rationale

In 2014, wind generation delivered 30.5% (11,664 GWh) of Scotland's electricity consumption; the total wind generation in Scotland increased in 2020 to 23,075 GWh. A geographical representation of the generation on the SPT network is shown in Figure 1, with interconnection to England across the B6 system boundary and to Northern Ireland through the HVDC Moyle interconnetor at Auchencrosh. Denmark, Germany, southern California, and Texas have a similarly weak but relatively well interconnected AC transmission systems as high levels of renewable generation displace conventional thermal generations. To future proof their transmission systems, these power systems have begun to strategically deploy SCs to support the transition to a zero-carbon future whilst not compromising system security and stability.



Project Name	MW Connected	Plant Type
Torness	1,250	Nuclear
Cruachan	440	Pump Storage
Clyde North	374	Wind Onshore
Whitelee	305	Wind Onshore
Kilgallioch	228	Wind Onshore
Whitelee Extension	206	Wind Onshore
Fallago Rig Wind Farm	144	Wind Onshore
Crystal Rig II Wind Farm	138	Wind Onshore
Clyde South	128	Wind Onshore
Harestanes	125	Wind Onshore
Grangemouth CHP	120	CHP (Combined Heat and Power)
Blacklaw	118	Wind Onshore

Figure 1 - SP Transmission Generation Profile

2.1.1. Technical Description of Project

SCs can improve the voltage of the surrounding network through import or export of reactive power (MVAr). These MVArs are used to control voltage within the grid and improve power transfer over circuits and between system boundaries. Two operating conditions are possible according to the capability curve of individual SCs:

- Over-excitation: generation of reactive power with leading power factor (capacitive behaviour),
- Under-excitation: absorption of reactive power with lagging power factor (inductive behaviour).

Additionally, because of the rotating mass and characteristics like synchronous generators (except for producing active power), SCs can contribute to system inertia and Short Circuit level (SCL). These services are increasingly important given the growing challenges relating to increasing penetration of Inverter Based renewable generations connecting to the GB system.

2.1.2. Introduction to Hybrid Synchronous Condenser (H-SC)

The H-SC is the novel combination of a synchronous condenser and a STATCOM, with an innovative control system. The SC characterised by a high rotating energy with high short circuit current generation capability, is used as the main contributor to boost the system inertia and increase the system SCL. The characteristic response time i.e., relatively fast response for large disturbances and slower response for small signal control, together with its specific overload capability make the SC very suitable to play an important role in providing voltage support in severe dips and contributing to system frequency response.

The STATCOM device in the H-SC combination (Figure 2) is able to rapidly contribute highly controllable voltage regulation during voltage dips. During fault recovery and switching phenomena, the STATCOM has the capability to quickly provide the reactive power support to maintain the system voltage within the allowed limits. The STATCOM also has a response time suitable for solving the power quality concerns, to actively dampen harmonics in the power system and voltage fluctuations that produce annoying flickering effects for industrial and domestic consumers. The H-SC combines the complementary operational characteristics of both the SC and the STATCOM to provide highly responsive voltage and frequency regulation.

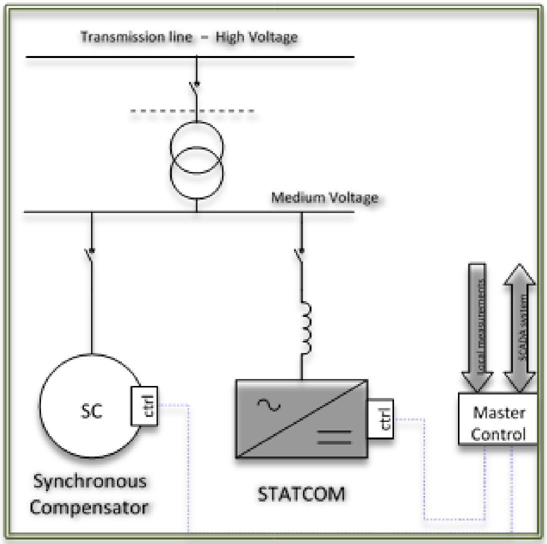


Figure 2:Hybrid Synchronous Condenser (H-SC)

Within the Phoenix project scope, it was considered beneficial to investigate and test the SC as the main technology combined with STATCOM. This provides benefits such as the boosting of system inertia by emulating generator behaviours, with a limitation on the energy contribution. The benefits also include the advantages on the speed of response and ability to fine tune the power output.

The hybrid control strategies delivered for Phoenix provide insights on:

- Possible future similar plants with the combination of the two technologies installed at the same electrical node
- Interactions and operational coordination of such technologies installed at different nodes in the network, a likely scenario in the future GB power system.
- Extension of research to apply hybrid control methods to combined SCs and Battery Energy Storage System (BESS).

2.2. Project Scope and Outcomes

The main objective of Phoenix is to develop and demonstrate the use of a Hybrid Synchronous Compensator (H-SC). The scope of this project includes six dedicated work packages set up based on the project objectives and associated Successful Delivery Reward Criteria (SDRC), each with their own set of objectives, to collectively achieve the overall objectives, as summarised below:

Table 1 - Phoenix Work Packages

WP1: Hybrid-Synchronous Condenser (H-SC) Installation (SDRC 1, SDRC 6)	
Work Stream	Pre-Site Planning and Design On-Site Deployment and Commissioning
Purpose	This work package was intended to provide a final design of the pilot H-SC installation following the preliminary design during the bid phase, including the building and planning requirements for deployment of H-SCs. The detailed technical and commercial studies carried out in the bid phase would allow for a quality and cost-effective design. The strong design would allow a smooth installation and commissioning of the pilot H-SC. This would then allow knowledge gathering and learning from these works.
Outcome	The quality initial design allowed a high standard and timely delivery during the installation and commissioning phases of the project, and this increased the quality of the information gathered regarding the installation and commissioning.
WP2: Live Trial (SDRC 6, SDRC 7)	
Work Stream	• SC and H-SC Performance Monitoring • SC and H-SC Output Monitoring • System/Operational Performance Monitoring • Extended Live Performance Trials Report and Recommendations

Purpose	The live trial was designed to enable validation of the technical and commercial modelling carried out in the design. The purpose of monitoring the output and performance of the system was to assess against modelled outputs and to build knowledge regarding the behaviour, benefits and issues with the system to enable even higher quality deployments in future if beneficial to the system.
Outcome	The trial has confirmed how accurately the system studies and financial models actually performed. The pilot H-SC live operation resulted in cost savings for the system operator confirming the financial value associated with it and most importantly resulting in savings for GB customers. The phase monitored performance of the pilot SC in standalone mode and in H-SC mode at component level, capturing losses, vibrations, noise levels and oscillation damping. The system was monitored on the usage of the SC and H-SC for voltage support, short-circuit level and inertia contribution. The trial phase tested the hybrid coordinated control methods developed in this project. This validated the system studies, and system and financial models were updated with the findings of this project. Whilst also providing lessons which could be carried into future developments. Confirmation of a net benefit of up to £86 million.
WP3: Commercial Model Development and Roll-Out Recommendations (SDRC 2)	
Work Stream	• Development of Cost Benefit Analysis (CBA) model for SCs and H-SCs • Financial evaluation based on economic and emerging energy policies • Validation of the CBA against actual utilization on the system. • Regulatory recommendations for future roll-out of SCs and H-SCs
Purpose	The purpose of this work package was to develop modelling for the commercial side of this specific project and generic H-SC projects for other parts of the country. This includes what specific designs would most benefit certain locations facing different grid conditions or scenarios, providing recommendations on technical, commercial and regulatory facets for future project developments.
Outcome	This work package confirmed the financial value of services that can be provided by SCs and H-SCs regarding, voltage inertia and SCL support. It was also determined the need for availability and capability of SCs/H-SCs in future with regulatory recommendations for future roll-out. It has worked with the GB SO to create a robust CBA model for the value evaluation. In the implementation phase this model was put to test along-with the results from the system studies. It has been tested if the application of SCs and H-SCs in different parts of GB system results in similar or increasingly variable benefits. This model generated a return on investment (ROI) value for service providers and the learnings can be used to in future service agreements for inertia and SCL.
WP4: Hybrid Co-ordinated Control & Integration (SDRC 3)	
Work Stream	Hybrid coordinated control to maximize benefits from different technology solutions
	Lab Simulation of Control Methods Hybrid Control method Site Deployment and Testing
Purpose	The purpose of this work package was to develop and test the control systems in laboratory and live environments to assess and optimise how different grid support devices perform together to best support the grid and provides financial benefits for the customers.
Outcome	This work package was globally innovative in demonstrating new control strategies to maximize different outputs from SCs with hybrid coordinated control methods. Depending on the future site of installation SCs may be required to maximize on certain outputs in standalone and/or H-SC mode. This work package has proved that SCs are complementary to other types of compensation devices and with storage services and can be operated in H-SC mode to

	maximize all system benefit cases. This improves the business case of SCs and H-SCs for TOs and SO. The work package has also confirmed that maximising system benefits through hybrid control methods will help reduce costs associated with system balancing and frequency reserve markets.
WP 5: Component and System Studies (SDRC 5)	
Work Stream	Component Level Studies System Level Studies
Purpose	The purpose of this work package was to assess, using modelling, how different grid support devices, specifically H-SC and SCs would support the grid in future considering different FES tfor future developments.
Outcome	This work package bridged the gap between past and future system studies regarding system operation and role of SCs and H-SCs in different FES scenarios. The system studies analysed results from previous innovation projects (Appendix H of the Project Submission). The models developed through previous projects were used in various streams of studies at component and system level. The component level studies were extended to H-SC models from the existing studies regarding SC inertial and SCL performance in SCAPP (Synchronous Condensers APPlication in Low Inertia systems) (see Appendix H of the Project Submission) project, . The system level studies analysed the application of SCs and H-SCs at different locations of GB network and will directly feed into FES and SOF studies conducted by GB SO. Detailed analysis was performed for specific use cases such as role of SCs/H-SCs in frequency response market in conjunction with fast frequency solution developed through EFCC and potential constraint of western HVDC link in low SCL conditions after planned closure of Hunterston in 2023. The research component of this project resulted in GB roadmap for future rollout of SCs/H-SCs and will aid RIIO T2 planning for GB TOs and SO.
WP 6: Knowledge Dissemination (SDRC 8)	
Work Stream	• Dissemination in GB and international conferences and paper submissions • Quarterly Internal stakeholder events - WebEx and Focus Group Meetings • Annual External stakeholder events • Engagement with technical standard bodies and working groups • Engagement with GB SO for development of commercial mechanisms and participation in working groups
Purpose	The purpose and main aims of this work package is described in detail in Section 5 of the Project Submission.
Outcome	Successful disseminations of information were organised to industry partners and relevant bodies through seminars, project bursts, reports and technical documentation as detailed in Section 11 of this report.

2.3. Overall Project Outcomes

All the project objectives and SDRC for Phoenix were achieved successfully.

The H-SC technology was successfully installed and live trialled at Neilston substation, the learnings from live trials and studies carried out by the project partners have validated the technology and identified the significant financial and carbon benefits roll out of H-SCs on the GB electricity network.

Key project outcomes are listed below:

1. A net cost benefit up to £51m can be achieved with the Phoenix Neilston H-SC device as showcased in SDRC 2.2 report (access provided in Table 12) [2].

2. Phoenix will achieve a cumulative carbon benefit estimated at over 16 thousand tonnes by 2030 [1].
3. As stated in the SDRC 2.2 report, the Phoenix device can increase boundary transfer capability between SPT and NGET by 98 MW facilitating the transfer of more renewable generation across the transmission system [2].
4. All Phoenix Project Successful Delivery Reward Criteria have been met to the planned time and costs.
5. Building on the learning from the Phoenix project, it is planned to roll out this technology during RIIO-T2 at Eccles, providing a 280 MW B6 transmission system boundary uplift between Scotland and England through T2 details of which can be found in the Engineering Justification paper for the same [3].
6. H-SC can be deployed through existing regulatory and commercial arrangements. These arrangements include:
    - Deployment as a regulated asset to meet Transmission Owner (TO) licence requirements,
    - Deployment through NOA recommendation, and
    - Deployment through the Stability Pathfinder process or other mechanisms that emerge based on the findings of the Pathfinder.

2.4. Project Aims and Objectives

The project aimed to resolve some of the issues caused by the change in generation mix from conventional synchronous generators to more inverter based generation that has already occurred and is expected to continue based on the existing Future Energy Scenarios (FES). The project provided counter measures to the technical and commercial challenges that risk the security of supply to GB customers as described below.

Technical

- Reduced inertia which compromises the network stability and security in event of major disturbance such as a large loss of generation or load, resulting in a big rate of change of frequency (RoCoF).
- Lower SCL results in poor power quality and can also result in certain protection schemes failing to operate and introduces an increased risk of operation failure in HVDC links.
- Limited voltage control in absence of immediate dynamic response conventionally obtained from synchronous generators that may result in voltages outside the statutory limits.
- The reduced loading capability of the transmission system with more un-damped sub-synchronous oscillations and increased levels of harmonics

Commercial

- Increased cost of acquiring more frequency response – 300-400% increase expected by 2030, currently 1% of customers electricity bill so this is expected to have a substantial impact,
- Lower efficiency providers of inertia would result in higher costs to system operators and customers.
- Requirement to maintain expensive fossil fuel plants to provide inertia.

2.5. Key Project Learnings

Phoenix has delivered significant new learning on the design, deployment and operation of H-SC in the transmission system to resolve challenges with increasing renewable generation and reducing synchronous generation. The method has been successfully proven in this project. Besides the successfully delivered outcomes and benefits, some Key Technical Learnings have been obtained from the project, including:

1. Boundary transfer capability: employment of the H-SC system is able to increase the boundary transfer capability in similarly constrained areas of a network as the trial site.
2. Control Interaction: To avoid harmful control interaction between the SC and STATCOM, appropriate measures should be taken at the design stage to ensure the transformer impedance between the STATCOM and SC branches is sufficient, and the control parameters are tuned appropriately. The different electrical distances between the devices can affect the stability and performance of the H-SC system which depending on the operation of the individual controls of each device.
3. Control coordination: We Learnt that utilisation of the master controller can coordinate control of both devices resulting in minimized losses and maximised network inertia contribution.

4. System impact and Dynamics: It was found that it is key to verify the impact of the hybrid device on the connected system. Depending on the system strength and device rating the impact would vary. The dynamics of the hybrid device should be also validated against the requirements.
5. From the technical aspects: the parallel operation of SC and STATCOM may bring various challenges in equipment, control and system interactions. It is thus important to verify the feasibility of hybrid operations of such devices for future installations in all those respects. Detailed system studies are needed to verify impacts, and control and system interactions.
6. Regulatory Requirements: It was found that current regulations can inhibit the roll out of H-SC systems as TOs are not allowed to participate in market services and there is currently no mechanism for providing a high ROI which might encourage 3rd parties to invest the high levels of capital required.
7. Project Management:
    - It is a key to success to have good project management practices employed by the project managers and the support teams through the project. Efficient communication among all project partners and relevant stakeholders need to take place in various forms such as quarterly meetings, commercial working group workshops.
    - A pre-emptive project planning approach was another learning point from Phoenix which aided in the early identification of areas requiring added resources and support. The Punch-lists created for each stage to track the progress of any outstanding actions were proven to be really useful.
    - Thorough training was another key factor for the success of the project like Phoenix, this includes activities such as SPEN engineers visiting ABB manufacturing facilities in Sweden to ensure the continuous operation of the H-SC.

3. The Details of Work and Methodology Employed

The project has demonstrated the installation and operation of H-SC solution for the first time in GB. The innovative hybrid control method has been used to co-ordinate complementary technologies to assure the maximisation of the system value. The successful outcomes will have a positive impact in the rollout of the technology for future installations throughout the electric system. The outcomes will also be used to inform the development of commercial framework for future installations of SCs and H-SCs. The experience gained will provide guidance on the further research and development to maximize operational efficiency, system performance and identify potential sites for the rollout of SCs and H-SCs within GB power networks. This section firstly introduces the three key development stages of the Phoenix project (Conceptualisation, Implementation and Validation), and then lays out the methodology and control system deployed for H-SC.

3.1. Key Stage of Project Development

3.1.1. Conceptualisation

This stage involves choosing a site out of the 3 possible sites on SPT Network and determining the engineering feasibility of the H-SC installation. Parallel to this procedure, a cost benefit analysis is developed specific for value evaluation of SC/H-SCs. The research component of the project at this stage entails results analysis and investigation of system models from previous innovation projects, which helps preparing for system studies to be undertaken as part of the project.

3.1.2. Implementation

This stage implements the methods developed in the conceptualisation phase. The recommendations for future installations and procurement of SCs and H-SCs was developed throughout this phase. This stage also included the deployment and connection of the H-SC solution to the SPT network. The system and component level studies carried out in this stage feed into the CBA model to determine the return of investment and financial value of Phoenix and further installations of SCs and H-SCs.

3.1.3. Validation

This is the most important stage of the project which validates the perceived benefits of the H-SC installation through performance monitoring both at component and system level. The GB roadmap for rollout of SCs and H-SCs was developed at this stage. Most importantly the commercial framework developed at the earlier stages was tested at this phase. The details of the technical solution trialled as a part of the project and the network diagrams are described in Appendix C Project Submission [1].

The progress of Phoenix Live Trial Plan was documented and reported on monthly basis from November 2020. Findings and conclusions on H-SC performance were discussed among representatives of the involved parties. This helped validate the model and proved the technical functionality of the H-SC technology and control methodology.

Knowledge dissemination has been an integral part of the project and as described in detail in Section 11 at every phase of the project the learnings and outcomes had been shared with the wider audience and stakeholders.

3.2. H-SC Control System and Methodology

This section provides the technical details of H-SC and master control functions and its operation, explains how the technical requirements for the H-SC at Neilston have been achieved.

3.2.1. H-SC and Master Control

The H-SC system has been designed according to the alternating current (AC) power system characteristics at the point of common connection (PCC). Those characteristics were specified by the grid operator and include aspects such as system voltage, short circuit levels, expected over-voltages and under-voltages, the maximum rate of change of frequency (df/dt), etc. IEEE Standard 1031-2011 gives an example of the necessary power system characteristics to specify.

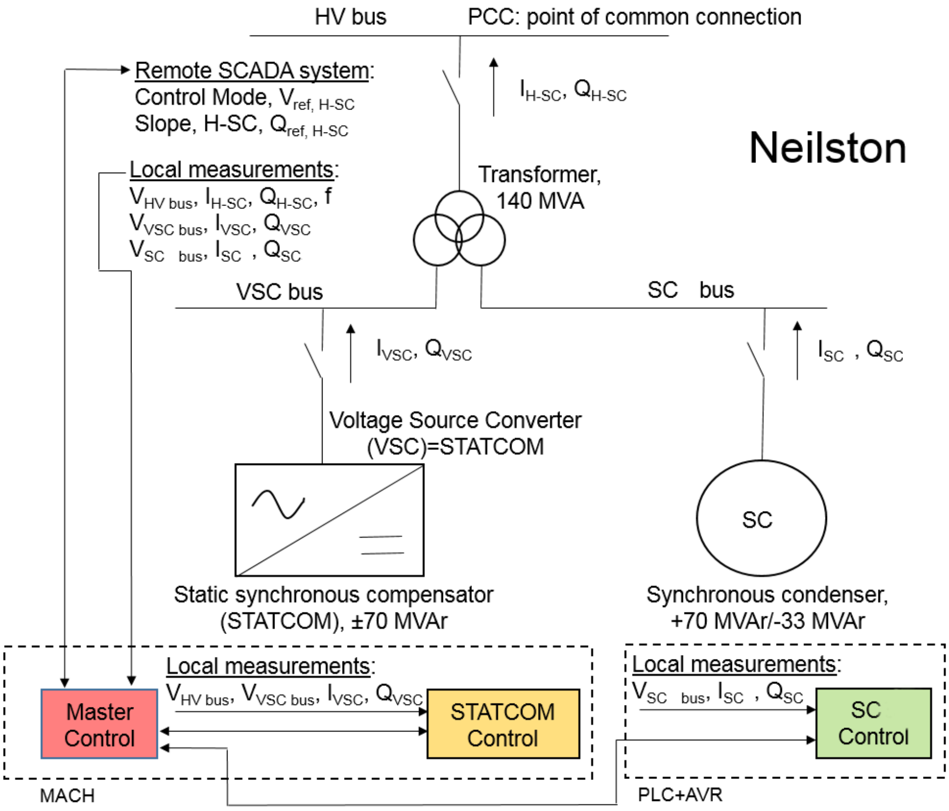


Figure 3 - Simple single-line diagram of the H-SC system

As shown in Figure 3, a ±70 Mvar STATCOM operates in parallel with a +70/-33 Mvar SC, connected to the HV bus via a three-winding power transformer rated for 140 MVA. The STATCOM, SC and power transformer have been manufactured by ABB. The STATCOM utilizes Modular Multi-level Converter (MMC) valve technology, while the SC is a 4-pole motor with brushless excitation system and inertia constant of 1.34 s. The SC has been designed for installation in a safe area according to IEC 60034-1, 275 kV is the HV bus voltage.

3.2.2. H-SC Control and Operation

SC and STATCOM technologies are traditionally supplied with standalone control systems. The STATCOM control is a MACH® control platform manufactured by ABB. The SC control consists of a PLC and an AVR also manufactured by ABB.

The SC controls the SC bus voltage ($V_{SC\ bus}$) by using the local measurements I_{SC}, $V_{SC\ bus}$ and Q_{SC} illustrated in Figure 3, whereas the STATCOM controls the HV bus voltage ($V_{HV\ bus}$) by using the local measurements I_{VSC}, $V_{VSC\ bus}$, $V_{HV\ bus}$ and Q_{VSC}.

In addition to the standalone operation of the STATCOM and SC, a hybrid control functionality (Master Control) has been developed inside the MACH® control platform. The developed functionality avoids "control hunting" between the two control systems (STATCOM Control and SC Control), thus allowing the stable, coordinated, and efficient operation of both branches simultaneously.

As depicted in Figure 3, Master Control uses all the local measurements mentioned above plus $I_{H\text{-}sc}$, $Q_{H\text{-}sc}$ and the network frequency (f), in addition to the control modes, setpoints ($V_{ref,\ H\text{-}SC}$ and $Q_{ref,\ H\text{-}SC}$), and slope (Slope, H-SC) chosen by the operator for the H-SC system. This information can be obtained remotely via SCADA or locally via the HMI of the MACH® platform, and it is then used to calculate the setpoints and slopes required by the STATCOM and SC controls.

The available control modes in the STATCOM are automatic voltage control (V control) and MVAr control (Q control). In V control the voltage of the HV bus ($V_{HV\ bus}$) is controlled according to the voltage setpoint ($V_{ref,\ VSC}$) and slope (Slope, VSC) chosen by the operator, whereas in Q control the reactive power output at HV bus level is controlled according to the chosen power setpoint ($Q_{ref,\ VSC}$).

The available control modes in the SC are automatic voltage control (V control), MVAr control (Q control) and field current control (Manual control). V and Q controls are like those in the STATCOM, but they control the SC bus voltage ($V_{SC\ bus}$) and the reactive power output at SC bus level (Q_{SC}), respectively. In

Manual control, the exciter field current is controlled according to the current setpoint chosen by the operator. Manual control is only for commissioning or loss of voltage measurement.

The STATCOM control does not require the transformation of $V_{ref, H\text{-}SC}$ and $Q_{ref, H\text{-}SC}$ at HV bus level into $V_{ref, VSC}$ and $Q_{ref, VSC}$ at VSC bus level. In that case, the problem is solved by using the branch current I_{VSC} on the VSC side of the power transformer to regulate the voltage and reactive power output on its high voltage side. However, the SC control requires the transformation of $V_{ref, H\text{-}SC}$ and $Q_{ref, H\text{-}SC}$ into $V_{ref, SC}$ and $Q_{ref, SC}$ at SC bus level. Master Control does that transformation by adding the voltage drop across the power transformer and the reactive power losses to $V_{ref, H\text{-}SC}$. and $Q_{ref, H\text{-}SC}$, respectively.

Therefore, under normal circumstances, the H-SC operating modes will be given by the possible combinations of V and Q control between the STATCOM branch and the SC branch. Table 2 lists the alternatives employed in Phoenix. As indicated by the third column, there are three H-SC operating modes: only STATCOM (SC out of service), only SC (STATCOM out of service) or both STATCOM and SC in service.

The operator can also assign V control or Q control to any of the two branches. As a result, there will be several possible combinations (described as 'Applications'), as shown in Table 2.

Besides, if the goal of the operator is to provide inertia services without SC MVAr, then the Q setpoint of the SC branch ($Q_{ref, SC}$) is set to zero (e.g., for Applications 3, 8 and 9 in Table 2).

Application 7 (both branches in V control) is expected to be the most used mode of operation. In that case, the H-SC system provides inertia with a variable MVAr split to provide automatic voltage control (or V control). Application 6 is expected to be the next most used mode. In that case, the H-SC system provides inertia with a constant MVAr split to provide fixed MVAr Control (or Q control).

Table 2 – H-SC Operation Modes

Application	Setting	H-SC Operating Mode	STATCOM (VSC)		Synchronous Condenser (SC)		Setpoints calculated by Master Control
			Control Mode	Setpoint	Control Mode	Setpoint	
1: MVAr only	Constant MVAr	Only STATCOM	Q	Qref , VSC ≠ 0 @ HV bus	NA	NA	NA
2: MVAr only	Variable MVAr		V	Vref , VSC @ HV bus	NA	NA	NA
3. Inertia only	NA	Only SC	NA	NA	Q	Qref , SC = 0 @ HV bus	Qref , SC = 0 @ SC bus
4: Inertia with SC MVAr	Constant MVAr		NA	NA	Q	Qref , SC ≠ 0 @ HV bus	Qref , SC ≠ 0 @ SC bus
5: Inertia with SC MVAr	Variable MVAr		NA	NA	V	Vref , SC @ HV bus	Vref , SC @ SC bus
6: Inertia with MVAr split(2)	Constant MVAr	Both STATCOM and SC	Q	Qref , VSC ≠ 0 @ HV bus	Q	Qref , SC ≠ 0 @ HV bus	Qref , SC ≠ 0 @ SC bus
7: Inertia with MVAr 8: split(1),(2)	Variable MVAr		V	Vref , H-SC @ HV bus	V	Vref , H-SC @ HV bus	Vref , SC @ SC bus
9: Inertia with STATCOM MVAr(2)	Constant MVAr		Q	Qref , VSC ≠ 0 @ HV bus	Q	Qref , SC = 0 @ HV bus	Qref , SC = 0 @ SC bus
10: Inertia with STATCOM MVAr(2)	Variable MVAr		V	Vref , VSC @ HV bus	Q	Qref , SC = 0 @ HV bus	Qref , SC = 0 @ SC bus
11: Inertia with MVAr split(2)	Variable MVAr		Q	Qref , VSC ≠ 0 @ HV bus	V	Vref , SC @ HV bus	Vref , SC @ SCS bus
12: Inertia with MVAr split(2)	Variable MVAr		V	Vref , VSC @ HV bus	Q	Qref , SC ≠ 0 @ HV bus	Qref , SC ≠ 0 @ SC bus
(1) With or without Power Loss Minimization							
(2) With or without Inertia Maximization							

Master Control comes with several objective functions to achieve its goals. Some are objective functions for optimization, whereas others are simply coordinating functions, control strategies and/or calculation functions. The functions developed by ABB are: 1) Coordinated Voltage Control and Reactive Power Sharing, 2) Power Loss Minimization, 3) Loss Reduction, 4) Fast Transients Compensation, 5) Inertia Support Maximization, 6) Losses Calculation and 7) Slow MVAr Control.

Figure 4 depicts the block diagram of Master Control. As shown the input signals are the local voltage, current and power measurements, in addition to control mode, setpoint and slope chosen by the operator for the H-SC system. Other inputs are the on/off signals for the different objective functions and the STATCOM and SC current limits. The outputs are the setpoints (rightmost column in Table 2) and slopes required by the coordinated operation of both control systems.

The operator can also choose different control modes for the branches, according to the applications listed in Table 2, but these have not been depicted in Figure 4 for simplicity. The developed functions for Master Control are described below.

3.2.2.1. Co-ordinated Voltage Control and Reactive Power Sharing

The main objective of this function is to determine the setpoints required by both control systems for their coordinated and stable operation. For V control, the outputs are voltage setpoints ($V_{ref,\ VSC}$ and $V_{ref,\ SC}$) and slopes (Slope, VSC and Slope, SC), whereas for Q control the outputs are reactive power setpoints ($Q_{ref,\ VSC}$ and $Q_{ref,\ SC}$). In both cases, the output setpoints and slopes are determined as functions of the input setpoints ($V_{ref,\ H\text{-}SC}$ or $Q_{ref,\ H\text{-}SC}$) and slope (Slope, H-SC) chosen by the operator for the HV bus.

To achieve equal reactive power-sharing between STATCOM and SC, this function sets equal slopes for the branches (i.e. Slope, H-SC @140 MVA = Slope, VSC @70 MVA = Slope, SC @70 MVA) when using Application 7 (without Power Loss Minimization, which is explained in section 3.2.2.2) in Table 2. The operator can also set different reactive power setpoints per branch (i.e. $Q_{ref,\ VSC}$ $Q_{ref,\ SCS}$) when using Application 6 in Table 2 (without Power Loss Minimization) or Application 8 in Table 2, but that option has not been depicted in Figure 4 for simplicity. For the applications listed in Table 2, the operator **cannot** turn off (co-ordinated voltage control and reactive power sharing) function.

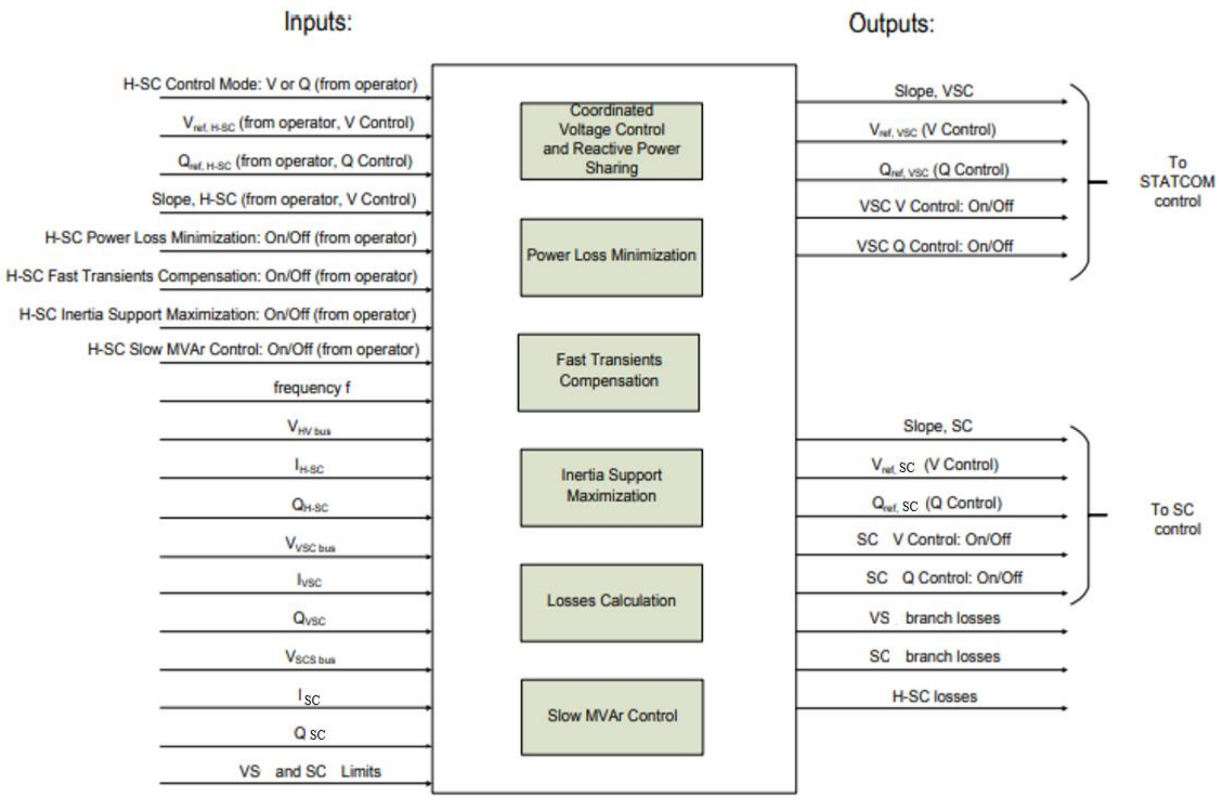


Figure 4 - Block Diagram of Master Control

3.2.2.2. Power Loss Minimisation (PLM)

This is an innovative function proposed by ABB, and its main objective is to determine how the total reactive power output of the H-SC system should be shared between its two branches so that the total losses are as low as possible. To minimize losses, the losses and their derivatives have been expressed as functions of the branch currents (or branch reactive powers) by using the component ratings and the design data.

The outputs of this function are optimized slopes (in V control, i.e. Application 7 in Table 2) or optimized Q set-points for both the STATCOM and the SCS (in Q control, i.e. Application 6 in Table 2) if the input setpoint is the total reactive power $Q_{ref,\ H\text{-}SC}$). In both cases, the output setpoints and slopes are determined as functions of the input setpoints ($V_{ref,\ H\text{-}SC}$ or $Q_{ref,\ H\text{-}SC}$) and slope (Slope, H-SC) chosen by the operator for the HV bus. The operator can also turn off this function, as shown in Figure 4.

3.2.2.3. Loss reduction mode (LRM)

Loss Reduction Mode (LRM) is a mode to reduce the switching losses for a STATCOM. The LRM function blocks the STATCOM when the reactive power output from STATCOM is close to 0 MVAr, to save the power loss incurred by the STATCOM. The power loss reduction due to LRM function is low, as the power loss incurred by STATCOM is generally low and it only works when STATCOM output is closer to 0 MVAr.

With the Phoenix device configuration of equal size of STATCOM and SC, the amount of power loss savings with PLM function is negligible. With the different configuration such as higher rating of STATCOM could provide more power loss savings with PLM and LRM functions, by reducing the power loss incurred by the SC.

3.2.2.4. Fast Transients Compensation (FTC)

This is also an innovative function proposed by ABB, and its main objective is to speed up the response time of the H-SC system in case of sudden changes in voltage (e.g., due to network disturbances), in particular when using Application 7 of Table 2. The response time of the whole installation can be slowed down by the natural dynamics of the SC, for example immediately after clearing a fault, in addition to the communication delays between the two control systems.

To solve the problem this function adds the SC voltage error to the STATCOM voltage setpoint Vref, VSC while waiting for the SC to catch up. As a result, the response time of the H-SC system goes from the expected SC response of seconds to the expected STATCOM response of milliseconds, thus showing the benefits of a coordinated control between the STATCOM and SC. As shown in Figure 4 the operator can also turn off this function.

3.2.2.5. Inertia Support Maximisation (ISM)

The main objective of this function is to maximize the H-SC system contribution to the Inertial Frequency Response (IFR) of the power network. The IFR will take place during the first few milliseconds or seconds following the loss of a large power generator or the increase of load. The H-SC system will contribute to the total inertia of the power network from the kinetic energy stored in the SC. This function is triggered by the values of frequency (f) and Rate of Change of Frequency (RoCoF) measured at the PCC. The values (thresholds) for the activation are adjustable by the operator and are expected to be in the interval of 47.5-49.5 Hz and 0.1-3 Hz/s for frequency (fth) and Rate of Change of Frequency (RoCoFth), respectively.

The SC and STATCOM generate losses during their operation, and the STATCOM losses will reduce the actual active power contribution of the SC to the grid during the first seconds following the loss of generation. An optimal operation strategy for the H-SC system should then aim to fully utilize the active power contribution from the SC in the expected operating frequency range of the H-SC system (47 – 52 Hz).

To maximize the inertia contribution of the SC when the frequency decreases (47 Hz < f < fth and RoCoF < - RoCoFth), the system simply sets the STATCOM to Q control mode with a fixed reactive power output of 0 Mvar. As soon as the frequency starts to increase, the STATCOM control is released and goes back to the previously chosen control mode (for example V control) and setpoint before the frequency deviation. If the frequency becomes greater than 52 Hz or lower than 47 Hz, then the STATCOM is temporarily blocked. As shown in Figure 4 the operator can also turn off this function.

3.2.2.6. Losses Calculation

The measurement of the losses of operating STATCOMs and SC Systems is not practical; the main reason is the difficulty with measuring active currents that are much smaller than the reactive currents of the main circuit. However, the losses are a major part of the operating cost and should be known. As a result, the common practice is to obtain them by calculations.

The objective of this function is to calculate the total losses of the H-SC system during steady-state operating conditions. The total losses of the H-SC system are the sum of the STATCOM losses, the SC losses, the transformer losses, the cooling system losses, and the auxiliary system losses. For a representative number of capacitive and inductive operating points, all the losses mentioned above have been obtained from the component ratings and the design data, and the results have been expressed as functions of the branch currents (or reactive powers) by using quadratic polynomials. The losses are displayed on the human machine interface (HMI).

3.2.2.7. Slow MVAr Control

The objective of the Slow MVAr Control function is to slowly return the reactive power output of the H-SC system to a present steady-state value so that its reactive power capacity to support voltage is held in reserve. This higher-level regulator is available when operating the STATCOM in V control (Applications 2, 9 and 11 in Table 2), or when operating the H-SC system in V control with both branches (STATCOM and SC) in service (Application 7 in Table 2). The slow MVAr control is slow compared to the voltage regulators of both branches, and its output is a small addition/subtraction ΔVref to/from the voltage setpoint Vref, H-SC of the H-SC system. The output signal ΔVref is added to the voltage setpoint in such a way that in steady-state the H-SC system remains within a window defined by two limits, one at the capacitive range and one at the inductive range. The operator can also turn off this function.

4. The Outcomes of the Project

This section provide detail on the Project's outcomes with some supportive quantitative data, it includes the information on Design, Installation and Build (4.1), Project Live Trial (4.2), Commercial and Regulatory Outputs (4.3) and System and Component Level Study Outputs (4.4).

4.1. H-SC Design, Installation and Build

This section of the report details the technical design and specifications of the H-SC device as was detailed by NGESO, in addition an overview of the site installation considerations and installation testing is also provided.

4.1.1. Technical Specifications

As the system operator NGESO provided the technical specifications required for the H-SC as part of the NGESO deliverables for the Phoenix project. The technical specification developed for H-SCs under the Phoenix project are summarized below, additionally a separate technical specification was also developed for SCs under the Phoenix project. For the complete guidance on the technical specifications for SC and H-SC, please refer to the detailed specifications document ("Functional Specification for H-SC – Objective Functions") which can be made available upon request.

1. The H-SC shall be designed for a continuous and controllable operation at all system voltages between 0.9 p.u. to 1.1 p.u. and at all system frequencies between 47 Hz to 52 Hz.
2. The H-SC must be capable of operating in either "Voltage Control" mode or "Constant Reactive Power Control" mode with a single operating mode instruction. The facility must be able to switch between voltage control mode and constant reactive power control mode on instruction from the company (system operator) within an agreed time scale of no longer than 2 minutes and changes in operating mode should be achieved without any sudden disturbance to the system via a smooth transition. The technical requirements applicable to the H-SC operator are:
    i) The different parts of the Hybrid device should be selectable to different operating modes and there should be no control interactions between any of the parts of the device or any undamped oscillations.
    ii) In the voltage control mode, a voltage control slope setting of between 2% and 7% inclusive must be available. The voltage control setpoint should be selectable between 0.95pu to 1.05 pu with a resolution of 0.0025pu.
    iii) In the reactive power control mode, the reactive power output should be controlled to deliver a value of reactive power equivalent to the reactive power setpoint unless acting to address high or low voltage conditions. Under such conditions the voltage control capability would be enabled to contribute to the correction of the voltage during the disturbance. The low and high voltage limits shall be adjustable between 0.93 pu and 1.07 pu with a resolution of 0.005pu.
3. The H-SC shall be capable of continuous operation at any point within the reactive capability limits entered in the Bilateral Connection Agreement between the company and the user.
4. The SC component of any H-SC device should have a short circuit ratio of no lower than 0.5pu.
5. When operating in Voltage Control Mode, the hybrid device shall provide continuous steady state control of the voltage at the connection point or other point as agreed with the TNO with a Setpoint Voltage and Slope characteristic as illustrated in Figure 5. The continuously acting automatic control system shall be capable of operating to a Setpoint Voltage between 95% and 105% with a resolution of 0.25% of the nominal voltage. The Slope characteristic of the continuously acting automatic control system shall be adjustable over the range 2% to 7% (with a resolution of 0.5%). The initial Slope setting will be 4%.

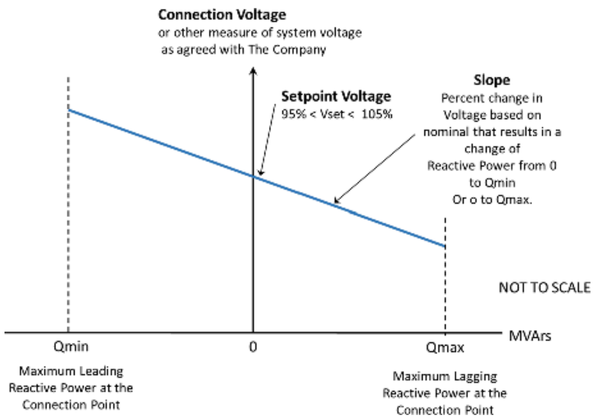


Figure 5 - Voltage Control Mode – Setpoint Voltage and Slop Characteristics

6. For an on-load step change in the measured connection point voltage the continuously acting automatic control system shall respond according to the following minimum criteria:
   i) The Reactive Power output response of the Hybrid Synchronous Condenser device shall commence within 0.2 seconds of the application of the step. It shall progress linearly although variations from a linear characteristic shall be acceptable provided that the MVAr seconds delivered at any time up to 1 second are at least those that would result from the response shown in Figure 6.

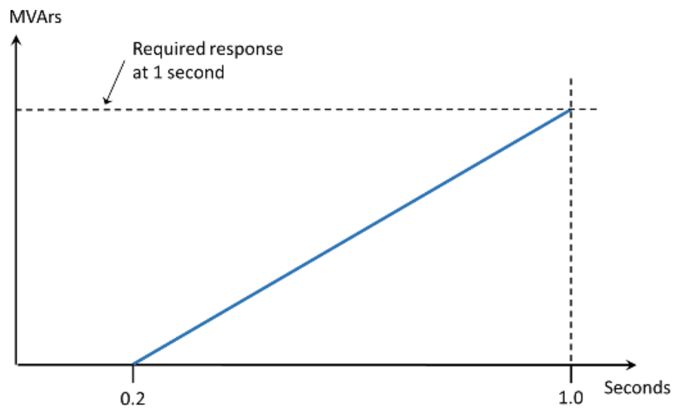


Figure 6 - H-SC reactive power output response

   ii) The response shall be such that 90% of the change in the Reactive Power output of the H-SC device will be achieved within
      - 2 seconds, where the step is sufficiently large to require a change in the steady state Reactive Power output from its maximum leading value to its maximum lagging value or vice versa.
      - 1 second where the step is sufficiently large to require a change in the steady state Reactive Power output from zero to its maximum leading value or maximum lagging value as required.
   iii) The magnitude of the Reactive Power output response produced within 1 second shall vary linearly in proportion to the magnitude of the step change.
   iv) Within 5 seconds from achieving 90% of the response as defined above the peak-to-peak magnitude of any oscillations shall be less than 5% of the change in steady state maximum Reactive Power.
   v) Following the transient response, the conditions of steady state voltage control shall apply.
7. H-SC should meet the fault ride through requirements where H-SC shall remain stable and connected to the network for system voltages at the HV side of the unit step up transformer
   i) Falling to 0pu for at least 140ms
   ii) Falling to 0.4pu for at least 300ms

8. H-SC and any of the constituent parts, controls and auxiliaries of the overall device shall remain active and permit delivery of reactive power during any low voltage incident where the measured system voltage remains above 0.2pu. For a voltage below this value on any phase, any part of the hybrid device is permitted to 'block' the output and must be consistent with the fault ride through requirement.
9. H-SC shall remain stable and connected to the network for instantaneous Transient Overvoltage (ToV) limit of 1.4 pu for 0.5s and 1.3 pu for 1s.
10. The H-SC or any of its constituent parts, as required, shall start-up from standstill and synchronise to the system within 15 minutes of receipt of an instruction from the System Operator. The H-SC or any of its constituent parts, as required, shall be fully available to restart no longer than 15 minutes after disconnection from the system following a shutdown instruction.
11. H-SC device should achieve an availability of 98%.

4.1.2. Site and Installation Considerations for H-SC Devices

This section focusses on several practical aspects regarding H-SC sourcing and installation. These include site considerations, H-SC procurement and the control and communications that are likely to be required. The content of this section draws on the experience gained by SPT and Hitachi ABB through the installation of the Neilston H-SC.

4.1.2.1. Site Considerations

Connection of an H-SC at a transmission substation will normally require a single 275kV or 400kV switch bay. For the 140MVA rated H-SC at Neilston, the site footprint of the H-SC is around 4000m^2 to accommodate equipment including the SC elements, the STATCOM elements, a 3 winding step-up transformer, an earthing transformer, the banking arrangements and auxiliary supplies. For Neilston, these elements are illustrated in Figure 7 in a picture of the pilot installation.

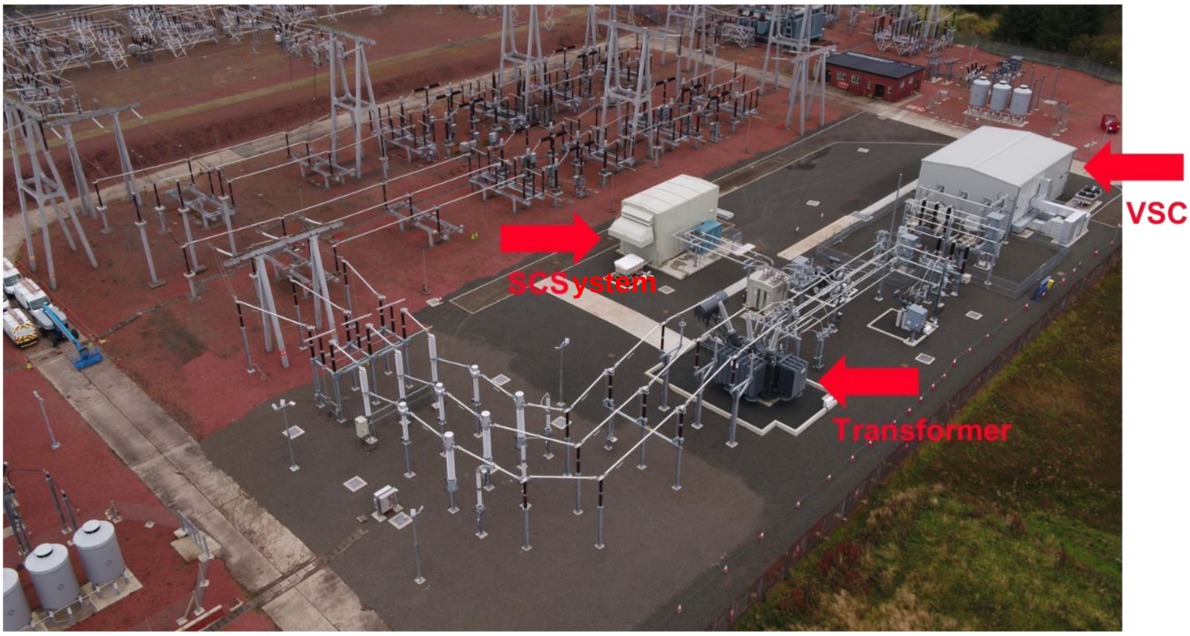


Figure 7 - H-SC at Neilston denoted

On the right-hand side of the site, the STATCOM or VSC is located. The STATCOM building and outdoor phase reactors take approximately 300 m^2. To the left is the synchronous condenser system. The SC building plus its lubrication unit use approximately 150 m^2. At the front we can see the 140-MVA three winding transformer that connects the 2 branches (i.e., the STATCOM branch and the SC branch) to the same Point of Common Coupling (PCC).

For a larger H-SC of 250MVA rating, the STATCOM and SC buildings would be larger than for an H-SC of 140MVA rating. It is likely that the overall site footprint would be increased by 100-200m^2.

In respect of GB planning and environmental aspects, key considerations include the following:

Internal Use

- Local Planning Requirements:
    - Depending on the location and size of the H-SC and associated works, local authority planning permissions may be required to progress the works. The works for the Phoenix H-SC at Neilston were not subject to planning permission as these were contained within the existing substation boundary.
    - The need for planning permissions is more likely for installations on greenfield sites and allowance should be made in the project planning process for identifying the need for planning permissions and obtaining these.
    - For higher rated H-SCs, it may be possible to reduce the site footprint by stacking phases above each other in the STATCOM building rather than placing these side by side as at Neilston. This approach would increase the height of the STATCOM building such that planning permission may be required.
    - Consideration should also be given to any lighting towers for the H-SC site as, depending on height, these will be subject to planning considerations on brownfield and greenfield sites.
- Acoustic Noise Considerations:
    - Another factor to consider in planning an H-SC installation is the acoustic noise that the H-SC will produce when operating. The level of noise produced will depend on the detailed design and configuration of the H-SC solution. Typically, the components creating the largest noise levels for a H-SC are the Main/Power Transformer and the SC.
    - The need to reduce or mitigate noise levels will depend on the location of the H-SC, ambient noise levels locally and the H-SC's proximity to other development including residential dwellings. When considering use of an H-SC, noise data should be obtained early in the planning phase to allow a noise study evaluation and a comparison against current noise levels at local receptors.
    - For the Neilston H-SC, a noise impact assessment was carried out at local noise receptors within proximity to the substation. Then a digital noise propagation model of the substation and surrounding area was created to determine any additional noise impact from the Phoenix H-SC installation. This determined that the Phoenix H-SC required an enclosure to mitigate noise levels due to its relatively remote location and its proximity to residents.
    - The noise propagation model was run for two proposed enclosure designs for the SC. The original proposed enclosure design exceeded the permitted threshold and so a more robust design was proposed and deemed compliant. As a contingency, mitigation measures in the form of additional silencer baffles were available in case the noise levels, once operational, exceeded the permitted limit but a follow up noise assessment demonstrated that further mitigation was not required.
    - As mentioned above, the earlier the noise propagation study is carried out the better, but this will rely on the early supply of the supplier's SC/H-SC proposed installation noise data.
    - On the Phoenix project, the change in sound requirements following the noise propagation study required the supplier to go from a solution with a difference of 12-13dB(A). This meant that the enclosure had to handle significantly more energy.
    - This increased the size of the silencers (longer), increased the pressure drop, and required the total enclosure area to double in size. The weight of the whole silencer/filter module trebled with the walls of the enclosure requiring heavier construction to reduce the sound and support and encapsulate the larger silencer ducts.
- H-SC Site Electrical Supplies
    - The need for local electricity supplies to support operation of an H-SC should be considered. Generally, two independent supplies are required. For the Phoenix H-SC at Neilston, a 150kVA supply is provided from the Phoenix auxiliary transformer, with a backup supply from the local distribution network.

4.1.3. Installation Testing

4.1.3.1. Factory Acceptance Test (FAT)

NGESO visited HITACHI ABB Sweden facility and witnessed FATs carried out to demonstrate the master control functions. During these tests SC and STATCOM were represented by its equivalent in RTDS environment.

4.1.3.2. Site Acceptance Test (SAT)

The H-SC was successfully commissioned during the Site Acceptance Test (SAT) before entering the live trial period. NGESO provided a list of tests that were carried out in the SAT to demonstrate the compliance of the Phoenix device against the specification for Grid Code compliant equipment. NGESO also produced an Excel spreadsheet to indicate the format of the results to be presented for the NGESO compliance team. HITACHI ABB produced a report based on the SAT carried out during the commissioning process. NGESO and SPEN reviewed this report and provided feedback to HITACHI ABB. The report confirmed that in open load conditions the dynamic response of the SC was slower than expected, both in standalone SC mode as well as in hybrid mode operation. Compliance to the required response time was planned to be demonstrated through the live trial.

4.2. Project Live Trial

This section constitutes an extensive synopsis of the results of Live Trial Plan for Phoenix project. It covers the period from November 2020 till May 2021, during which several test cases were conducted to evaluate the performance of the Hybrid Synchronous Condenser (H-SC) at Neilston station in Scotland under different operational modes. Moreover, the six-month report highlights the response of H-SC to several unplanned events that occurred over the period of Live Trial Plan enabling the deeper understanding of system behaviour.

The results are given in form of plots presenting a series of signals that were recorded during the performance of test cases and occurrences of unplanned events. The plotted signals were retrieved from TFR and TREND files that were provided by SPEN.

The progress of Phoenix Live Trial Plan has been documented and reported on monthly basis since November 2020.

4.2.1. Live Trial Test Plan

SPEN, NGESO, and HITACHI ABB collaborated to provide a list of trial tests that need to be carried out to demonstrate the value of H-SC. The sequence of live trial test list has been communicated to control room and NGESO planners, through SPT planners, to ascertain that different modes of testing can be carried out without any system risks.

4.2.2. Scope of the Live Trial

The scope of Live Trial Plan has been to assess the combined operation of STATCOM and SC technology alongside with the operation of hybrid control functionalities (Master Control). In this context, the tests have been conducted under different operational modes with both STATCOM and SC or only one of each in service. Under these modes, Live Trial Plan verifies several functions of the master controller performing setpoint changes of the voltage and reactive power and analysing system response to events e.g. faults, power imbalance due to trip of network circuits, switching close/open events etc.

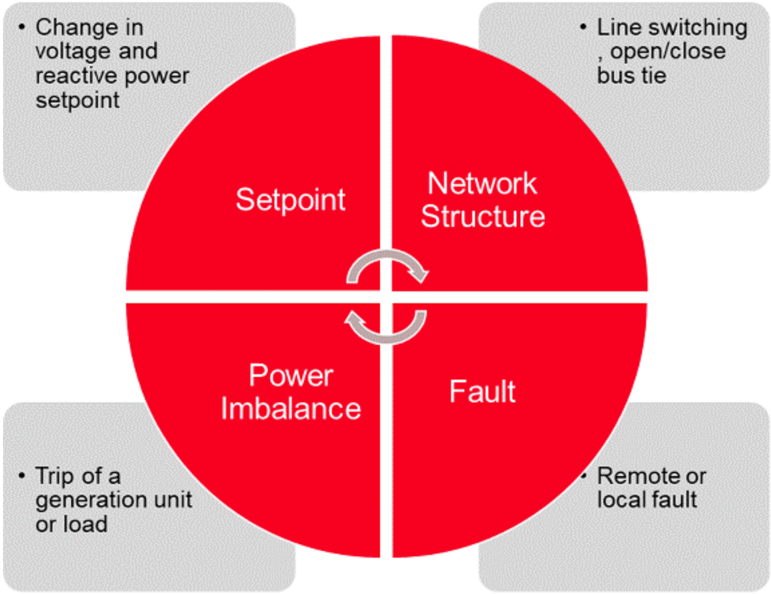


Figure 8 - Under these modes, Live Trial Plan verifies several functions of the master controller performing setpoint changes of the voltage and reactive power and analysing system response to events e.g., faults, power imbalance due to trip of network

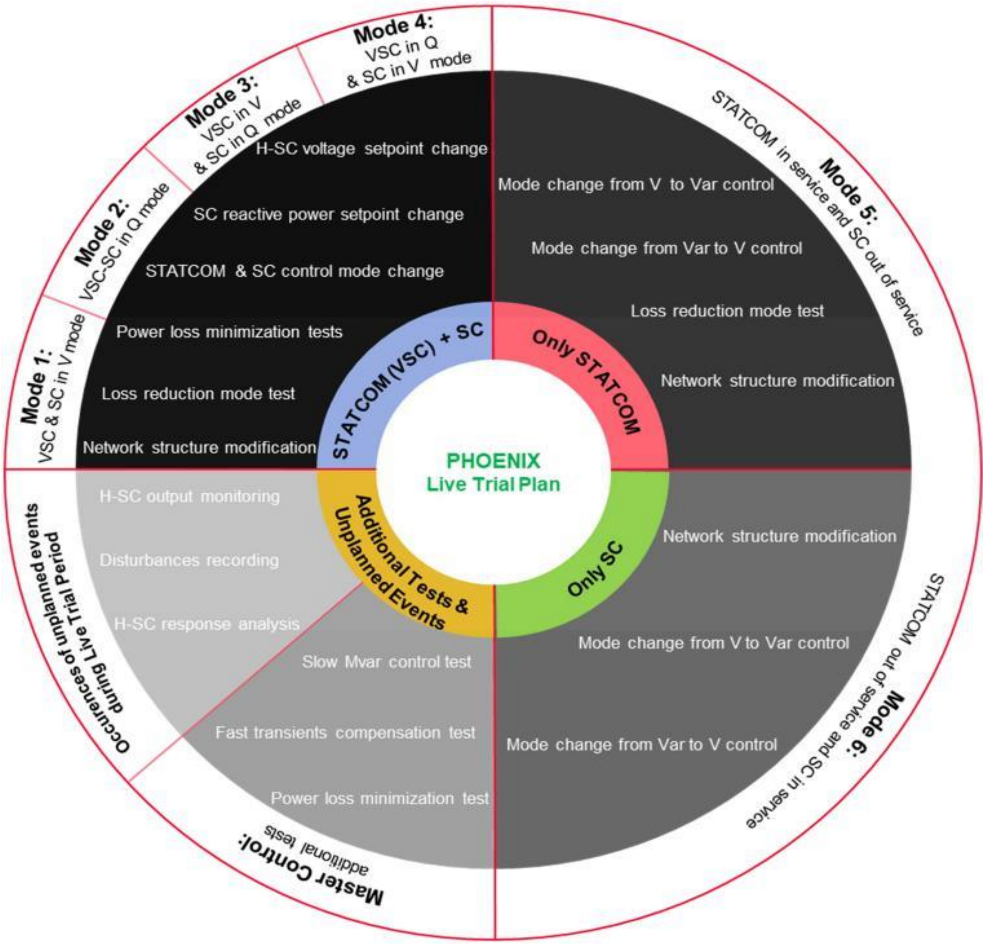


Figure 9 - Over the period of Live Trial Plan, H-SC has been tested under different operational modes. During these tests, it has been investigated how the system responds to setpoint changes, network structure modifications, operational modes changes and un-planned events

4.2.3. Timeline of Live Trial Plan

The Live Trial Plan was performed from November 2020 till May 2021. Over this period, the personnel of SPEN conducted the required actions for the performance of the test cases including the confirmation of control settings necessary for the valid execution of the tests. Aside from these tests, people working in the control room monitored and recorded unplanned events which occurred in the grid. The response of H-SC was also a major part of the conducted analysis by Hitachi ABB – Power Grids. The received recorded data files were processed and analysed and the results of this work were reported monthly. Meanwhile, during weekly meetings topics about work progress, findings and ambiguities were discussed among the involved parties. The timeline of the Live Trial Plan and the tested cases are shown in Figure 10 [4].

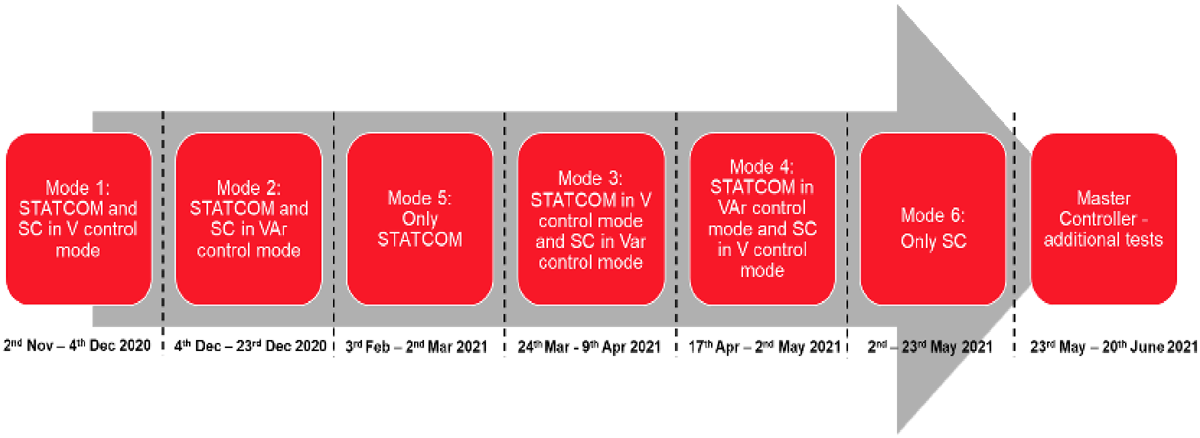


Figure 10 - Live Trial Plan was performed from November 2020 till May2021.

Over the period of the live trial, the personnel of SPEN conducted the required actions for the performance of the test cases including the confirmation of control settings necessary for the valid execution of the tests.

After the completion of the main phase of the Live Trial Plan, additional tests have been performed with focus on the evaluation of SC response time.

4.2.4. Live Trial Monitoring and Data Exchange

The assessment of H-SC performance relies on the consistent and continuous monitoring of the system to collect, to analyse and to use proper data. Moreover, the general request for analysing system performance has been the acquisition of high- and low-resolution data, which ensures a thorough and comprehensive investigation of H-SC behaviour under the tested operational modes and the occurrence of unplanned events. The provision of such data enables the analysis of a significant number of signals contributing to a deeper understanding of H-SC responses. Thus, as it's shown in Figure 11, high-resolution data enlightens system dynamic behaviour, whereas signals of low-resolution present system performance under steady state modifications. The study of the test cases and unplanned events relied on the analysis of analogue signals (terminal voltages, active and reactive power, frequency) and of digital signals that identified the operational status of H-SC (STATCOM & SC control mode, PLM etc).

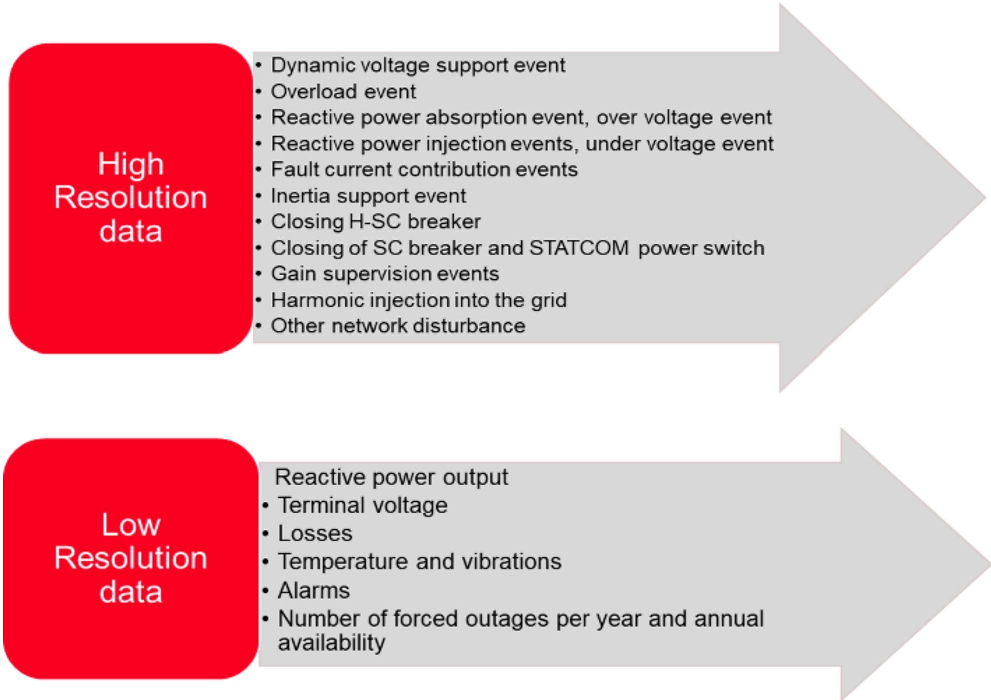


Figure 11 - High- and low-resolution data is necessary for performing a comprehensive analysis of H-SC performance under operational modes and unplanned events.

Following the completion of tests, the recorded data was collected and provided to Hitachi ABB – Power Grids in form of TREND and/or TFR files for further processing and analysis. In several cases, TFR data retrieved on-site was not sufficient or valid for the analysed case or event. This does not limit the correctness and validity of the analysis, as the study of event list files in most of such cases was enough to clarify at least the operational mode status of STATCOM and SC. However, unlike TREND files, TFR data includes the recording of digital control signals, among which are the operational mode of STATCOM and SC, and the reference values of the voltage and reactive power.

A selection of the operational modes and test cases are shown in Appendix C – Live trial testing results summary which summarises key results of tested cases for the different operational modes of H-SC during Live Trial Plan execution. Note, the full suite of live trial tests is provided in “Report on extended live trial and recommendations for future installations” report (available upon request).

4.2.5. Conclusions from Project Live Trial

Over the period of Live Trial Plan, H-SC performed as expected under most of the operational modes and during the occurrence of unplanned events. Only in few cases e.g., Mode 4 and Mode 6, the system response could not be completely analysed, as the conducted changes of the reference values were very small. In cases such as Mode 6 Case 3, SC response is shown to be quite slow. The response of SC is slow as the ramp rate limiter for the voltage reference in the AVR had a very low setting (0.3%/s). Also, the voltage reference of SC changes according to the following equation $V_{ref,sc}\ @\ 13.8\ kV = V_{ref,il\_sc}\ @\ 275\ kV + V_{drop,sc}$. In this equation, it is shown that due to the voltage drop term, SC voltage reference is calculated as ramp and so SC follows the ramped voltage reference. Therefore, the high response time is not related to the machine speed of response but was due to the ramp rate limiter settings in addition to the way how the voltage reference is calculated.

Regarding the test cases, H-SC had a stable operation under the change of STATCOM and SC control mode and of setpoints. Useful conclusions were drawn with investigating H-SC response to unanticipated occurrences, such as switching events, circuit trip, sudden power loss at the grid etc. Especially, it has been shown that H-SC has the capability of providing inertial and voltage support with SC and STATCOM injecting active and reactive power correspondingly. Also, dynamically STATCOM responds within few cycles (47 – 120 ms) as expected constituting the main driver of the overall system dynamic response.

Finally, the contribution of Master Control was verified as all the tested functions worked as expected.

Setpoint and Change of Control Mode Verification
• H-SC achieved the expected values in stable manner • SC slow due to communication delay and ramp rate limiter • It was possible to distribute the reactive power and voltage controlling effort between SC and STATCOM from HSC bus with the help of master controller
Dynamic Response
• STATCOM response time is within few cycles as expected • In section 0 (Trip & DAR of a circuit in North Scotland) there is the dynamic response from SC mainly injecting active power for providing inertial support • SC response time is slow due to the activation of ramp rate limiters and communication delay • H-SC response time is driven mainly by STATCOM for Q support and by SC for P support
Unplanned Events
• H-SC responded as expected and contributed with reactive support injection or absorption • Both SC and STATCOM performed voltage control in voltage control mode • SC provides inertial support with active power injection during frequency event. • STATCOM could absorb and then inject a small amount of active power during frequency event. This is achieved with DC voltage control relaxation • STATCOM overload protection function can be triggered continuously if the STATCOM is overloaded. This can be avoided with suitable voltage reference value SC also provided fast inertial support section 0 (Trip & DAR of a circuit in North Scotland)
Verification of Master Controller
• Tests for the Master Controller will be repeated, as the existing data is not adequate for a complete analysis • In the case of Slow MVAr, the test will be repeated, as the gain was quite low • The distribution of reactive power, voltage control, inertia support, loss minimization in various operation worked as expected • The actual value (e.g. inertial support, loss minimization) may not be very high for specific test system in Phoenix, but the functions have been validated.
Repeated tests
• SC dynamically has a lower contribution to the response of H-SC. Nevertheless, the response time of SC reactive power is fast. • Overall, the size of the conducted modification was small. However, it has been shown that the measurements of reactive power follow the reference values
TFR and additional tests

• TFR setting has been adapted to capture setpoint change and control mode change • In some cases, TFR data has not been captured. • More test cases are planned to evaluate SC response	
Collaboration and Reporting	
• Monthly report with test cases and unplanned events were prepared and reviewed by SPEN and National Grid	

4.3. Commercial and Regulatory Outputs

Alongside the technical development and assessment of H-SCs in the Phoenix project, work was carried out to consider the commercial and regulatory requirements to enable the use of SCs and H-SCs alongside other solutions for the emerging voltage and system stability challenges. This work focussed on completing the commercial deliverables included in the Phoenix NIC proposal including SDRC 2.1 to 2.7. These deliverables are summarised in Table 3.

SDRC 2.1, 2.2 and 2.6 which cover the cost benefit analysis are summarised elsewhere in this close-down report. SDRC 2.3, 2.5 and 2.5 cover the commercial mechanisms being developed to address emerging voltage and system stability challenges and are summarised in this section.

Table 3 - Phoenix Project Successful Delivery Reward Criteria (SDRCs) for Commercial Work

Deliverable	Title
SDRC 2.1	Cost benefit analysis model for SCs and H-SCs.
SDRC 2.2	Report on cost benefit analysis of SCs and H-SCs based on system studies and FES (Future Energy Scenarios).
SDRC 2.3	Report on international application of SCs and benefit analysis.
SDRC 2.4	Report on value-evaluation of SCs/HSCs based on pilot installation and performance.
SDRC 2.5	Report on impact of SCs/H-SCs on existing balancing schemes and markets.
SDRC 2.6	Report on value analysis from roll-out of SCs and H-SCs in GB in future potential sites.
SDRC 2.7	Report on regulatory considerations and recommendations for future roll-out of SCs and H-SCs.

To support the Phoenix commercial work, a working group was established early in the project. The composition of this group is illustrated in Figure 12. The Phoenix Commercial Working Group (CWG) met 9 times through the duration of the project to provide ideas and critical input. During the project, the working group reviewed all the published commercial deliverables.

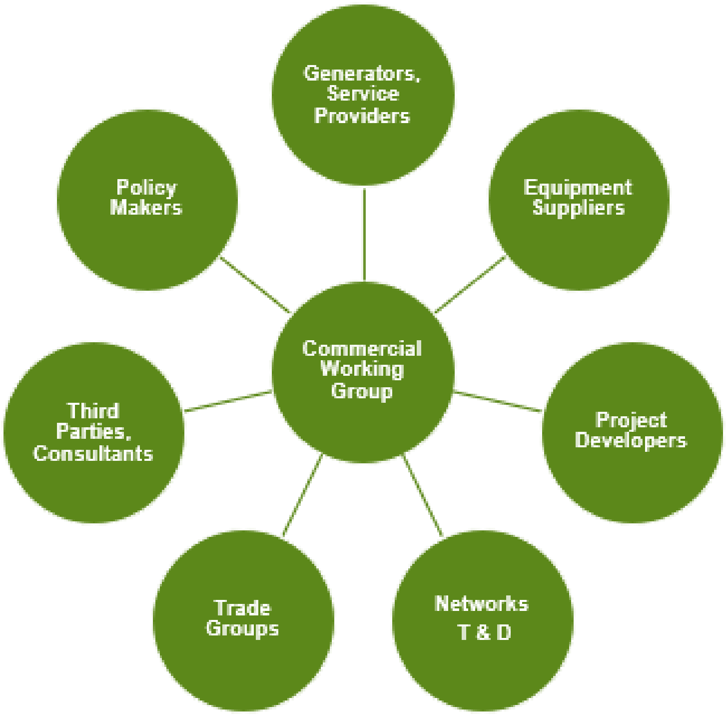


Figure 12 - Membership of Phoenix Commercial Working Group

The remainder of this section summarises the main outputs for SDRC 2.3 (International Review), SDRC 2.5 (Impacts on Balancing Schemes and Markets) and SDRC 2.7 (Regulatory Considerations) in three sub-sections.

Practical considerations for parties considering the use of SCs and H-SCs to provide services are also provided in a further sub-section. Before these outputs however, the developing arrangements for voltage and system stability services on the GB electricity transmission are summarised.

4.3.1. Grid System Services for Voltage and System Stability

SCs and H-SCs can provide voltage and system stability services to electricity networks including voltage management, inertia, and system strength. The use and ongoing development of these services on the GB electricity transmission network is briefly described below.

4.3.1.1. GB Voltage and Market Arrangements

Reactive power services are used by NGESO to ensure acceptable voltage levels. Voltage is managed by maintaining a balance between elements on the system which absorb reactive power (decreasing voltage) or generate reactive power (increasing voltage). Voltage is managed on a regional basis and voltage needs are met through a combination of network assets and balancing services. Network assets (e.g. capacitors, reactors) are installed by network companies to comply with system security standards and provide much of the reactive power requirements. Balancing services are used to fill the gap when network assets are not available or when system requirements are greater.

NGESO have previously procured reactive power generation and absorption services through the Obligatory Reactive Power Service (ORPS) though this can only be used where providers are running to provide real power. As patterns of generation and demand change, there are fewer ORPS providers at times when they are needed (e.g. during periods of low active power demand when conventional thermal generation is less likely to run). This has caused increasing levels of voltage constraints when there is not enough reactive power available regionally.

Since the Phoenix project was initiated, NGESO has developed further voltage services. These include Voltage Pathfinder projects to address regional voltage challenges. The early Voltage Pathfinders (Mersey and Pennines) have identified and tendered for reactive power services to operate alongside regulated network assets and so meet the expected requirements in particular areas.

4.3.1.2. GB Inertia and System Strength Management, and Market Arrangement

Transmission system stability has previously been provided by synchronous generators that have been operating to provide real power. To enable system operation with lower levels of synchronous generation, work is underway to update standards, to better monitor requirements, to identify new sources of stability and to introduce new markets to procure the services required.

System standards are being updated for a system with less synchronous generation. Revised Loss of Mains protection requirements will reduce the volume of generation at risk of disconnecting in response to a large infeed loss or an electrical fault on the system. This will enable operation with lower levels of inertia and will reduce the actions and costs to manage this constraint. By addressing Loss of Mains limitations, faster frequency response services will become key to containing frequency before frequency limits are reached.

To better understand system stability, real-time systems to monitor the inertia of the GB transmission system are being built and tested. These solutions will measure the combined inertia-like effects of conventional synchronous generation, power electronic converted generation (such as wind and solar) and passive load. One system is non-intrusive, continuously monitoring boundary activity and using machine learning to forecast the inertia up to 24 hours ahead. Another system includes one of the world's largest ultracapacitors to 'inject power' into the grid, while measurement units directly measure the response, enabling the full system inertia to be established. Ultimately, these systems will measure system inertia in real-time to optimise real-time operation and service procurement.

New sources of stability capability and new markets to procure capability are being introduced through Stability Pathfinders and through the development of a future GB Grid Forming market. The Stability Pathfinders allow NGESO to test feasible solutions. Through Stability Pathfinder phase 1, NGESO have awarded 12 contracts to 5 providers to secure 12.5GVAs of inertia until 31st March 2026. (All the solutions are SCs.) Through Stability Pathfinder phase 2, specific locational requirements for SCL and inertia in Scotland are being addressed while opening the service to a range of new technologies.

The pathfinder process is also informing updates to the NOA methodology to ensure an enduring approach for procuring voltage and stability solutions. By reviewing requirements for stability alongside the requirements for voltage, areas where these requirements may be combined will be identified.

4.3.2. Conclusions of International Review (SDRC 2.3)

The report completed as part of SDRC 2.3 considered other parts of the world with similar challenges to those faced in GB due to the closure of synchronous generation and operation with increased levels of renewable generation. These included areas where information was available on recently installed, or proposed, SCs including Denmark, Germany, Italy, California, Ohio, Texas, and Australia. Two other areas, Iceland, and Ireland were included as they have smaller island based synchronous systems with increasing levels of renewable generation.

At the time of publishing the SDRC 2.3 report (access provided in Table 12), the international use of SCs included the conversion of 9 existing generation units across 4 sites and the installation of 22 new SCs to support voltage and system strength. The main conclusions of the international review were as follows:

- Different approaches have been employed to address network challenges including the use of SCs. No single or standard approach was evident.
- SCs were being used in different geographic areas (e.g. Europe, the US and Australia) and in different market structures. SCs have been assessed and preferred as solutions in areas where TSOs drive electricity infrastructure planning and also where ISOs take a lead role.
- At transmission voltages, new SCs have usually been installed to improve system voltage and system strength. In a few cases, system inertia has also been cited as a reason for the SC installation.
- SCs can provide a relatively quick means to provide voltage support and improve system strength where synchronous generation is no longer available or is expensive to operate. Typically, new SCs are installed in around 24 months without the need for major transmission works such as new overhead lines or substations. Where system support has been needed urgently, generators have been converted to SCs within 6-12 months.
- The MVAr rating of new SCs connected to transmission networks has tended to be in the range 150 to 250MVAr and designs are often specific to local system challenges. For example, in some cases SCs have been designed to provide greater levels of short circuit infeed (with lower Xd''). In other cases, they are designed for increased inertia (with a higher value of inertia constant H).

- So far, new SCs are generally owned by transmission network companies. As with other major network investments, the need for the SCs is being tested through local planning processes. Competitive mechanisms for the provision of the SCs are developing (e.g., California).

In summary, several SCs have been used internationally to support transmission systems with reducing levels of synchronous generation. The local context, system requirements and commercial arrangements are diverse across the examples that were reviewed, and these don't indicate a clear direction for commercial and regulatory arrangements in GB.

4.3.3. Conclusions from SDRC 2.5 Report

The work carried out for SDRC 2.5 considered the potential impacts of wider SC and H-SC use on existing balancing schemes and markets.

From the system studies for the H-SC installation at Neilston (SDRC 2.2 report (access provided in Table 12)) and from the further studies assessing wider GB system opportunities (SDRC 2.6 report (access provided in Table 12)), it is evident that H-SCs provide system benefits which will continue to be important as the sector transitions to lower carbon forms of generation and demand. The system studies illustrate that:

1. Both the SC and STATCOM elements of the H-SC can provide steady state reactive power support and dynamic reactive power support.
2. The short circuit contribution from the SC would increase fault levels and local system strength.
3. The inertia contribution from the SC would improve the system inertia, which could improve the system stability limit and the system frequency response.

Whilst the Phoenix studies and the trial haven't demonstrated particular benefits that suggest H-SCs should be widely deployed ahead of other solutions, it is clear that H-SCs can provide services which could operate alongside other assets in managing voltage and system stability. The use of H-SCs adds to the options currently available to NGESO.

4.3.3.1. Existing Routes to Market for SC / H-SC

Since the Phoenix project was initiated, new GB commercial arrangements to address voltage and system stability requirements have been developed. SC and H-SC can be deployed through existing arrangements including the NOA process to recommend options for increasing system power transfers, and through Stability Pathfinder tenders to address system strength and inertia requirements.

For example, as part of the 2020 NOA process, SPT proposed installation of 2 x 300MVA rated H-SCs at Eccles to increase the capability of the transmission boundaries between the south of Scotland and the north of England. Each of these H-SCs was based on a 150MVA SC element and a 150MVA STATCOM. The H-SC was assessed by the GB ESO and recommended for installation by 2026. This requirement for increasing the capability of these transmission boundaries and for installing the H-SC at Eccles was reviewed as part of the 2021 NOA process and the H-SC continues to be recommended for installation by 2026.

As part of the Phase 1 Stability Pathfinder, new SCs are being installed at sites at Keith and at Lister Drive by Statkraft UK Limited. In addition, Uniper UK are building two new SC units at Grain and repurposing redundant steam generators at Killingholme. Welsh Power are also providing a new SC at Rassau.

Both the NOA and Stability Pathfinder processes require SC / H-SC solutions to be cost effective against other technology options. Using these deployment routes, SC / H-SC can be connected and operational in the timescales required by the system.

In summary, SC / H-SC are being proposed within the developing commercial mechanisms and their deployment is complimentary to other assets and service providers such that there are no detrimental effects on existing balancing schemes or service providers. If these developing mechanisms continue to be operated so that a range of providers can offer services, then SC / H-SC solutions will be compared on a level playing field with other potential solutions to voltage and stability challenges. At this stage, it seems likely that a range of solutions will be offered, and the GB network will not become over reliant on a particular technology.

Table 4 - Current Routes to Market for H-SC and SC

Deployment Route & Description	Implications & Potential Improvements
Network Company Regulated Assets SCs or H-SCs could be installed by network companies and remunerated in the same way as other regulated assets such as static reactive compensation equipment. When services are required, these assets would be made available to NGESO. As an example, as part of its RIIO-T2 business plan, SPT proposed the installation of an H-SC solution at Eccles to increase the Anglo-Scottish boundary capability and, in the longer term, to help maintain system strength without Torness generation. RIIO-T2 funding for the Eccles H-SC solution has been allowed. The classification of SC as generation, storage or demand was being considered because of issues raised through Stability Pathfinder.	• The wide scale deployment of SC or H-SC by TOs would reduce the opportunity for competition in the provision of stability services and could preclude the future deployment of other more efficient technical solutions. • In cases where the need for services has not been identified in advance, TO assets could be deployed quickly. A "standard" H-SC solution could be developed so that key elements such as space requirements, lead times and other parameters are well understood. • Where SC and H-SC are deployed by TOs to support system stability, asset availability requirements should be agreed with NGESO. • If TOs were not competing directly with Third Parties to provide services, TOs could set a ceiling cost for the service and provide stability assets where commercial processes fail to deliver solutions at a reasonable cost. This approach would reduce level playing field concerns and would limit the costs that would be paid by consumers for the stability services.
NOA Process NOA allows different options to be proposed to increase transmission boundary capability, and the "least regrets" option to be identified and recommended by NGESO. If a SC or H-SC solution is the best available solution, this can be taken forward by the proposer. As an example, as part of the 2020 and 2021 NOA processes, the Eccles H-SC solution was recommended for installation by 2026.	• Whilst NOA provides a means to recommend solutions, it does not provide funding. Funding for TO solutions can be provided through RIIO-T2 mechanisms, including the Incremental Wider Works (IWW) and the Medium Sized Investment Project (MSIP) mechanisms, but there is no mechanism yet in place to fund Third Party solutions identified through the "Interested Persons' Options process. Ongoing work including the establishment of Early Competition arrangements should be followed through to address this.
Stability Pathfinder The Phase 1 and 2 commercial tenders have allowed different solutions to be compared to address identified shortfalls in inertia and short circuit levels. Through Stability Pathfinder, NGESO can compare SC and H-SC solutions against other solutions and can select those options that are the most cost effective and most suited to meeting the specific requirements. Contracts are then put in place for the most suitable solutions. As part of the Phase 1 Stability Pathfinder, SCs have been tendered and are being installed at various sites.	To enable more effective competition to provide services, further changes could be introduced including: • Improved information on connection sites could help optimise service effectiveness and mitigate perceived TO/Third Party conflicts of interest. • When comparing TO and Third-Party options, all the cost elements of proposed solutions should be compared on an equivalent basis (e.g., energy losses, charges). • If H-SC or SC are being provided by TOs or Third Parties, the contract requirements should ensure that solutions provide the required levels of performance (e.g., asset availability). (If necessary, further provisions will be included in Stability Pathfinder contracts to ensure that stability assets are available when required.) • Clarity on the classification of SC as generation, storage or demand would help Third Parties to fully understand the costs associated with their solution. • Where TOs are competing to provide commercial services through Stability Pathfinder, consideration could be given to the assets being outside the TO regulated asset base so that TOs are remunerated on the same basis as Third Parties. TOs would receive service payments in the same way as Third-Party providers and contract provisions around service performance would equally apply to all providers.

4.4. System and Component Level Studies

4.4.1. System Studies and Evaluation of H-SC Benefits

This section describes component and system level studies carried out to evaluate the benefits of Neilston H-SC and the potential regions in the GB system where H-SC could be installed. The system analysis was carried out in DigSilent PowerFactory software.

4.4.1.1. Validation of H-SC Model

NGESO carried out validation of the following models prepared by our project partners:

1. Generic SC Model provided by DTU
2. Generic STATCOM model provided by HITACHI ABB
3. Generic H-SC model provided by HITACHI ABB
4. Neilston H-SC (Phoenix device) model provided by HITACHI ABB

The performance of these devices was compared against the device specifications, to verify the expected behaviours of SC/ STATCOM/ H-SC.

The generic SC model, provided by DTU, has Automatic Voltage Regulator (AVR), Power System Stabiliser (PSS) and Over Excitation Limiter (OEL) functions. It was found that there is no significant difference in the performance of the device with or without Power System Stabiliser (PSS). Hence for the system analysis, it was decided that PSS component in SC was considered out-of-service. The generic model of STATCOM produced by HITACHI ABB consists of dynamic modelling of voltage regulator and under voltage block capability. The generic SC / STATCOM models are connected to the system through two-winding transformer.

The generic H-SC model has been produced by HITACHI ABB consists of 70 MVA SC and 70 MVA STATCOM. Both SC and STATCOM are connected to LV windings of a three winding transformer rated of 140 MVA. There are number of operational modes for H-SC being developed in the Phoenix project. The generic H-SC model was assumed to be operating at automatic voltage control mode. In automatic voltage control mode, H-SC will deliver reactive support to maintain the target voltage of the busbar. The SC will be energised in this mode so that it is providing inertia and short circuit infeed. The generic H-SC model has coordinated voltage control and reactive power sharing and fast transient compensation functions. In the generic H-SC model, the STATCOM power loss was not modelled, and the Power Loss Minimisation (PLM) and Inertia Support Maximisation (ISM) functions are not included in this assessment.

The H-SC model for Phoenix device includes all the master controller functions designed for the Phoenix project. This model also has been validated against its specifications. The validated model was provided to NGESO planners and control room to carry out system analysis during the live trials of the Phoenix device.

The generic SC/ STATCOM/ H-SC models are suitable to carry out steady state and dynamic analysis and also suitable to change the rating and hence analysis can be carried out for different rating of H-SC. The validated generic models were used to analyse the benefits of H-SC when rolled out to install in different locations in the GB system.

4.4.1.2. Benefits of Neilston H-SC Device

The impact of a 140 MVA H-SC at Neilston on the boundary transfer capability between Scotland and England & Wales is evaluated and compared against other options; standalone SC, standalone STATCOM and SC and STATCOM together (without master control). These study results are provided as input to a well-established Cost Benefit Analysis (CBA) method, using BID3 economics tool, to determine the economic benefit of H-SC. The installation cost, maintenance cost, asset life and availability factors of each option are provided as input for CBA analysis. Figure 13 illustrates the overall CBA methodology used for this analysis and SDRC 2.1 report (access provided in Table 12) provides detailed information on CBA specifications.

The cost benefit of the H-SC at Neilston are compared with other options that could resolve the same system issues. Hence analysis is carried out for the following options:

1. Counterfactual case – base case without other solutions implemented to the network
2. With 140 MVA STATCOM at Neilston.
3. With 140 MVA SC at Neilston.

4. With 70 MVA SC and 70 MVA STATCOM (total of 140 MVA), without hybrid control scheme at Neilston.
5. With 140 MVA H-SC at Neilston.

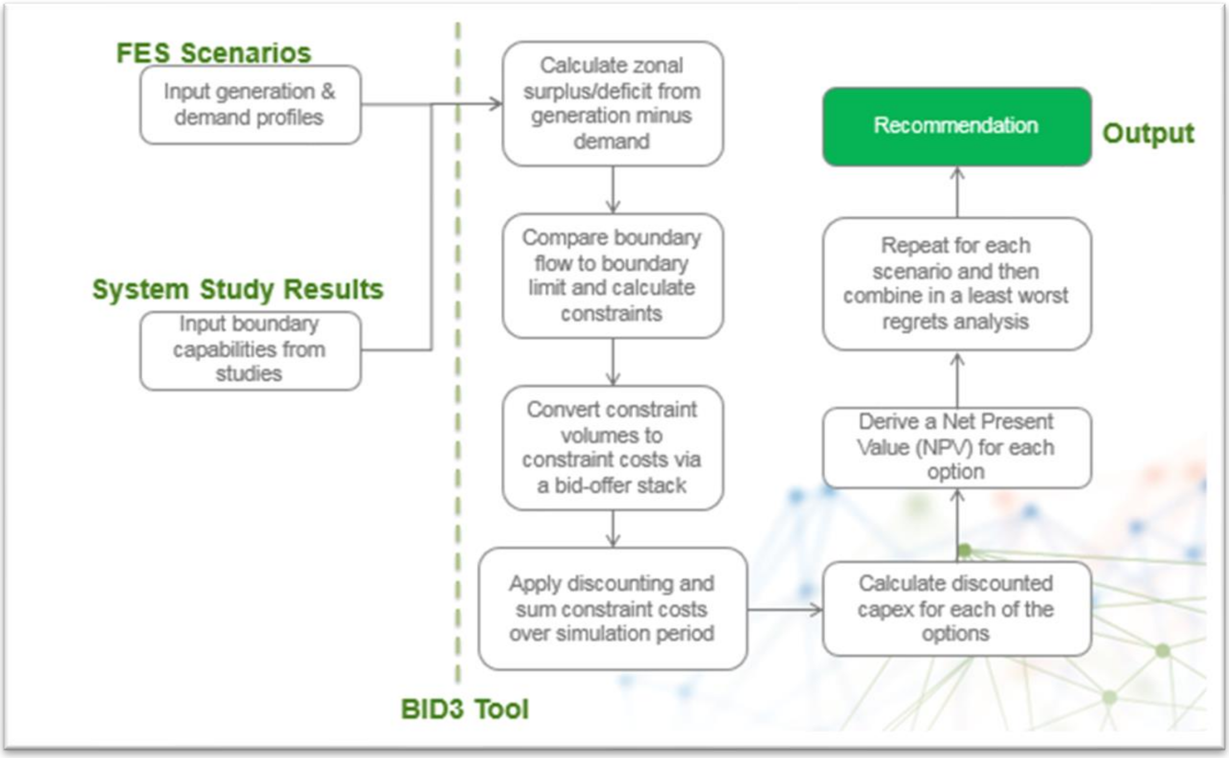


Figure 13 - Cost Benefit Analysis Methodology

To analyse the potential benefits from H-SC, through boundary transfer capability analysis, the following assessments are carried out:

a) Thermal limit
b) Steady state voltage limit
c) Short Circuit Level
d) Transient stability limit
e) Voltage stability limit

NGESO carries out system capability analysis and provides Electricity Ten Year Statement (ETYS) every year. The ETYS 2017 network model, with update on dynamics of plant, was used to carry out the above assessments. The generation and demand backgrounds are based on Future Energy Scenarios (FES) 2018 Community Renewables (CR) scenario background.

The following network backgrounds have been considered to analyse the benefit of H-SC at the Neilston location:

a) 2019 Network – The planned H-SC trial start date
b) 2023 Network – Assumed closure of Hunterston nuclear generation
c) 2027 Network – Assumed closure of Torness nuclear generation

The main findings were:

1. Dynamic reactive support from SC / STATCOM/ H-SC improved the B6 boundary transfer limit, after the closure of nuclear plants in the region, as the boundary is limited by voltage collapse issue.
2. With the addition of H-SC / SC / STATCOM, in addition to the boundary transfer improvement, there was an improvement in residual voltage of the system, TOV, voltage angle changes in the system.

3. Standalone SC / SC and STATCOM together (without master control) / H-SC options could increase the SCL and inertia contribution to the system. However, with the selected size of 140 MVA there is no significant difference in the system operation.
4. There was no significant observed difference between different options, in terms of boundary transfer improvements with the assumption of 140 MVA device at Neilston location. The difference in boundary transfer capability with different ratings of the device and multiple devices in the region are presented in the following sections.
5. The coordinated voltage control and reactive power sharing function is included in the H-SC model. This function in H-SC helps to avoid any conflicts between SC and STATCOM controls. With the SC and STATCOM together without hybrid control option, an additional transformer is required to avoid the conflict.
6. Based on other FES 2018 scenarios, a net cost benefit in the range of £40m to £86m can be achieved with the Phoenix Neilston H-SC device. Assuming all other Network Option Assessment (NOA) 2018-19 options are included in the background, the net cost benefit from the Phoenix Neilston H-SC is reduced to the range of -£7m to £51m.

The detailed results are provided in the SDRC 2.2 report (access provided in Table 12).

4.4.1.3. Benefits using Higher Device Ratings at Neilston

Using the same ETYS 2017 network model and FES 2018 scenarios, the boundary transfer capability between Scotland and England & Wales network was analysed with the higher device ratings. For this purpose, the rating of the device was assumed as 280 MVA and 420 MVA, double and triple the rating of Phoenix 140 MVA device. The increase in boundary transfer capability was used in Cost Benefit Analysis (CBA) to determine the economic benefits of the H-SC. For the economic analysis, the cost of a 280 MVA and a 420 MVA device was assumed as double and triple the cost of a 140 MVA device, respectively.

The key findings were:

1. Following the nuclear generation closures in the region, B6 boundary transfer was limited due to the voltage stability issue. The dynamic reactive power support from the device helped to increase the boundary transfer capability.
2. The standalone STATCOM option provided more benefit due to their fast-dynamic response compared with other options then followed by the H-SC, the SC and STATCOM (without hybrid) and the standalone SC options.
3. The SC and STATCOM together option provided the same level of boundary transfer capability as the H-SC option. However, the cost of this device was higher than H-SC device. Hence the net economic benefit was higher for the H-SC option compared with SC & STATCOM (without hybrid) option.
4. For the assumed 2023 and 2027 scenarios, due to the reduced system SCL, the Western HVDC was not loaded to its full capacity. Adding a single H-SC device at Neilston location, with rating up to 420 MVA, was not sufficient to load the Western HVDC to its full capacity.
5. The study analyses showed that with a 280 MVA H-SC at Neilston a net cost benefit in the range of £114m to £232m could be achieved and a 420 MVA H-SC at Neilston could provide a net cost benefit in the range of £128m to £266m, based on the ETYS 2017 background and FES 2018 scenarios.

4.4.1.4. Benefits with Multiple H-SC Devices in SPT Region

Further analysis was carried out for the year 2023 and 2027 scenarios, assuming multiple devices installed in six different locations in the SPT region. Neilston, Hunterston, Strathaven, Kincardine, Torness and Eccles locations were selected six locations in the SPT region, as shown in Figure 14. Generation closures in future years, and locations where voltage issues identified from previous system studies for the Neilston location device were used to identify the possible locations for installing these devices. These chosen locations are not necessarily optimal locations for the device. This analysis was carried out with different ratings of these devices; 280 MVA devices at the selected six different locations and 420 MVA devices at the selected six different locations.

From the previous analysis it was concluded that for the year 2019, the B6 boundary transfer capability is limited by thermal overloading. Hence for the multiple device analysis, studies have not been carried out for 2019. The previous analysis also showed that there is no difference in boundary transfer capability benefits between options H-SC and SC and STATCOM together (without master control) option. Hence the analysis was carried out for 2023 and 2027 scenarios for standalone SC, standalone STATCOM and H-SC options.

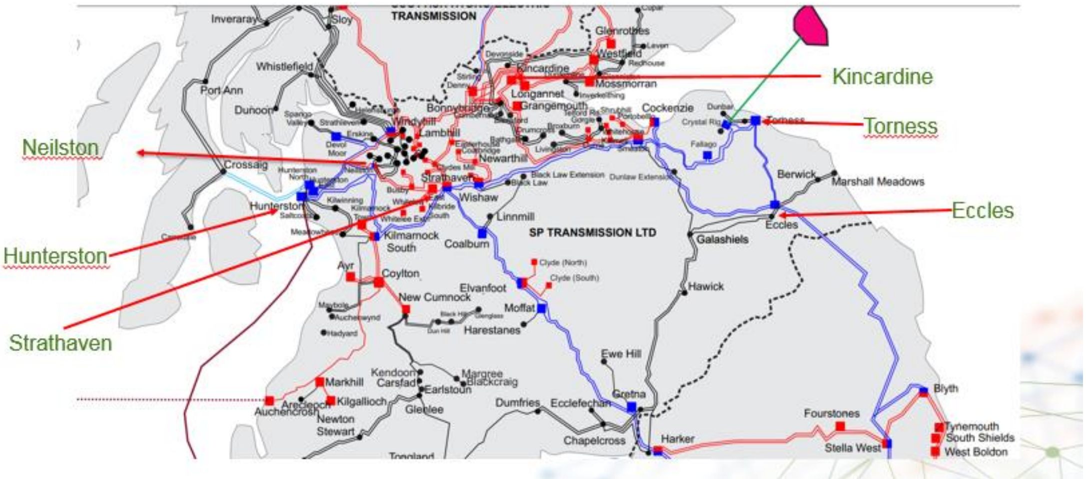


Figure 14 - Selected Multiple Locations in the SPT region

The key findings were:

[redacted]

2. With multiple standalone SC and multiple H-SC in the SPT region, the increased system SCL helps to increase the Western HVDC loading to full capability. The increase in the Western HVDC loading increased the B6 boundary transfer considerably.
3. For certain scenarios, when multiple SC and H-SC provided sufficient SCL to load the Western HVDC to full capability, multiple H-SC provided more boundary transfer capability compared with multiple SC as the H-SC provided better dynamic voltage response.
4. The fault level contribution from a STATCOM is lower than fault level contribution from SC/H-SC. The loading of Western HVDC was not improved with multiple STATCOM with the net increase in boundary transfer lower when compared to multiple SC/ H-SC.

[redacted]

Table 5 - The increase in B6 Boundary Transfer Capability (MW) with multiple devices in SPT Region

[redacted]

4.4.1.5. GB System Level Studies

System analysis was carried out by NGESO to explore further opportunities for H-SC deployment, in different areas of the GB system. For this purpose, the following regions were selected as shown in Figure 15:

- North region of England & Wales (East and West)
- South Coast of England & Wales
- South West of England & Wales

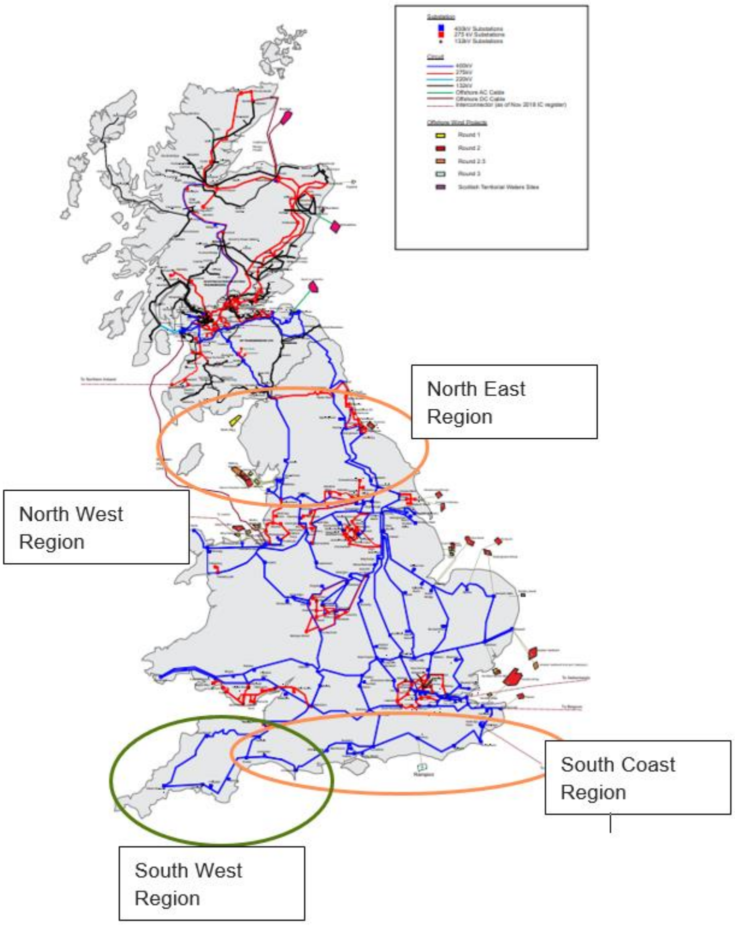


Figure 15 - Regions Considered for Further System Analysis

The full set of system analysis is available in Appendix D – GB System level studies and results.

4.4.1.6. Conclusion on System Studies

H-SC can provide a range of services, they are likely to be most effective where a range of voltage, inertia and system strength services are being sought. There are locations on the GB network (e.g., north of the Anglo-Scottish B6 boundary) where the combination of voltage support and fault infeed can be particularly effective. The wider studies of GB network requirements indicate that H-SC may be valuable in other parts of the GB network including the North East and North West of England and the South Coast of England.

Table 6 - Conclusion of System Studies and H-SC Benefits

Region (Boundary)	Summary of H-SC Benefits
Scotland (B6 with single device at Neilston)	A single H-SC device provides better boundary transfer capability than a standalone SC. A standalone STATCOM provides greater benefit than a single H-SC. A single H-SC device (with rating up to 420 MVA) provides insufficient SCL to enable full loading of the Western HVDC, with the assumed generation and network condition.
Scotland / B6 with multiple devices	Multiple H-SC enable full loading of the Western HVDC cable and improve voltage stability. This provides greater benefit than multiple standalone SC or multiple standalone STATCOM. The multiple H-SC provided higher SCL contribution compared with standalone multiple STATCOM. The multiple H-SC provided faster dynamic response compared with multiple standalone SC. Hence the multiple H-SC provided greater benefit, with a combination of SCL and improved dynamic response, compared with standalone STATCOM or SC. It could be possible to add standalone SC where more SCL is required and STATCOM where dynamic response is required. This could also provide the similar benefits of multiple H-SC in all locations; however, this combination was not analysed in this project.
North East & North West (B7 & B7a) with multiple devices	H-SC based solutions are effective at increasing the boundary transfer capability. In certain scenarios, in particular for 2027 networks, the boundary transfer benefit is limited due to transient stability issues in the Scotland region. It could be possible to further increase the boundary transfer if H-SC are installed in both Scotland and the North of England & Wales.
South Coast (SC1) with multiple devices	H-SC based solutions are effective at increasing the boundary transfer capability, once thermal overload issues are resolved.

4.4.2. University of Strathclyde System Studies

The aim of the work described in this section is to summarise the impact and quantify the contribution of SC units to the wider electricity network. The studies presented in this section are based on a model of the national electricity transmission system of GB which is represented by a 36-bus equivalent network. The model has been developed by NGESO in DIgSILENT PowerFactory.

4.4.2.1. Modelling

Most of the system studies have been conducted using the RMS simulation tools in DIgSILENT PowerFactory. The model used for the studies is a 36-zone equivalent of the GB transmission network (refer to Figure 16 below). Each numbered zone in the model represents a part of the system and consists of a mix of different energy sources and loads. Generators within each zone are represented by static generators and synchronous machines including relevant dynamic controllers. In each zone, generation, loads, HVDC interconnectors and transmission lines are connected to 400 kV busbars. The GB model has been dispatched to reflect an inertia level of 82 GVAs, which corresponds to a minimum inertia level at solar peak period and is expected to be a credible minimum level of inertia in the GB transmission system in 2025/26.

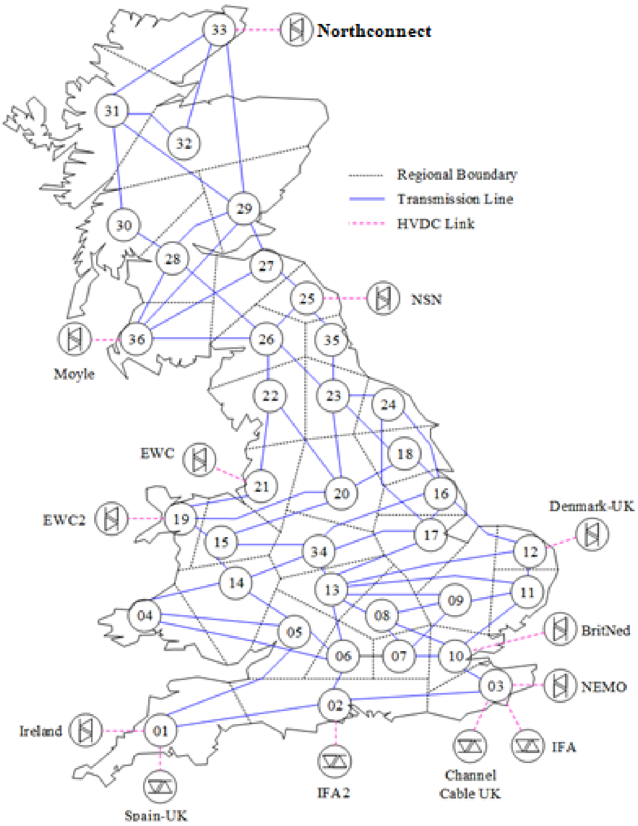


Figure 16 - GB transmission network represented by 36 zones.

4.4.2.2. SCL Contribution

Simulation studies conducted by UoS have been conducted to investigate the impact and quantify the contribution of SC units to system short-circuit level. The simulation-based analysis and the corresponding results presented have considered both static and transient simulation environments.

<u>Static Simulation Analysis</u>

The SCL has been calculated in DIgSILENT PowerFactory using static power flow studies at each number bus using the super-position method ('complete' method in PowerFActory short-circuit calculation tool). The short circuit power in MVA (i.e. Sk) and short circuit peak current in kA (i.e. Ip) have been extracted during the SCL assessment. The results for short circuit power and short circuit peak current are presented in Figure 17 and Figure 18 respectively, for years 2019, 2023 and 2027 for both winter peak and summer minimum. By observing the results, during the summer minimum periods (i.e. refer to dotted lines) and for all dispatch scenarios, the SCL is significantly reduced in most of the zones. Additionally, even for winter period, there is some level of variation observed.

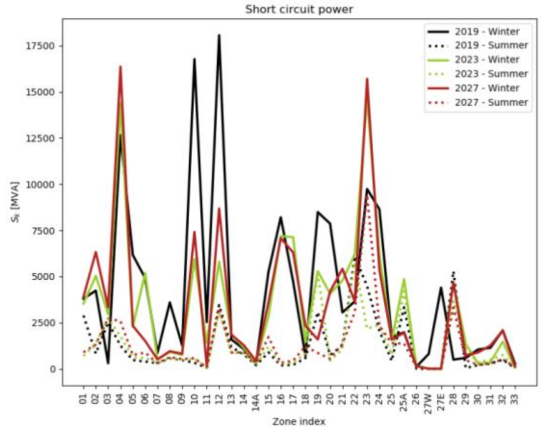


Figure 17 - Short circuit level at different zones for different dispatch scenarios.

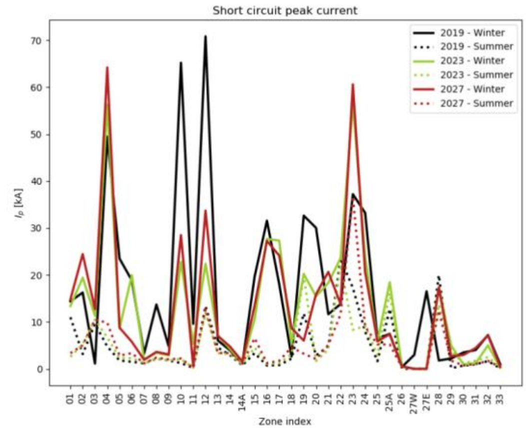


Figure 18 - Short circuit peak current at different zones for different dispatch scenarios.

At this point it is of utmost importance to calculate the actual changes in SCL within the years and different periods. This will assist the identification of the critical regions in which the SCL will be mostly declined. With respect to those zones, this can be a significant metric regarding the design, control and operation of power system protection schemes and devices driven by phase locked loops. Figure 19 and Figure 20 below, illustrate the changes in SCL from 2019 to 2023 and from 2023 to 2027, for winter peak and summer minimum periods respectively. Positive values indicate that SCL is increasing while negative values indicate that SCL is declining. For winter peak period the changes in SCL are more pronounced between years 2019 and 2023. Zone 10 and Zone 12 will be subject to a decline of more than 10 GVA. The SCL decline between years 2023 and 2027 is not that significant, as most of the zones will not be subject to a decline more than 1.0 GVA, excluding Zones 6, 19, 22, 25A in which the decline is just beyond 2.5 GVA. For summer minimum period the changes in SCL are not that significant compared to winter peak period (please note that the graphs illustrate the change and the actual SCL during summer minimum is already low). From Figure 20 it can be seen that Zone 19 is the one subject to the largest SCL decline. It is also interesting to highlight that during summer period and for years 2023 to 2027 Zone 23 is subject to a large positive SCL change of approximately 7 GVA. From the SCL sensitive analysis it is revealed that Zones 10, 12 and 19 are worth investing with respect to SCL elevation measures.

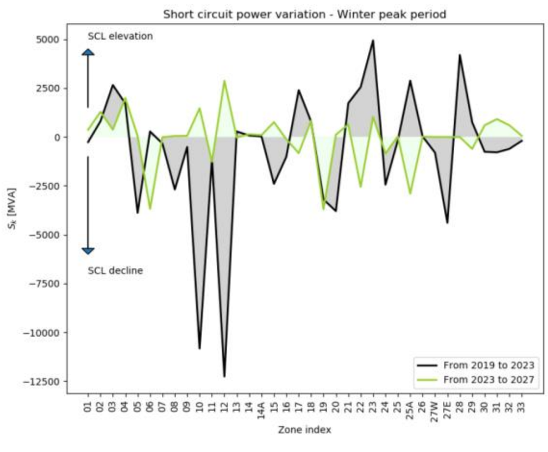


Figure 19 - Short circuit level change from 2019 to 2023 and 2023 to 2017 for winter peak period.

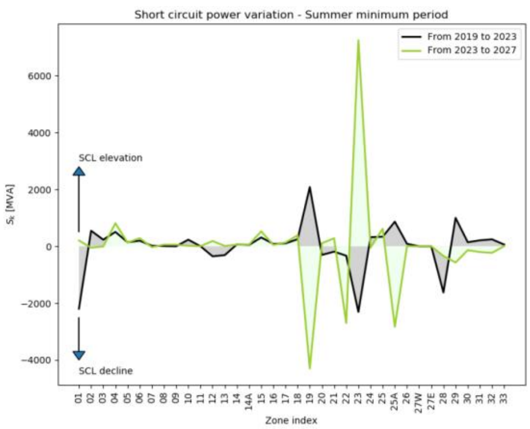


Figure 20 - Short circuit level change from 2019 to 2023 and 2023 to 2017 for summer minimum7 period.

From previous analysis it has been highlighted that Zones 10, 12 and 19 will be subject to large SCL decline in future energy scenarios (i.e. years 2023 and 2027). This section will demonstrate a typical example of how SC units can be used to elevate the SCL in these zones. In order to calculate the contribution of SC units to the SCL, a set of simulation scenarios has been setup to incrementally change the capacity of SC units in Zones 10, 12 and 19. The maximum capacity has been set to 700 MVA with increments of 70 MVA. Figure 21, Figure 22 and Figure 23 illustrate the short circuit power Sk for Zones 10, 12 and 19 respectively. The results present the SCL when SC units with capacities of up to 700 MVA are deployed. It is evident from the graphs that SC can significantly elevate the SCL levels, by approximately four times the rated capacity of the machine. This seems to be extremely important during summer periods when the SCL is significantly low (i.e. to near-zero region). By conducting such a large set of simulations (sensitivity analysis has been conducted for the SCL elevation on other zones and the results are reported for SDRC 5.2 with report access provided in Table 12), it is concluded that by deploying SC units the SCL can be undoubtedly elevated. However, the selection of a precise rated capacity of those units is anticipated to be based upon other features and metrics, including power system protection performance and commutation failure of HVDC links.

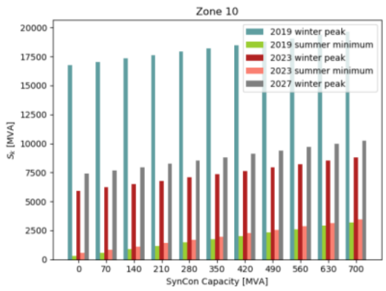


Figure 21 - Short circuit power at Zone 10 for different SC capacities and different dispatch scenarios.

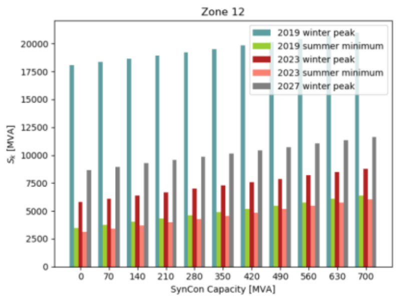


Figure 22 - Short circuit power at Zone 12 for different SC capacities and different dispatch scenarios

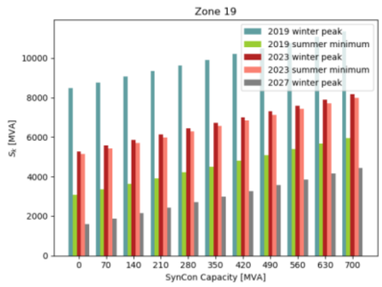


Figure 23 - Short circuit power at Zone 19 for different SC capacities and different dispatch.

Transient Analysis

The studies conducted through this simulation environment is aimed to assess the performance of distance protection relays in the occurrences of transmission line faults. For the purposes of carrying out transient simulation analysis, a part of a typical transmission network model has been utilised (the network topology is shown in Figure 24). The network operates at 400 kV and consists of a 100-km transmission line, a grid (represented by a voltage source) and three different generation units accounting for synchronous generator (SG), SC and a wind farm connected via a voltage source converter (VSC).

The SG and SC units are modelled as a standard salient-pole synchronous machine. Three control systems have been integrated which include i) automatic voltage regulator, ii) power system stabiliser and iii) over excitation limiter. In the case of SC unit, the prime mover and governor have been omitted as well (i.e. there is no mechanical input Pm). Wind farms constitute of permanent magnet synchronous generators connected via VSCs, which operate under the standard D-Q axis current injection (DQCI) control scheme. A validated dynamic model of a commercially available distance protection relay (i.e. 'MICROMHO - Static Distance Protection Relay') has been utilised in this analysis. Time- domain voltage and current signatures are captured from the generation terminals and imported to the relay for post processing. The studies consider scenarios under different generation mixes starting from 100% synchronous to 100% Inverter connected generation. In the latter setup, SC units under different capacities are deployed to qualify and quantify their impact on transmission line protection in terms of number of successful trips and response time.

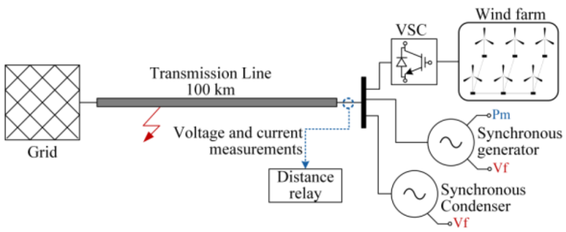


Figure 24 - Transmission network illustrating integration of SGs, SCs and ICG.

To quantify the contribution of SC to the performance of distance protection, a series of simulation test-sets have been conducted for different generation scenarios, fault resistance values, fault positions along the line and fault types. The analysis considered three types of faults within Zone 1 of the protected line:

three-phase, phase-phase and single-phase to ground with fault resistances up to 150 Ω. In total, the distance protection relay has been tested under 2,223 different faults scenarios.

The generation scenarios for this analysis are presented in Table 7, where three dominant generation technologies are included (i.e. SG, ICG and SC). These groups subsequently formed nine distinct generation mixes including single technology connections, as well as mixes of two (the base power has been set to S_b = 500 MVA). For all the scenarios an automatic search routine has been developed to iteratively change the position of the fault along the line, fault resistance and fault type.

Table 7 - Portion of generation technologies within a 500 MVA generation mix.

Scenario	SG	ICG	SC
1	S_b		
2	0.75 S_b	0.25 S_b	
3	0.50 S_b	0.50 S_b	
4	0.25 S_b	0.75 S_b	
5		S_b	
6		S_b	0.05 S_b
7		S_b	0.10 S_b
8		S_b	0.15 S_b
9		S_b	0.20 S_b

Figure 25 depicts the number of successful trips for each of the generation scenario. The percentage of the successful operations has been calculated by dividing the total number of the correct operations by the number of the desired trips for each scenario. The number of the desired trips is based on the definition of the power protection dependability, which is the degree of ability of the protection system to operate correctly for faults within the protected zone. As the proportion of ICG increases, the operation of the relay is compromised. This behavior is more pronounced at Scenario 5 (i.e. 100% ICG) where the number of successful trips reaches only 20%. However, when SC is deployed in the system (i.e. scenarios 6 to 9), the percentage of successful relay trips increases, reaching values up to 60%. The impact of SC units has been quantified against the response time of the distance protection (response time is defined as the time elapsed between the fault occurrence and the time when the trip signal is initiated). The average response time for all the fault scenarios is depicted in Figure 26. It is evident that the as the penetration of ICG increases, the response time increases. Specifically, when the generation mix consists of 100% SG, the response time is approximately 20 ms (i.e. 1 electrical cycle) while for 100% ICG the response time reaches values approximately up to 70 ms. When SC units are utilized, the average response time starts improving reaching values close to 40 ms, hence improving the speed of protection operation.

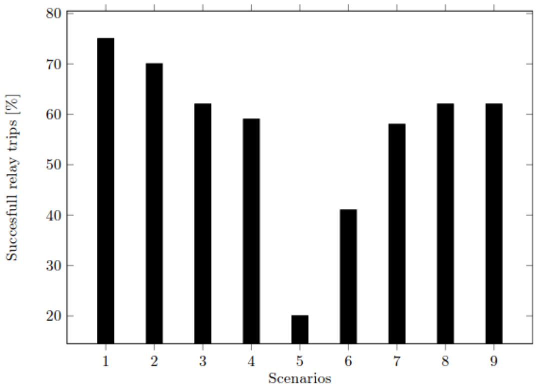


Figure 25 - Number of successful trips

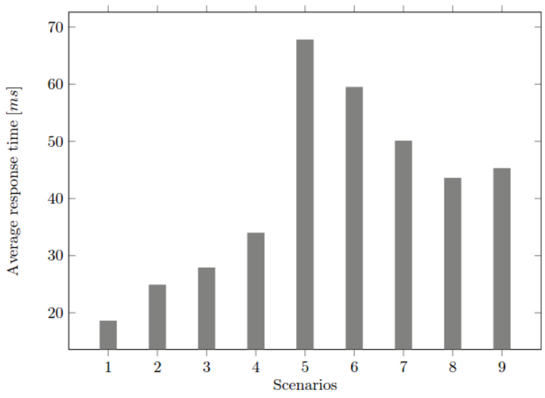


Figure 26 - Average response time

4.4.2.3. SV vs BESS

Simulation studies conducted by UoS were conducted to investigate the impact and quantify the contribution of SC and Battery Energy Storage Systems (BESS) to system inertia.

A loss of generation (LoG) event (675 MW of non-synchronous generation) has been triggered to drive frequency to reach a nadir of 49.2 Hz. SC and BESS units with different capacities and control settings have been put forward to investigate their contribution. Simulation results revealed the following:

- Active power output from SC units connected in close vicinity to the location of the LoG event, is highly oscillatory. On the contrary, as the total SC capacity is concentrated far away from the location of the LoG event, the SC active power output is smoother. Effectively, the placement of a SC unit at the location of the LoG event, can potentially introduce an oscillatory behaviour.
- By connecting a total of 4 GVA SC units (which corresponds to 5 GVAs considering 1.25 s inertia constant), the maximum infeed loss can be increased by 50 MW, considering a 49.2 Hz frequency nadir limit (refer to Figure 27).
- Active power output from BESS units is not affected significantly by their geographical allocation. Considering a 100 MW BESS unit and a 675 MW LoG event, different frequency droop characteristics had different impact on the frequency nadir. Specifically, for frequency droop settings 0.016 p.u., 0.02 p.u. and 0.04 p.u., the frequency nadir is improved by 0.08 Hz, 0.06 Hz and 0.03 respectively.
- Considering a maximum infeed loss limit, it has been found that by connecting 100 MW BESS unit with frequency droop setting at 0.016 p.u., the maximum infeed loss can be increased by 50 MW, considering a 49.2 Hz frequency nadir limit.
- By combining SC and BESS units the frequency nadir (i.e. 4 GVA of SC and 100 MW of BESS) can be elevated by approximately 0.15 Hz and the maximum infeed loss can be increased by 100 MW, considering a 49.2 Hz frequency nadir limit (refer to Figure 27 and Figure 28).

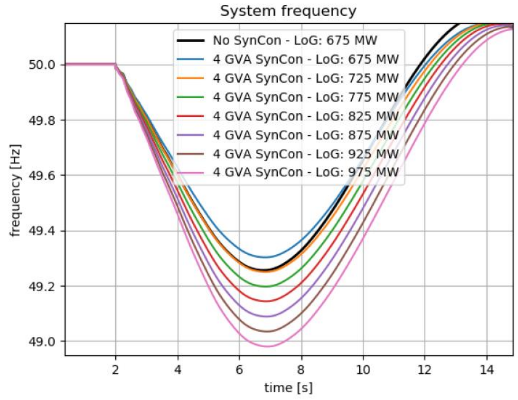


Figure 27 - Frequency traces for different LoG capacities.

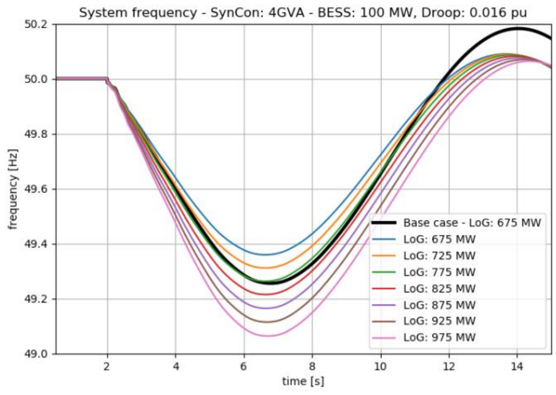


Figure 28 - Frequency traces for different LoG capacities combining both SC and BESS units.

4.4.2.4. EFCC Scheme

Studies on system inertia have been conducted with a loss of generation (LoG) event (approximately 675 MW of non-synchronous generation) triggered to drive frequency to reach a nadir of 49.2 Hz. SC units totalling 4 GVA and the EFCC scheme under different configurations have been put forward to investigate their contribution. Considering a frequency nadir of 49.2 Hz, it was found that different LoG events can be sustained by different combinations of the EFCC scheme and SC units, as follows:

- LoG: 675 MW, without EFCC resources [5] deployed and SC units
- LoG: 725 MW with 5% of EFCC resources deployed and without SC units
- LoG: 775 MW, with 10% of EFCC resources deployed and without SC units
- LoG: 775 MW, with 5% of EFCC resources deployed and with SC units
- LoG: 825 MW, with 10% of EFCC resources deployed and with SC units
- LoG: 925 MW, with 25% of EFCC resources deployed and without SC units
- LoG: 975 MW, with 25% of EFCC resources deployed and with SC units

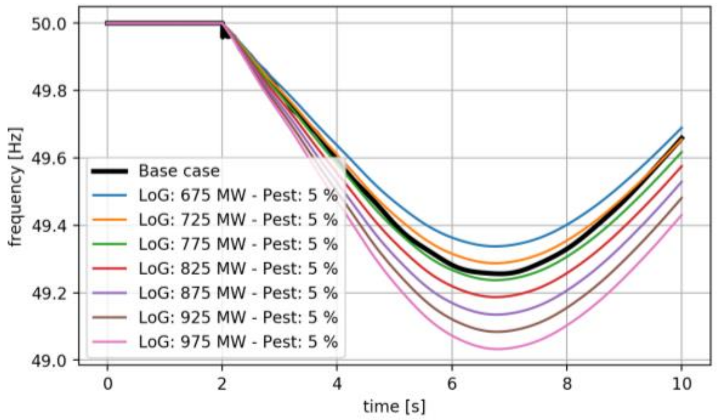


Figure 29 - frequency traces for different LoG capacities considering 5% of EFCC resources deployed.

Further sensitivity analysis indicated that SC units can bring certain savings to the active power required from synchronous generators and the EFCC scheme. These results highlight that the capacity of the EFCC scheme and SC units need to be carefully selected to achieve satisfactory frequency control performance.

4.4.2.5. SC Location

The aim of the work reported in this section is to investigate the impact of the SC location with respect to the location of loss of generation events. Studies on system inertia have been conducted considering different loss of non-synchronous generation events at the following locations:

- Zone 01: Loss of 675 MW (Solar unit)
- Zone 06: Loss of 721 MW (Solar unit)
- Zone 20: Loss of 400 MW (Solar unit)
- Zone 32: Loss of 441 MW (Wind unit)

These locations have been selected in a way to cover a wide geographical spread of the GB network (i.e. north, middle and south). For such LoG events, SC units have been utilised at different locations, including the location of the LoG event as presented in Table 8. Figure 30 to Figure 33 illustrate the locations of LoG events and SC deployment for Scenarios 1 to 4 respectively.

Table 8 - LoG scenarios.

Scenario	Location of LoG event	LoG	Location of SC			
1	Zone 1	Solar – 675 MW	Zone 1	Zone 8	Zone 20	Zone 30
2	Zone 6	Solar – 721MW	Zone 6	Zone 1	Zone 20	Zone 30
3	Zone 20	Solar – 400 MW	Zone 20	Zone 1	Zone 8	Zone 30
4	Zone 32	Wind – 441 MW	Zone 32	Zone 1	Zone 8	Zone 25

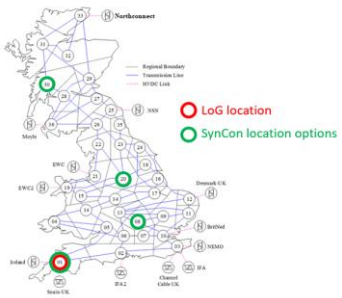


Figure 30 - GB transmission network illustrating locations of LoG and SC for Scenario 1.

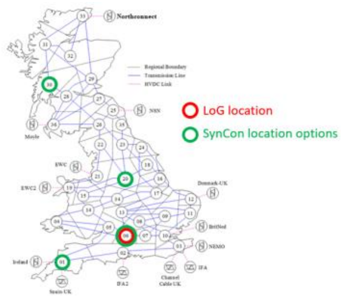


Figure 31 - GB transmission network illustrating locations of LoG and SC for Scenario 2.

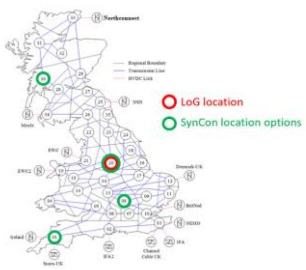


Figure 32 - GB transmission network illustrating locations of LoG and SC for Scenario 3.

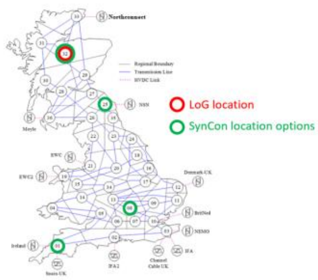


Figure 33 - GB transmission network illustrating locations of LoG and SC for Scenario 4.

- For each simulation set, frequency and RoCoF traces, as well as the active power from SC units have been monitored and exported for post-processing. Additionally, minimum values of frequency (i.e., frequency nadir) as well as maximum values of absolute RoCoF traces have been extracted for comparison. With respect to frequency measurement, the average value from frequency traces across all zones has been calculated; this was also utilised for the calculation of RoCoF traces.

- The frequency nadir values are captured and presented in Figure 34, Figure 35, Figure 36 and Figure 37, for Scenarios 1 to 4 respectively. By observing these figures, it is really challenging to derive any generalisation with respect to optimal SC location and the effectiveness of the frequency nadir containment, which is anticipated. For example, in Scenario 1 (LoG event at Zone 01) the lowest frequency point is observed when the SC is installed at Zone 08 (i.e. not in the same location as the LoG event). On the contrary, in Scenario 4 (LoG at Zone 32) the lowest frequency nadir is observed when the SC is installed at Zone 32 (i.e. in the same location as the LoG event).

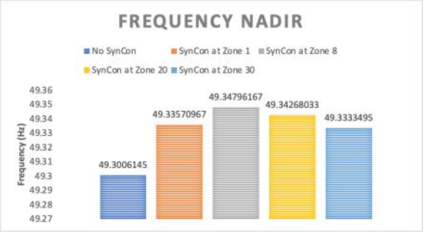


Figure 34 - Frequency nadir values for Scenario and 1 (LoG in Zone 1) for different SC locations.

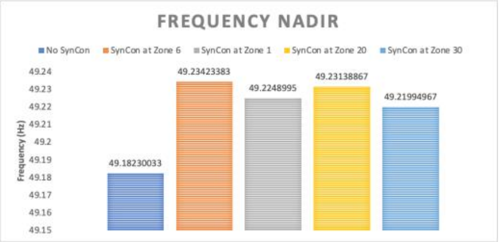


Figure 35 - Frequency nadir values for Scenario 2 (LoG in Zone 6) considering different SC locations.

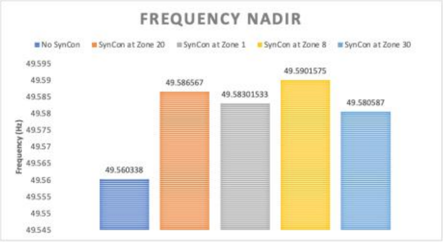


Figure 36 - Frequency nadir values for Scenario 3 (LoG in Zone 20) considering different SC locations.

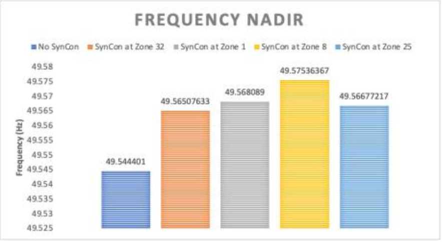


Figure 37 - Frequency nadir values for Scenario 4 (LoG in Zone 32) considering different SC locations.

With respect to the active power exchange with the SC units, it has been observed that all scenarios with SC collated as the LoG event, produces the most oscillatory behaviour in the active power of SC. Additionally, the instantaneous active power output is much larger (i.e. 4 to 5 times higher) compared to the power delivered when SC units were utilised in other zones.

The corresponding maximum absolute RoCoF values are captured and presented in Figure 38, Figure 39, Figure 40 and Figure 41. As opposed to frequency traces, where no generalisation could be derived, in the case of RoCoF traces, it appears that the least RoCoF values are always generated when SC units are installed at the same location with that of the LoG event. Such behaviour is possibly stemming from the fact linked to the previous observation – i.e. that the instantaneous active power in four to five times greater when SC is installed at the same location with that of the LoG event. This could potentially indicate 'preferrable' locations of SC installation - for example SC units could be installed to locations where any anticipated LoG could impose higher RoCoF traces, leading to unnecessary activation of RoCoF-based protection and control schemes.

Figure 38 - RoCoF values for Scenario 1 (LoG in Zone 1) considering different SC locations.

Figure 39 - RoCoF values for Scenario 2 (LoG in Zone 6) considering different SC locations.

Figure 40 - RoCoF values for Scenario 3 (LoG in Zone 20) considering different SC locations.

Figure 41 - RoCoF values for Scenario 4 (LoG in Zone 32) considering different SC locations.

4.4.2.6. Conclusion of Study Results

The studies have revealed the deployment of SC units in GB electricity system can bring the following benefits:

- Enhance the short circuit level of the system and thus improving the protection system performance in terms of sensitivity and speed of operation
- Contribute to system inertia and therefore increase the loss of generation margin considering the low frequency system limits.
- Bring certain savings to the active power required from synchronous generators and the EFCC scheme
- Increase the loss of generation margins considering the colocation with BESS units
- Improve the system oscillations considering a careful design in terms of location and control.

4.4.3. Modelling of Hybrid Synchronous Condenser

The Phoenix project developed the modelling, simulation, and lab testing platform of hybrid synchronous condenser with combination of one synchronous condenser (SC) and one battery energy storage system (BESS). The contribution includes both from research layer that explores the different functionalities and services that can be provided from the hybrid system, such as different grid forming control methods of BESS, as well as the implementation layer where models of the components and testbenches have been developed for the project partners to develop their studies. This section summarises the implementation layer's work regarding,

- Modelling of the hybrid synchronous condenser
- Power hardware-in-the-loop testing platform

The modelling work is primarily based on the size and parameters of the equipment and the controls installed for the demonstration of the hybrid synchronous condenser with 70 MVA SC and 70 MVA battery pack. Hybrid control of the system has been developed for this system to enhance the frequency and inertia response. Furthermore, comparative studies have been carried out between grid forming and grid following control of BESS and the impact of it on the performance of the hybrid system. At the end, a real time simulation-based power hardware-in-the-loop test system has been developed for validation of the control system of the BESS.

4.4.3.1. Modelling of Hybrid Synchronous Condenser

The model of the hybrid SC is developed and verified based on the following system. The power system is represented by a Thevenin equivalent, and the synchronous condenser and BESS are connected through a three-winding transformer. The Thevenin impedance is calculated for 2800 MVA short circuit power level and 18.85 X/R ratio at 275 kV voltage level. The single line diagram of the hybrid system is shown in Figure 42. The nominal voltage of the system is 275 kV, while the terminal voltage of the synchronous condenser is 13.8 kV, and the AC side voltage of BESS is 12.3 kV.

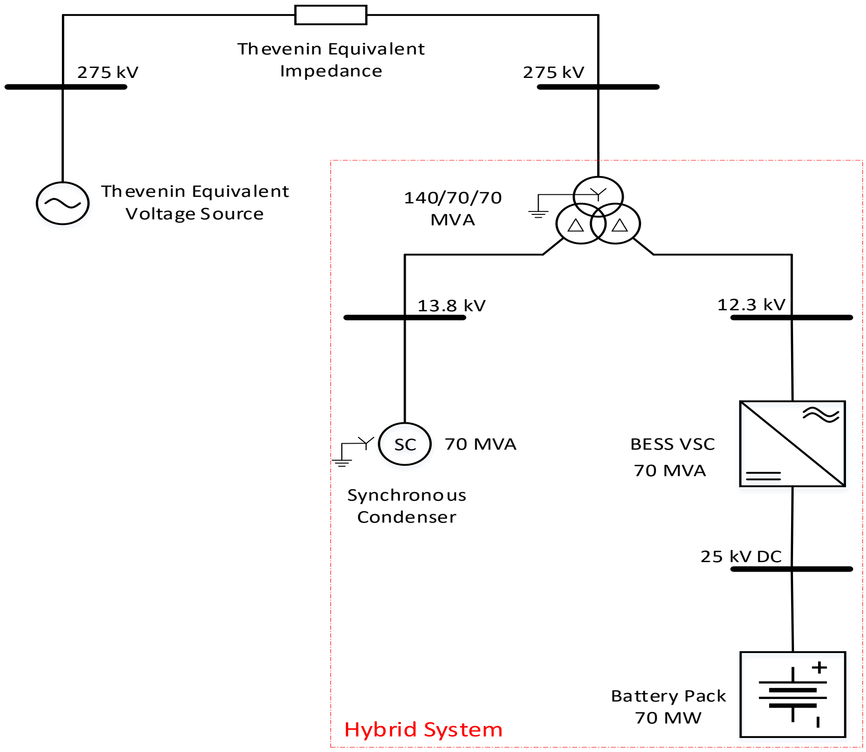


Figure 42 - Single Line Diagram of the Hybrid System

4.4.3.2. Synchronous Condenser Model

The model of synchronous condenser is created in power factory based on the parameters of the real system installed in the project. The model can be used to perform RMS and EMT based study for system level analysis. The basic parameters of the machine are based on ABB system however with certain scalability to represent large machines with high inertia. The model contains the following components

1) Automatic voltage regulator: The model of the AVR is according to IEEE Std 421.5-2005 type AC8B [6] . The controller parameters are based on the parameters provided by ABB.
2) Power system stabilizer: The model is based on the IEEE Std 421.5-2005 PSS1A with parameters provided from ABB based on the system deployed in the demonstration.
3) Overexcitation limiter: The model is based on the design from Ref. [7]

Verification of the synchronous condenser performance is done based on comparison of the result with the PSCAD model. One point worth to mention is that the conventional power system stabiliser does not have a pertinent influence on the response of the machine during voltage regulation test. Supplementary control of synchronous condenser can enhance the dynamic behaviour of the system if it can be designed based on the system topology, communication, and volt/var sensitivity. which has been demonstrated in [8].

4.4.3.3. Modelling of BESS

The model of the battery cell is based on an equivalent electrical circuit shown in Figure 43.

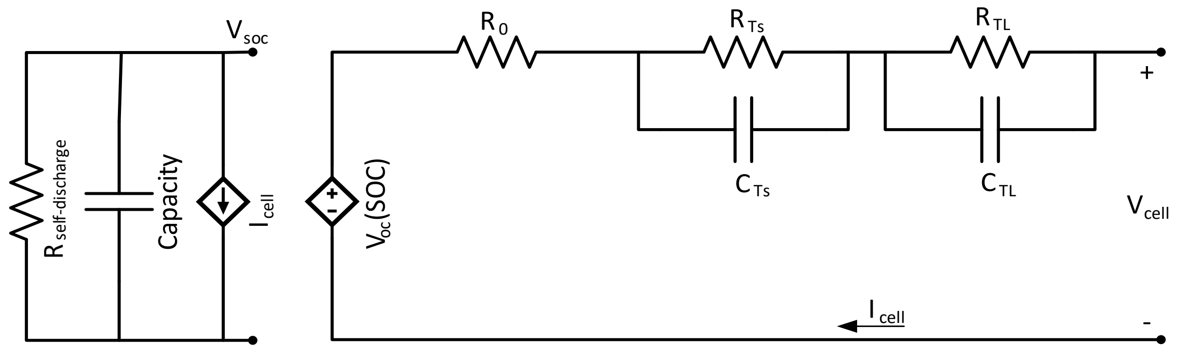


Figure 43 - Equivalent Circuit of a Battery

The equivalent circuit relatively accurately captures the behaviour of a battery during charging, discharging and open circuit conditions. The accuracy of the model is dependent on the number of RC circuits, the parameter extraction methods, the State of Charge (SOC) estimation method, temperature model, among others. The balance between accuracy and computational burden is obtained by using two RC circuits.

The control frame for the power converter consists of measurement blocks (AC voltage of the converter, active power, frequency, and phase angle), control blocks (frequency control, active/reactive power control, and battery charging control), and the component models (battery and converter). The measurement point is the bus on the AC side of the converter. The entire control frame is shown in Figure 44.

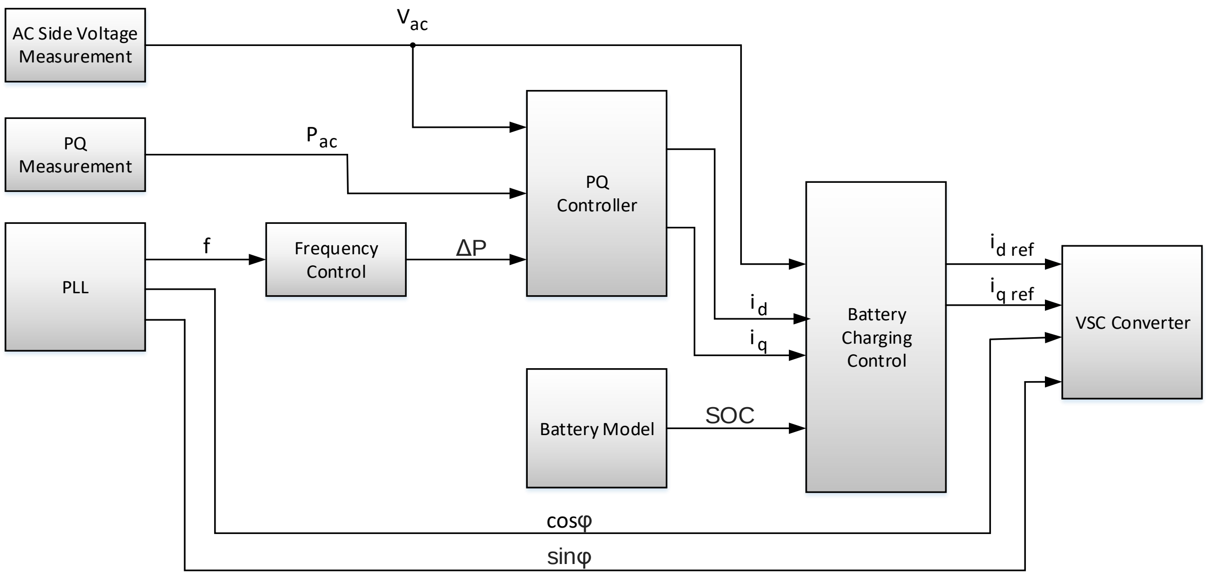


Figure 44 - Battery Control Frame

The inner (current) control is a well-known standard model with dq decoupling and feed-forward voltage. The reference currents are generated in the outer loop. The d axis current-control loop controls the active power and consequently provides frequency support in a form of droop control, while the q axis-control loop controls the reactive power and provides voltage support. More detailed description of the battery model can be found from "Report on optimal placement and capacity evaluation of SCs/H-SCs in GB" Table 15 - the live-trial results and other documents .

4.4.3.4. Hybrid System Controller

The hybrid system controller sets the type of control (VAR or automatic voltage control), while providing references for the reactive power and the voltage. The block diagram of the PowerFactory model of the hybrid system controller is shown in Figure 45. The master control ensures equal reactive power sharing between the SC and BESS (More information of the system can be found from "Report on Component model adapted to pilot demonstration and for further system studies" - Table 15.

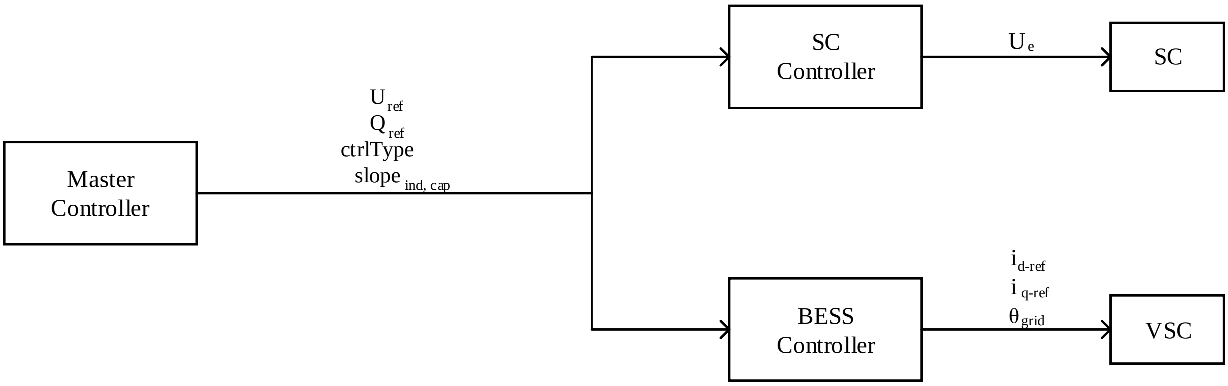


Figure 45: Block Diagram of the Hybrid System Controller

The main advantages of a hybrid system over a synchronous condenser are the extended range of frequency support, increased rating of reactive current, storing electric energy, compensating for slower voltage regulation of the SC, and maximization of the inertia support to the system by compensating for the SC oscillations. The advantages of the hybrid system over BESS are inertia support, increased overloading capability, and increased short-circuit current contribution. The obvious drawback of the hybrid system is that we are effectively reducing the contribution from the SC as the rating of the machine is two times lower.

4.4.4. Technological Comparison

There is a notable difference in how the synchronous machine and power converter operate, both in terms of control and in terms of their capabilities. One of the main advantages of synchronous condensers over power converters is the significant overloading capability and short-circuit contribution. Synchronous condenser can provide up to 3.5 pu of rated current during faults, while the power converters are limited by design for up to 1.3 pu of rated current. The short circuit level of the system has a significant influence on voltage levels and protection operation during faults.

Furthermore, synchronous machines have rotating masses, and this means that the inertia is an inherent feature of synchronous condenser, which is an especially important factor for future systems with high penetration of renewable energy. Power converters, on the other hand, provide fast frequency support (if coupled with active power source), fast voltage control, and the possibility of several different control strategy implementations. Synchronous condenser has much slower response to voltage reference change and voltage dips in comparison with power converters and since there is no prime mover the only contribution in terms of active power is inertia. Additional advantage for power converters is the capability to provide full rated current in inductive and capacitive mode. In terms of control strategies, power converters can be divided in grid-following and grid-forming converters. Grid-forming converters have two main advantages; to save the use of cascaded control loops and PLL, and to provide faster voltage and frequency support. The main drawback is switching to current control in case of current exceeding the maximum limits.

Based on the characteristics of the individual technologies, some general assumptions on the performance of the combined effect of the individual technologies considered as a single hybrid system can be made as shown in Table 9. The hybrid system is assumed to be of the same total rating as the individual components. This will affect some of the characteristics of the SC and the power converter response. In general, services that can be achieved by SC+BESS include the following facets as summarised in Table 9. Detailed simulation results can be found in "Report on GB Roadmap for Roll out of H-SC" - Table 15.

Table 9. Technological comparison

Technology	Inertia/Fast Freq. Response	Volt./Curr. Characteristic	Short-Circuit Current	Response Time
BESS Grid Following	No intrinsic inertia Droop control Possibility of providing synthetic inertia	Full rated reactive current for cap. and ind. mode Possible instability due to cascaded control loops and PLL	Constrained by the overcurrent limiter, typical values 1.1 - 1.3 pu	> 1 cycle
BESS Grid Forming	Inertia response like SGs Fast frequency response similar to SM Possibility of providing synthetic inertia	Full rated reactive current for cap. and ind. mode. Typical overload 1.1 - 1.3 pu	Requires current limiting strategy once the commanded current exceeds max. value	> 0.5 cycles
SC + BESS Grid Following	1-3s inertia constant from SC Instantaneous response + droop control Possibility of providing synthetic inertia	High overloading capability Less than 1 pu of inductive current due to the SC limitations Possible instability due to cascaded control loops and PLL for BESS	>4 pu for SC, 1.1-1.3pu for BESS. Final value depends on the rating composition.	Improved response for post-fault settling time and reference voltage change due to the compensation of SC's response by BESS
SC + BESS Grid Forming	>3s inertia constant Instantaneous response +fast freq. response, similar to SM Possibility of so-called synthetic inertia	High overload capability Less than 1 pu of inductive current due to the SC's limitations (close to 0.75 pu)	>4 pu for SC, 1.1-1.3pu for BESS. Final value depends on the rating composition. BESS requires current limiting strategy once the commanded current exceeds max. value	Improved response for post-fault settling time and reference voltage change due to the compensation of SC's response by BESS

4.4.5. Power Hardware-In-the-Loop Tests

The validation of power-converter-based energy storage devices to be deployed in the power system is challenging, particularly because the advanced functionalities of these power converters are difficult to accurately model. Therefore, it is likely that the system studies carried out using simplified power converter model fail to capture certain dynamics and fault events. In this regard, real-time power hardware in loop (PHIL) test has gained increasing interest in the recent time. The PHIL type of testing provides a high-fidelity validation for any new device or control strategies for power converters connected to the grid.

The developed PHIL setup is shown in Figure 46. The system structure has four main components, the real-time digital simulator (RTDS), signal interface section, power amplifier and voltage source converter platform connected to a battery emulator. One of the buses of the test power system simulated in RTDS can be powered up by utilizing the analog I/O terminals of RTDS (GTAO/GTAI) and connected to the PAS 4-Quadrant linear Power Amplifier. One of the buses of the powers system is available for connecting a battery emulator by an actual three-phase voltage source converter (VSC). In this way, there is only signal level interaction between the RTDS and the battery energy storage to provide safe and repeatable conditions. Moreover, such testing also allows the validation under faulted and extreme conditions without damaging laboratory equipment while maintaining a safe environment for operating personnel.

The signal interface section between RTDS and Power amplifier is one of the critical stages for PHIL platform building. It is necessary that the interface cable should have highest possible noise immunity.

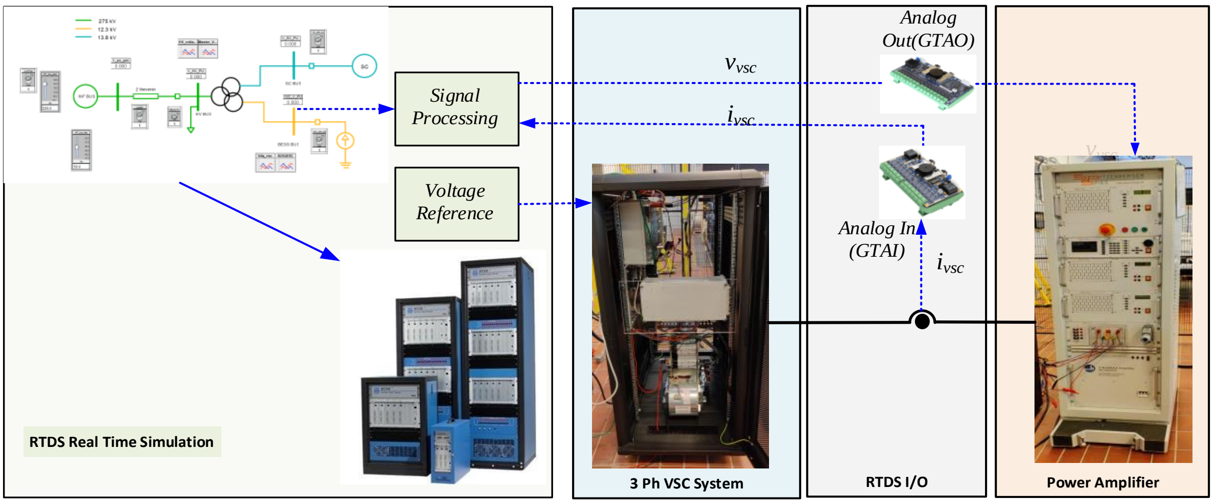


Figure 46: Overall PHIL system structure

DTU investigated the advantages of utilising a grid forming control strategy for BESS to be employed in the hybrid system, the results of which are published in the Wind integration conference. The paper is entitled “Comparative study of Hybrid Synchronous Condenser Incorporating Battery Energy Storage System for Ancillary Service Provision”.

5. Project Costs and Variances

5.1. Overview

The Overall project spend was in line with the project direction and there was a small overspend of 1% due to project delays mainly associated with COVID and change requests.

Overall, the project was delivered in line with the original budget set out in the project direction. Reduced labour costs were achieved through effective project management and the realisation that specialist support was required to reduce any delays of deliverables. Due to COVID related project delays, change requests and extension of the live trial, additional costs were incurred utilising the contingency set out at the start of the project. The table below shows the approved budget, actual costs, and variance against each cost category. Reasons for variance > 5% and process for deriving an efficient cost are explained in the commentary below.

[redacted]

5.2. Significant Cost Variance

The following table breaks down where the project under or overspent by more or equal to 5% of the original budgeted value.

[redacted]

5.3. Contingency Budget Use

SP Energy Networks applied robust project management techniques and processes to Phoenix. Contingency was utilised to cover the costs of various change requests brought about during the design and build stage.

[redacted]

6. Project Performance Compared with Original Aims & Objectives

6.1. Project Aims and Objectives

The major issue identified in the Phoenix project proposal to OFGEM, which resulted in the conceptualisation of Phoenix, was the impact of a reduction in conventional thermal generations and increase of the Inverter Based Generations (IBG) on the GB network.

In the proposal it was detailed that the problem(s) which need to be resolved are as detailed below.

- Technical challenges:
  I. Reduced inertia which compromises the network stability and security in event of a large loss of generation or load and results in a large rate of change frequency (RoCoF).
  II. Lower SCL results in poor power quality can also result in certain protection schemes failing to operate and introduces an increased risk of loss of commutation in current-sourced (LCC) HVDC links and the PLL type Inverter Based Generations (IBGs).
  III. Limited voltage control in absence of immediate dynamic response conventionally obtained from synchronous generators can result in voltages outside the statutory limits.
- Commercial challenges
  I. Lower system inertia requires the ESO to procure larger volumes of frequency response to compensate the potentially faster and more severe frequency drops that will be experienced in future, increasing the balancing costs. The SOF 2015 predicts there will be a 30% to 40% increase in frequency response required for all scenarios by 2020 and a 300% to 400% increase in frequency response required for all scenarios by 2030, and this would clearly increase costs to system operators and customers
- Regulatory Risks
  I. To comply with various regulatory requirements, SPT is obliged to consider not only conventional transmission-based investment solutions but also alternative solutions which may be more economic on a short term or long-term basis in maintaining economic and efficient operation of the national electricity transmission system. However, TOs under the present regulations, cannot participate in services market and with no mechanism to provide a clear ROI against high capital investment for third parties, there is a concern that GB may not be able to exploit the benefits of large-scale roll-out of SC technology and/or technologies other than synchronous generation that can provide inertia and/or SCL as a service.

The results from the Phoenix project are discussed in this report. The outcome of the live trial has proven the devices' ability to help reduce the impact of the technical challenges as mentioned above, providing inertial and voltage support with SC and STATCOM injecting active and reactive power correspondingly. Furthermore, commercial work carried out by NGESO and the market specialist within the project have examined and identified key commercial and regulatory needs to enable the use of SCs and H-SCs alongside other solutions to address the emerging voltage and system stability challenges.

6.2. Successful Delivery Reward Criteria

As can be seen in the below table Phoenix has successfully met the successful delivery criteria defined in the project scope. The project has proven that H-SC technology is viable for use on the GB network, and it will be rolled out as network asset once handed over to SPT, the H-SC technology is being deployed at Eccles in RIIO-T2.

Table 12 - Successful Delivery Reward Criteria Status

SDRC Title	Description	Required Evidence	Availability	Evidence Status
1) Architecture, Design and	Engineering design and feasibility analysis for pilot H-SC deployment and	1.1 Report on engineering and	Available upon request	Complete

SDRC Title	Description	Required Evidence	Availability	Evidence Status
Engineering feasibility	demonstration. Site selection and planning consent for H-SC installation. Detailed layout, civil designs, and approval through system review group for finalising tender for site works and ordering equipment.	design feasibility analysis.		
		1.2 Report on environmental studies and life cycle analysis.	Available upon request	Complete
		1.3 Report on detailed installation diagrams and site layouts.	Available upon request	Complete
		1.4 Report on routine and type testing procedure and results.	Available upon request	Complete
2) Financial Value Evaluation and Regulatory Recommendations	Develop and demonstrate a commercial framework to financially incentivise services provided by synchronous condenser. Enable service providers to participate in a new market for inertia and other ancillary services provided by SCs. Create recommendations for regulatory considerations for future roll-out of SCs/H-SCs.	2.1 Cost benefit analysis model for SCs and H-SCs.	Available upon request	Complete
		2.2 Report on cost benefit analysis of SCs and H-SCs based on system studies and FES.	LINK	Complete
		2.3 Report on international application of SCs and benefit analysis	LINK – Title "International Project review"	Complete
		2.4 Report on value evaluation of SCs/H-SCs based on pilot installation and performance.	Available upon request	Complete
		2.5 Report on impact of SCs/H-SCs on existing balancing schemes and markets.	Available upon request	Complete
		2.6 Report on value analysis from roll out of SCs/H-SCs in GB in future potential sites.	Available upon request	Complete
		2.7 Report on regulatory considerations	LINK	Complete

SDRC Title	Description	Required Evidence	Availability	Evidence Status
		and recommendations for future roll-out of SCs and H-SCs.		
3) Control Methods Development and Testing	Innovative control methods to maximize benefits of SC/H-SC installations in different network conditions and different locations across GB. Simulation of co-ordinated control schemes with other network components such as SVCs, STATCOMS and battery storage. Development and on-site testing of hybrid control scheme for H-SC.	3.1 Report on methods and functional specifications of hybrid control mechanisms developed and trialled in pilot demonstration.	Available upon request	Complete
		3.2 Report on output of SCAPP project on protection and control of synchronous condenser and simulation results of new control methods.	Available upon request	Complete
		3.3 Report on performance of pilot hybrid co-ordinated control system.	Available upon request	Complete
		3.4 Report on methods and functional specifications of innovative control schemes for future roll-out.	Available upon request	Complete
		3.5 Report on FAT test procedure and results of pilot hybrid co-ordinated control system.	Available upon request	Complete
		3.6 Report on SAT test procedure and results of pilot hybrid co-ordinated control system.	Available upon request	Complete
4) Lab Functionality	Testing of different operational scenarios in laboratory environment to generate results to better	4.1 Component model adapted to pilot demonstration	Available upon request	Complete

SDRC Title	Description	Required Evidence	Availability	Evidence Status
and Component Model Testing	understand performance of SC/H-SCs under various limits and constraint conditions. Lab testing will test different operational parameters of SC/H-SCs. Use of RTDS to facilitate simulation of technical models and control algorithms.	and for further system studies.		
		4.2 Report on component level studies from SCAPP project and relevance to pilot demonstration and future installations.	Available upon request	Complete
		4.3 Report on co-simulation for faster prototyping for new designs and controls.	Available upon request	Complete
5) Application of synchronous condenser: GB system studies	System studies using SC/H-SC component model and GB system model developed through EFCC project and SOF studies to critically analyse impact of future roll-out of SC/H-SCs in GB network. Case studies for specific system cases on GB network.	5.1 Report on System Studies and Quantification of overall benefits from application of SCs/H-SCs in GB system.	Available upon request	Complete
		5.2 Report on case studies on system characteristics of SCs/H-SCs in conjunction with other innovative solutions proposed through EFCC and HVDC converters.	Available upon request	Complete – merged with SDRC 5.1
		5.3 Report on optimal placement and capacity evaluation of SCs/H-SCs in GB.	Available upon request	Complete
		5.4 GB roadmap for roll-out of SCs/H-SCs.	LINK	Complete
6) Pilot Installation and Operational Trial	On-site installation and commissioning of pilot H-SC demonstration. Civil work and electrical connection of H-SC to the transmission network.	6.1 Report on site installation process, details, and recommendations for future - Civil.	Available upon request	Complete
		6.2 Report on site installation process, details, and	Available upon request	Complete

SDRC Title	Description	Required Evidence	Availability	Evidence Status
		recommendations for future - Electrical.		
		6.3 Report on SAT procedure and test results.	Available upon request	Complete
		6.4 Report on electrical layout of H-SC design with protection and control architecture.	Available upon request	Complete
		6.5 Report on extended live trial and recommendations for future installations.	Available upon request	Complete
7) Performance Monitoring	Monitoring of equipment performance such as losses, vibrations, and maintenance requirements of rotating parts of the pilot H-SC. Condition monitoring of the H-SC output and impact on the regional and wider power system.	7.1 Report on pilot H-SC installation component level SC, STATCOM condition monitoring.	Available upon request	Complete
		7.2 Process documentation for SC type testing requirements for future installations.	Available upon request	Complete
		7.3 Functional specifications for H-SC output monitoring - Methods and User Interface.	Available upon request	Complete
		7.4 Functional specification for H-SC wider system operational performance monitoring	Available upon request	Complete
		7.5 Report on pilot H-SC installation output data logging and monitoring	Available upon request	Complete
		7.6 Report on H-SC system impact in local and wider system context -	Available upon request	Complete

SDRC Title	Description	Required Evidence	Availability	Evidence Status
		Usage, Control methods and Interactions.		
8) Knowledge Dissemination	Stakeholder engagement and dissemination of learnings and outcomes of the pilot H-SC demonstration through project.	8.1 Report summarising findings of TO SO working groups.	Available upon request	Complete
		8.2 Report on emerging technical standards for synchronous condenser.	Available upon request	Complete
		8.3 Innovation testing and Demonstration Workshop	LINK	Complete
		8.4 Phoenix regular project progress reports.	LINK	Complete
		8.5 Phoenix Close down report.	LINK	Complete

7. Required Modifications to Planned Approach

Phoenix has been delivered successfully; the original approach has been largely unchanged to that set out at the project commencement.

8. Updated Business Case and Lessons Learnt

The original project submission identified H-SC technology as a vital tool to assist transmission owners and operators in managing the volatility of the GB transmission system associated with the move toward a low carbon future. Phoenix sought to establish the required infrastructure to demonstrate a suite of new applications to enhance understanding and visibility to address the following key challenges:

- Reduced Inertia due to closure of thermal synchronous power generation
- Low Short Circuit Level
- Limited Voltage Control
- Limited Boundary Transfer Capabilities between England and Scotland

Furthermore, the complexity and extent of these challenges is likely to increase in the future. At the project inception time (2017) there were around 2000 MW of wind connected and 3000 MW of synchronous generation (nuclear, pumped storage, CHP, gas, biomass) on the SPT transmission network. If the current projections under different energy scenarios and ten-year statement are to be realised the last of synchronous generation in SP Transmission area, Torness is planned for closure in 2030. Thus by 2030 there could be 9300 MW of wind and only 635 MW of synchronous generation (pumped storage, CHP, gas, biomass) connected to the SPT transmission network [1].

The H-SC can be used to improve the voltage of the surrounding network through import or export of reactive power (MVAr). These MVArs are used to control voltage within the grid and improve power transfer over boundary lines and between areas. Two operating conditions are possible according to the capability curve of individual SCs are:

- Over-excitation: generation of reactive power with leading power factor (capacitive behaviour);
- Under-excitation: absorption of reactive power with lagging power factor (inductive behaviour).

Additionally, because of the rotating mass and characteristics like synchronous generators (except for producing active power), SCs/H-SCs can contribute to system inertia and SCL. In regional level the effect of inertia provided by SCs is much greater than the whole system perspective. These services are increasingly important given the changes to the grid

8.1. Benefit Areas

The present GB grid codes are not specific regarding the system security and operation particularly in the context of a weak AC system in the future. There is an urgent need to define what the GB system will need technically and commercially, both in terms of responses to system disturbances and under steady state conditions, to maintain network security and reliability of supply.

8.1.1. Development of a low carbon energy

The development of a low carbon energy sector delivers environmental benefits whilst having the potential to deliver net financial benefits to future and existing customers.

SP Energy Networks is supportive of innovation accelerating GB's transition to a low carbon economy by enabling best practice throughout its transmission system. Enabling the roll-out of SCs and innovative H-SCs in GB through Phoenix will help facilitate this by enhancing network strength and stability to ensure renewable energy sources can be securely accommodated and fully utilised. SCs and H-SCs are complementary technologies to the increased distributed and intermittent renewable generation, capable of offering essential network services such as inertia, SCL and dynamic voltage control to a lighter weaker AC system. The current energy policies indicate increased levels of renewable generation are required to meet the GB low carbon targets. Introducing additional reactive power sources such as SCs/H-SCs can help deal with the challenges associated with integrating more renewable generation as highlighted in Figure 47. SCs and H-SCs are non-generating plants that provide voltage support, inertia and SCL without any emissions associated with fossil power generation sources and at lower capital cost and greatly reduced footprint than large scale generation plants.

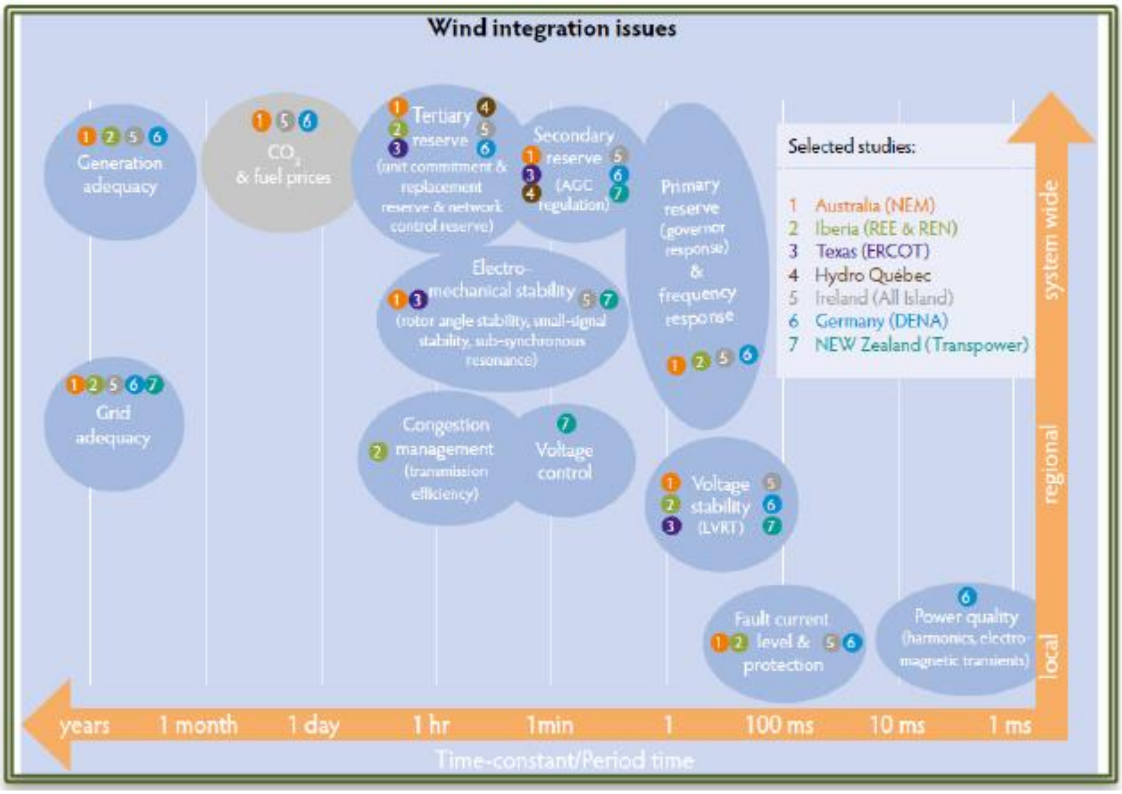


Figure 47- Wind Integration Issues

Studies undertaken by the Technical University of Denmark illustrates the impact of a large-scale wind farm penetration on the frequency response of Western Danish power system and the effect of SC in enhancing frequency stability [9] Figure 48 validates the results of the paper with simulation on GB system which highlights the offset of primary response that can be realised with increased levels of synchronous compensation as levels of asynchronous generation increase up to 100%. Furthermore, it suggests that the cost of providing additional response, and any associated curtailment requirements, will be reduced by the introduction of synchronous compensation.

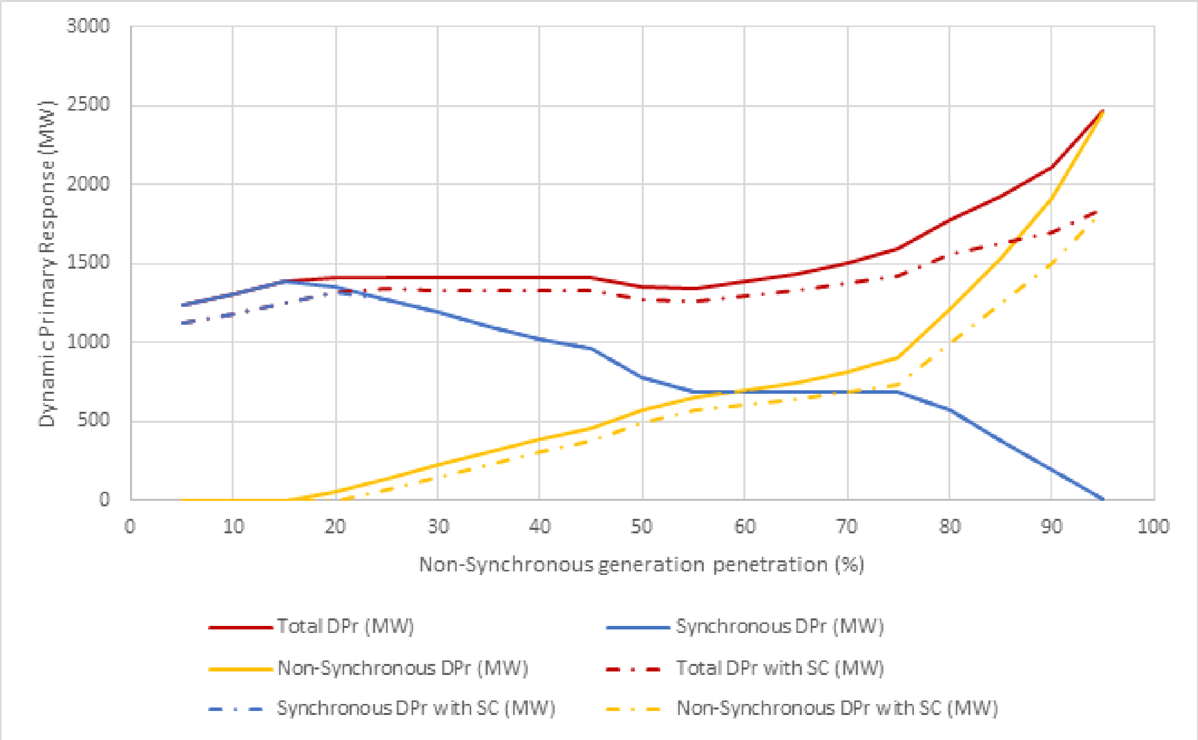


Figure 48 Offset in levels of Primary Response by SC

In conclusion a successful demonstration of H-SC technology through Phoenix will help meet GB's low carbon targets by addressing wind integration issues:

- Boosting system inertia to ensure the stability of the grid and limit the RoCoF (df/dt). Higher system inertia reduces the risk of a large generation infeed or load loss triggering cascading losses of large amounts of embedded generation due to their RoCoF protection relays.
- Increasing system SCL which helps improving efficiency of interconnectors and mitigating the risk of failure of protection systems.
- Improving power quality
- Providing dynamic voltage control which helps increasing power transfer capabilities of constrained boundaries in transmission circuits and enabling more renewable generation to be connected to the network.
- Provide similar services as synchronous generation with much lower capital investment and reduced footprint.

8.1.2. Provides value for money to electricity TO and DNO Customers

The roll-out of SCs/H-SCs in GB system enabled by Phoenix will deliver significant financial benefits to TOs, DNOs, OFTOs, SO and ultimately to GB customers. Phoenix will reduce the constraint payments by increasing the availability of the network to generators, through increasing the active power transfer capability of the existing transmission network. It will also potentially offset costs in frequency reserve market by decreasing the dependence on "must-run" requirements of synchronous generation. The project submission report contains the breakdown of costs to manage constraints for the financial year 2015/16 and illustrates that £91.83 million was spent on constraining wind farms alone [1]. This is obviously a major problem in Scotland where installed wind generation capacity is significantly more than the demand, thus improving transfer capability across B6 and B4 boundaries will help reduce constraint costs paid to wind farms. Initial studies suggest the cumulative capacity released by deployment of SCs/H-SCs across SP Transmission area in RIIO T2 and T3 in year 2050 is 887 MW.

9. Lessons Learnt for Future Innovation Projects

A list of key lessons learnt which may prove valuable for similar future innovation projects are listed and broken down into categories below:

Table 13 - Lessons Learnt for Future Innovation Projects

Category	Lesson Learnt	Proposed Action for Future Projects
Communication	Hold monthly project partner meetings (virtual) and in person quarterly meetings among all project partners to help facilitate communication, planning and successful delivery of the work packages and stakeholder events.	Regular meetings with project partners from an early stage to discuss the current ongoing activities and progress of work packages.
Communication	Holding CWG meetings on a quarterly basis in London to influence the decision making and action planning of upcoming milestones.	Regular CWG meetings to plan and influence the scope of upcoming activities. SPEN presence limited to 1/3rd of the time to avoid the session being SPEN centric.
Work Packages	Pre-emptive approach to the planning and delivery of the design and construction of the site work by all parties involved in this phase. In the case of Phoenix this included ABB, SPT, Construction, SCADA, and SAP's due to the site being within an operational SPT substation. This allows for early identification of any potential issues such as earthing discharge regulations or unforeseen site constraints.	Early planning of the site works before construction commences, with direct engagement from all parties involved in this phase of the project.
Work Packages	Early appointment of the commissioning team would have facilitated the on-time commissioning of the H-SC.	Inserting contractual obligations for the early appointment of the commissioning teams.
Contingency planning	Monthly Reporting of the project facilitated in the creation of annual project progress reports, slides for stake holder events, end of trial reports and project milestone reports.	Monthly reporting will help monitor project progress and help facilitate annual reports and other project outputs.
Contingency planning	SPEN engineers visited the manufacturing factories in Sweden for weeklong training workshops since the control systems technology developed was a first for both ABB and SPEN.	Importance of SPEN engineering team visiting the factory to develop the SPEN team's operational knowledge of the new technology before it arrived in the UK.
Contingency planning	Punch lists were created specifically to close out any outstanding actions required for BaU operation of the H-SC device on the network.	A greater emphasis on Business as Usual (BaU) requirements and punch lists to facilitate the same.

Category	Lesson Learnt	Proposed Action for Future Projects
Contingency planning	Early involvement of the RTS and SCADA teams led to the identification of gaps in control panels required to manage the site from OCC which were then addressed by inhouse development of new control panels.	Interaction between the OCC and the site at an early stage to facilitate the management of the device when in operation.
Training	The issues in the training plan were resolved during the project after it had been implemented. A better approach would have been the resolving of such issues at the stage of tender.	Get input from SAP's and other operational staff in the approval of training plan.
Communication	The only way to avoid bottlenecks in the project was for the commissioning engineers to visit the site regularly.	Strong communication between site engineers and manufacturers.

10. Planned Implementation

10.1. Future Implementation

The positive outcomes and learnings from this project exemplify the positive impact that H-SC technology can have in maintaining grid stability. SPT's RIIO-T2 plan includes the delivery of the Eccles voltage support and real time rating system (ECVC) project. This upscaled project further exploits the benefits that Phoenix has introduced to the network as ECVC will give a boundary transfer uplift of up to 280MW on the B6 boundary ahead of the closure of Torness nuclear power station in 2030, maintaining the current boundary transfer capability. ECVC will be delivered by 2026, helping to enable the Eastern Link HVDC project which is due to be delivered by 2027. [10]

This project involves the installation of two H-SC devices as illustrated in Figure 49, each comprising of a 150MVA SC and a 150MVar STATCOM at the existing Eccles 400kV substation at a total estimated cost of £95.3m.

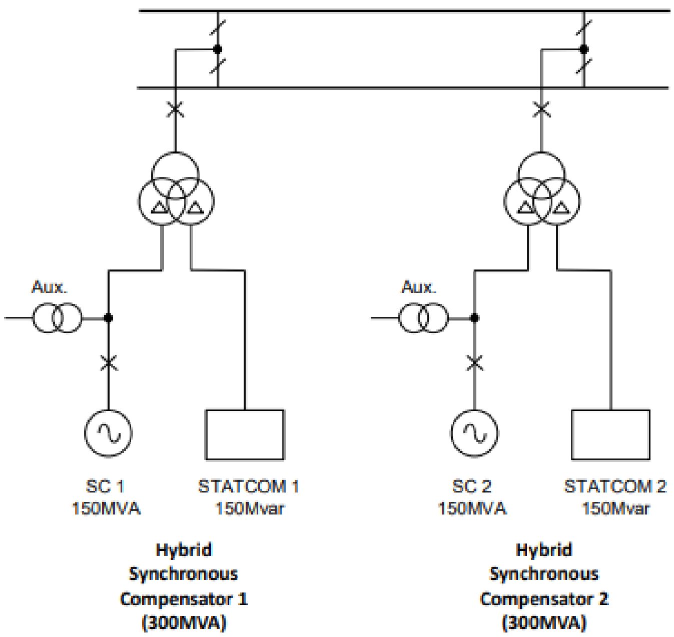


Figure 49 - Eccles voltage support and real time rating system (ECVC) project diagram [3]

This project is building on the learnings from the Phoenix project to trial the benefits of H-SC technology on the network, the Phoenix team engaged with the Eccles team at an early stage to provide lessons Learnt and help guide the technical standard which would be employed.

Eccles Voltage support and real time rating system (ECVC) **Total value: £95.3m**

This project gives a boundary uplift of up to 280MW on B6 ahead of the closure of Torness power station, which is currently expected to be in 2030, and maintains the current boundary capability once this has closed.

ECVC is included in our RIIO-T2 business plan to be delivered by 2026. This is required as an enabler to the Eastern Link which is to be delivered in 2027. The NOA process has recognised this need, having indicated via the NOA 2018/19 to progress the development on the basis of this being required by 2027. This project also provides additional value due to the system strength that the solution offers, which has been in decline due to the decreasing amount of synchronous generation on the system. System strength is not considered as part of the NOA process at present.

This project involves the installation of two hybrid synchronous compensators at the existing Eccles 400kV substation. This project is building on the learning from our PHOENIX project to trial the benefits of a hybrid synchronous compensator.

Additionally, a real-time rating system on the existing thermal 'bottle necks' at Moffat to Harker and Gretna to Harker 400kV overhead line circuits is included to maximise the benefit.

Figure 50 - Eccles voltage support and real time rating system (ECVC) project [11]

Internal Use

Furthermore, a key aim of the Phoenix project is to share what the future roll out of this technology would look like on the GB network, as a result the project has published a GB road map report [11]. This report provides guidance which is targeted at future investors in H-SC technology and provides insight into:

- The technical specifications required from a H-SC and results from system studies.
- Potential variants of deployment.
- Location and installation considerations for future installations.
- Commercial incentives for the roll out of this technology on the GB network such as the NOA process and Stability Pathfinder.

In addition to this report a short video [12] was produced and shared on our social media channels, this provided a high-level overview of the report and signposts interested viewers to the full report on the Phoenix page of the SPEN website.

The success and learnings from the Phoenix project have shaped the planning of additional H-SC deployments such as the £95m installation of two H-SCs at Eccles 400 kV. The cost estimate was informed by the Phoenix project for this large-scale project. This opens the gates to further large-scale H-SC rollouts within the GB network based on the learnings of the project. These learnings will also contribute to the 5 SC projects recently announced by NGESO (due to start construction in 2024) are cost effective for the consumer (refer to "Scotland's wind success story bolstered by £323m stability investment | National Grid ESO").

The GB roadmap (SDRC 5.4) report highlights methods of deployment for H-SCs in GB using three different approaches:

- Network Company Regulated Assets
- NOA Process
- Stability Pathfinder

These approaches highlighted within the GB Roadmap are indictive of the actions and steps which would be required of network licensees and private H-SC owners when considering future installations.

11. Knowledge Dissemination

Phoenix has continuously shown a strong commitment to knowledge dissemination throughout the project. During the project several stakeholder engagements events have been held with the aim of involving internal and external stakeholders to the business in the project and sharing the findings and results.

The main focal point of stakeholder engagement throughout Phoenix has been knowledge-sharing and stakeholder engagement activities hosted by the Phoenix project delivery team. The main object of these events has been to:

- Raise awareness of the projects aims and objectives both internally and externally of the business.
- Disseminate key learning from the project.
- Provide an opportunity for internal and external stakeholders to engage with the project team through Q&A and open discussions.

A summary of these events is provided in this section.

11.1. 2019 Technical Stakeholder Engagement Event

In February 2019 the first Phoenix stakeholder engagement event was held in Edinburgh. This aim of this event was to provide a project update, this included topics such as:

- The H-SC design
- An overview of the H-SC master control systems
- Updates from project partners on modelling and studies
- And provide a view ahead of future solutions and the need for this technology.

11.2. 2021 Innovation Testing and Demonstration Webinar

During the 2021 reporting period Phoenix held a second stakeholder engagement event, due to the UK wide Covid-19 restrictions this was held as an online webinar via MS Teams. The main aim of this event was to provide an update to our internal and external stakeholders on the project and provide preliminary results from the first 6-months of the live trial. The event covered the below topics:

- An update on the 6-month live trial and results from ABB Hitachi.
- Results from Boundary Analyses studies conducted by NGESO.
- Progress update on commercial reports and commercial working group outputs from project market specialist.
- Short circuit level and system inertia study results from the University of Strathclyde.
- Update on component level studies from the Technical University of Denmark.

This event was attended by individuals from a wide variety of backgrounds both internally within SP Energy Networks and externally from private companies. During the event questions were allowed via Sli.do and the MS Teams chat function, a survey was activated at the end of the event to collect stakeholders experience.

The presentation and slide pack from this event have been uploaded to the Phoenix page on the SP Energy Networks website (LINK).

Figure 51 - 2021 Stakeholder Event Sli.do Summary Report

11.3. Eccles H-SC Knowledge Dissemination

During the first half of 2021 the Phoenix team provided support in the scoping and specifications of the RIIO-T2 Eccles voltage support and real time rating system project.

The Phoenix deliver team worked in collaboration with the Eccles team and the contractor 3rd party who would lead the design, installation, and construction of the devise to develop a list of over 100 lessons Learnt from the Phoenix project, encompassing a wide range of areas including:

- Training requirements
- Electrical and civil design
- Engineering standards and compliance
- Operational functionality
- Control interfaces
- Contract award and the tendering process

Overall, this allowed the Phoenix project to contribute towards the future roll out and implementation of H-SC technology.

11.4. 2022 Phoenix Close Down Event

This event is programmed to be held in late 2022, after the time of writing of this report, the aim of the event is to provide an overview of the project in its entirety and also provide information on the results and conclusions drawn from the project.

The project partners will engage with this event and give a presentation on their contributions to the project overall and a summary of their findings.

- SPEN – Introduction
- Hitachi Energy – H-SC design and build, and live trial results and learnings
- NGESO – Overview of research in the project i.e., system studies, lessons Learnt, and live trial. (progress, reporting, etc)
- UoS - Overview of the research conducted for the projects i.e., summarise studies (results and lessons Learnt) and previous annual report contributions including 2021. (progress, reporting, etc)
- DTU – Overview of the research conducted for the projects i.e., summarise studies (results and lessons Learnt) and previous annual report contributions including 2021. (progress, reporting, etc)
- Market Specialist – summary of CWG and commercial outputs
- SPEN – Conclusion

Furthermore, Phoenix CDR port has been peer reviewed by SSE and the summary of their comments is provided in Appendix B – SSE Comments Summary

12. Project Replication

Phoenix deployed a H-SC device in a world-first live trial to help addressing the issues posed by the changing generation landscape on the GB power network. This section of the report details the physical components and knowledge required to replicate the outcomes of the project along with details of the expected business-as-usual costs of replicating the project.

12.1. Physical Components

H-SC is the combination of the mature technology of the synchronous condenser combined with the more recent technology of the STATCOM. Figure 52 depicts the simplified single line diagram of an H-SC. It consists of a STATCOM branch with a Voltage Source Converter (VSC) and an SC branch with a Synchronous Condenser. The STATCOM and SC branches can be connected to the same high voltage (HV) bus via a three-winding, three-phase transformer, or via separate two-winding, three-phase transformers. If required, two or more VSC can be connected to the VSC bus and/or two or more SC can be connected to the SC bus.

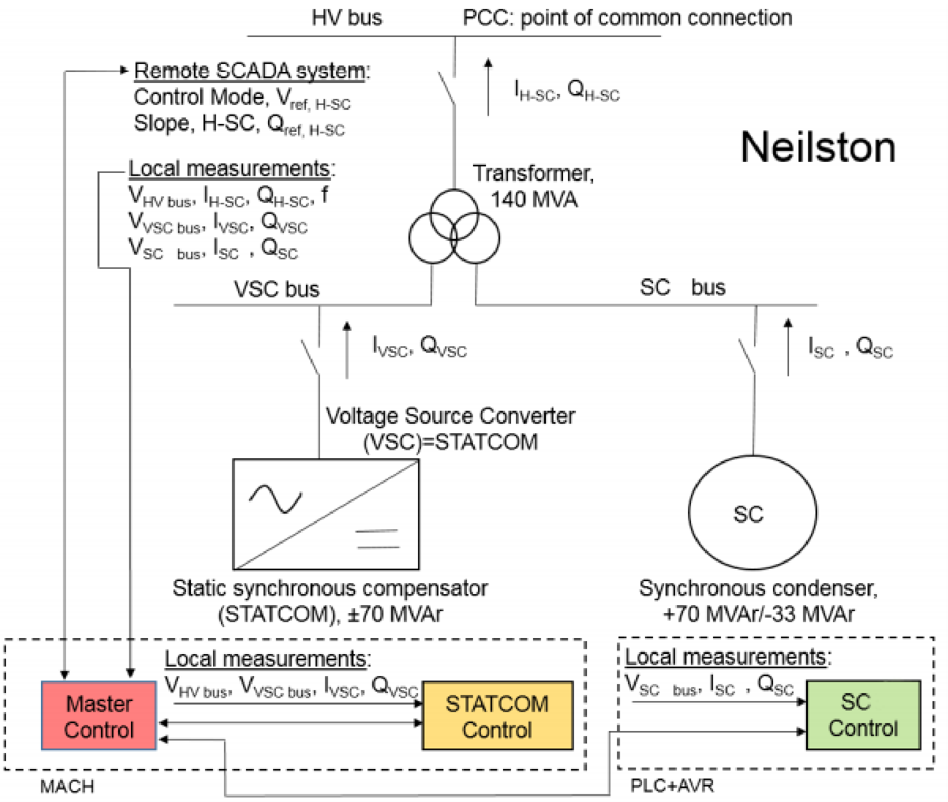


Figure 52 - Simplified Single Line Diagram of an H-SC

SC and STATCOM technologies are traditionally supplied with standalone control systems. The STATCOM control is a MACH® control platform manufactured by Hitachi Energy. The SC control consists of a PLC and an AVR also manufactured by Hitachi Energy.

The SC controls the SC bus voltage (V_{SC} bus) by using the local measurements I_{SC}, V_{SC} bus and Q_{SC} illustrated in Figure 52, whereas the STATCOM controls the HV bus voltage (V_{HV} bus) by using the local measurements I_{VSC}, V_{VSC} bus, V_{HV} bus and QVSC.

In addition to the standalone operation of the STATCOM and SC, a hybrid control functionality (Master Control) has been developed inside the MACH® control platform. The developed functionality avoids “control hunting” between the two control systems (STATCOM Control and SC Control), thus allowing the stable, coordinated, and efficient operation of both branches simultaneously.

12.2. Roll out of Project and Associated Costs

As discussed in section 10 of this report, a larger version of Phoenix is being implemented at Eccles during the RIIO-T2 price control period, learnings from the Phoenix project have been provided to the

Eccles team to provide guidance for the project scope and specifications. This is a positive step in the roll-out of H-SC technology on the GB network. In an update from the ESO in April 2022 an announcement was made regarding 5 new long term grid stability projects utilising synchronous condensers are to be deployed starting in 2024. The work carried out and disseminated (refer to " Scotland's wind success story bolstered by £323m stability investment | National Grid ESO") during the Phoenix project will allow for these projects to be deployed in a more cost effective way for the consumer.

Expected costs associated with replicating a device of a similar scale to that being installed at Eccles has been examined in the projects GB roadmap report. For a 250 MVA rated SC, the costs to procure and install the equipment is likely to be in the range £21m to £27m depending on a number of factors including site conditions and installation costs. For a 250 MVA rated H-SC, meaning a 125 MVA SC and a 125 MVA STATCOM, these costs would be greater and are likely to be in the range £26m to £32m [11].

As for running costs, as a rule of thumb, the no load losses for a H-SC device, will be between 50-60% when compared to a SC for same total MVA rating. This should be taken into consideration when calculating the total cost of ownership.

The costs to maintain equipment and potentially upgrade control systems over the asset lifetime should also be considered when assessing the use of SC or H-SC. For a 280 MVA rated SC, typical maintenance costs could be around £0.05m per annum over a 40-year life. In addition, a control system upgrade after 20 years could cost around £0.4m. For a similar rated H-SC, the maintenance costs are likely to be slightly higher at around £0.06m per annum and control system upgrades after 20 years could cost around £0.7m.

When an H-SC is compared to a SC and a STATCOM, there is no planned or foreseen need of any specific additional maintenance for the H-SC compared to the SC and the STATCOM individually.

As well as the costs to build and maintain SC and H-SC, service providers would also need to consider other ongoing costs including losses and network charges. The different elements of these costs will depend on the service provider type and whether SC and H-SC are defined as generation or demand. For example, if a Third Party where to provide a transmission connected solution and this was treated as a generation asset, then the provider would need to consider Transmission Network Use of System (TNUOS) charges, Balancing System Use of System (BSUOS) charges and the costs of the equipment's energy losses.

In assessing the suitability of an SC or H-SC alongside other potential solutions, service providers should also consider how long the service is likely to be required for. SC and H-SC are long-life assets and could provide services over a 20 to 40-year asset life. This should be considered in assessing whether a solution is appropriate to meet a Network Option Assessment (NOA) or Stability Pathfinder requirements. The funding mechanisms for Third Party solutions to meet NOA requirements have yet to be finalised and so it is possible that funding could be aligned to the expected life of the asset. For the Stability Pathfinder Phase 1 and Phase 2 requirements, the expected contract periods are up to 5 years and up to 12 years respectively, so consideration needs to be given to the asset's use at the end of the contract period and what residual value it would have.

12.3. Considerations when Deploying H-SCs

In assessing options to provide additional transmission boundary capability or to meet commercial service requirements, SC and H-SC will be compared with other solutions that are being developed to provide voltage and stability capability. These solutions include energy storage systems such as batteries, and Grid Forming Converter (GFC) technologies that would enable Direct Current (DC) or other asynchronous power sources to be used to mimic synchronous generators.

The suitability and cost-effectiveness of SC and H-SCs compared to other technical solutions will be assessed by potential service providers. As SCs and H-SCs can provide a range of services, they are likely to be most effective where a range of voltage, inertia and system strength services are being sought. In assessing whether a SC or H-SC should be proposed to meet a NOA boundary requirement or to provide a commercial service, several cost and practical development aspects need to be considered.

In considering the location of SCs or H-SCs, several aspects should be considered. Firstly, the electrical connection of the device to a transmission substation will be required. This substation will need to be suitably located if the SC or H-SC is to be effective in providing services. If connection substations are not identified by NGESO as part of a tender process, sites can be discussed with the local TO.

Normally the SC or H-SC developer will own the electrical connections (e.g. underground cable) to the transmission substation including the HV switchbay. When connecting to an existing substation, modifications may be required to infrastructure such as cable trenches, buildings, drainage, etc.

The equipment size and weight will also bear on the practicality and costs of an SC or H-SC solution. For the 140MVA rated H-SC at Neilston, the site footprint is around 4000m^2 to accommodate equipment including the SC elements, the STATCOM elements, a 3 winding step-up transformer, an earthing transformer, the banking arrangements, and auxiliary supplies. For a 250MVA rated H-SC, the site footprint is likely to increase to around 5000m^2. In some cases, depending on soil conditions and geotechnical concerns, the construction of piles below the SC foundation may be required.

Other development factors include local planning requirements, audible noise limits and the provision of independent electrical supplies to the H-SC / SC.

13. Key Project Learning Documents

13.1. Project Progress Reports and Key Learning Reports

All project progress reports, and key learning documents are listed below on **Error! Reference source not found.**. They have also been made publicly available on the project webpage.

Table 14 - Phoenix Project Progress Reports and Key Learning Documents on Website

Document Title	Document Description	Project Partner	Access Link
Phoenix Progress June 2017	This is the first in the series of biannual progress reports for the Phoenix project, covering the project delivery period January 2017 – June 2017.	SPEN	LINK
Phoenix Progress Report December 2017	This is the second in the series of biannual progress reports for the Phoenix project, covering the project delivery period June 2017 – December 2017.	SPEN	LINK
Phoenix Annual Progress Report 2018	This is the third in the series of biannual progress reports for the Phoenix project, covering the project delivery period June 2017 – December 2017.	SPEN	LINK
Phoenix Annual Progress Report 2019	This is the fourth annual progress report for the Phoenix project, covering the project delivery period January 2019 – December 2019.	SPEN	LINK
Phoenix Project Progress Report 2020	This is the fifth annual progress report for the Phoenix project, covering the project delivery period January 2020 – December 2020.	SPEN	LINK
Project Fact Card Print Version	This short project pamphlet provides a high-level overview of the project, its deliverables and timeline. This document was primarily targeted towards stakeholders.	SPEN	LINK
Phoenix – International Project Review	The international review work on the Phoenix project is intended to consider and learn from how similar challenges to those faced in the GB are being addressed in other parts of the world. This includes consideration of other transmission networks with high levels of renewable generation including networks were synchronous compensation is being installed.	NGESO	LINK
Phoenix – Cost benefits of SC and H-SC Based on System Studies	These study results are provided as input to a well-established Cost Benefit Analysis method, using BID3 economics tool, to determine the economic benefit of H-SC technology. The installation sots, maintenance cost, asset life and availability factors of each option are provided as input for CBA analysis.	NGESO	LINK
Phoenix – Report on Regulatory Considerations for Future Roll-out of SC and H-SC	This document reports on the regulatory considerations for the future roll-out of SC and H-SC assets.	NGESO	LINK
Phoenix – Impact of SC/H-SC on	This document reports on the impact of SC and/or H-SC on existing balancing schemes and markets. This report	NGESO	LINK

Existing Balancing Schemes and Markets	examines the different deployment routes that are being used for SC and H-SC. It considers the range of services that are used by NGESO to support system balancing and operation and the different parties that provide these services.		
Phoenix – Report on GB Roadmap for Roll out of H-SC	This document reports on a GB roadmap for the roll out of H-SC technology. The report is based on evidence and learnings gathered by the Phoenix project. It outlines the potential system benefits of the H-SC and the associated deployment routes. It also summarises the key learning from the Phoenix live trial which is a useful reference point in how the H-SC device could be deployed more widely on the GB electricity system.	NGESO	LINK
Phoenix – 2021 Innovation and Testing Demonstration Webinar	The main aim of this webinar was to provide an update on the project 6-month live trial results. In addition to this the project partners provided an update on the work they have been carrying out on the project.	SPEN	LINK

Technical documents related to the live-trial results and other documents are available upon request, these documents are listed in Table below**Error! Reference source not found.**.

Table 15 - the live-trial results and other documents

Document Title	Document Description	Report Location	Project Partner
Report on performance of pilot hybrid co-ordinated control system.	This report constitutes an extensive synopsis of the results of Live Trial Plan for Phoenix project. It presents the results of tests that were conducted to evaluate the performance of the Hybrid Synchronous Condenser (H-SC) at Neilston substation in Scotland under different operational modes and conditions. The tests presented in the report was performed from November 2020 till May 2021 in accordance with the Live Trial Plan. Moreover, this report presents some highlights of the response of H-SC to several unplanned events that occurred over the period of Live Trial Plan enabling the deeper understanding of system behaviour.	Available on request.	Hitachi Energy
Report on extended live trial and recommendations for future installations.	This report constitutes an extensive synopsis of the results of Live Trial Plan for Phoenix project. It presents the results of tests that were conducted to evaluate the performance of the Hybrid Synchronous Condenser (H-SC) at Neilston substation in Scotland under different operational modes and conditions. Most of the tests were performed from November 2020 till July 2021 in accordance to the Live Trial Plan During this period the control functions of the Master Controller have been tested as well, while some tests were repeated, as the complete analysis of their results in the first place was not possible. A part of the repeated tests has been performed on 13th October 2021. Moreover, this report presents some highlights of the response of H-SC to several unplanned	Available on request.	Hitachi Energy
Report on pilot H-SC installation component level SC, STATCOM condition monitoring.	This report constitutes an extensive synopsis of the results of Live Trial Plan for Phoenix project. It presents the results of tests that were conducted to evaluate the performance of the Hybrid Synchronous Condenser (H-SC) at Neilston substation in Scotland under different operational modes and conditions. The tests presented in the report was performed from November 2020 till May 2021 in accordance with the Live Trial Plan. Moreover, this report presents some highlights of the response of H-SC to several unplanned events that occurred over the	Available on request.	Hitachi Energy

Document Title	Document Description	Report Location	Project Partner
	period of Live Trial Plan enabling the deeper understanding of system behaviour.		
Report on pilot H-SC installation output data logging and monitoring.	This document presents the selection of all the reports, which have been submitted during the Live Trial Plan and have presented the analysis of test results for the performance evaluation of H-SC. The reporting was conducted on a monthly base from November 2020 till April 2021 assessing the response of H-SC under the different H-SC operational mode and under unplanned occurrences and network changes. The merging of the monthly reports follows the chronological order in which they were made. Moreover, this work was supplemented with the reporting of tests that were made for validating the Master Controller functions as well as of repeated test cases.	Available on request.	Hitachi Energy
Report on H-SC system impact in local and wider system context - Usage, Control methods and Interactions.	The main purpose of the live trial is to verify the H-SC master controller performance, in addition to verifying the various control modes of the SC and STATCOM. Therefore, a series of test cases are performed, and the measured data is collected and analysed. The monthly reports present the collected data by plotting them out in the result curves. It also analyses if the H-SC system shows the expected performance. In this report, the results for certain cases performed in November 2020 are included, as well as an event on December 1st.	Available on request.	Hitachi Energy
Report on emerging technical standards for synchronous condenser.	These two reports aim to set out the minimum requirements users must comply with when seeking to provide reactive power, inertia and short-circuit infeed services to NGESO via the connection of a H-SC device.	Available on request.	NGESO
Component model adapted to pilot demonstration and for further system studies.	Testing of different operational scenarios in laboratory environment to generate results to better understand performance of SC/H-SCs under various limits and constraint conditions. Lab testing will test different operational parameters of SC/H-SCs. Use of RTDS to facilitate simulation of technical models and control algorithms.	Available on request.	DTU
Report on co-simulation for faster prototyping for new designs and controls.	For Phoenix project, the developed PHIL platform at DTU can cater to high fidelity validation of control system developed for the hybrid synchronous condenser system.	Available on request.	DTU
Report on optimal placement and capacity evaluation of SCs/H-SCs in GB.	This document contains a report of the work undertaken by the University of Strathclyde. The aim of the work described in this report is to assess and quantify the contribution of SC and Battery Energy Storage System (BESS) units to system inertia and frequency response.	Available on request.	UoS/NGESO
Report on System Studies and Quantification of overall benefits from application of SCs/H-SCs in GB system.	The aim of the simulation analysis (RMS simulation) presented in this report aims to quantify with the contribution of SC and STATCOM units to i) Dynamic reactive power provision during three-phase transmission faults, ii) SCL and peak currents during transmission line faults and iii) System inertia (LoG	Available on request.	UoS/NGESO

Document Title	Document Description	Report Location	Project Partner
	followed by frequency deviation). The GB system has been dispatched to reflect year 2019.		

14. Data Access Details

To access and download material generated through the project, please visit the Phoenix website using the below link:

https://www.spenergynetworks.co.uk/pages/Phoenix.aspx

Access to the project data must be requested by contacting SPInnovation@spenergynetworks.com. Please provide the following information in your request:

- Affiliation, position and contact details of requesting party
- Relevant project and type of data required
- Reasons for requesting this data and evidence that this data will be used in the interest of the UK network electricity customers

Full details on the SPEN data sharing policy is described on the link below:

https://www.spenergynetworks.co.uk/pages/data_sharing_policy.aspx

For more information regarding Phoenix please contact James Yu, Future Networks Manger, SP Energy Networks.

15. Contact Details

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Future Networks Manager

SP Energy Networks

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Appendices

Appendix A – Project Programme

[redacted]

Appendix B – SSE Comments Summary

SSE have provided their comments as part of the standard per review process for the Phoenix CDR.

The majority of the SSE's comments were of grammatical and editorial nature with few centred around the content. Their comments can be categorised as follows:

- Keeping the consistency of the specific term's usage throughout the report.
- Rephrasing and breaking down sentences and paragraphs to have a better flow and read well.
- Updating the information/stats provided to reflect the current situation on the GB network.
- Providing more clarification on some points to avoid readers guessing.
- Upgrading the quality of some graphs.

Most points raised by SSE were addressed which helped elevating the state of the Phoenix CDR report; with the exception of some points regarding the quality of few graphs, which could not be replaced due to their original forms being unavailable at the time.

The email below is the confirmation from SSE regarding the clarity and sufficiency of the Phoenix CDR report in line with the requirements of the NIC funding governance arrangements.

Scottish & Southern Electricity Networks
TRANSMISSION

POWER CUT? CALL 105

Contact us 0800 300 999

SSEN Transmission
1 Waterloo Street
Glasgow
G2 6AY

Ross Davison
Senior Innovation Engineer
SP Energy Networks
320, St Vincent Street
Glasgow
G2 5AD
Ross.davison@spenergynetworks.com

Date: 15/04/2022

Dear Ross,

Phoenix – Close Down Report – TNO Peer Review

Further to your request for SSEN Transmission to review and comment on the Close-Down Report produced with respect to SP Energy Networks Phoenix, NIC funded project, I can confirm that we have undertaken this review and consider that the objective and deliverables as agreed in the Project Direction have been satisfied by SP Energy Networks.

In addition, subject to the requirements of the NIC funding governance arrangements, we can confirm that we consider that the Close-Down Report as reviewed by SSEN Transmission is clear and understandable and contains sufficient detail and information to enable a TNO, not closely involved with the project, to make use of the learning generated to implement their own network solution.

Should you wish to discuss anything further or have any additional requirements that you need to address in respect to the Phoenix project, please do not hesitate to contact me.

Your sincerely,

[redacted]

Alan Ritchie
Innovation Delivery Manager
alan.ritchie2@sse.com

Appendix C – Live trial testing results summary

C.1 Operational Modes and Tested Cases

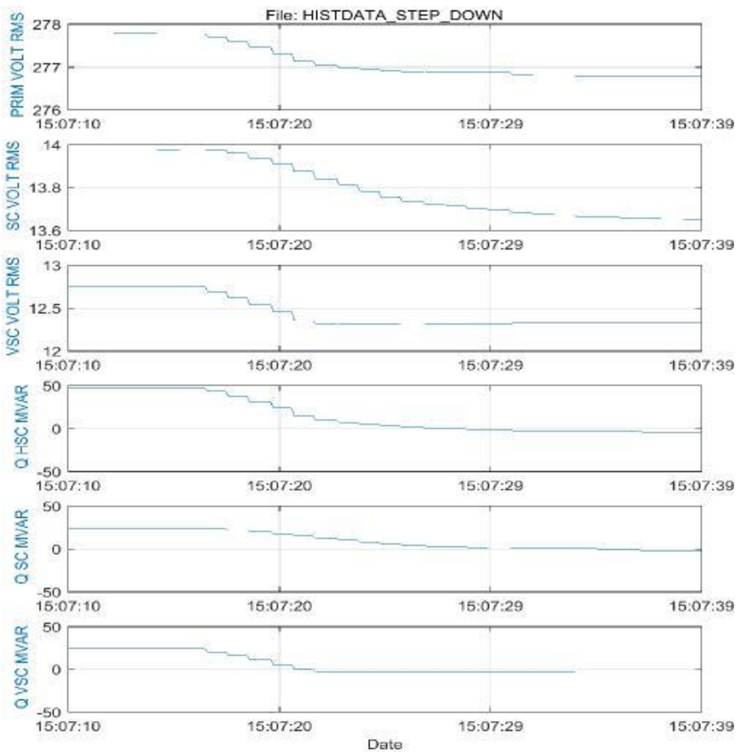
This section summarises key results and conclusions of tested cases for the different operational modes of H-SC during Live Trial Plan execution. Note, the full suite of live trial tests is provided in "Report on extended live trial and recommendations for future installations" report (available upon request).

C.1.1 Hybrid Operation of STATCOM and SC

This section presents plots of signals that were recorded during the performance of tests to assess H-SC operation with both STATCOM and SC in service.

Mode 1: STATCOM & SC in V control mode

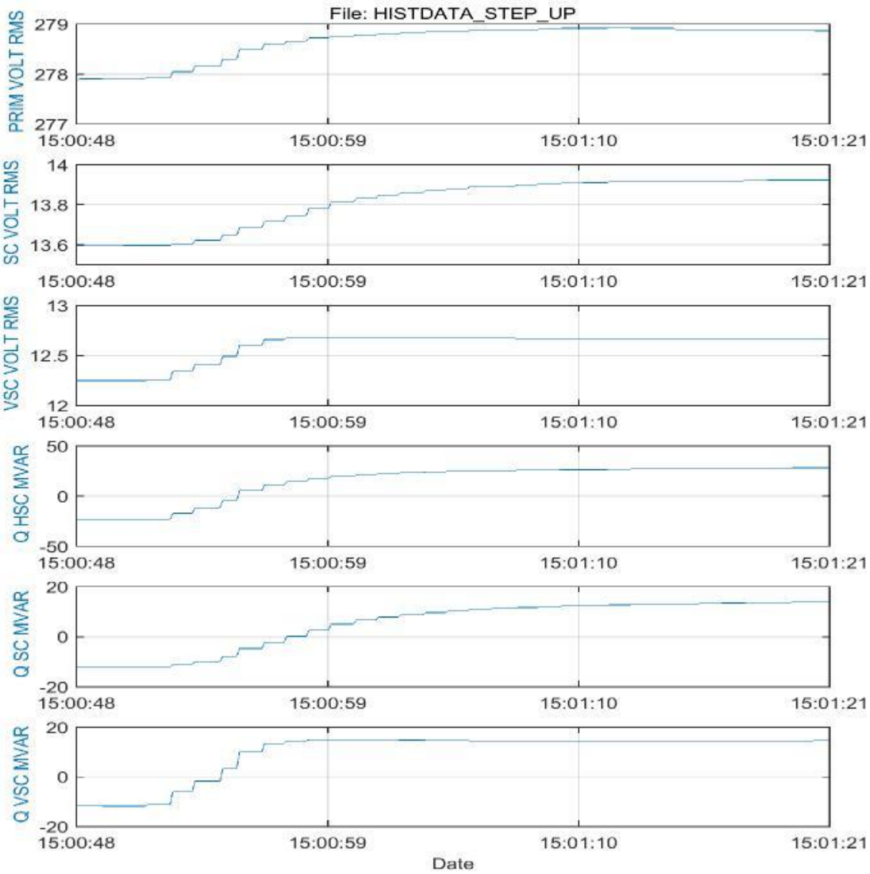
Case 1: Change in voltage setpoint - down



Time	**2nd November 2020, 15:07 (CET)** [13]
Control Mode and Settings	**STATCOM and SC in voltage control,** [14]
Steps	**Change of H-SC voltage setpoint from 1 to 0.98 pu** [14]
Key observations	• **H-SC reaches a stable steady state after voltage setpoint change** • **H-SC voltage reaches the new steady state within 10-12 s** • **H-SC reactive power ramps down from 50 MVAr to 0 MVAr** • **SC response is relatively slower compared to STATCOM due to higher time constant** • **STATCOM & SC have equal sharing of reactive power due to their identical slopes**

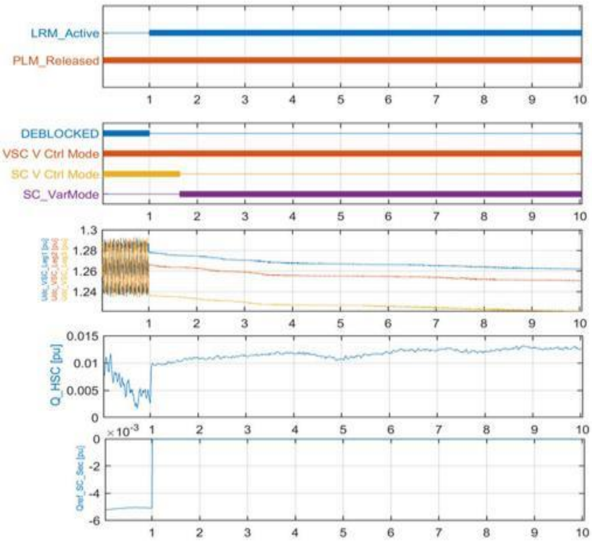
Conclusions	• **STATCOM and SC respond to voltage setpoint change as expected** • **H-SC has a stable operation during the performance of the test** • **The step time is around 10-12 s and the main delay comes from the communication of the setpoint and ramp rate limiter.**

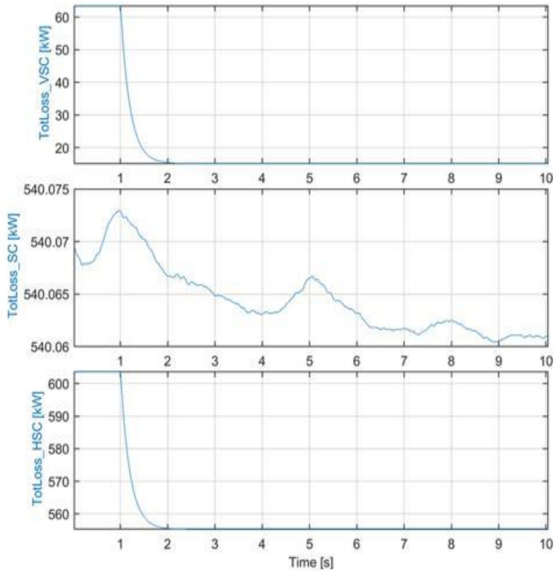
Case 2: Change in voltage setpoint – up



Time	5th November 2020, 15:00 (CET) [13]
Control Mode & Settings	STATCOM & SC in V control [14]
Steps	Change of H-SC voltage setpoint from 1.01 to 1.015 pu [14]
Key observations	• H-SC reaches a stable steady state after voltage setpoint change • H-SC voltage reaches the new steady state within 10-12 s • H-SC reactive power ramps up by 50 MVAr from -25 MVAr to 25 MVAr • SC response is relatively slower compared to STATCOM due to higher time constant • STATCOM & SC have equal sharing of reactive power due to their identical slopes
Conclusions	• STATCOM and SC respond to voltage setpoint change as expected • H-SC has a stable operation during the performance of the test • The step time is around 10-12 s and the main delay comes from the communication of the setpoint and ramp rate limiter.

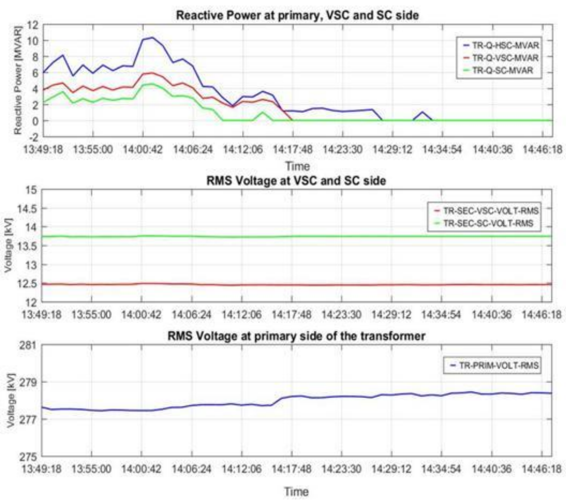
Case 3: Loss Reduction Mode (LRM-ON) test

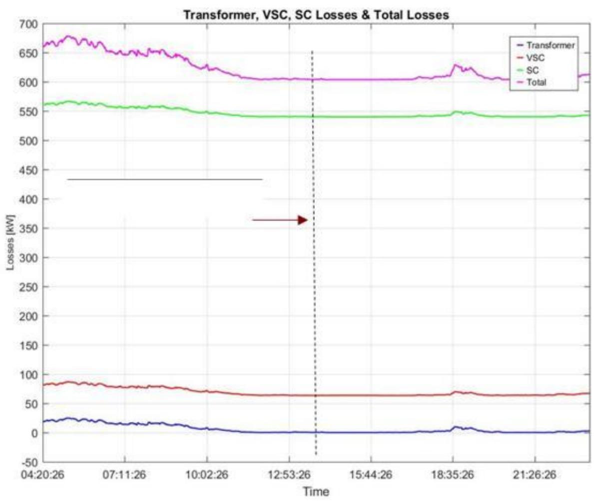




Time	**21st November 2020** [15]
Control Mode & Settings	**STATCOM & SC in V control** [14]
Steps	**Simultaneous activation of LRM + PLM** [14]
Key observations	• **STATCOM & SC operate in V control mode. STATCOM is blocked at 1 s** • **LRM was ON before 1 s but not active. PLM was active before and after 1 s** • **Both LRM & PLM are active after 1 s** • **STATCOM DC voltage ramps down slowly** • **H-SC reactive power setpoint is set equal to 0 pu at 1 s** • **H-SC reactive power reaches the new steady state staying closed to 0.01 pu** • **Total losses ramp down rapidly by 50 kW due to LRM activation**
Conclusions	• **The H-SC master control functions PLM and LRM performed as expected** • **H-SC losses are reduced with the PLM and LRM functions**

Case 4: Loss Reduction Mode (LRM-OFF) test

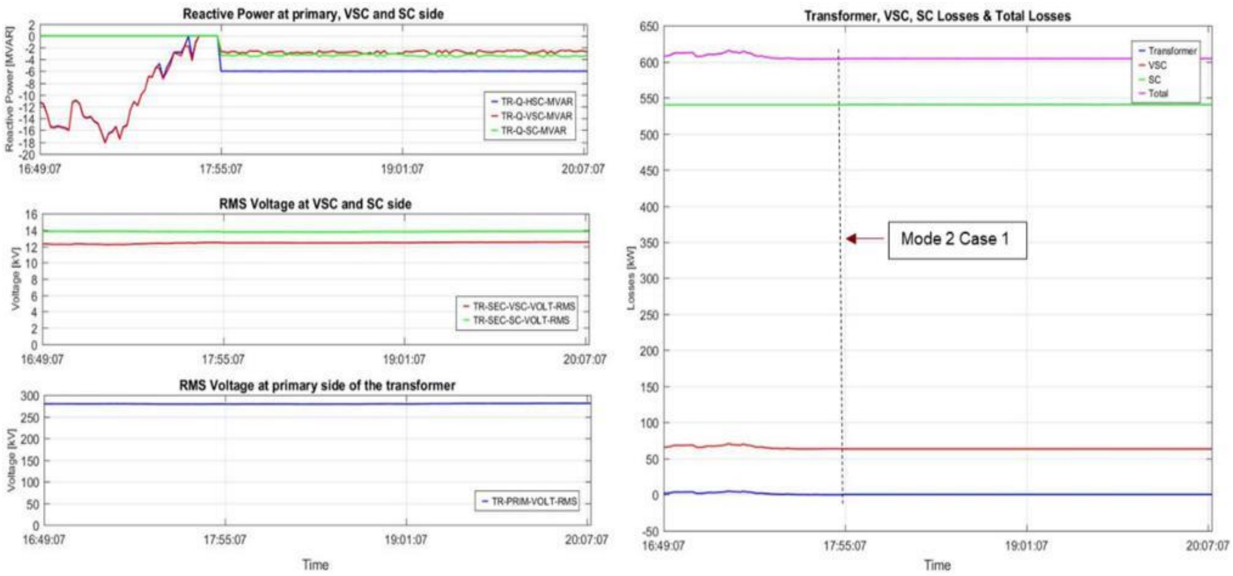




Time	**21st November 2020** [16]
Control Mode & Settings	**STATCOM & SC in V control** [14]
Steps	**Only LRM is off** [14]
Key observations	• **H-SC reactive power output becomes equal to 0 MVAr around 14:28** • **STATCOM & SC losses are stabilized at 63 kW and 540 kW** • **The total losses of the VSC, SC and transformer are 603 kW** • **Loss in SC+STATCOM** – **Case 6: LRM OFF - 600 kW** – **Case 5: LRM ON and active - 545 kW**
Conclusions	• **The deactivation of LRM in Mode 1 Case 6 resulted in higher total losses compared to Case 5** • **H-SC has a stable operation during the performance of the test**

Mode 2: STATCOM & SC in Var mode

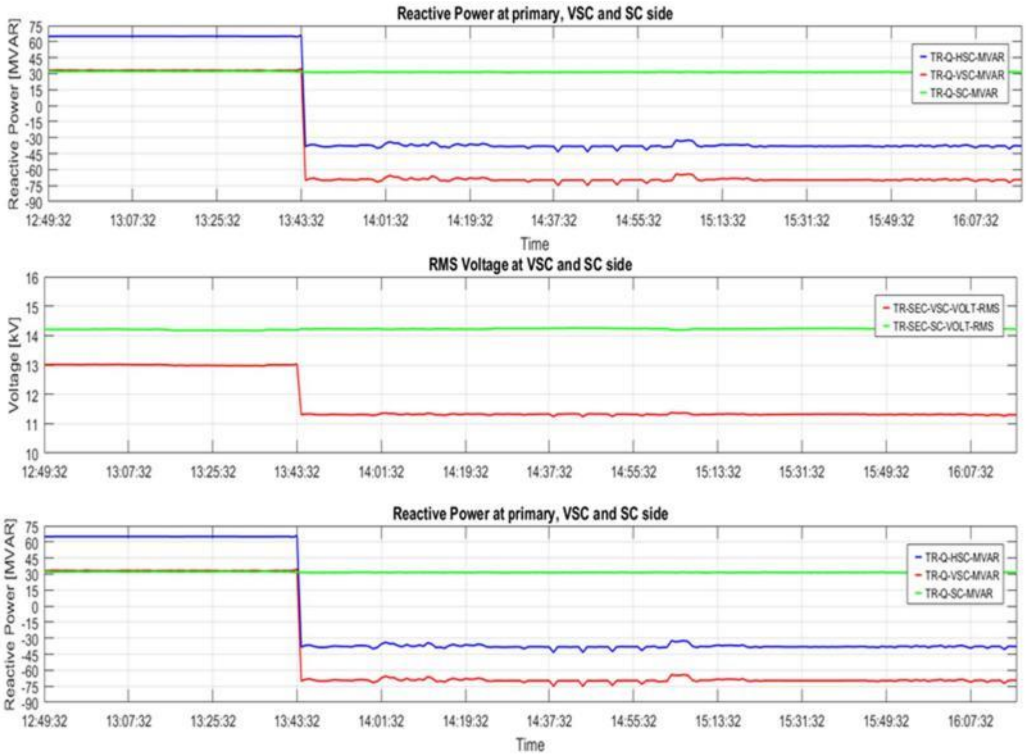
Case 1: PLM test 1 under Var control mode



Time	**4th December 2020, 17:55 (CET)** [16]
Control Mode & Settings	**STATCOM & SC in VAr control, Qref =6 MVAr & PLM ON** [14]
Steps	• **Set different Q setpoint to STATCOM and SC** • **Turn on PLM** [14]
Key observations	• **At 17:53, STATCOM & SC Q reference change and PLM is ON** • **STATCOM and SC losses are minimized at 63,4 kW and 540 kW** • **The total losses of STATCOM, SC and transformer are 604 kW**
Conclusions	• **The test has not been performed in accordance with the specifications** • **The aim was to set non-zero reference for STATCOM reactive power output and zero SC before turning on PLM to investigate the impact of the power loss minimization function** • **H-SC has a stable operation during the performance of the test**

Internal Use

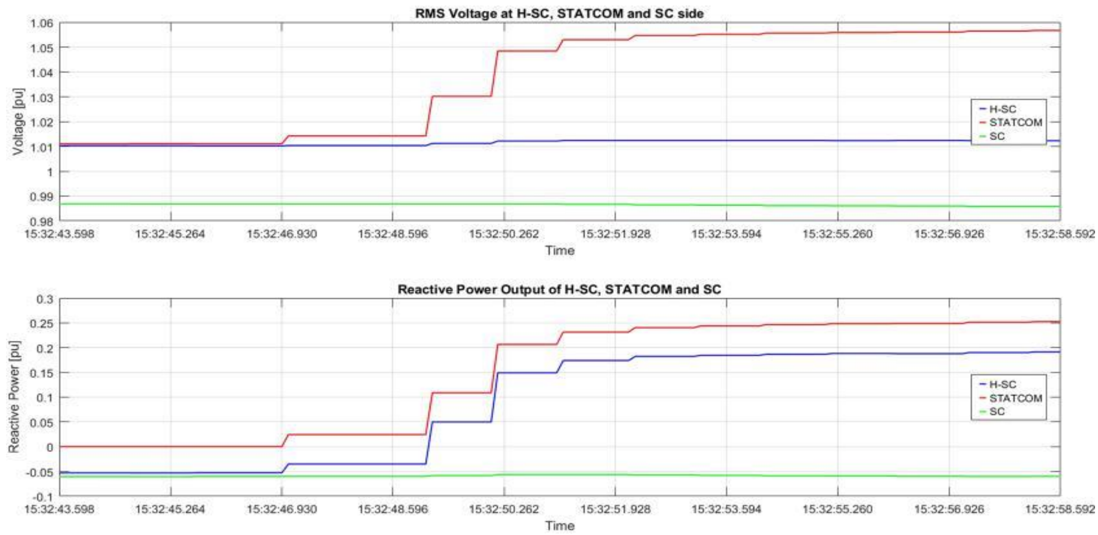
Case 2: Change of STATCOM operation mode from Var to V control



Time	**21st December 2020, 13:43 (CET)** [16]
Control Mode & Settings	**STATCOM & SC in VAr control** [14]
Steps	• **Change of STATCOM operation mode from VAr to V control**
Key observations	• **At 13:43 STATCOM control mode changes from VAr to V control** • **STATCOM voltage is reduced after the mode change due to a setpoint change** • **TFR data shows the new control mode state (see Appendix)**
Conclusions	• **The test verifies the correct performance of the mode change** • **H-SC has a stable operation during the change**

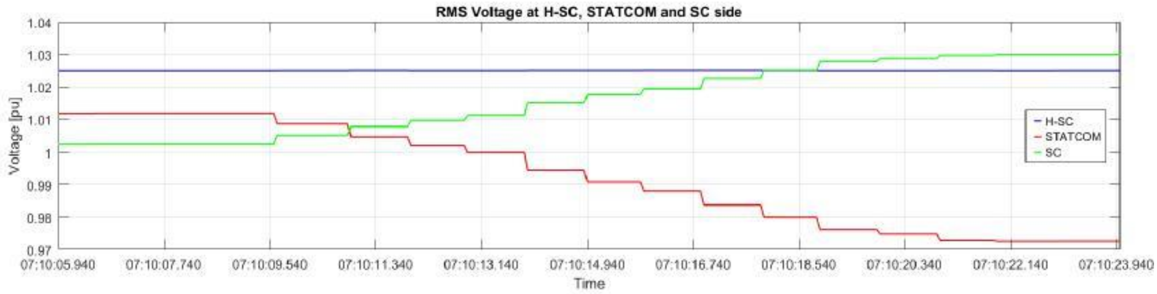
Mode 3: STATCOM in V & SC in VAr mode

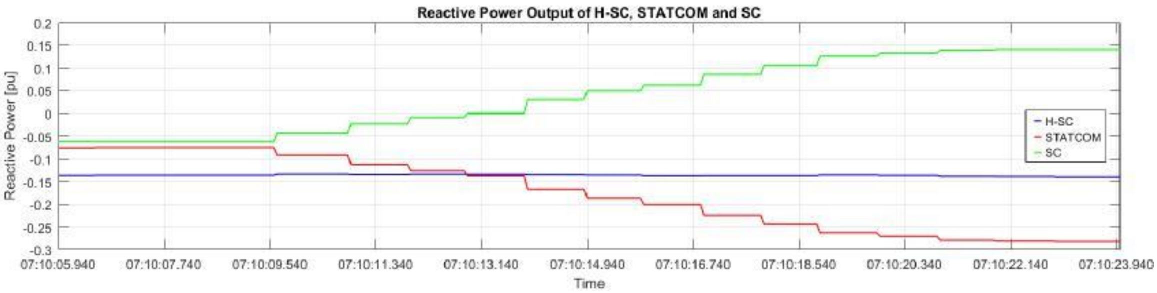
Case 1: Change in voltage setpoint of H-SC



Time	**25th March 2021, 15:32 (CET)** [17]
Control Mode & Settings	**STATCOM in V control, SC in Var control, Vref = 1.01 pu** [14]
Steps	• **Change of H-SC voltage setpoint** [14]
Key observations	• **H-SC voltage setpoint is set equal to 280 kV (1,02 pu) at 15:32** • **The voltage on STATCOM side starts increasing at 15:32:46:930** • **Within 5 s, the voltage on STATCOM becomes equal to 1,055 pu (12,98 kV)** • **STATCOM injects reactive power operating in V control peaking at 0,25 pu (35 MVAr) within 5 s**
Conclusions	• **The test verifies a well performed change of the voltage setpoint at H-SC side** • **H-SC has a stable operation during the performance of the test**

Case 2: Change reactive power setpoint of SC

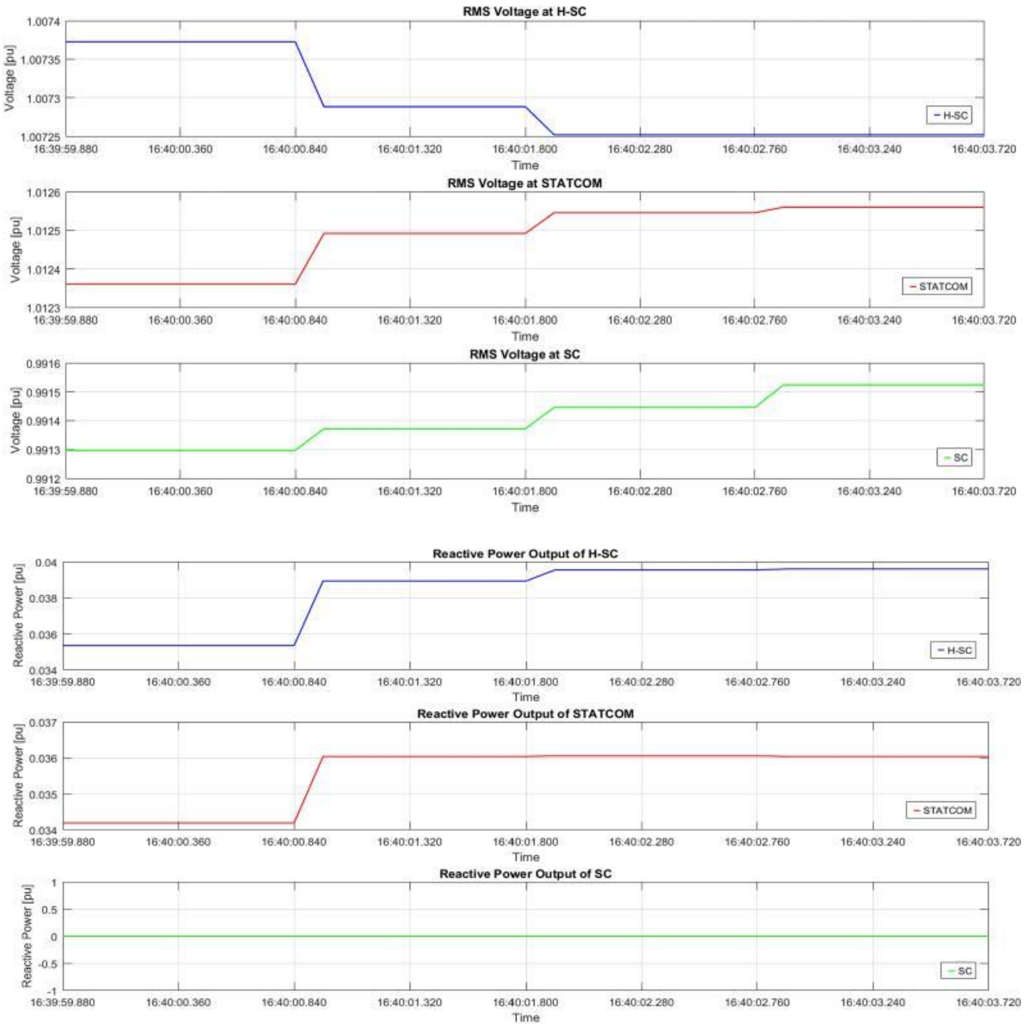




Time	**27th March 2021, 07:10 (CET)** [17]
Control Mode & Settings	**STATCOM in V control, SC in Var control** [14]
Steps	**Change of SC reactive power setpoint** [14]
Key observations	• **SC operates in VAr control mode** • **SC reactive power setpoint is set equal to 0,143 (20 MVAr, capacitive) at 07:10** • **SC reactive power output starts increasing from -0,05 pu (7MVAr inductive, Qref = 0) at 07:10:09** • **SC reactive power output becomes equal to 0,148 pu (20,58 MVAr, capacitive) within 13 s** • **To keep the voltage at the value set, the STATCOM absorbs more reactive power**

Conclusions	• **The test verifies a well performed change of SC reactive power setpoint** • **H-SC has a stable operation during the performance of the test** • **The response of SC is slow as the ramp rate limiter for the voltage reference in the AVR had a very low setting (0.3%/s). Also, the voltage reference of SC changes according to the following equation $V_{ref,x}@13.8\ kV = V_{ref,f\_x}@275\ kV + V_{drop,xc}$. In this equation, it is shown that due to the voltage drop term, SC voltage reference is calculated as ramp and so SC follows the ramped voltage reference. Therefore, the high response time is not related to the machine speed of response but rather to the presence of ramp rate limiters with very low settings. in addition to the way how the voltage reference is calculated**

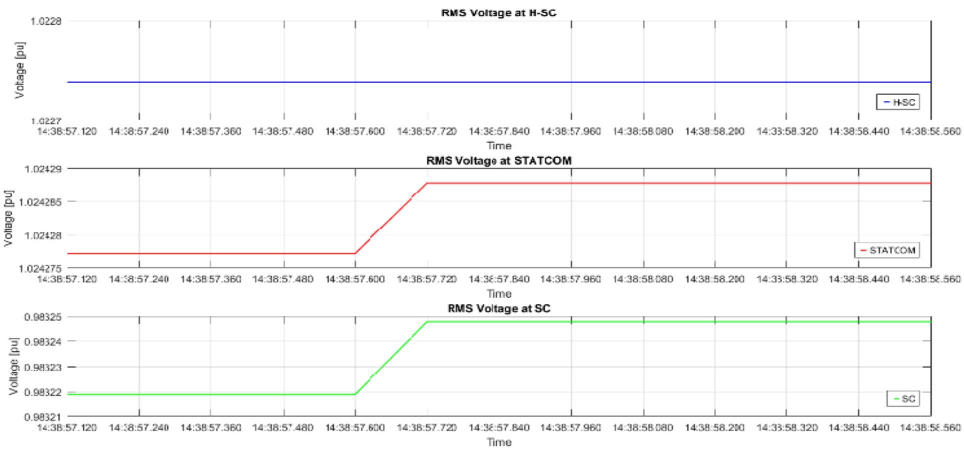
Case 3: Change of STATCOM operational mode from V to Var control

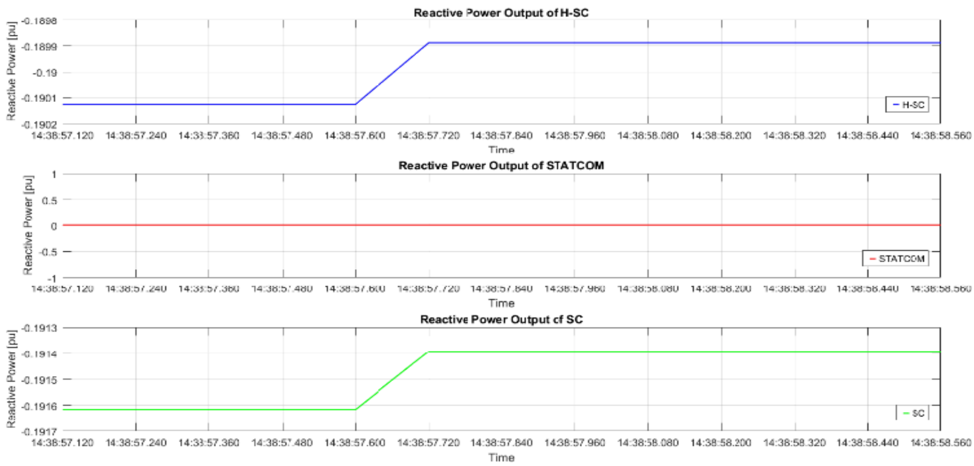


Time	**6th April 2021, 16:40 (CET)** [17]
Control M ode & Settings	**STATCOM in V control, SC in Var control** [14]
Steps	**Change of STATCOM operation mode from V to VAr control** [14] **Change of STATCOM setpoint**
Key observations	• **STATCOM control mode is changed at 16:40 (CET)** • **STATCOM mode change is followed by at STATCOM and SC side increase** • **The new steady state values are reached within 2 s after 16:40:00:840** • **Within the same time, the voltage at H-SC side decreases becoming equal to 277 kV (1,0073 pu)** • **STATCOM starts injecting higher reactive power** • **The reactive power output of STATCOM is equal to 0,036 pu (5,04 MVAr, capacitive) and reaches the new steady state within less than 1 s** • **As expected, the changes in H-SC power and voltage are very small**
Conclusions	• **The test verifies a well performed change of the voltage setpoint at H-SC side** • **H-SC has a stable operation during the performance of the test**

Mode 4: STATCOM in Var & SC in V mode

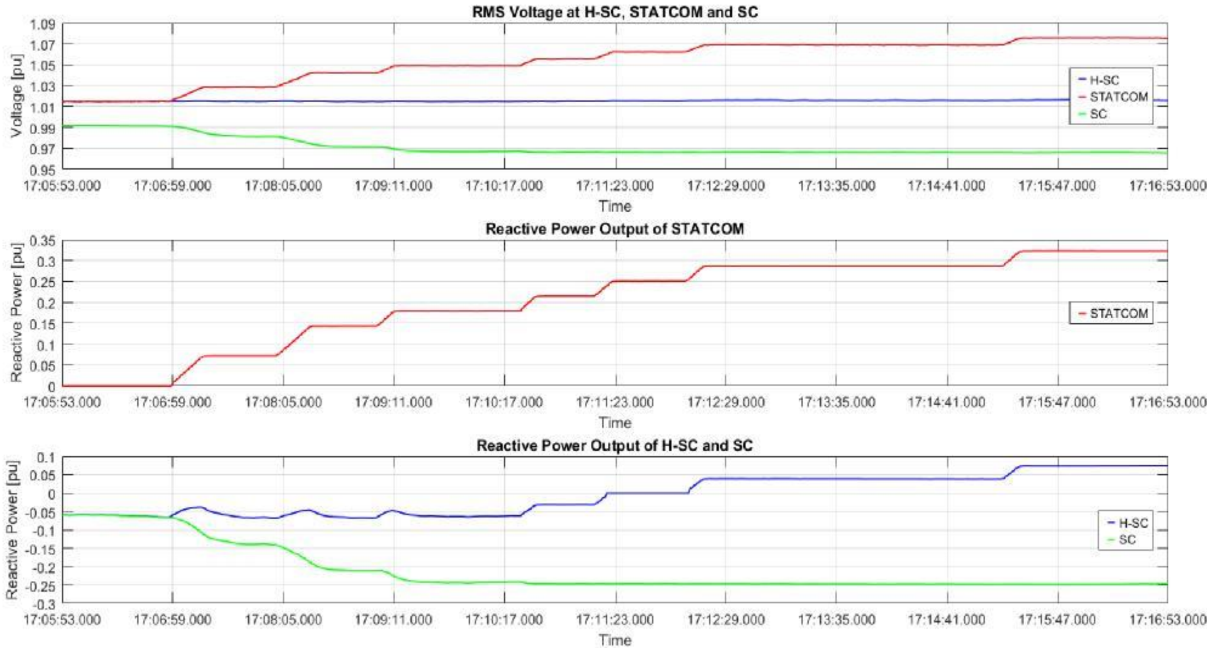
Case 1: Change of H-SC setpoint





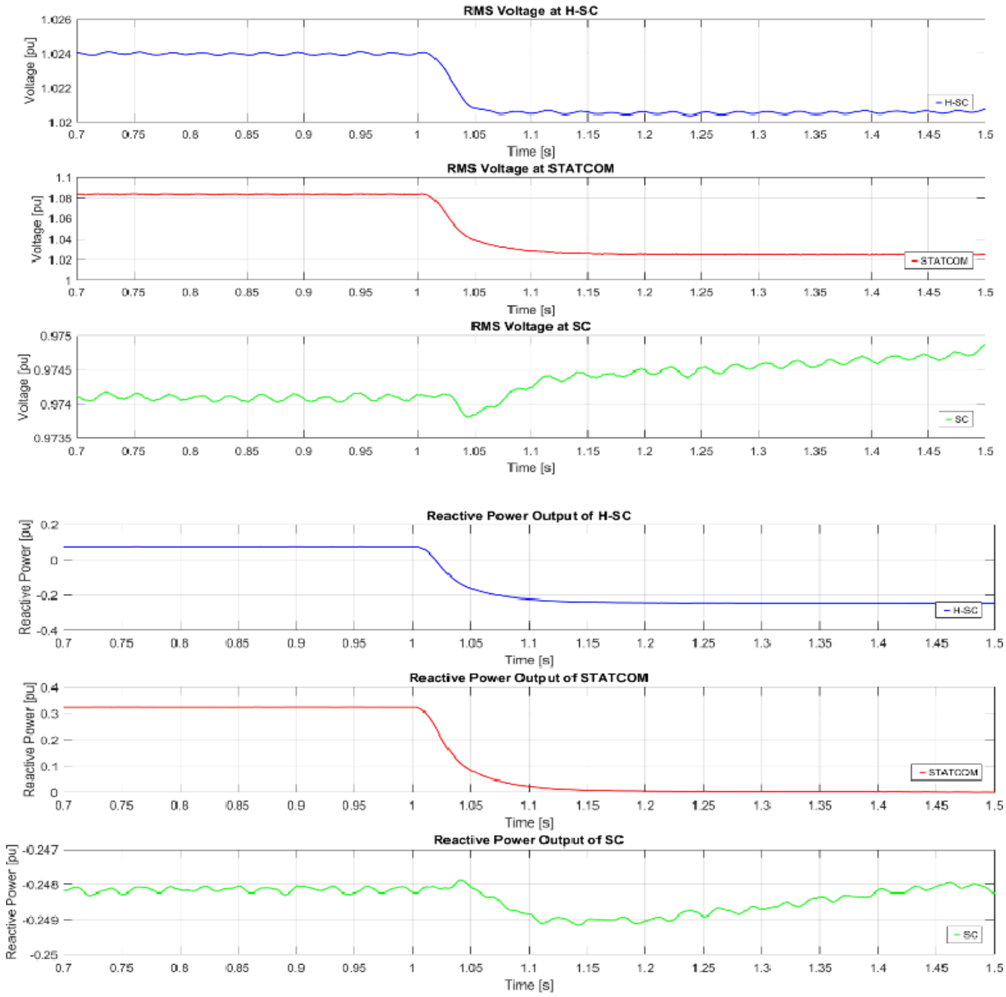
Time	17th April 2021, 14:38:57 (CET) [17]
Control Mode & Settings	STATCOM in Var control, SC in V control [14]
Steps	Change of H-SC voltage setpoint [14]
Key observations	• At 14:38:57 H-SC voltage setpoint is set equal to 280 kV (1,018 pu) • 700 ms later STATCOM and SC voltage and reactive power reach the new steady state in 120 ms • SC absorbs less reactive power due the voltage increase • STATCOM reactive power setpoint is equal to 0 • STATCOM reactive power output does not vary, as it operates in VAr control mode
Conclusions	• The test verifies a well performed change of the voltage setpoint at H-SC side • H-SC has a stable operation during the performance of the test

Case 2: Change of H-SC reactive power setpoint



Time	26th April 2021, 17:06:59 (CET) [17]
Control Mode & Settings	STATCOM in Var control, SC in V control [14]
Steps	Change of STATCOM reactive power setpoint [14]
Key observations	• STATCOM reactive power reference change is done in seven steps from 0 to 45 MVAr with duration of 2 min between consecutive steps • The first change of STATCOM reactive power setpoint occurs around 17:06:59 • STATCOM starts injecting reactive power • STATCOM voltage ramps up stepwise from 1,015 pu to 1,076 pu • STATCOM response mainly drives the reactive power output of H-SC • SC responds to the increase of STATCOM reactive power by absorbing higher reactive power to keep the set voltage value • As the TFR for these changes in reactive power output references are not available, the dynamic performance and speed of response are not analysed
Conclusions	• The test verifies a well performed stepwise change of H-SC reactive power setpoint • H-SC has a stable operation during the performance of the test

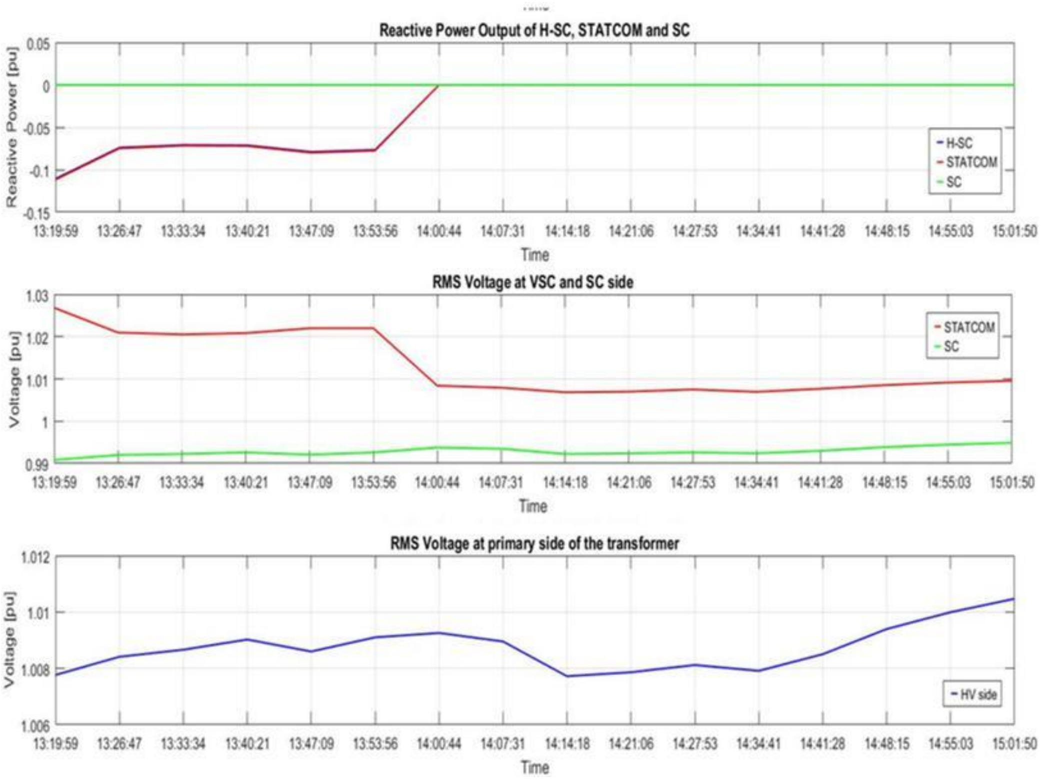
Case 3: change of STATCOM operational mode from Var to V control



Time	**29th April 2021** [17]
Control Mode & Settings	**STATCOM in Var control, SC in V control** [14]
Steps	**Change of STATCOM operation mode from VAr to V control** [14]
Key observations	• **At 1 s, STATCOM mode changes from VAr to V control** • **STATCOM voltage decreases from 1,08 pu to 1,02 pu within 100 ms, after 1 s due to voltage set-point change** • **Setpoint of STATCOM reactive power output is set equal to 0** • **STATCOM reactive power goes to 0 within 100 ms** • **H-SC voltage decreases and SC voltage that operates in V control stays closed to its initial voltage** • **SC only contributes to H-SC reactive power output operating in the inductive area**
Conclusions	• **The test verifies a well performed change of STATCOM mode change** • **H-SC has a stable operation during the performance of the test**

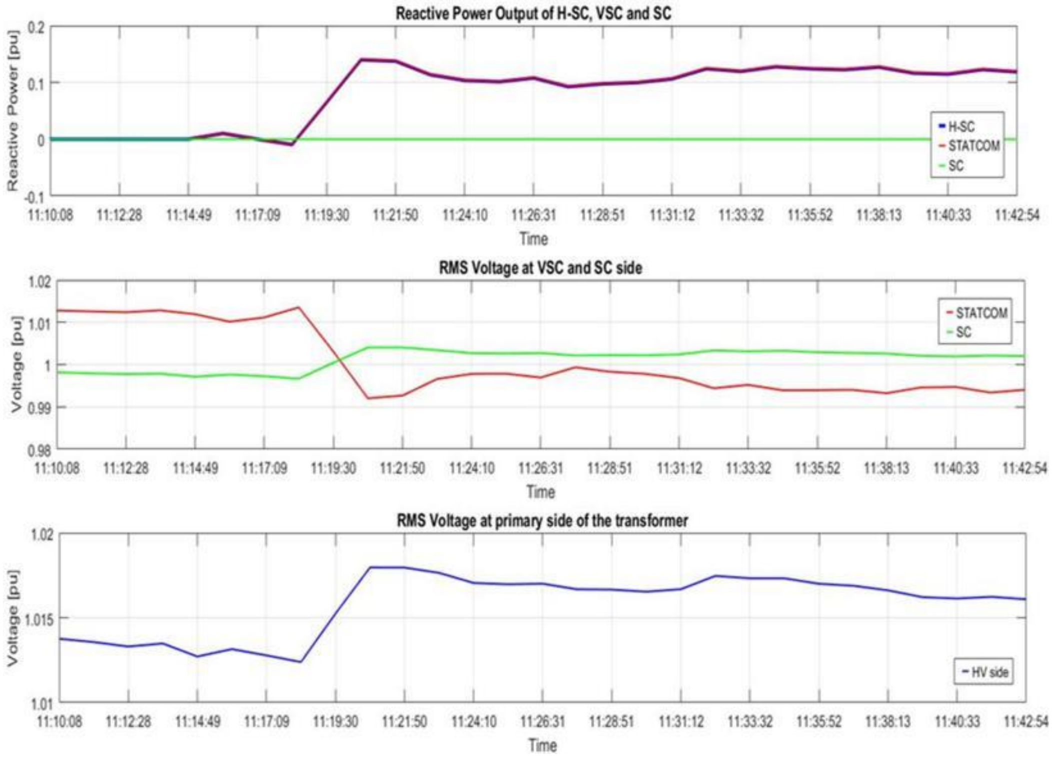
Mode 5: Only STATCOM in service

Case 1: Change of STATCOM operation mode from V to Var control



Time	**3rd February 2021, 13:54 (CET)** [18]
Control Mode & Settings	**STATCOM in V control mode** [14]
Steps	• **Change of STATCOM operation mode from V to Var control** [14] • **Change of STATCOM reactive power setpoint to 0** [14]
Key observations	• **At 13:54, the operation mode of STATCOM is changed from V to VAr control mode** • **Next Q setpoint is set equal to 0** • **Before 13:54, STATCOM injects reactive power, as the voltage at its side in pu is higher than the voltage in pu at H-SC side**
Conclusions	• **The test verifies the correct performance of the mode change** • **H-SC has a stable operation during the change**

Case 2: Change of STATCOM operation mode from Var to V control

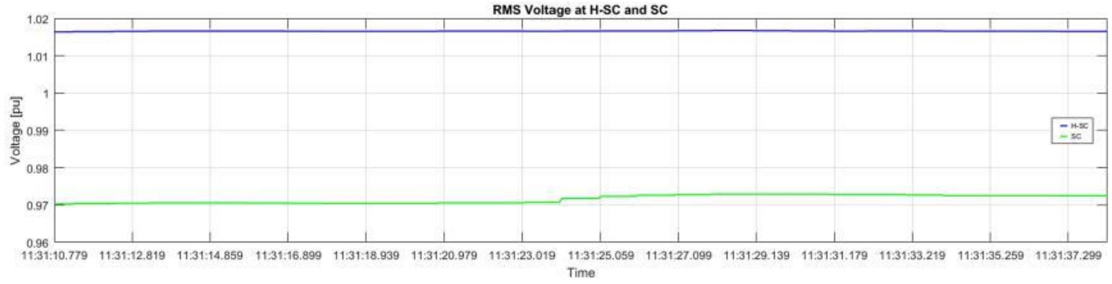


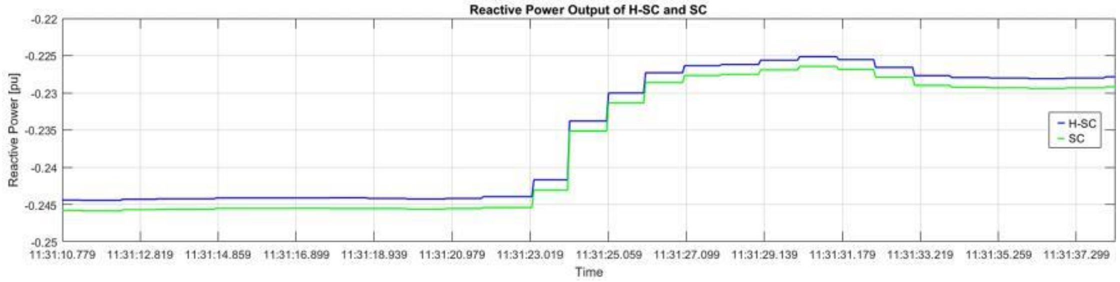
Time	**8th February 2021, 11:15 (CET)** [18]
Control Mode & Settings	**STATCOM in VAr control mode** [14]
Steps	• **Change of STATCOM operation mode from VAr to V control** • **Change of H-SC voltage setpoint** [14]
Key observations	• **At 11:15, the operation mode of STATCOM changes from VAr to V control mode** • **H-SC voltage setpoint took place between 11:17:09 and 11:19:30** • **STATCOM absorbs reactive power as response to voltage increase at primary side** • **TFR data shows the change of STATCOM control mode (see Appendix)**
Conclusions	• **The test verifies the correct performance of the mode change** • **H-SC has a stable operation during the change**

Internal Use

C.1.2 Only SC in Service

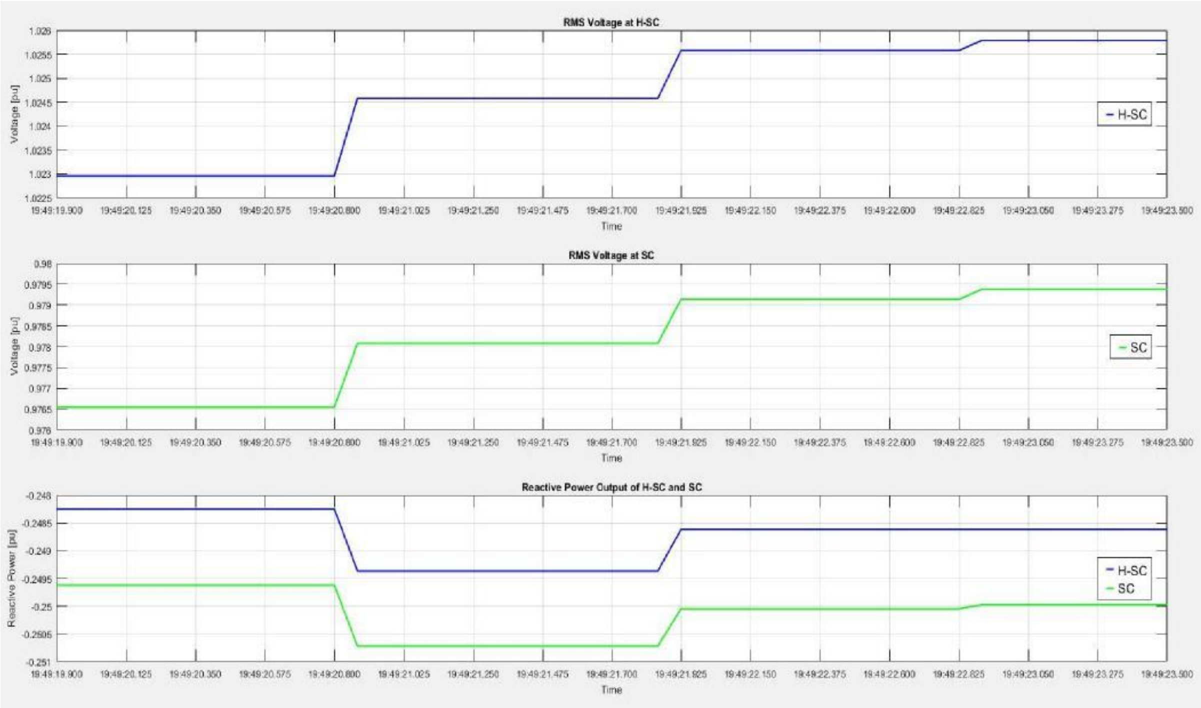
Case 1: Change of SC operation mode form Var control





Time	**11th May 2021, 11:31 (GMT)** [19]
Control Mode & Settings	**SC in V control mode** [14]
Steps	• **Change of SC operation mode from V to VAr control** [14] • **Change of SC reactive power setpoint to 32 MVAr**
Key observations	• **VAr control mode is selected for SC at 11:31:14** • **At 11:31:22 H-SC reactive power setpoint changes to 32 MVAr, inductive (-0,228 pu)** • **SC operating in VAr control mode absorbs lower reactive power with its peak being equal to 31,64 MVAr inductive (-0,226 pu)** • **Within 3-4 s, SC reactive power rises to -0,226 pu (31,64 MVAr inductive)** • **The new set value of H-SC reactive power is reached in approximately 10 s after its change** • **The voltage on SC side does not change during the performance of Case 1 staying closed to 0.97 pu and always lower than the voltage in pu on H-SC side (~ 1.01 pu).**
Conclusions	• **The test verifies the correct performance of the mode change** • **H-SC has a stable operation during the change**

Case 3: Change of network structure with SC in V control mode



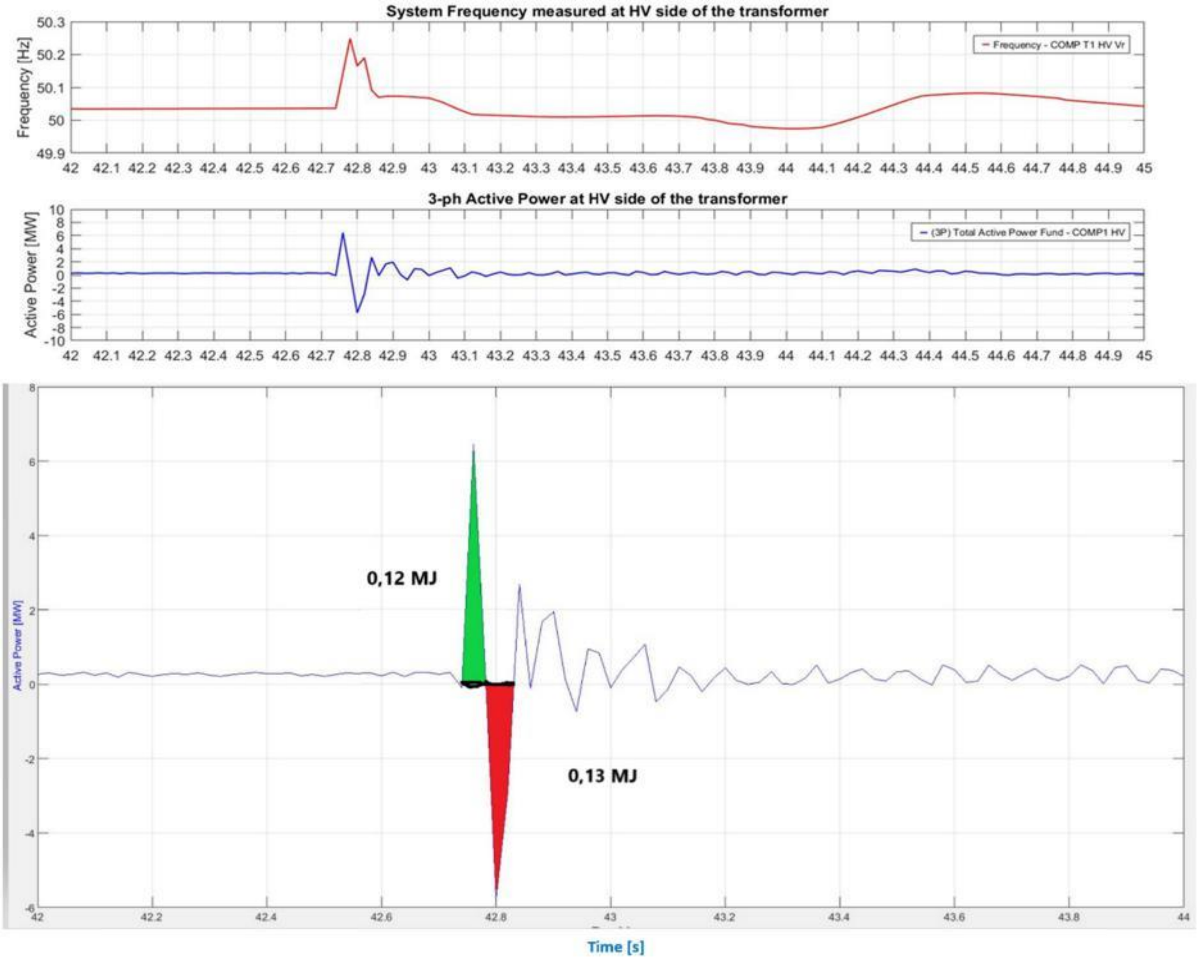
Time	**14th May 2021, 19:49 (GMT)** [19]
Control Mode & Settings	**SC in V control mode** [14]
Steps	**Allow a network switching event close to H-SC**
Key observations	• **The switching event is referred as “Event 11 - EKIS-NEIL reconnected”** • **SC is in V control mode at the time of event** • **H-SC voltage increases from 1,023 pu to approximately 1,0245 pu in approximately 2 s** • **SC responds absorbing more reactive power from 34,93 MVAr (-0,2495 pu) to 36 MVAr (-0,2508 pu)** • **SC reactive power output is stabilized at 35 MVAr (-0,25 pu)** • **More tests are planned to validate SC response time, as its performance cannot be evaluated completely due to the small changes**
Conclusions	• **SC responded to the event as expected** • **SC provided voltage control**

Internal Use

C.2 Unplanned Events

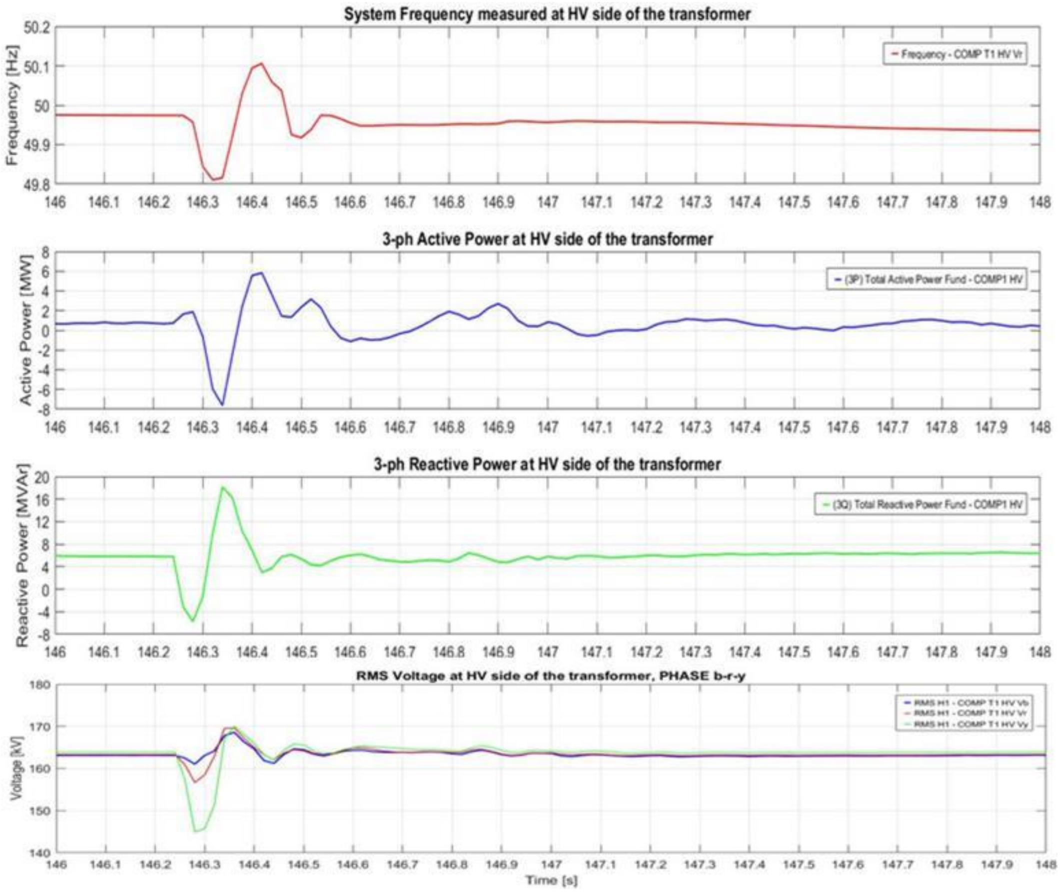
This chapter presents H-SC response to events that occurred during the performance of Live Trial Plan. However, over this period there were more unexpected occurrences that required H-SC to respond accordingly, and the results have been included in the monthly reports. The following events constitutes a representative sample of the unanticipated cases, as many of them were of the same nature having very similar impact on H-SC behaviour.

C.2.1 H-SC Response Due to External Fault



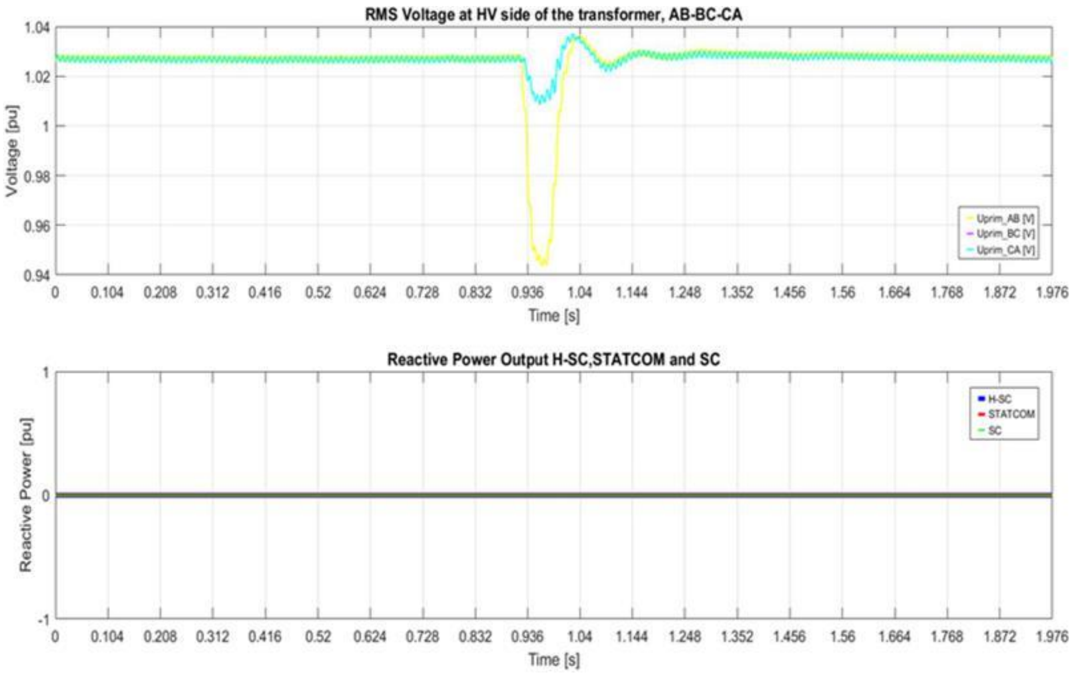
Time	**3rd December 2020** [16]
Control Mode & Settings	**Only STATCOM is in service** [4]
Type	**H-SC response due to external fault**
Key observations	• **System frequency disturbance occurs due to external fault** • **Active power is injected from STATCOM and its peak is around 5 ms** • **STATCOM absorbs positive energy that is dissipated during the negative swing of the frequency** • **This is presented not for inertia support (as the energy is small) rather the effectiveness of STATCOM to absorb and then dissipate energy during over**
Conclusions	• **An HVDC link response due to external fault leads to a frequency disturbance** • **H-SC responds as expected to the disturbance**

C.2.2 275kV Network Fault



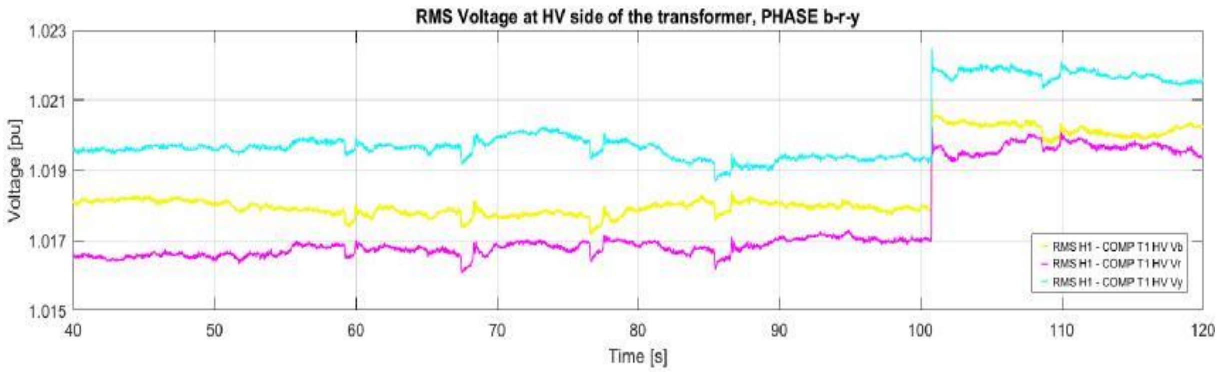
Time	**5th December 2020** [16]
Control Mode & Settings	**Full H-SC in service** [4]
Type	**275 kV Fault (East Scotland)**
Key observations	• **System frequency disturbance occurs due to external fault** • **Active power is injected from H-SC reaching its peak within 50 ms** • **Reactive power is injected from H-SC reaching its peak within 80 ms STATCOM absorbs more reactive power as response to voltage increase**
Conclusions	• **An external grid fault leads to a frequency disturbance** • **H-SC provided inertial and voltage support by injecting active and reactive power** • **H-SC responds as expected to the disturbance**

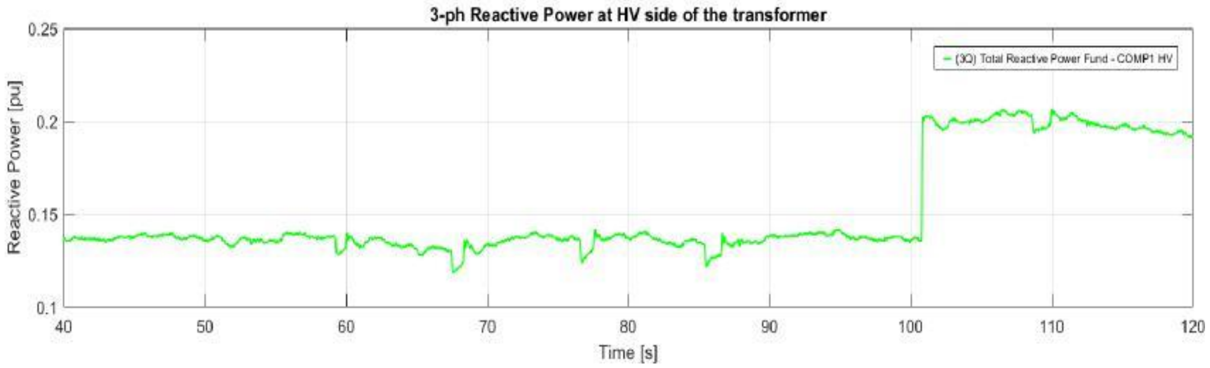
C.2.3 132Kv Network Fault



Time	**4th February 2021** [18]
Control Mode &Settings	**Only STATCOM is in service** [4]. **STATCOM operates in VAr control**
Type	**132kV Network Fault**
Key observations	• **The voltage at primary side drops below its reference value** • **Voltage is stabilized again around its initial value (1,01 pu) after 200 ms** • **STATCOM does not react to the fault, as it operates in reactive power control mode** • **If STATCOM had been in V control, then it would have responded by injecting Q to support the voltage drop due to the fault.**
Conclusions	• **A fault at 132 kV network causes a voltage disturbance at H-SC side** • **H-SC responds as expected to the disturbance**

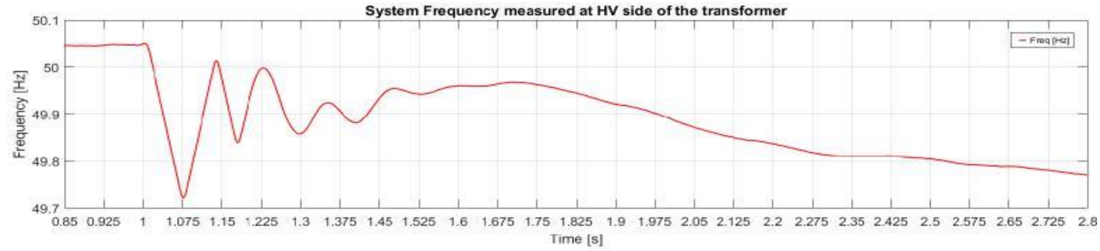
C.2.4 Shunt Reactor Switched Out

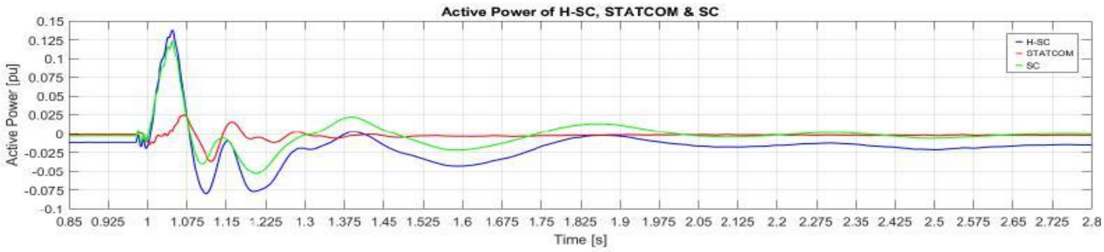


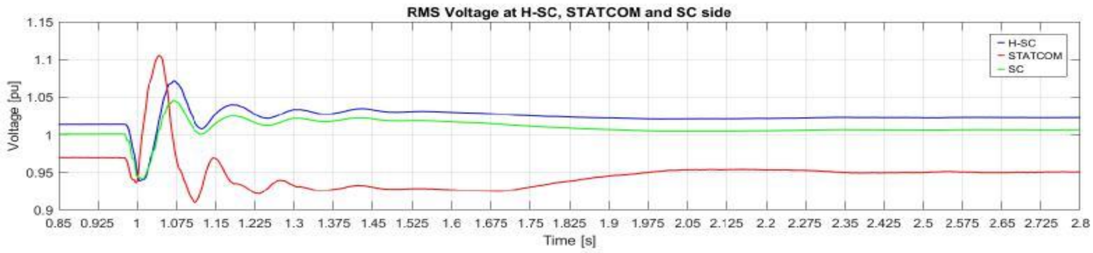


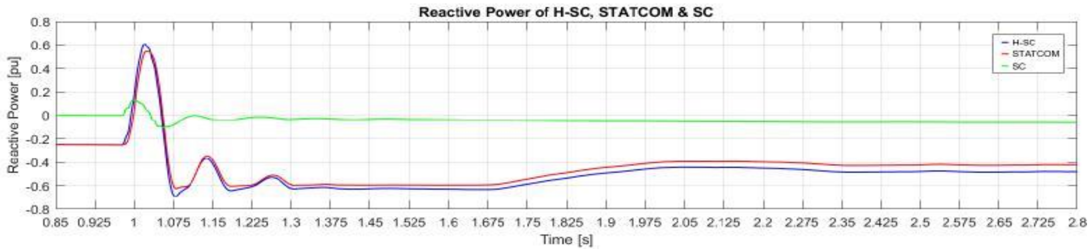
Time	**9th February 2021** [18]
Control Mode & Settings	**Only STATCOM is in service and V control, Vref=1.02 pu** [4]
Type	**Shunt Reactor switched OUT**
Key observations	• **The phase to ground voltages on the HV side of the transformer step up** • **Increase of the reactive power absorbed by the H-SC** • **STATCOM is not in reactive power control.**
Conclusions	• **A switching event of shunt reactor causes a voltage step at H-SC side** • **H-SC responds as expected to the disturbance**

C.2.5 Trip & DAR of a circuit in North Scotland



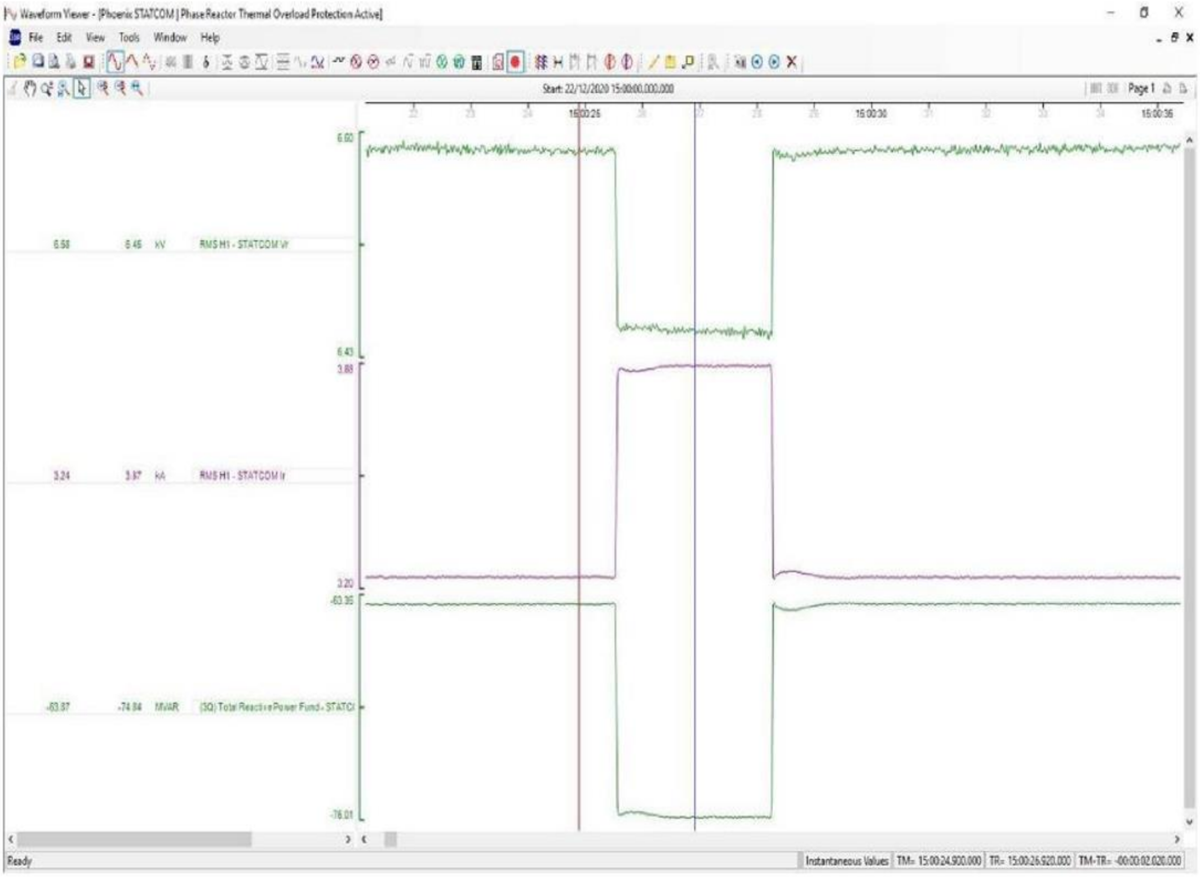






Time	**4th April 2021** [17]
Control Mode & Settings	**Full H-SC is in service** [4], **Vref= 1.0 & Qref= 0**
Type	**Trip & DAR of a circuit in north Scotland causing 800MW loss**
Key observations	• **Trip leads to a frequency disturbance at 1s** • **Frequency oscillates for 375 ms and stabilizes around 49,73 Hz** • **H-SC injects active power that reaches its peak (19.6 MW) in 47 ms** • **Active power contribution from SC is higher than STATCOM** • **Due to the event, voltage variations are observed** • **STATCOM reactive power oscillates responding to voltage variations** • **STATCOM injects reactive power that reaches its peak (77 MVAr) in 47 ms** • **SC operating in VAr control stays closed to its fixed reactive power value**
Conclusions	• **SC has provided inertial support** • **STATCOM in V control has provided voltage support to H-SC during and after the event**

C.2.6 Phase Reactor Thermal Overload Protection



Time	4th April 2021 [16]
Control Mode & Settings	Full H-SC is in service [4]
Type	Phase Reactor Thermal Overload Protection
Key observations	• The injected reactive power of STATCOM steps up to -75 MVAr which is beyond 70 MVA rating • This activates the thermal overload protection • The protection function allows the STACOM to inject 1.19 pu current for 3 seconds maximum before limiting it to 1 pu for 180s or 3 minutes • Due to the continuous overload condition, the limitation of STATCOM output and release of limitation in every 3 min resulted in continuous reactive pulses • Slow MVAr settings of gain and limits have been updated to improve the impact of the function
Conclusions	Thermal overload protection performed as expected

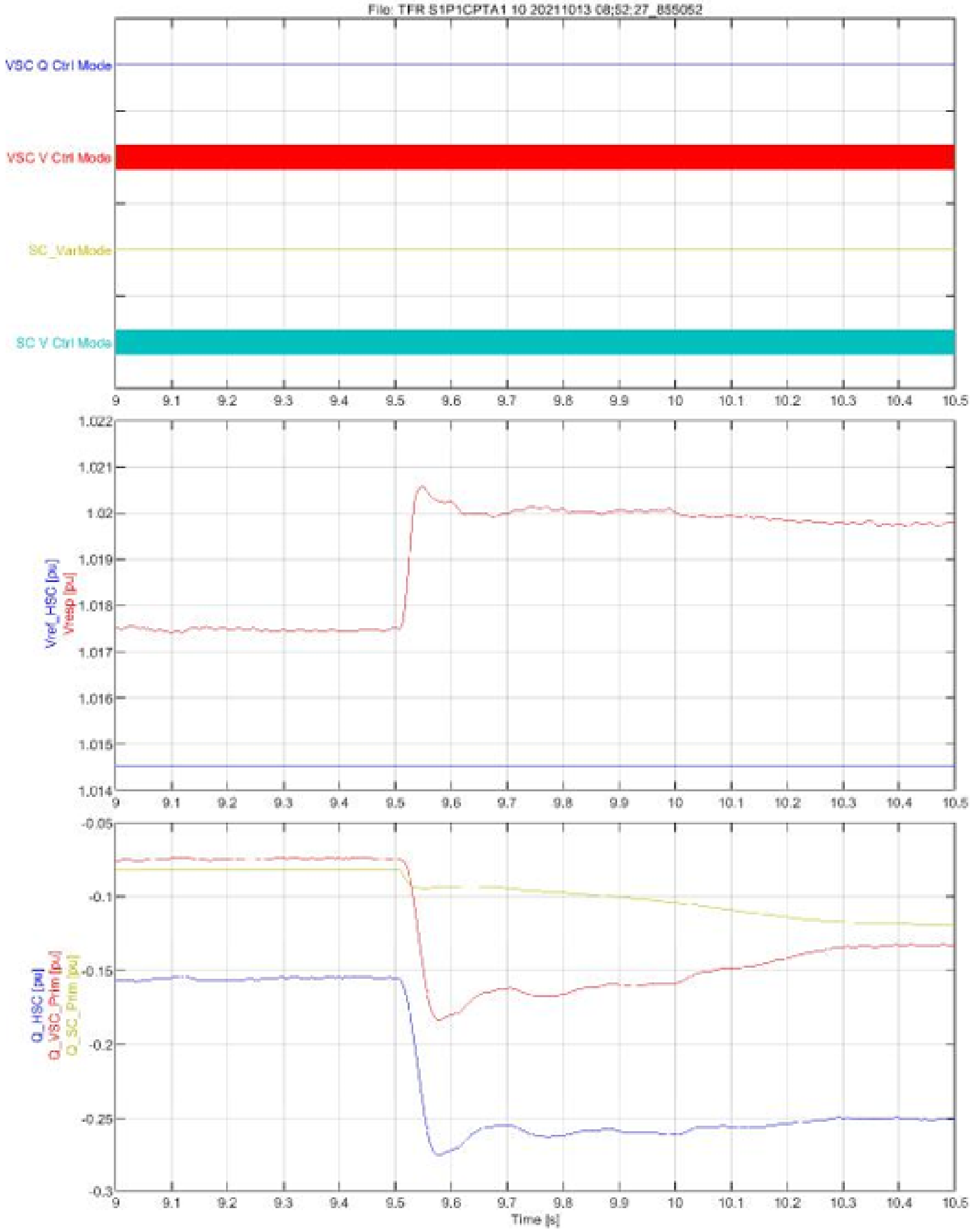
C.3 Repeated Tests

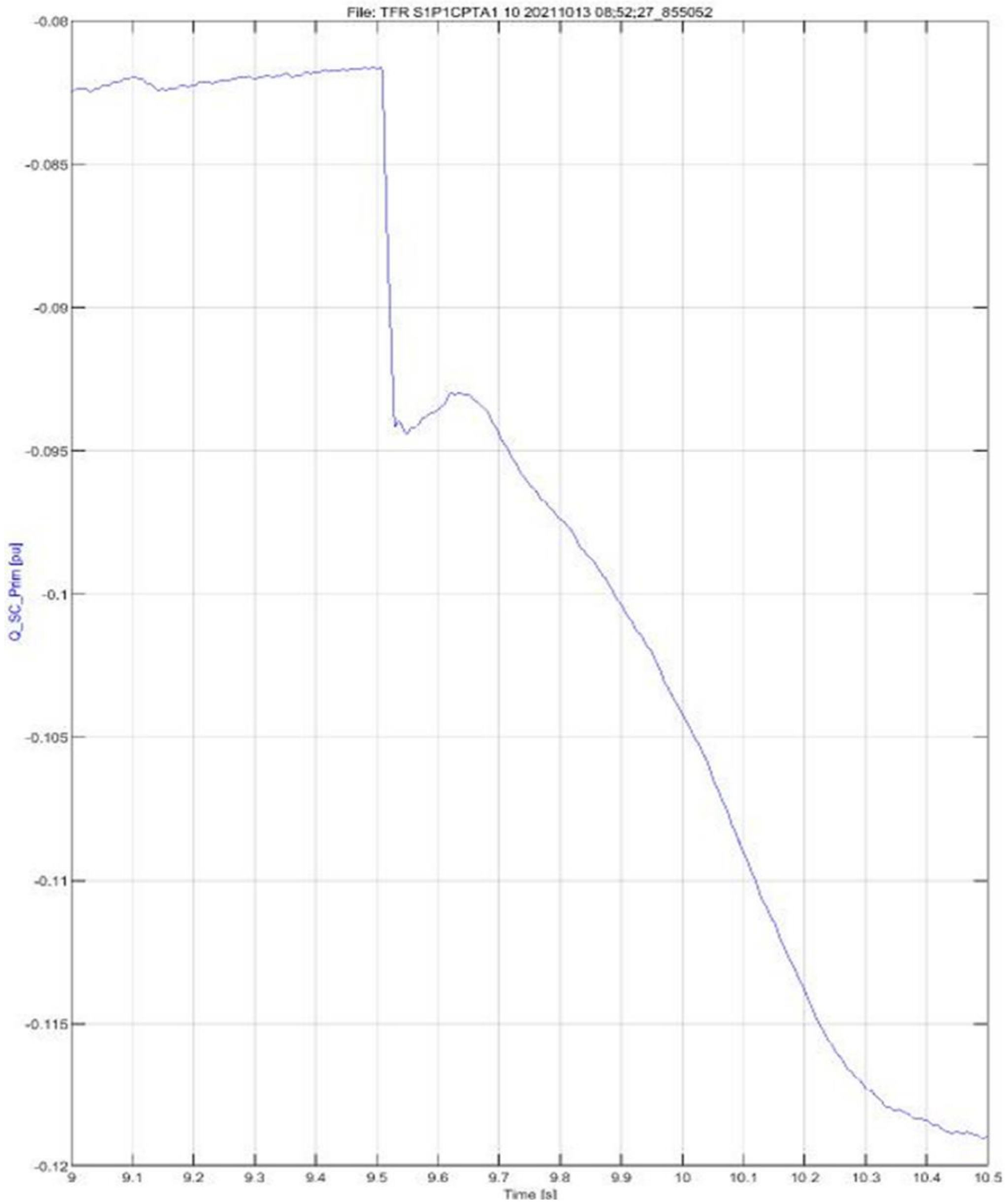
This chapter presents results of tests that had to be repeated, as they were performed in a way that did not allow a complete analysis of H-SC response. The repeated tests are listed in the following table:

Table 16 - Repeated Test Cases

Case or Event	Date / Time[2]	Name
Mode 1 / Case 3	29th July 2021 (11:27 - 11:43)	Change control mode-STATCOM
Mode 1 / Case 7	13rd October 2021 (08:52:31)	Change network structure
Mode 4 / Case 1	13rd October 2021 (09:02:33 & 09:05:09)	Change voltage setpoint of HSC
Mode 4 / Case 2	13rd October 2021 (09:20:06)	Change reactive power setpoint of HSC
Mode 4 / Case 3	29th July 2021 (13:25 - 14:46)	Change control mode STATCOM
Mode 4 / Case 4	29th July 2021 (13:46 - 14:06)	Change control mode SC
Mode 4 / Case 5	29th July 2021 (14:06 - 14:32)	Change network structure under the mode
Mode 6 / Case 3	13rd October 2021 (09:33:25)	Change network structure under the mode SC in V control

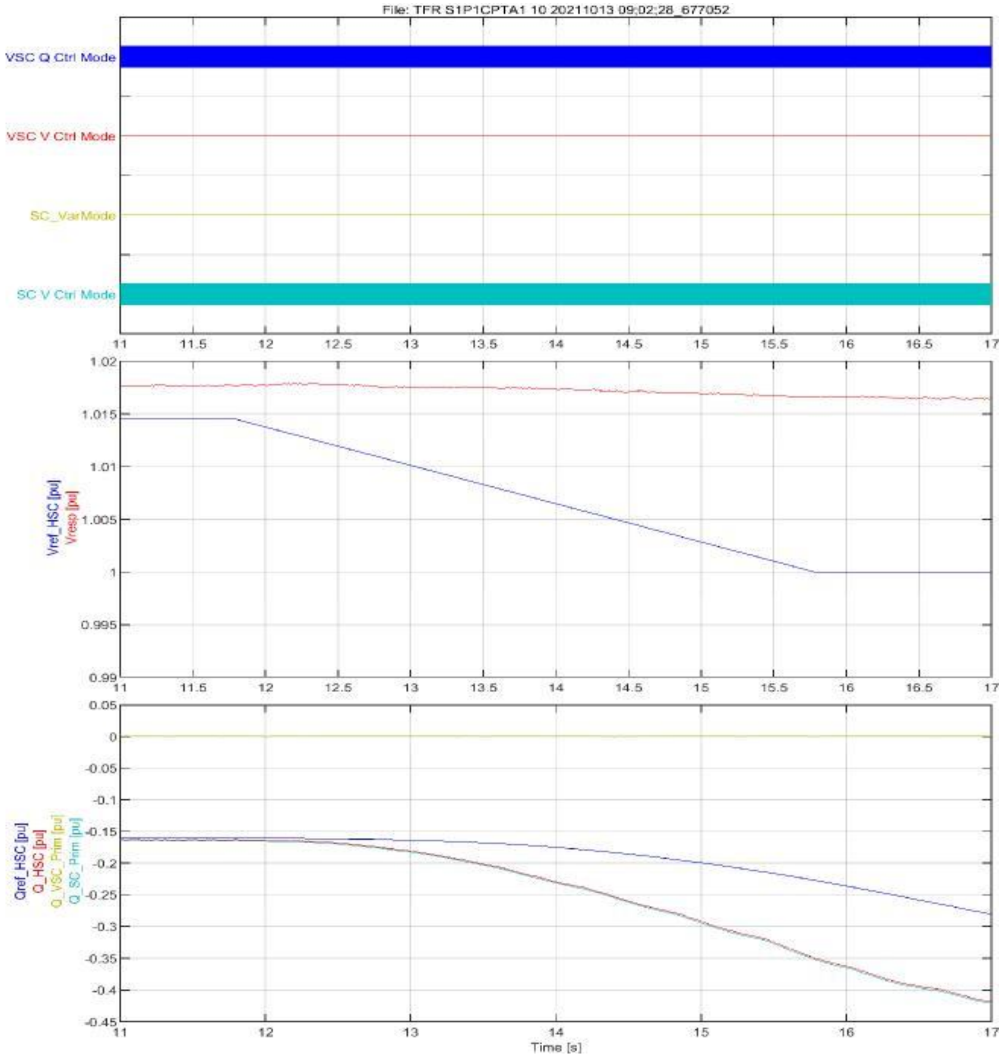
C.3.1 Mode 1 Case 7: Change Network Structure





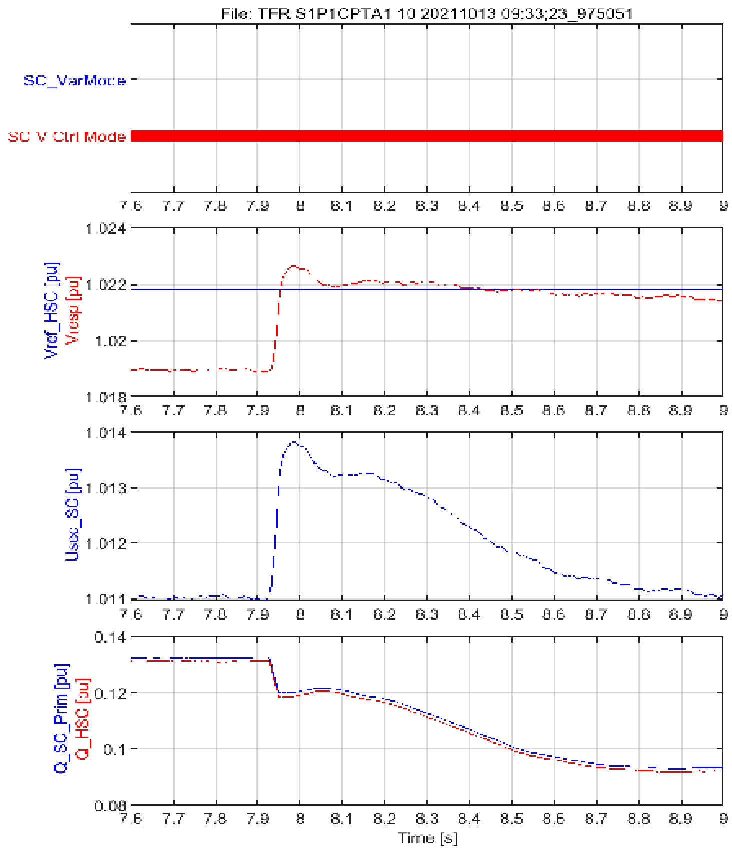
Time	**13rd October 2021, 08:52:31 (CET)** [20]
Control Mode & Settings	**STATCOM and SC operate in V control mode** [14]
Steps	• **Allow a network switching event close to H-SC** [14]
Key observations	• **Shunt reactor (R1) is open at 08:52:31 (CET) = (9.51 s) in the graph** • **H-SC voltage rises fast within less than 40 ms** • **H-SC responds absorbing more reactive power** • **Reactive power increases from 11.2 MVAr (-0.16 pu) to 16.2 MVAr (-0.23 pu)** • **STATCOM drives H-SC response** • **SC dynamically has a lower contribution** • **SC initial fast response is decelerated, when STATCOM becomes prevailing**
Conclusions	• **H-SC has a stable operation during the change and a fast response time under the switching event**

C.3.2 Mode 4 Case 1: Change of H-SC Voltage Setpoint



Time	**13rd October 2021, 09:02:33 (CET)** [20]
Control Mode & Settings	**STATCOM in VAr and SC in V control mode** [14]
Steps	• **Change of H-SC voltage setpoint** [14]
Key observations	• **H-SC voltage reference is changed from 1.015 pu (279,13 kV) to 1 pu (275 kV) at 09:02:33 (CET) = (11.75 s) in the graph** • **H-SC voltage setpoint is complete within 4 s with ramp** • **The setpoint of STATCOM reactive power is 0** • **Only SC contributes to H-SC reactive power output** • **SC reactive power output follows the change of the reference value with similar ramp**
Conclusions	• **SC has a proper response, as it follows the change of H-SC voltage setpoint, despite that it takes few seconds instead of milliseconds** • **H-SC has a stable operation during the change and a fast response time under the switching event**

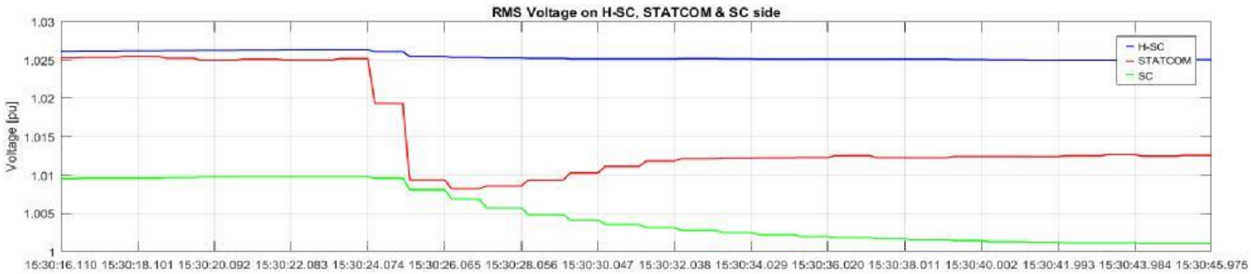
C.3.3 Mode 6 Case 3: Change Network Structure with SC in V control

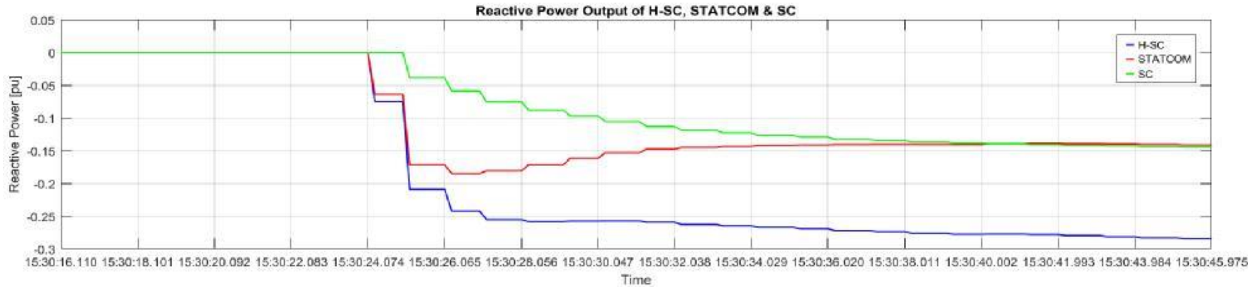


Time	**13rd October 2021, 09:33:25 (CET)** [20]
Control Mode & Settings	**Only SC in V control** [14]
Steps	• **Allow a switching event close to H-SC** [14]
Key observations	• **Reactor (1R0) is switched opened at 09:33:25 (CET) = (7.93 s) in the graph** • **H-SC voltage slightly increases within 50 ms** • **SC voltage increases within 20 ms** • **Less reactive power is injected from SC** • **The change in reactive power output (0.04 p.u.) is achieved within 900 ms**
Conclusions	• **H-SC has a stable operation during the change and a fast response time under the switching event**

C.4 Master Controller Tests

C.4.1 Fast Transient Compensation (FTC) – Case 1: H-SC Voltage Step





Time	**28th June 2021, 15:30:20 (CET)** [20]
Control Mode & Settings	**STATCOM and SC in voltage control mode** [14]
Steps	• **FTC is ON** • **Change of H-SC voltage setpoint** [14]
Key observations	• **H-SC voltage setpoint is set equal to 280 kV (1,018 pu) at 15:30:20** • **H-SC voltage is equal to 282 kV (1,026 pu)** • **No exchange of reactive power between H-SC and the network** • **Due to change, STATCOM and SC voltage decreases** • **H-SC absorbs reactive power** • **SC has a slower response than STATCOM due to its natural machine dynamics** • **The undershooting of STATCOM reactive power output indicates the contribution of FTC** • **The ramp rate limiters inside the MACH system are not disabled in case of setpoint changes**
Conclusions	• **FTC activation implies that the dynamic response of the system is dominated by STATCOM** • **H-SC reaches the new steady state in the range of milliseconds** • **The results show that the STATCOM is compensating for the slower response of the SC**

Appendix D – GB System level studies and results

North East and North West of England & Wales Region

In this region, several synchronous generator units (Heysham Station1, Hartlepool nuclear generation) will be decommissioned in future years. To analyse the benefit of H-SC against other options, for this region, the B7 and B7a boundaries have been analysed.

The B7 boundary cuts through three 400 kV double circuits and the Western HVDC link, as shown in Figure 53.

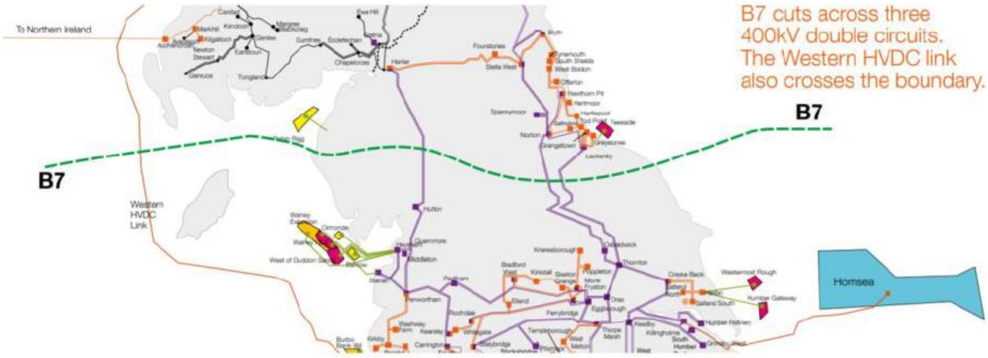


Figure 53 - B7 Boundary Line

The B7a boundary is just below the B7 boundary and cuts through three 400kV double circuits, the Western HVDC link and a 275kV circuit as shown in Figure 54.

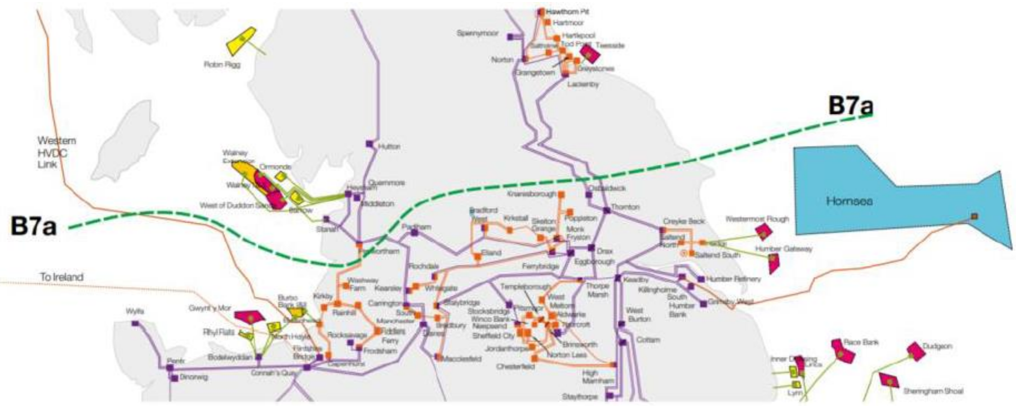


Figure 54 - B7a Boundary Line

The devices were assumed to be installed at five different locations (Heysham, Hartlepool, Spennymoor, Norton and Penwortham) in the North region of England & Wales.
The key findings were:

1. The increase in B7 and B7a boundary transfer with five devices installed in North region of England & Wales are provided in Table 17 and Table 18.
2. For most of the cases, standalone STATCOM solutions provide a greater increase in boundary transfer, followed by H-SC and standalone SC.
3. For 2027 network scenarios, the boundary limit is mainly due to the issues in Scotland region rather than local boundary. Having devices in both Scotland and the North of England & Wales would increase the boundary transfer further.

4. For the B7 and B7a boundary assessments, for the year 2023 and 2027, the Western HVDC is not loaded to the full capability. By adding H-SC/SC in the SPT region, the system SCL could be increased and WHVDC could be loaded fully.
5. For the 2027 summer scenario, H-SC provide more B7a boundary transfer benefit than STATCOM or SC.

Table 17 - The increase in B7 boundary transfer with five devices installed in North region of England & Wales

[redacted]

Table 18 - The increase in B7a boundary transfer with five devices installed in North region of England & Wales

[redacted]

<u>South Coast Region</u>

In the south coast region, there are number of non-synchronous generators and HVDC interconnectors that are connected or expected to be connected in coming years. To analyse the benefit of H-SC devices, power transfer across SC1 boundary was analysed. Figure 55 shows the south coast region, indicating SC1 boundary line which cuts through three 400 kV double circuits. The system analysis is carried out for 2019, 2023 and 2027 networks. For the 2019 network, thermal overloading is the limiting factor and detailed studies to assess the benefits of H-SC, SC and STATCOM solutions were not carried out.

To assess the benefits of H-SC, SC and STATCOM solutions, it was assumed that these are installed at five locations in the south coast region based on the steady state voltage issues and changes in generation background. The five locations are Alverdisot, Bramley, Dungeness, Exeter, and Nursling.

Figure 55 - SC1 Boundary Line

The studies found that voltage stability is the first limiting factor for SC1 boundary transfers and by adding H-SC / STATCOM/ SC in the region, boundary transfers can be increased see Table 15Table 15 - the live-trial results and other documents "Report on optimal placement and capacity evaluation of SCs/H-SCs in GB".

South West Region

Figure 56 shows the south west region of the England & Wales transmission network and the B13 boundary that cuts through two 400 kV double circuit lines. To evaluate the benefit of H-SC, B13 boundary transfer has been analysed for 2019, 2023 and 2027 networks, for both summer and winter scenarios. This region includes a large level of Distributed Energy Resources (DER) in the DNO network.

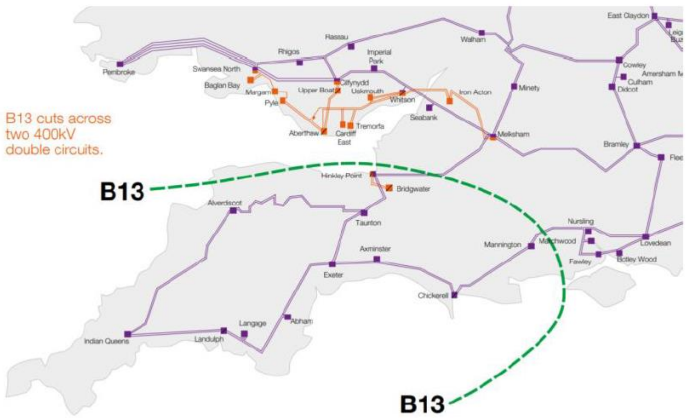


Figure 56 - B13 Boundary Line

The study analysis results show that the B13 boundary is limited by thermal overloading of DNO networks given the high levels of DER in the South West region. NGESOs' Regional Development Program (RDP) project, is working on reducing the thermal overloading in DNO networks in this region. When thermal overloading issues are resolved, voltage in the region becomes limiting depending upon the way the DNO network is reconfigured. At that stage, the addition of standalone SC/ standalone STATCOM/H-SC would provide additional benefits see Table 15 "Report on optimal placement and capacity evaluation of SCs/H-SCs in GB".