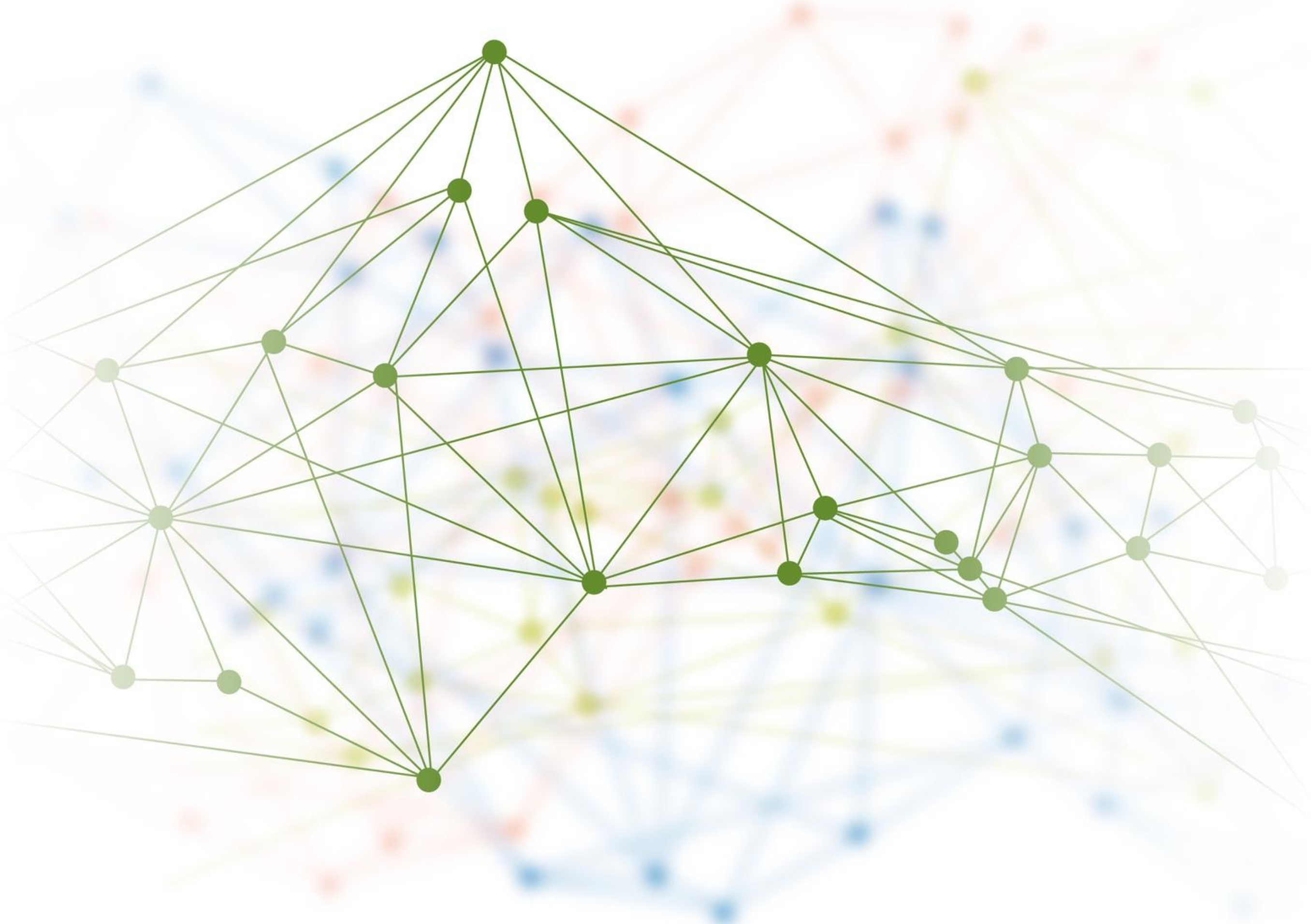
PHOENIX

Cost Benefit Analysis of SC and H-SC based on System Studies



About Report

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Contents

List of Figures

List of Tables

Executive Summary

As the UK moves to a low-carbon economy, the energy landscape is changing. In the GB Electricity System, the amount of conventional synchronous generation is declining due to the planned closure of coal and nuclear power stations as well as due to the increasing amount of solar and wind power generation being connected to transmission and distribution networks. The declining amount of synchronous generation on the network has impacts on voltage controllability, Short Circuit Level (SCL) and inertia of the system.

The NIC Phoenix project aims to design, deploy and operate a Hybrid Synchronous Compensator (H-SC) to mitigate system issues that are being encountered on the GB Electricity Transmission System because of the declining synchronous generation. The H-SC consists of a Synchronous Compensator (SC) and a STATic COMpensator (STATCOM) with an innovative hybrid control system to maximise the benefits from both the SC and STATCOM. The installation of H-SCs on the electricity system could provide voltage control capability, SCL and inertia contribution to the system.

The Phoenix project will deploy a 140 MVA H-SC at Neilston 275kV substation in Scotland and carry out a year-long trial to evaluate the benefits of H-SC. One of NGESO's objectives is to carry out system analysis to evaluate the benefit of H-SC. This report focusses on results obtained from evaluating the benefits of a 140 MVA H-SC at Neilston 275kV location, in terms of boundary transfer capability.

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; SC only, STATCOM only and SC and STATCOM together. 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.

Dynamic reactive support from SC / STATCOM/ H-SC improves the B6 boundary transfer limit, after the closure of nuclear plants in the region, as the boundary is limited by voltage collapse. With the addition of H-SC / SC / STATCOM, in addition to the boundary transfer improvement, there is an improvement in residual voltage of the system, Transient Over Voltage (TOV) and voltage angle changes in the system. There are also small increases to SCL and inertia through the installation of H-SC at Neilston. However, these are not large enough to have an effect on the operation of the system.

The Phoenix Neilston 140 MVA H-SC device increased the boundary transfer in the range of 45 MW to 98 MW, for the Community Renewables (CR) Future Energy Scenario (FES) 2018. With this increase in boundary capability, the Phoenix Neilston H-SC device gives the net cost benefit range of £53 to £66m, based on the ETYS 2017 background (the network developed through the 2017 ETYS process including future network reinforcements) for the Community Renewables (CR) FES 2018 scenario. 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[1], the net cost benefit from the Phoenix Neilston H-SC is reduced to the range of £11m to £27m for the Community Renewable (CR) FES 2018 scenario. Based on other FES 2018 scenarios, the total savings are in the range of -£7m to £51m. This report evaluates the benefit that the installation of H-SC may bring to the system but it does not provide a

[1] Different options recommended that could affect B6 boundary capability and the corresponding timescales are available at https://www.nationalgrideso.com/insights/network-options-assessment-noa

recommendation to invest. To decide the suitable investment, the benefit of installation of H-SC should be compared against other technology options through NOA process.

In certain scenarios, H-SC or SC and STATCOM together options, provided more boundary transfer capability than SC only or STATCOM only options. The H-SC control function avoids conflicts between SC and STATCOM controls and hence with this option both SC and STATCOM can be connected through one three-winding transformer. Whereas SC and STATCOM together option assumes two separate two-winding transformers, to avoid any conflicts between SC and STATCOM control. Because of the different transformer arrangements, the capital cost of the H-SC is lower than SC & STATCOM together option. As the H-SC and the separate SC and STATCOM together options provided similar benefits, the lower capital cost of the H-SC option means that it provides more cost benefit compared with other options against the ETYS 2017 background.

Summary of Results

The Phoenix Neilston H-SC device increases the boundary transfer between Scotland and England & Wales for different scenarios. The increase in boundary transfer values for these analysed scenarios are shown in Table 1.

Table 1 The increase in Boundary Transfer with the Phoenix Neilston H-SC Device

Network	Season Background	Increase in B6 Boundary
2019 Network	Summer	0 MW
2019 Network	Winter	0 MW
2023 Network	Summer	45 MW
2023 Network	Winter	90 MW
2027 Network	Summer	65 MW
2027 Network	Winter	98 MW

With these increased boundary transfer capabilities, the net cost benefit that can be achieved by the Phoenix Neilston H-SC device is shown in Table 2. In this case, not all NOA 2018-19 options are included in the background. When the boundary transfer capabilities are adjusted to consider all NOA 2018-19 options, the net cost benefit that can be achieved by the Phoenix Neilston H-SC device is shown in Table 3.

Table 2 The Net Cost Benefit range from Phoenix Neilston H-SC, based on absolute Boundary Capacities

FES Scenario	Net Benefit £m
Consumer Evolution (CE)	73 to 86
Community Renewables (CR)	53 to 66
Two Degree (TD)	54 to 67
Slow Progression (SP)	40 to 53

Table 3 Net Cost Benefit range from Phoenix Neilston H-SC, based on Adjusted Boundary for NOA 2018-19 Options

FES Scenario	Net Benefit £m
Consumer Evolution (CE)	(-7) to 9
Community Renewables (CR)	11 to 27
Two Degree (TD)	35 to 51
Slow Progression (SP)	(-13) to 3

The power losses incurred by the devices (SC / STATCOM / H-SC) are not considered in the net cost benefit analysis. The power losses incurred by these devices will have the effect of reducing the net cost benefit. During the H-SC device life time of 40 years, assuming 50% of time H-SC required to provide the system benefit, the cost of power loss incurred by H-SC is estimated as £12.6m. Hence the net cost benefit range shown in Table 2 and 3 will be further reduced by £12.6m. H-SC has control functions that can reduce the steady state power losses of the device. Hence, H-SC could provide savings by reducing the power losses compared with other options. Further analysis on power losses incurred by these devices will be carried out in future studies.

The inertia contribution from one 140 MVA H-SC at Neilston is 0.0938 GVA-s is very small compared with the typical GB system inertia range from 130 GVA-s to 400 GVA-s. However, with the multiple SCs, inertia contribution could be high and could add additional cost benefits apart from boundary transfer capability. The SCL contribution from one 140 MVA H-SC is not significant to affect the operation of HVDC interconnector in the region. The SCL contribution from multiple H-SC / SC could have impact on the operation of HVDC interconnectors in the region and hence could influence the boundary transfer capabilities.

This report also highlights the benefits on improving SCL and inertia from multiple SCs in the system. Further analysis will be carried out with multiple H-SCs with different ratings and locations to establish the benefits of H-SCs against other options.

Background

The Climate Change Act 2008 legally binds the UK to reduce greenhouse gas emissions by at least 80 percent from 1990 levels by 2050. This is the UK's contribution to the Paris Agreement, seeking to hold the increase in global temperatures to less than 2^{0}C above pre-industrial levels. In order to meet these targets, one of the actions is to reduce the electricity production from fossil fuels such as coal and to increase the renewable electricity contribution. The European Union's 2030 Climate Energy Framework also includes a number of decarbonisation targets for 2030, namely:

- At least a 40 percent reduction in greenhouse gas emissions (from 1990 levels)
- Renewable energy to make up at least 27 percent of energy consumption in the EU
- Reducing energy use by at least 27 percent (when compared to the projected use of energy in 2030).

National Grid Electricity System Operator (NGESO) has also announced its ambition that, by 2025, electricity system operation would have transformed such that the system can be operated safely and securely at zero carbon. As the UK moves to a low-carbon economy, the GB energy landscape is changing. In the GB Electricity System, the amount of conventional synchronous generation is declining due to the planned closure of coal and nuclear power stations as well as due to the increasing amount of solar and wind power generation being connected to transmission and distribution networks.

The declining amount of synchronous generation on the network has the following impacts:

- Reduces the steady state and dynamic voltage control availability and will have an impact on voltage stability of the system
- Reduces the fault level, also known as Short Circuit Level (SCL) of the system, an indicator of system strength, that will have an impact on operation of HVDC and stable operation of Phase Locked Loop (PLL) in converter based generation, power quality and reliable operation of protection
- Significant reduction of synchronous generation also reduces the level of system inertia, which will have an impact on frequency containment, Rate of Change of Frequency (RoCoF) and system stability

The NIC Phoenix innovation project aims to design, deploy and operate a Hybrid Synchronous Compensator (H-SC) to mitigate system issues that are being encountered on the GB Electricity Transmission System because of the declining synchronous generation in the system.

The H-SC consists of a Synchronous Compensator (SC) and a STATic COMpensator (STATCOM) with an innovative hybrid control mechanism to maximise the benefits from both the SC and STATCOM. The SC has rotating mass and can provide Short Circuit Level (SCL) contributions, reactive power support and inertia to the system. A SC is similar to a synchronous generator without any active power (MW) contribution. The STATCOM provides steady state and dynamic reactive support to the system but does not have ability to provide SCL contribution and inertia.

The installation of H-SCs on the electricity system could provide the following benefits:

a) SCs and STATCOMs are both able to provide reactive power support in steady state conditions. For certain system boundaries, the installation of a H-SC or H-SCs would provide reactive power support and could potentially increase the boundary transfer capabilities.

b) SCs and STATCOMs are both able to provide dynamic reactive power capabilities. For particular system boundaries, the installation of a H-SC or H-SCs could provide dynamic reactive support and could improve the voltage stability limit/voltage collapse limit.

c) The amount of fault current contribution by H-SCs would increase the Short Circuit Level (SCL) of the system. The increase in SCL could improve the operation of High-Voltage Direct Current (HVDC) links by reducing the likelihood of commutation failure of Current Source Converter (CSC) type HVDC links. This could potentially improve the thermal, voltage and angular stability limits for certain boundaries.

d) The inertia contribution from a H-SC or H-SCs could improve the angular stability limit for certain boundaries. The inertia contribution from H-SCs could impact the Rate of Change of Frequency (RoCoF) and hence frequency nadir could be improved. As a result, H-SCs could reduce the amount of generation which is constrained to meet the RoCoF and maximum infeed loss limit for the given scenario.

The Phoenix NIC innovation project will deploy a 140 MVA H-SC at Neilston 275kV substation in Scotland and carry out a year-long trial to evaluate the benefits of H-SC. One of the NGESO's objectives is to carry out system study analysis to evaluate the benefits of H-SC specified above. These study results will be provided as input to a well-established Cost Benefit Analysis (CBA) method to determine the economic benefit of H-SC. **This report focusses primarily on results obtained for evaluating the benefits of the 140 MVA H-SC Phoenix device at Neilston 275kV location.** In future, further studies will be carried out to evaluate benefits of installing multiple H-SCs at different locations with different ratings.

In addition to the benefits that will be quantified through the CBA work, H-SCs could provide other benefits to the GB network. For example, the fault level contribution from a H-SC or H-SCs could improve the residual voltage level and fault ride through capabilities of generation connected to the DNO network. The increase in fault level contribution from the H-SC would also reduce the requirement to change the protection settings (otherwise required if there is not enough system fault infeed). It should be noted that whilst some qualitative assessment will be provided on these benefits (for example the improvement of residual voltage with H-SCs). These additional benefits will not be analysed or quantified in the proposed CBA method.

H-SCs could also improve the power quality (harmonics, power oscillation damping) and the restoration capability of the system. The power quality and restoration capability of the system are out-of-scope for Phoenix project.

Report Structure

The next section **Hybrid Synchronous Compensator (H-SC)** provides background on H-SC to be installed at Neilston 275kV substation. This section provides reactive power range of H-SC, typical layout of H-SC, overview on operating modes and master control functions.

System Analysis Methodology section explains the methods followed to evaluate the benefits of H-SC, generation and demand background assumptions of future years and seasonal variations considered in the system studies.

Power System Model section explains the GB Electricity Transmission System model, SC, STATCOM and H-SC models used in system analysis

System Study Results explains the study results obtained from system analysis that include performance of SC and STATCOM, impact of H-SC on boundary transfer levels, validation of results obtained from analysis, boundary limit analysis and evaluation of benefits of H-SC compared with other options.

Cost Benefit Analysis (CBA) section explains the Cost Benefit Analysis (CBA) methodology and results obtained from CBA analysis.

The last section explains the future works planned to evaluate the benefits of H-SC.

Hybrid Synchronous Compensator (H-SC)

The Hybrid Synchronous Compensator (H-SC) proposed in Phoenix project is rated 140 MVA which consists of 70 MVA of Synchronous Compensator (SC) and 70 MVA of STATCOM. 70 MVA SC can provide a reactive power range of -34 Mvar to +70 Mvar. The SC can provide inertia support to the system and its inertia constant (H) is 1.34s. 70 MVA STATCOM can provide a reactive power range of -70 Mvar to +70 Mvar. Hence the total reactive power range of 140 MVA H-SC is -104 to +140 Mvar [REF 1]. SC and STATCOM are connected to Neilston 275kV busbar through a three-winding transformer with rating of 140 MVA. The layout of the proposed H-SC is shown in Figure 1 [1].

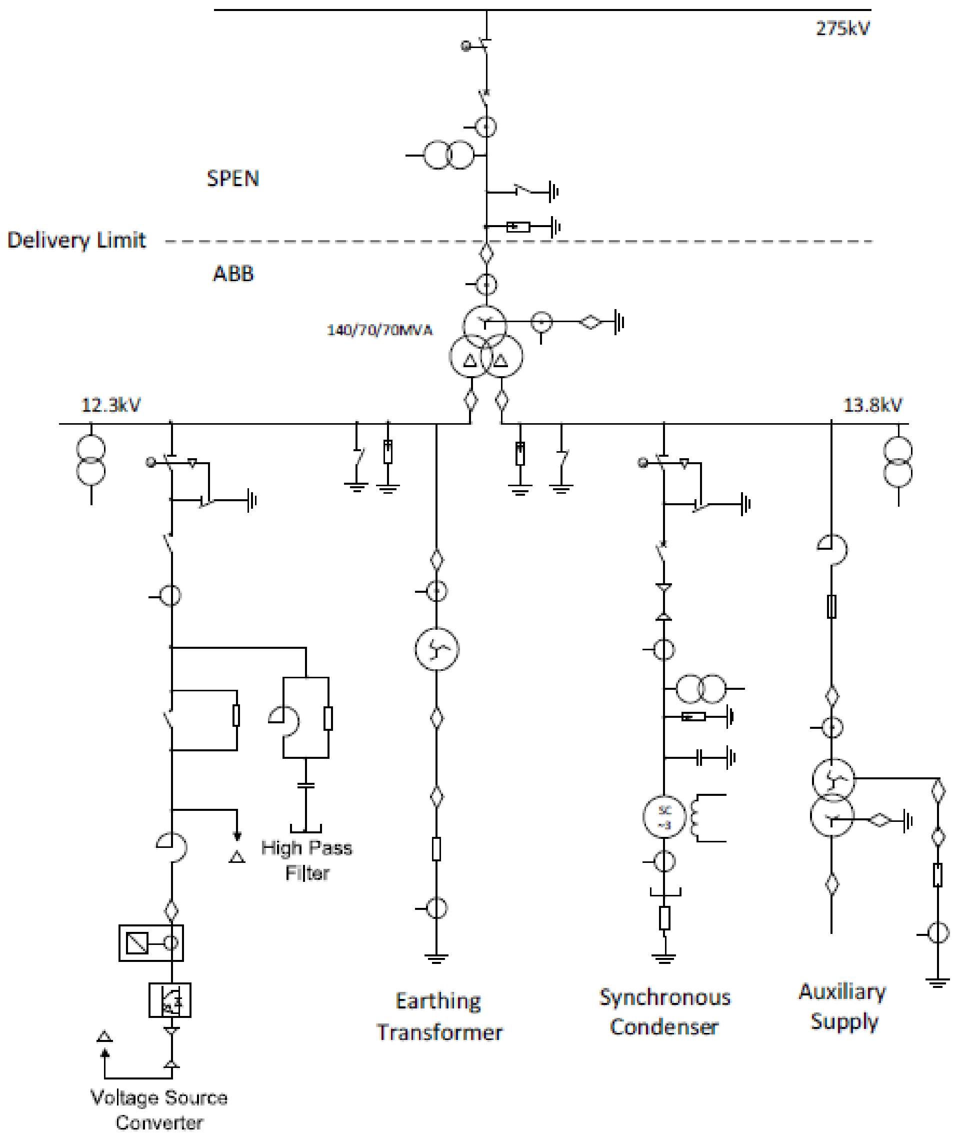


Figure 1 Layout of Hybrid Synchronous Compensator (H-SC) at Neilston

The H-SC can be operated as

- Only STATCOM
- Only SC
- Both SC and STATCOM

The standard control mode for the H-SC is having both SC and STATCOM in service and both are operating in automatic voltage control mode. However, it is possible to operate STATCOM and SC in manual control mode rather than automatic voltage control mode. With these options, there are number of operating modes are possible with the H-SC.

In this study analysis, it has been assumed that the H-SC will be operating in standard mode of having both SC and STATCOM in service and operating in automatic control mode. With this mode operation, inertia and SCL contribution from SC is always available along with dynamic reactive support from both SC and STATCOM. However, with this mode of operation, both SC and STATCOM incur more power losses than operating SC only or STATCOM only modes.

The H-SC has master control that monitors, coordinates and optimises the simultaneous operation of STATCOM and SC. The master control works as a coordinator to avoid “control hunting” between the two control systems and to maximise the efficiency of both branches (SC and STATCOM) as a single unit. The master control includes the following functions [1]:

- Coordinated voltage control and reactive power sharing

  The main objective of this function is to calculate the setpoints for both SC and STATCOM control systems. In case of automatic voltage control mode, the setpoint is based on voltage reference and in case of manual control is based on reactive power setting.

- Power Loss Minimisation (PLM)

  PLM function is responsible for the calculation of optimised slopes (in automatic mode) or optimised Q setpoints (in manual mode) for both the STATCOM and the SC, so that the total losses of the H-SC will be minimum.

- Fast Transient Compensation (FTC)

  The main objective of this function is to speed up the response time of the H-SC in case of network contingencies, when operating the H-SC in Automatic Voltage Control with both SC and STATCOM branches in service.

- Inertia Support Maximisation (ISM)

  The main objective of this function is to maximise the H-SC contribution to the inertial frequency response, by activating and deactivating PLM depending upon the frequency event.

The study analysis has been carried out with generic H-SC model[2] that has coordinated voltage control and reactive power sharing and fast transient compensation functions. In the generic H-SC model, STATCOM power loss is not modelled and hence Power Loss Minimisation (PLM) and Inertia Support Maximisation (ISM) functions are not included in this model.

The ISM aims to maximise the inertia contribution by activating or deactivating PLM function of STATCOM. The no-load power loss of STATCOM is less than 0.2% @70 MVA base (i.e. 0.14 MW) and load losses is less than 1% @70 MVA base (i.e., 0.7 MW). Due to the small value of

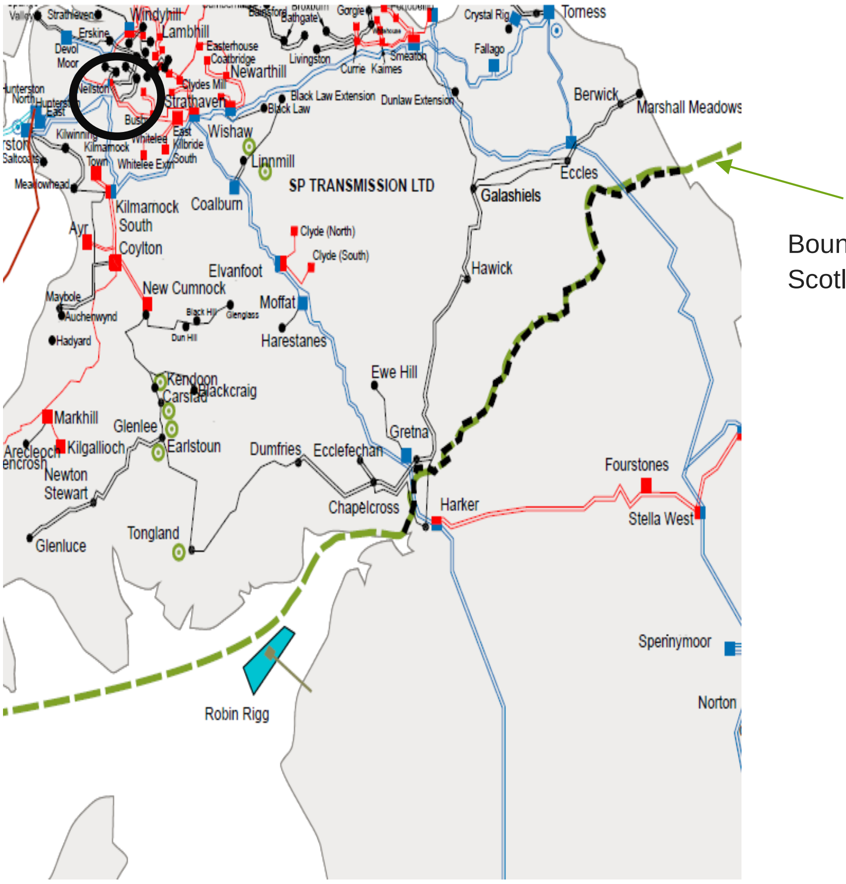
[2] The generic model was provided by ABB and was built to represent the Phoenix H-SC device specifically. The generic model has the capability to scale the rating of H-SC device. This model could be used to represent the H-SC at different locations and H-SC with different ratings.

power losses from STATCOM, ABB found that inertia support maximisation function provides very little to no benefits to the system.

The steady state power loss savings with H-SC, from PLM function, is not considered in this study. During the trial period, H-SC will be considered as TO asset and losses will be part of transmission losses.

System Analysis Methodology

The Phoenix NIC innovation project will deploy a 140 MVA H-SC at Neilston 275kV substation in Scotland, shown in Figure 2 below. To analyse the impact of H-SC on system performance and to evaluate the potential benefits of the H-SC, detailed power system analysis has been carried out. This section explains the methodology, background assumptions used in this analysis.



Boundary Line between Scotland and E&W

Figure 2 Network Map Indicating Boundary between Scotland and England & Wales

Assessment Approach

As discussed before, H-SC will provide dynamic voltage support, inertia and fault infeed that could improve the system performance. H-SC at Neilston location is rated for 140 MVA, with 70 MVA of SC and 70 MVA of STATCOM. The inertia constant of the SC is 1.34s and hence the inertia contribution from H-SC is 93.8 MVA-s (0.0938 GVA-s)[3]. Currently the typical GB system inertia could range from 130 GVA-s to 400 GVA-s. The system inertia is expected to decline to the range of 70GVA-s to 310 GVA-s by 2027. Hence the inertia contribution from one H-SC, 0.0938 GVA-s will be very small compared with the system inertia.

140 MVA H-SC at Neilston location could improve the fault level, though this is unlikely to be sufficient to impact the operation of Western HVDC link or protection system. It should be noted that a higher rated H-SC, additional H-SCs or H-SCs at different locations may have impacts on the operation of Western HVDC. In this case, this will impact the net boundary transfer capability.

[3] The inertia contribution is only from SC and no inertia contribution from STATCOM. For the SC, there is no power factor and hence inertia contribution from SC is 93.8 MVA-s or 93.8 MW-s.

The benefit of a single 140 MVA H-SC on SCL and inertia could be very small. However, the combination of dynamic reactive power support, inertia contribution and SCL contribution improves the system performance. Hence, to determine the benefit of a single H-SC installed at Neilston location, approach of analysing the net boundary transfer will be used rather than defining benefit for each service.

With the multiple H-SCs, system SCL will increase and will improve Western HVDC loading condition and could increase the boundary transfer capability. Hence the contribution of H-SC on system SCL will be taken in to account through the boundary transfer analysis. With the multiple H-SCs, the system inertia will be improved that could have impact on frequency and Rate of Change of Frequency (RoCoF) constraint limits. This additional cost benefit will be added to the cost benefit obtained from boundary transfer capability, to define the cost benefit of multiple H-SCs.

It should be noted that NGESO is currently carrying out projects such as Voltage Path finder[4], Stability Pathfinder, where the requirement for steady state reactive power, dynamic reactive power, inertia and short circuit contribution for the system are being defined.

For the H-SC installed at Neilston location, its impact on boundary transfer capability from Scotland to England & Wales (generally known as "B6" boundary) are analysed. The Scotland to England & Wales boundary is shown in the Figure 2. The increase in boundary transfer capability is used in Cost Benefit Analysis (CBA) to determine the economics of H-SC.

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
f. Frequency and RoCoF limit

These assessments will be carried out to determine the boundary transfer capability that will meet the criteria set out in the Security and Quality of Supply Standard (SQSS) [2]. SQSS sets out limits applicable to operational switching and to secured events (faults). For the possible single and double circuit fault cases, there should not be any thermal, voltage and stability violations for the given boundary transfer levels. SQSS provides limits on pre-fault, post-fault voltage levels, voltage step change levels and stability criteria such as pole slip and damping time constant. These assessments are carried out using DigSilent-PowerFactory package.

Network Background

National Grid ESO carries out system capability analysis and provides Electricity Ten Year Statement (ETYS) every year. ETYS 2017 network model, with update on dynamics of plant, is used to carry out the above assessments.

[4] Voltage Path Finder project is taken as Business As Usual (BAU) in the current year (2019-20) NOA process as High Voltage Management

The analysis outlined will be carried out for Year 2019 set up in PowerFactory when the actual H-SC is planned to be installed in the year 2019. In addition to the year 2019, analysis will be carried out for two other years when major generation background changes are likely to have material impact on the Scotland to England & Wales (B6) boundary transfer capability.

The Hunterston nuclear generation is expected to be closed in the year 2023 [3]. As it is expected to have material impact on the boundary transfer capability, the above assessments are carried out for the year 2023.

Torness nuclear generation is expected to be closed in the year 2030 [4]. As the network model is available only up to 2027, as part of Electricity Ten Year Statement (ETYS) studies, 2027 network will be analysed with the assumption of Torness closure.

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

1. 2019 Network – The trial of H-SC is expected to start
2. 2023 Network – Assumed closure of Hunterston nuclear generation
3. 2027 Network – Assumed closure of Torness nuclear generation

Future Energy Scenario (FES) Background

In order to carry out system analysis, generation and demand background for different years are obtained from Future Energy Scenario (FES) 2018 data produced by National Grid ESO. FES 2018 [5] considers four different scenarios based on "speed of decarbonisation" and "level of decentralisation" and they are:

- Consumer Evolution
- Community Renewables
- Steady Progression
- Two Degrees

Among these scenarios, Community Renewables and Two Degrees are the scenarios expected to meet 2050 target on decarbonisation. The Community Renewables scenario would achieve 2050 decarbonisation through a more decentralised energy landscape. It is expected that CR scenario will have more non-synchronous generation in the network and could represent the worst-case scenario, in terms of less synchronous generation. Hence generation and demand background corresponding to CR based on FES 2018 is used for system analysis.

For the 2019, 2023 and 2027 year network backgrounds, analysis is carried out for both winter peak and summer minimum (solar peak) periods using the 2018 FES Community Renewables scenario demand and generation background. During the winter, there is a possibility of high wind output generation in Scotland and hence the B6 boundary transfer would be high. During the summer minimum period, the amount of synchronous generation in E&W network is low and could impact the SCL at Scotland. This will enable a more accurate profile of the year round B6 boundary transfer limits to be established for the CBA model. Further sensitivity analysis would be carried out, if it requires, to profile the year round B6 boundary transfer limits.

The boundary transfer values obtained from the winter peak and summer minimum demand conditions are used to extrapolate the boundary transfer capabilities for other demand and generation scenarios and hence built up year around boundary transfer limits. The summer minimum period limit is used to define the stability limit for summer seasons and winter peak period limit will be used for other months. The boundary transfer limits calculated through these analyses are used as inputs to a year around cost benefit analysis and is explained in further sections.

For the selection of winter peak demand in a year, demand is selected that corresponds to 95 percentiles of the winter load demand (5 percentage of time demand will be higher than the selected demand). This is in consistent with the SQSS recommended peak study background. Similarly for the selection of summer minimum period in a year, demand is selected that corresponds to 95 percentiles of the summer demand (5 percentage of time demand will be lower than the selected demand).

Different Options

For comparison purposes, 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
5. With 140 MVA H-SC at Neilston

A SC in isolation or as part of an H-SC could be provided by a new asset or by converting mothballed or existing power station to SC operation. The conversion of existing generators to synchronous compensator will have different capital costs (site dependency) and also high operating costs (high losses, maintenance costs so on). The proposed methodology does not include a case covering the conversion of a mothballed or existing power station to SC. The methodology could accommodate the assessment of such solutions if these are shown to be viable options and if system models and cost data are made available. BAU case, NOA will be able to compare this option with new built H-SC / SC[5].

The aim is to compare different options of H-SC (different SC and STATCOM options) rather than different technologies that might also be considered as potential solutions for the local system issues. Hence this work will not compare H-SC against other technologies such as Battery, Virtual Synchronous Machines (VSM)[6] so on.

[5] NOA's purpose is to make recommendations to transmission owners across Britain as to which projects to proceed with to meet the future network requirements as defined in the Electricity Ten Year Statement (ETYS). More information is available at https://www.nationalgrideso.com/insights/network-options-assessment-noa

[6] "Virtual Synchronous Machine (VSM) is a control approach of achieving more flexible support from control power electronic converters in Non-Synchronous Generation, irrespective of the availability or quality of grid measurement. VSM and related technologies deliver approaches which provide in an electrically identical manner key features of synchronous generators to near instantaneously support grid disturbances with inertia, fault current and reactive power"

Assumptions on System Analysis

- System analysis is carried out with ETYS 2017 dynamic model that represents GB Electricity Transmission System.
- Demand and generation background for study analysis is based on FES 2018 Community Renewable scenario data.
- The benefit of H-SC is analysed by assessing the effect on boundary transfer capability. Increases to capability might arise through steady state and dynamic reactive support, SCL and inertia.
- The benefit of H-SC is compared with other options such as SC, STATCOM, SC and STATCOM without hybrid control.
- For the SC and STATCOM without hybrid control option, is has been assumed that SC and STATCOM are connected to the system through two separate two-winding transformers. By having two separate transformers, there will not be any control conflict occurs between SC and STATCOM.
- For the H-SC option, it has been assumed that SC and STATCOM in connected through one three-winding transformer. The hybrid control will co-ordinate these devices and avoids any conflict in SC and STATCOM controls.
- The benefit of H-SC is not compared against all other technologies such as battery and VSM.
- This report attempts to value the benefit that the installation of H-SC may bring to the system but it is not intended to provide a decision on investment. In order to decide the suitable investment, the benefit of installation of SC/ STATCOM/ H-SC should be compared against other technologies through NOA process.
- With H-SC steady state power loss will be reduced by the PLM function. These steady state power loss reduction is not considered in the analysis.

Power System Model

To evaluate the benefit of Synchronous Compensator (SC), Static Compensator (STATCOM) and Hybrid Synchronous Compensator (H-SC), a dynamic model to represent the GB Electricity Transmission System has been prepared by NationalGridESO using PowerFactory – DIgSILENT software package. The Electricity Ten Year Statement (ETYS) GB model with representative dynamic behaviour of all plants such as synchronous generators, HVDC interconnectors (VSC and CSC types), wind farms is used. Some of the key points are:

1. Western HVDC is represented by full dynamic model, as provided by the supplier
2. IFA HVDC is represented by full dynamic model, developed through consultancy work. This model is used to represent all CSC type HVDCs (BritNed, Moyle)
3. NEMO HVDC is represented by generic dynamic model, developed through consultancy work. This generic model is used to represent all VSC HVDC models (ElecLink, IFA2, FAB link, Viking, EWIC so on)
4. All wind farm models are represented by generic NGESO wind farm models developed to meet the grid code requirements
5. All future synchronous machines' dynamic models are represented by generic dynamic frame based on fuel type
6. Generic PLL model is added to embedded generators that are represented by static generator to get stable dynamic simulation. PLL model is required to achieve a stable dynamic simulation. PLL models are also required to represent the realistic system behaviour during frequency events.

The developed GB Electricity Transmission System dynamic model is validated to determine the suitability of this model to carry out steady state thermal and voltage analysis, dynamic voltage and angular stability analysis. The model is suitable to carry out dynamic analysis using RMS simulation method and it is not intended to carry out EMT type analysis.

With the GB Electricity Transmission System model, demand and generation backgrounds have been set up based on FES 2018 background. As discussed in the previous section, Community Renewables (CR) scenario is used for system studies.

To represent the Synchronous Compensator (SC) at Neilston location, a generic model for SC produced by DTU has been used. The SC model is suitable to carry out steady state and dynamic analysis. The SC dynamic model has Automatic Voltage Regulator (AVR), Power System Stabiliser (PSS) and Over Excitation Limiter (OEL) functions. The Neilston H-SC has SC with both Over Excitation Limiter (OEL) as well as Under Excitation Limiter (UEL). In the generic SC model, only OEL is included[7]. SC is connected to a two winding transformer and connected to a 275kV busbar. The dynamic frame structure is shown in Figure 3. The generic model is also suitable to change the rating of SC and transformer and hence analysis can be carried out for different rating of SC [6].

[7] Neilston H-SC model provided by ABB for planning time scale has both Over Excitation Limiter (OEL) and Under Excitation Limiter (UEL)

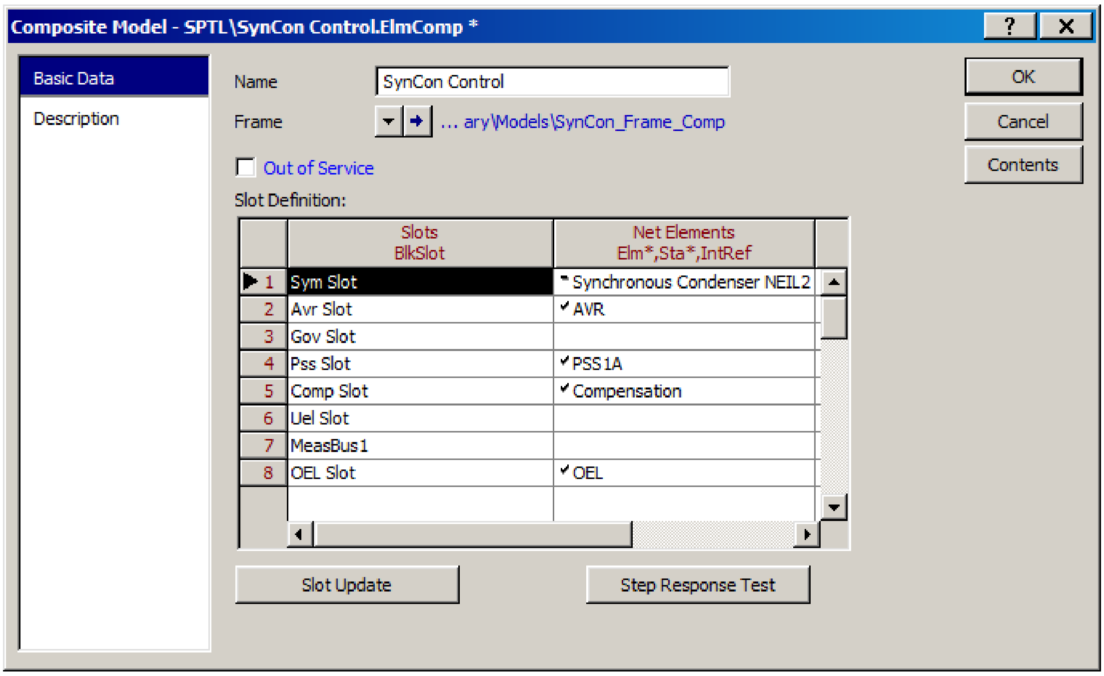


Figure 3 Synchronous Compensator Dynamic Frame

Similarly, to represent the STATCOM at Neilston location, a generic model of STATCOM produced by ABB has been used in this analysis. The STATCOM model consists of dynamic modelling of voltage regulator, under voltage block capability, as shown in Figure 4, and it is suitable to carry out steady state and dynamic analysis. STATCOM is connected to a two winding transformer and connected to 275kV busbar. The generic model [7] is also suitable to reflect changes the rating of STATCOM and transformer and hence analysis can be carried out for different ratings of STATCOM.

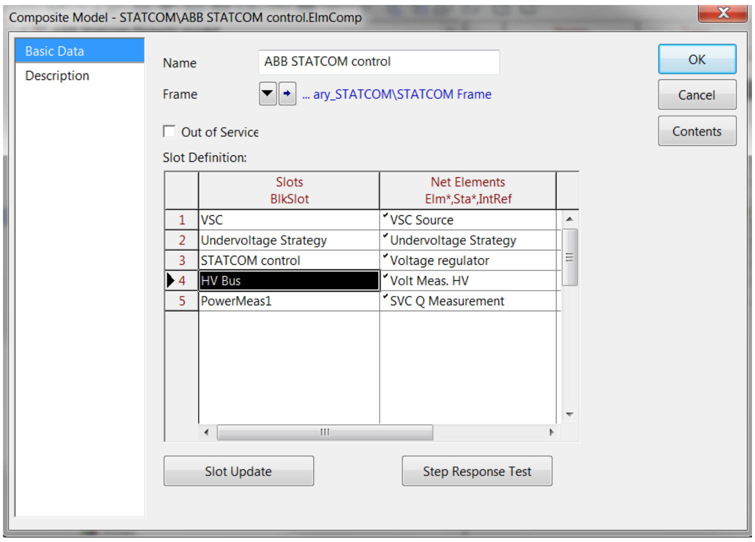


Figure 4 STATCOM Dynamic Frame

To represent the Hybrid Synchronous Compensator (H-SC) at Neilston location, a generic H-SC model has been produced by ABB [8]. The generic 140 MVA H-SC 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 is 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 Synchronous Compensator will be energised in this mode so that it is providing inertia and short circuit infeed. In the generic H-SC model, Power Loss Minimisation (PLM) and Inertia Maximisation Support (ISM) are not included in the model.

National Grid ESO has carried out validation of SC, STATCOM and H-SC models, using dynamic GB electricity transmission system model, to verify the expected behaviour of SC/STATCOM/H-SC. The validated models are then used to analyse the boundary transfer capabilities. The results obtained from these analyses are presented in the next section. The Phoenix project will deploy a 140 MVA H-SC at Neilston 275kV substation and carry out a year-long trial to evaluate the benefits of H-SC. The trial results will be used to validate the model against the performance of the installed H-SC at Neilston.

System Study Results

This section explains results of system study analysis to evaluate the benefit of H-SC. The first part of this section explains the performance of SC and STATCOM, Short Circuit Level (SCL) contribution from SC and STATCOM, dynamic reactive power support from SC and STATCOM during a fault and after the fault clearance time. The Second part of this section explains the B6 boundary transfer capability results for different scenarios and network conditions.

Performance of H-SC

Short Circuit Level Contribution

For a fault at Neilston 275kV busbar, fault contribution from H-SC and voltage at Neilston 275kV busbar are shown in Figure 5 and 6 respectively. Please note that the time scale (x-axis) for Figure 5 and 6 are different. Figure 5 shows the fault current contribution from a 140 MVA H-SC connected at Neilston 275kV location. ***Green line indicates the fault current contribution from SC branch and red line shows the fault current contribution from STATCOM branch.*** For a fault at Neilston location, the sub-transient and transient fault current contribution from SC is about 4.1 p.u. and 3.3 p.u. Whereas no fault current contribution from STATCOM branch has been observed. For the fault at Neilston location, Neilston busbar voltage is 0 p.u. during the fault as shown in Figure 6. When the busbar voltage drops below 0.4 p.u., the STATCOM will be blocked due to Under Voltage block capability. Hence the STATCOM is not providing any fault current contribution during the fault.

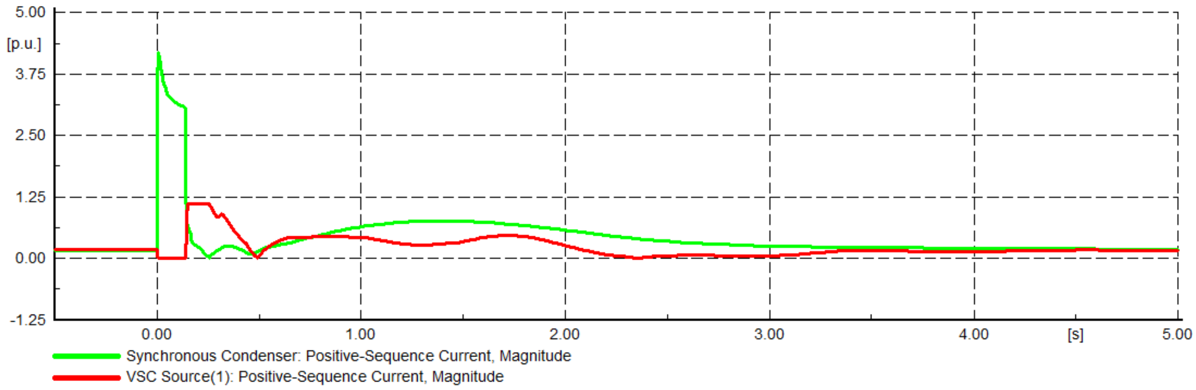


Figure 5 Fault Contribution from SC and STATCOM for a Fault at Neilston 275kV

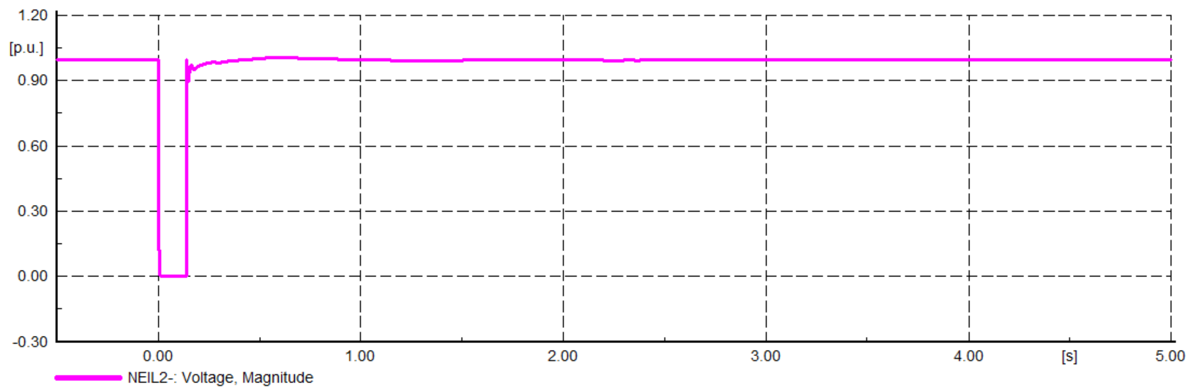


Figure 6 Voltage at Neilston 275kV for a Fault at Neilston 275kV

Figure 7 shows the fault current contribution from H-SC for a fault at B6 boundary circuits and the corresponding voltage profile is shown in Figure 8. Please note that the time scale (x-axis) for Figure 7 and 8 are different. As expected, the fault current contribution from SC is lower compared with fault current contribution from SC for a fault at Neilston busbar. During the fault, the current contribution from SC depends upon the voltage at Neilston as shown in Figure 8. When the voltage is low the current contribution from SC is high and when the voltage is increased the current contribution from SC is reduced. The unusual shape of voltage during the fault is due to the behaviour of converter based plants in the nearby locations.

Also, the STATCOM now provides the fault current of 1 p.u. during the fault. This is because for a fault at B6 boundary, voltage at Neilston is not reduced lower than 0.4 p.u., as shown in Figure 8, and hence the STATCOM is not blocked. These results show that fault current contribution from SC and STATCOM varies with the location of device and the impedance between the fault location and H-SC device. It should be noted that for a B6 boundary fault, voltage change is severe enough for STATCOM to provide its full output with or without Fast Transient Compensation (FTC).

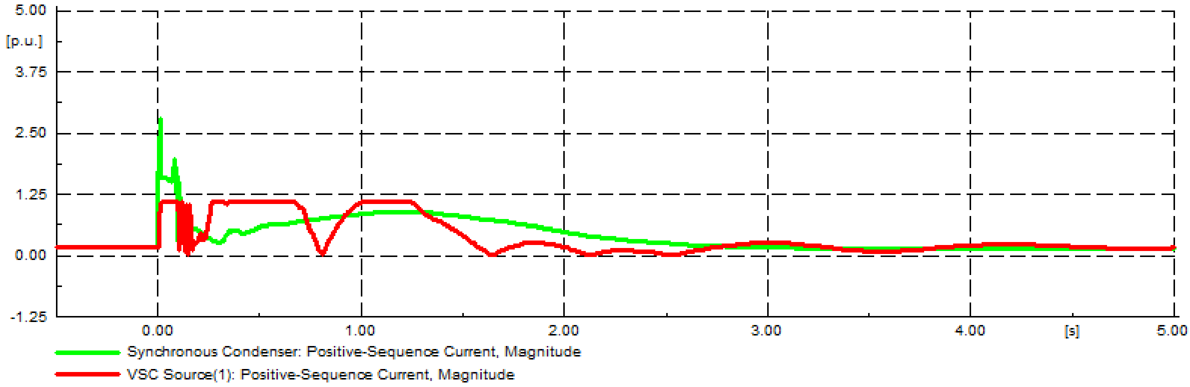


Figure 7 Fault Contribution from SC and STATCOM for a Fault at B6 Boundary

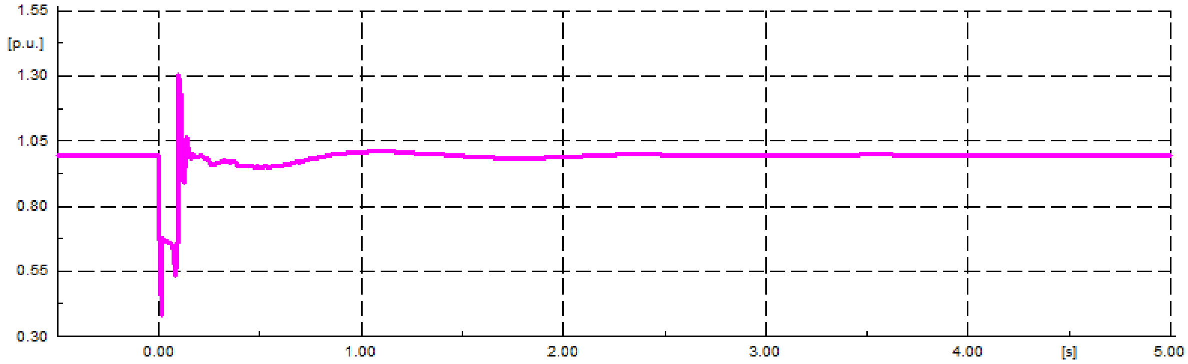


Figure 8 Voltage at Neilston 275kV for a Fault at B6 Boundary

Dynamic Reactive Power Support

Figure 9 shows the reactive power output from SC and STATCOM branch from a 140 MVA rated H-SC installed at Neilston 275kV, for a fault at Neilston busbar. When the fault occurs at 0 s, reactive power injection from SC increases immediately and provides reactive power support during the fault. Whereas STATCOM provides no reactive power support during the fault. As discussed before, due to the UV block capability of STATCOM, there is no reactive support from STATCOM during the fault. Due to this behaviour, SC improves the residual voltage profile at

Neilston location whereas STATCOM does not provide any support to improve the voltage profile at Neilston location.

When the fault is cleared, SC immediately absorbs reactive power whereas STATCOM injects reactive power and in a very short period it starts to absorb reactive power.

After the fault is cleared, STATCOM injects reactive power to the maximum and supports the post-fault voltage recovery. In comparison, the SC takes time to injects full reactive power output due to the time delay in the excitation system. Hence for the post-fault condition, STATCOM provides better dynamic voltage support compared with SC.

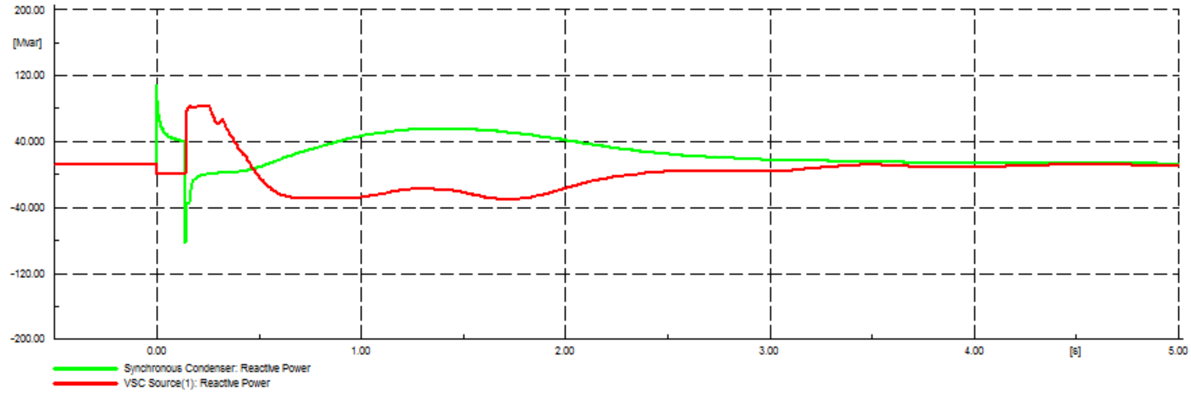


Figure 9 Reactive Power Contribution from AC and STATCOM for a fault at Neilston 275kV

Figure 10 shows the reactive power contribution from SC and STATCOM for a fault at B6 boundary circuit. In this case STATCOM injects reactive power during the fault, as STATCOM is not blocked for UV condition. Other performance behaviour of SC and STATCOM are similar to that of the fault at Neilston location. H-SC will have the combinational behaviour of SC and STATCOM.

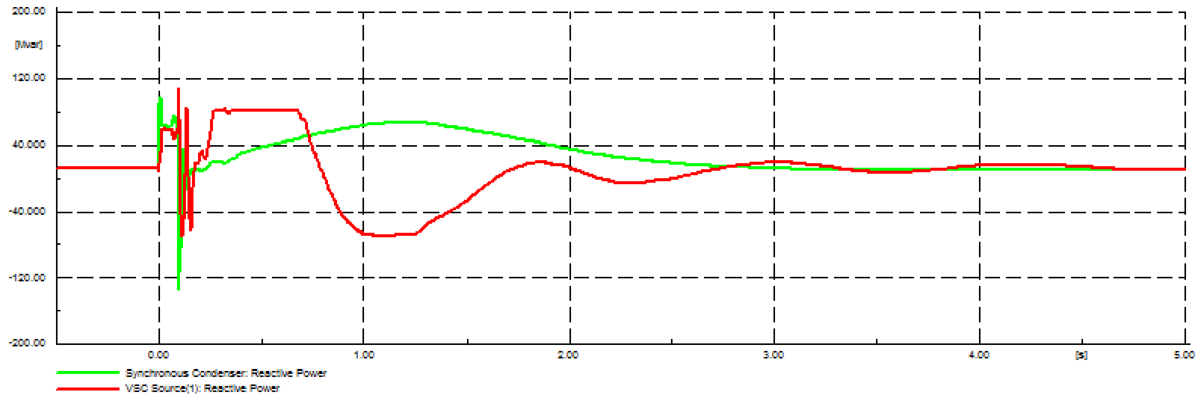


Figure 10 Reactive Power Contribution from SC and STATCOM for a Fault at B6 Boundary

Figure 11 shows the comparison of voltage profile with (Black line) and without H-SC (red line) at Neilston location, for a fault at B6 boundary. As discussed, after the fault clearance SC absorbs reactive power immediately. Due to this behaviour, SC reduces the Transient Over Voltage

(TOV) values whereas TOV is not reduced by STATCOM. In this case, TOV reached the maximum value of 1.247 p.u. without H-SC and reduced to 1.207 p.u. with H-SC.

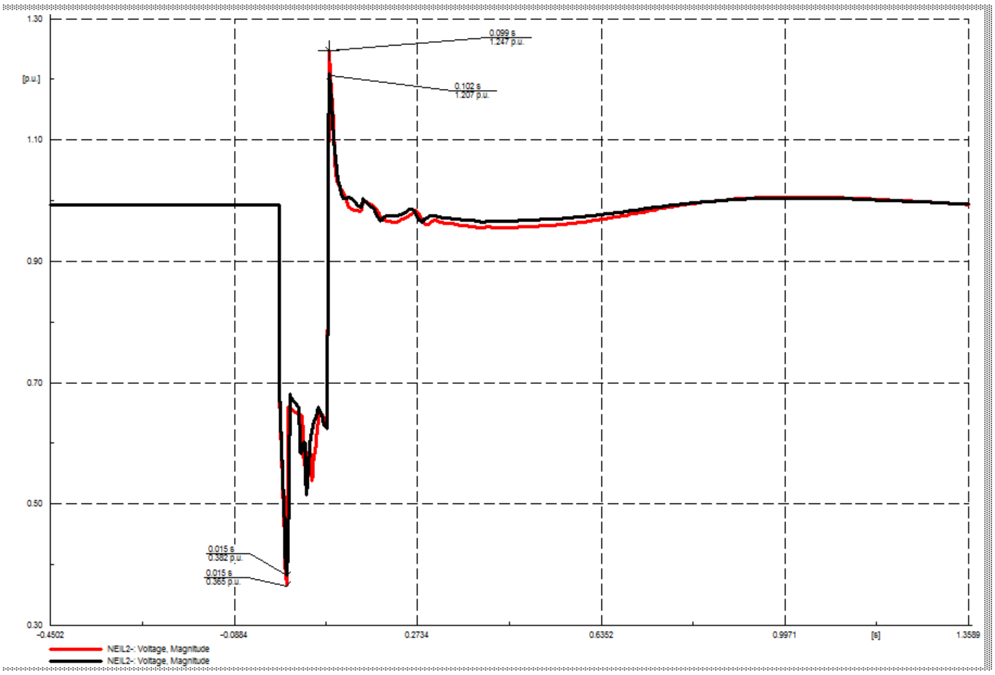


Figure 11 Comparison of Voltage Profile at Neilston Location for a Fault at B6 Boundary, with and without H-SC

From this analysis, the following has been observed:

- The amount of reactive power injection from SC and STATCOM, during the fault, depends upon the location and severity of the fault. For a fault closer to the H-SC, SC injects reactive power immediately and hence the residual voltage is improved. For this case, STATCOM will be blocked.
- If the impedance between the fault location and H-SC location is high, where voltage dip at H-SC is not severe, both SC and STATCOM provide reactive power during the fault and improve the residual voltage.
- When the fault is cleared, SC absorbs reactive power immediately and hence Transient Over Voltage (TOV) will be reduced. In comparison, the STATCOM takes some time to absorb reactive power and does not reduce the TOV.
- After the fault clearance, STATCOM responds quickly and provides better dynamic voltage support compared with SC.

Boundary Analysis

Scotland to England & Wales boundary (B6 boundary) has two double circuit AC interconnector lines and Western HVDC link. To determine the boundary limit, steady state contingency analysis has been carried out for all fault cases in Scottish Power Transmission (SPT) region, North East and North West of England & Wales Transmission regions. For the dynamic analysis, double circuit AC interconnector lines' fault cases and Western HVDC fault case are considered. From this analysis, boundary transfer limit has been identified for the base case. The study has been then repeated with the installation of SC/ STATCOM/H-SC at Neilston location. The difference in boundary transfer capability for different options is then used to evaluate the benefits. This section discusses the results obtained from the boundary analysis for different network conditions and scenarios and validations on boundary transfer limits.

Year 2019 Scenarios

For the 2019 background, with the assumed generation background in summer and winter seasons, the fault level at Hunterson end of Western HVDC is enough to load the Western HVDC to the maximum limit. With the maximum loading of Western HVDC, steady state and dynamic analysis has been carried out. For both winter peak and summer minimum periods, for a AC interconnector line fault, thermal overload occurs when the boundary transfer has been increased. With this boundary limit, dynamic analysis has been carried out. The results show that system is stable (both in terms of voltage and angular stability). For the analysed fault cases, frequency and RoCoF are within the limit. Hence for the year 2019 background, thermal loading becomes the limiting factor for the boundary. The assets that are limiting the boundary transfer levels, due to thermal loading, are already planned to be replaced through Network Option Assessment (NOA) 2018.

Thermal loading is the limiting factor for the Year 2019 network background, the addition of SC / STATCOM/ H-SC will not increase the boundary limit. However, addition of SC / H-SC will provide fault infeed and inertia to the system. For 2019 background, the fault level is enough to load the Western HVDC to the maximum. Hence there is no additional benefit could be realised with the addition of SC / H-SC.

For 2019 background, if Hunterston units are not available, then the fault level around the area will be reduced. With the reduced fault levels, Western HVDC link cannot be loaded to the maximum (limitation is due to the system condition). In this case, voltage stability will be the limiting factor and dynamic reactive support from H-SC will provide additional boundary transfer capability.

Year 2023 Scenarios

For the Year 2023 background, it has been assumed that Hunterston nuclear generation will be decommissioned. With the closure of Hunterston nuclear generation, fault level around the area is reduced. With the reduced fault levels, Western HVDC link can’t be loaded to the maximum (limitation is due to the system condition). NOA 2018 suggests that assets that are limiting the boundary transfer, due to thermal overloading, will be replaced before 2023. With these assumptions, boundary analysis has been carried out.

Results show that when the boundary transfer has been increased, for a double circuit AC line fault, voltage collapse occurs in the system. Figure 12 below shows the voltage profile for a busbar, for a double circuit fault case in B6 boundary, with the stable boundary transfer limit for the counterfactual case. It can be seen that after the fault clearance, voltage dips upto 0.8 p.u. and settles back to steady state value. If the boundary transfer is further increased, voltage dips below 0.8 p.u. and is not able to recover back to the steady state value and causes voltage collapse condition. This is due to the reduction of dynamic reactive support in the system. For both winter and summer scenarios, voltage stability is the limiting factor for B6 boundary transfer limit.

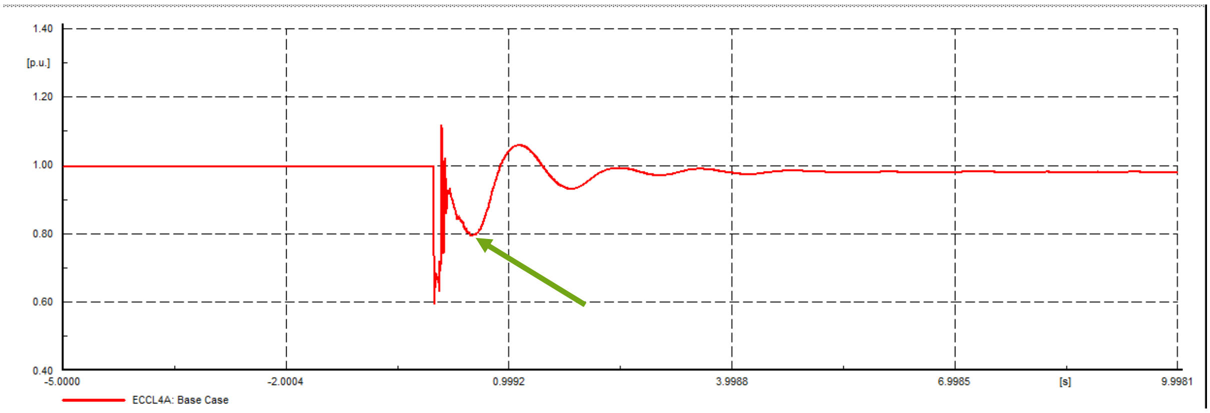


Figure 12 Voltage for a Busbar inScotland, for a fault in B6 Boundary

The addition of SC/ STATCOM / H-SC would provide dynamic reactive support and hence it would increase the boundary transfer capability. Dynamic analysis has been repeated for installation of:

1. 140 MVA STATCOM
2. 140 MVA SC
3. 70 MVA of SC and 70 MVA of STATCOM
4. 140 MVA of H-SC

For summer minimum scenario, for all these options, boundary transfer capability is increased by 45 MW. For winter peak scenario, the first two options (SC only, STATCOM only), boundary transfer capability is increased by 70 MW. With H-SC or combination of SC and STATCOM option, boundary transfer capability is increased by 90 MW.

Figure 13 shows the reactive power flow from SC/ STATCOM / H-SC. It shows that all these options provide dynamic reactive support during the fault and after the fault clearance. As discussed before, it can be seen that during the fault reactive power support from SC is superior compared with other options. The reactive power support from STATCOM after the fault clearance is more dynamic (i.e. fast response), however, there is an oscillation before it settles to steady state. Whereas reactive power support from H-SC has the combinational effect. It has also been observed that the dynamic reactive support from SC/STATCOM/ H-SC also improve the residual voltage levels, TOV and voltage angle changes. Hence in addition to the increase in boundary transfer capability, these options also improve the residual voltage, TOV and voltage angle changes.

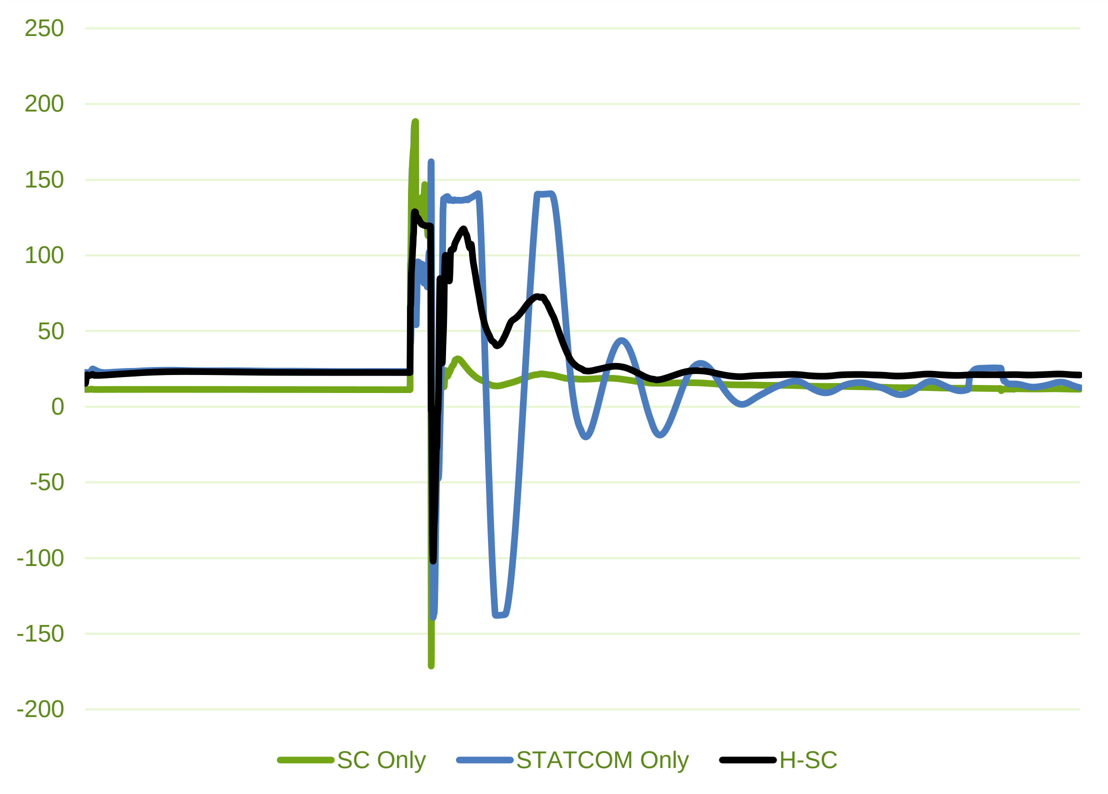


Figure 13 Comparison of Reactive Power Contribution from SC, STATCOM and H-SC

Year 2027 Scenarios

For the Year 2027 background, in addition to the Hunterston nuclear station closure, it has been assumed that Torness nuclear generation, Heysham station 1 nuclear station and Hartlepool nuclear generation will be decommissioned. With the closure of these nuclear generators, fault level at Western HVDC busbar is reduced. With the reduced fault levels, Western HVDC link can't be loaded to the maximum (limitation is due to the system condition). With these assumptions, boundary analysis has been carried out. As expected, the dynamic support of the system is reduced further and boundary transfer is limited by the voltage collapse.

For summer minimum scenario, for all these options, boundary transfer capability is increased by 65 MW. For winter peak scenario, the first two options (SC only, STATCOM only), boundary transfer capability is increased by 70 MW. With H-SC or combination of SC and STATCOM option, boundary transfer capability is increased by 98 MW. As discussed before, dynamic reactive support from these options improves the residual voltage, TOV and voltage angle profiles. The fault infeed from H-SC is too small to impact the fault level at Hunterston and hence the loading level of Western HVDC.

Further Analysis

The previous sections analysed the benefit of a 140 MVA H-SC at Neilston location, in terms of boundary transfer capability. As discussed before, a single H-SC contribution to the SCL and frequency response may not be significant. However, multiple units of SCs/ H-SCs would provide benefits in terms of SCL and inertia. This section illustrates the contribution of H-SC in terms of inertia and SCL to the system, in particular, with multiple SCs in the system. Please note that detailed analysis on benefit of multiple H-SCs/ SCs in the system will be carried out as part of the

SDRC 2.6 “Report on value analysis from roll out of SCs/ H-SCs in GB in future potential sites” and SDRC 5.3 “Report on optimal placement and capacity evaluation of SCs/H-SCs in GB”.

SCL and Western HVDC Operation

For the year 2023 and 2027 network background, due to the reduced fault level, Western HVDC loading has been reduced (due to the limitation of system condition). The addition of SC will provide fault infeed to the system. However, the addition of a 140 MVA SC is not enough for the fault level to increase to a level where loading of Western HVDC could be increased. Hence for the Year 2023 and 2027 background, with a 140 MVA SC/ STATCOM / H-SC options, loading on Western HVDC is reduced.

Further analysis has been carried out to determine the fault level requirement and loading level of Western HVDC. It has been found that at least 700 MVA SC should be added at Neilston 275kV location to operate Western HVDC at its maximum power transfer limit. It has been also found that installation of 350 MVA SC at Hunterston location is enough to provide fault level to operate Western HVDC at its maximum loading condition. Hence the size and location of the SC will have major influence on the boundary transfer limit. The analysis on different size of SC/H-SC and locational impacts will be analysed in the future studies.

Frequency and RoCoF Analysis

This section explains the analysis carried out on the impact of inertia contribution from SC and their impact on RoCoF and frequency constraint limits. Using the FES 2018 Community Renewable data and BID3 economic dispatch for each hour, inertia of the system has been calculated. With the RoCoF limit, the maximum infeed loss has been calculated. For every hour, with the maximum infeed loss limit, the amount of generation that needs to be constrained has been calculated. The amount of MWhr constraint for each year has been calculated and compared with the MWhr constraint when a 70 MVA SC is added to the system. In order to carry out this analysis, the following assumptions have been made:

1. The inertia constant for SC is assumed as 1.34s.
2. From the Year 2019 to Year 2022, RoCoF limit is considered as 0.125 Hz/s. RoCoF setting replacement program is expected to be completed by 2022 and hence for the years from 2023, RoCoF limit is considered as 1 Hz/s.
3. After the changes in RoCoF settings to 1 Hz/s, minimum and maximum frequency limit could be the limiting factor. Hence, the MWhr constraint has been calculated with the low and high frequency limits as 49.2 Hz and 50.5 Hz.
4. From the Year 2025 it has been assumed that sufficient Fast Frequency Response services will be in place.
5. Regional RoCoF variation and locational impacts of SC are not considered in this analysis.

The comparison results are presented in Figure 14. The amount of MWhr constraint is largely due to the high penetration of non-synchronous generation in the system that reduces the inertia of the system and restricts the maximum infeed on interconnectors to achieve RoCoF limit. In the future years, with the increase in number of interconnectors the amount of MWhr constraint increases. With the change in RoCoF settings to 1 Hz/s, the amount of MWhr constraint is reduced. With the sufficient Fast Frequency Response services available, from 2025, the amount of MWhr constraint is further reduced. It has been observed that with the addition of a 70 MVA SC with intertia constant of 1.34s, there is no noticeable reduction in the MWhr constraints.

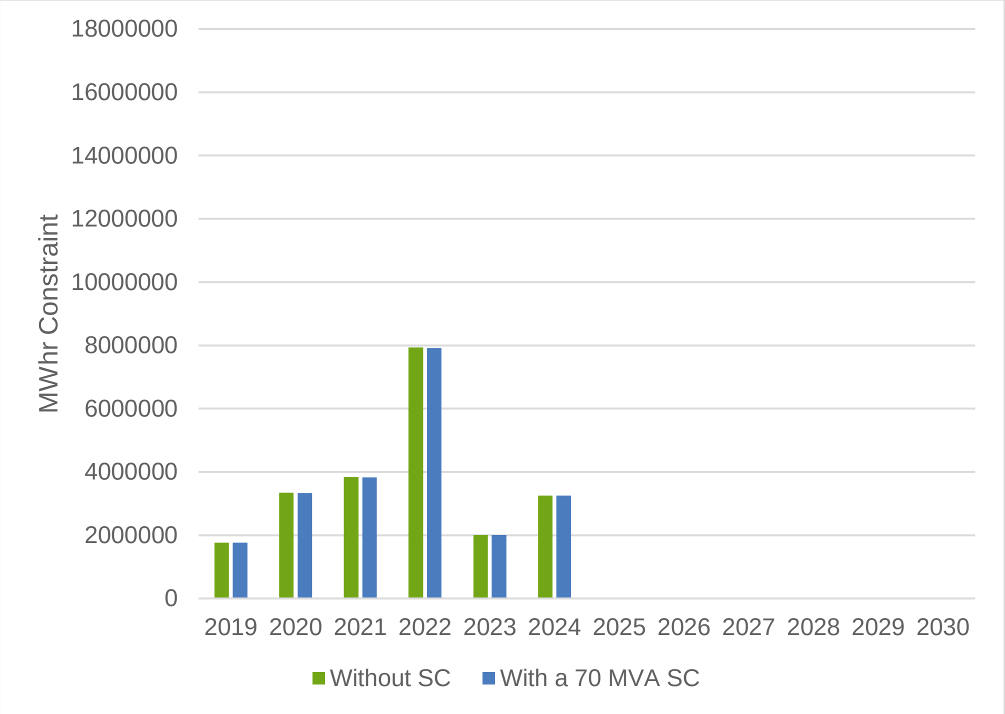


Figure 14Comparison of MWhr Constraint with and without a SC

Further analysis has been carried out with multiple units of SC installed in the system. Figure 15 shows the MWhr constraint for the following:

- Without SC
- With a 70 MVA SC (Phoenix SC size of 0.0938 GVA-s)
- With a 420 MVA SC (6 times the Phoenix SC size, 0.5628 GVA-s)
- With 4200 MVA SC (60 times the size of Phoenix SC, 5.628 GVA-s)

It can be seen that with the increased number of SC, MWhr constraint is being reduced. However, to see any noticeable difference, SC capacity of 4200 MVA (equivalent of 5.628 GVA-s) is required. From the international market analysis, it has been noticed that a typical rating of SC is about 215 MVA. With the assumption of 215 MVA, about twenty SC units are required to see noticeable difference in MWhr constraint. The international market analysis report also highlighted that SCs could be installed along with flywheels to increase the inertia contribution from SC. If the inertia constant of SC with flywheel type unit is assumed as 5s, then five units of 215 MVA SC with flywheel could see noticeable difference in MWhr constraint.

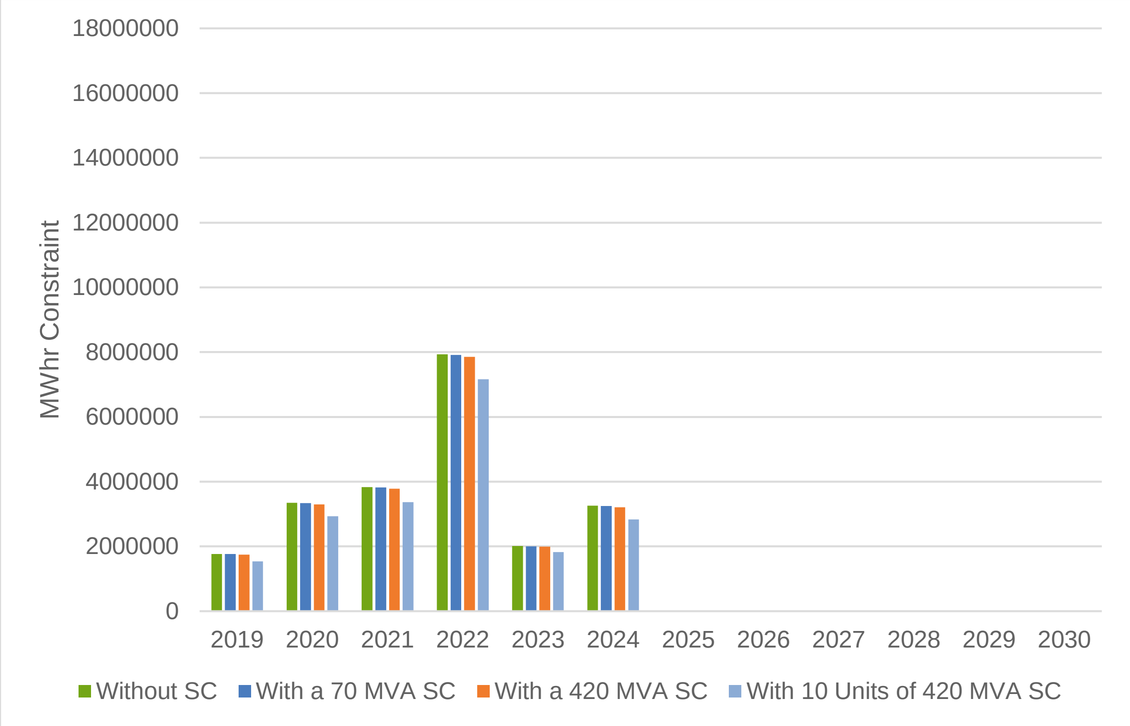


Figure 15 Comparison of MWhr Constraint with Different SC Ratings, Assuming Sufficient Fast Frequency Response

Figure 16 shows MWhr constraints if Fast Frequency Responses are not available. This shows that with the increased number of SC, the amount of MWhr constraint will be reduced for each year.

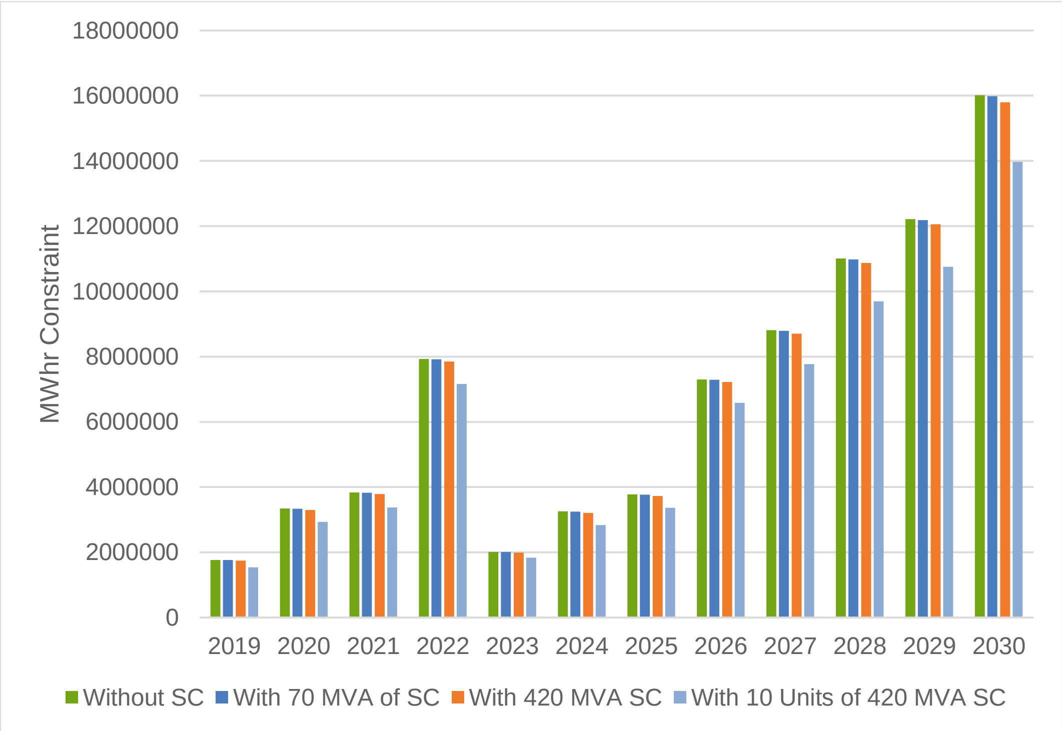


Figure 16 Comparison of MWhr Constraint with Different SC Ratings, Assuming no Fast Frequency Response

Validation of Results

Throughout the system analysis a number of validation checks have been carried out and this section explains these results.

1. Results obtained from thermal analysis work have been compared with ETYS study results. In particular, thermal overloading issues in the Year 2019 background showed the same results as obtained from ETYS studies.

2. The B6 boundary stability limit, without Hunterston units, has been compared against current year real time scenario during Hunterston units on outage. The study results from this work is similar to the boundary limit obtained from current year limits.

3. The performance of SC and STATCOM model has been verified with technical specification of these devices.

4. The fault level contribution from SC and dynamic reactive power support from AC and STATCOM are similar to the results obtained by University of Strathclyde, another Phoenix project partner.

Summary on Study results

The impact of a 140 MVA H-SC at Neilston location, on system performance, has been evaluated through system studies. The benefits of H-SC are compared with other options of SC only, STATCOM only and SC and STATCOM together at one node without hybrid control. The main findings are:

1. Dynamic reactive support from SC / STATCOM/ H-SC improves 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 is an improvement in residual voltage of the system, TOV, voltage angle changes in the system.

3. There is no significant observed difference between different options, in terms of boundary transfer improvements. In certain scenarios, H-SC or SC and STATCOM together options, provided more boundary transfer capability than SC or STATCOM options in isolation. **Further analysis, with different ratings and locations required to establish the difference**.

4. 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.

5. The Fast-Transient Compensation (FTC) function is included in the H-SC model. For the B6 boundary fault cases, voltage change at Neilston is high enough to trigger STATCOM to provide full output with or without FTC function. Hence there is no additional benefit has been observed from FTC function.

6. The Power Loss Minimisation (PLM) function is not included in the H-SC model. PLM function will reduce the power loss in the steady state condition and will not affect the dynamic behaviour of the system.

7. The Inertia Support Maximisation (ISM) function is not included in the H-SC model. The power losses in STATCOM is less than 1% and hence ABB found that ISM function provides little to no benefits to the system.

8. The addition of SC / SC in H-SC provided fault infeed to the system. With the multiple SCs installation, there will be a significant improvement in SCL of the system. This will further improve the residual voltage, TOV and voltage angle changes. The increase in SCL will also influence the operation of Western HVDC and could benefit the operation of protection systems.

9. The impact of inertia from SC on RoCoF and frequency containment, with the assumption of inertia contribution from SC as 0.094 GVA-s, is not significant. The study shows that significant number of SCs or high rating SCs or SCs with flywheel are required to realise the significant improvement in generation constraint cost.

Cost Benefit Analysis (CBA)

This section explains the methodology used for the CBA, assumptions and results obtained from the current CBA analysis on evaluating the benefits of a 140 MVA H-SC at Neilston location.

CBA Methodology

To assess the economic benefit of H-SC at Neilston location, assessment on boundary transfer benefits have been carried out against the benefit of different options:

1. STATCOM only
2. SC only
3. SC and STATCOM together at one node (Without hybrid control)
4. H-SC

The boundary power transfer limits obtained from the power system analysis are provided as input to a separate economics assessment tool BID3, tool to quantify the system benefit of the H-SC. BID3 is already used by the NGESO to carry out other cost benefit assessments in established industry processes.

BID3 is an externally owned tool built by Poyry and works in two parts; first is an economic market dispatch, and then there is a secondary re-dispatch of the market to satisfy boundary constraints. The dispatch is an hourly market dispatch across Europe, looking to minimise system prices. The re-dispatch is only within GB (although can take actions on the interconnectors) and seeks to minimise cost against bid and offer prices for each generator. The benefit driven from increasing boundary capability will come from lower operation costs. The benefit must be compared to the increased capital costs from the investment to define the Net Present Value (NPV) for each option. The power system analysis has been carried out for Community Renewables (CR) Scenario to determine the boundary transfer capability. Using the same boundary capability values, cost benefit analysis has been repeated for all other FES scenarios.

Other inputs to the CBA tool include the installation cost, maintenance cost, availability factors and life expectancy for each technology. For this project, ABB provided these data for SC, STATCOM and H-SC options. In the CBA methodology, the capital cost is discounted via the Spackman method and uses the discounting Social Time Preference Rate (STPR) which is from the Government Green Book (generally 3.5%). The operating cost is also discounted with the same values.

Using these inputs, the tool calculates the economic benefit of installing a H-SC or other options to increase boundary transfer capabilities and meets the criteria set out in SQSS. The Cost Benefit Analysis (CBA) specification report, submitted for SDRC 2.1, is provided in Appendix A. Figure 17 illustrates the overall CBA methodology.

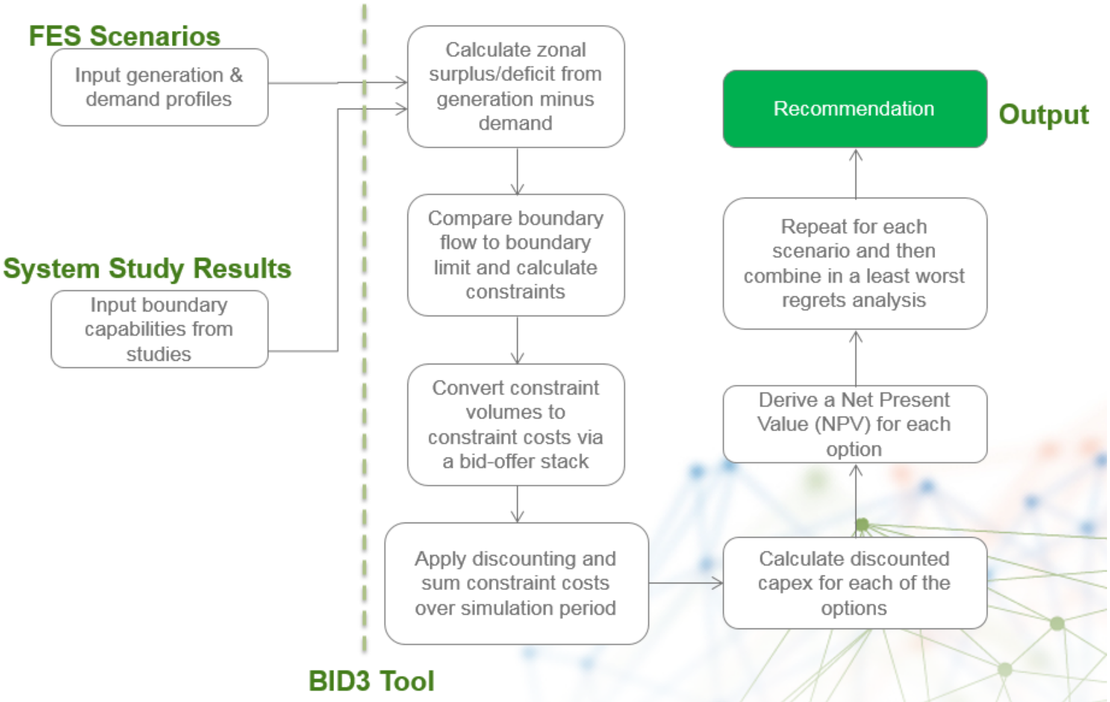


Figure 17 Cost Benefit Analysis (CBA) Methodology Flowchart

As discussed before, power system analysis has been carried out with the ETYS 2017 system model and hence some of the NOA 2018-19 recommendations are not considered in the background. Without considering all NOA 2018-19 options, the boundary transfer limit will be lower. This in turn means that the amount of generation that needs to be constrained will be higher. Hence each additional capacity provided by SC / STATCOM / H-SC options are much more valuable than if all NOA 2018-19 options are considered. To illustrate this difference, economics analysis also has been carried out for two cases:

1. The absolute boundary transfer capability based on NOA 2017-18 options (not all NOA 2018-19 options in the background)
2. Adjusted boundary transfer capabilities assuming all NOA 2018-19 options in the background (referred as NOA Delta method)
    a. Hence the base case / counterfactual had additional B6 boundary transfer capability higher than the previous case
    b. The same level of increase in boundary transfer with each option is assumed

CBA Results

The capital cost range for different options considered are provided in the table 4 below.

Table 4 Capital cost range for each option

	STATCOM	SC	SC & STATCOM	H-SC
Cost Range £m	10.5 to 20.9	11.3 to 22.5	15.3 to 30.5	12.9 to 25.9

A wide range of capital cost has been considered for each option as there will be site to site variation costs (such as ground works, civil works, cable works so on) and variation in market conditions (supplier capacity, exchange rate). The capital cost variation between different options are also due to the differences in number of transformers required, maintenance and refurb requirements and Hybrid Control requirements so on.

The following two tables shows the net benefit of reduced balancing costs (reduced balance costs against the baseline minus additional investment costs), for different options against the FES background. The benefit results are calculated over the assets' life period of 40 years. The positive sign indicates that the additional benefit is worth the increased investment.

Table 5 Net Cost Benefit range under Absolute Capacities, £m

FES Scenario	STATCOM	SC	SC and STATCOM	H-SC
CE	60 to 70	58 to 70	67 to 83	73 to 86
CR	45 to 55	43 to 55	47 to 63	53 to 66
TD	46 to 56	44 to 56	48 to 64	54 to 67
SP	37 to 47	34 to 46	34 to 50	40 to 53

Based on absolute capacities, each option is providing economic benefits to the system operation, for all FES scenarios. As discussed in the boundary analysis, with the closure of Hunterston nuclear generation in 2023, H-SC provides increase in boundary capability and provides economic benefit. The benefit is further increased with closure of additional nuclear stations in 2024 and beyond. The net cost benefits are high during the periods of high wind generation in Scotland region. The net cost benefits are more in the mid-2020s, and in the later years with the completion of NOA recommended projects the benefit of H-SC / SC / STATCOM is reduced.

With the H-SC and SC& STATCOM together options, boundary capabilities are higher in certain scenarios. Hence both these options are providing more economic benefit compared with SC only or STATCOM only options. H-SC option has only one transformer whereas SC and STATCOM together option has two separate transformers. Hence H-SC capital cost is lower than SC and STATCOM together option. Due to this difference in capital cost, even though boundary increase capability is the same, H-SC is more economical than other options.

Table 6 Net Cost Benefit range under NOA Delta, £m

FES Scenarios	STATCOM	SC	SC and STATCOM	H-SC
CE	(-4) to 6	(-7) to 5	(-11) to 5	(-7) to 9
CR	7 to17	5 to 17	7 to 23	11 to 27
TD	20 to 30	17 to 29	31 to 47	35 to 51
SP	(-13) to (-3)	(-15) to (-3)	(-17) to (-2)	(-13) to 3

With all other proposed NOA 2018-19 options in place, the boundary transfer capabilities have been adjusted in NOA Delta approach. With this approach, all options are providing economic benefit in CR and TD scenarios, backgrounds that would achieve 2050 decarbonisation target. As in the previous case, H-SC provides more benefit than other options. Whereas in CE and SP scenarios, the benefit is negative i.e., the investment is not justified under these scenarios.

It should be noted that the power losses incurred by these options is not considered in the CBA analysis. If the power losses incurred by the devices are taken into account, then the net cost benefit values will be lower than those shown in Table 5 and 6. This will be further analysed in future works.

Power Loss Calculation

In the current CBA calculation, the power loss incurred by the devices (SC / STATCOM) and the corresponding cost are not included. By considering the cost associated with the power losses incurred by different options, the net cost benefit values showed in Table 5 and Table 6 will be reduced.

For the H-SC option, the power loss for SC and STATCOM is about 2% and 1% at load conditions. This corresponds to the SC and STATCOM power loss of 1.4 MW and 0.7 MW respectively. Assuming H-SC to be in service for 50% of time in each year, the total power loss of H-SC is estimated as 9198 MWhr per year. With this value, the total power loss for the device life period of 40 years has been calculated. With the assumption of cost for MWhr power loss as £60 / MWhr and derating factor of 3.5%[8], the total cost incurred by the H-SC power loss is calculated as £12.6m. Hence the net cost benefit range for H-SC option shown in Table 5 and 6 will be further reduced by £12.6m.

Further analysis will be carried out to profile the power losses incurred by each option and the cost associated with power loss.

[8] In the CBA methodology, the capital cost is discounted via the Spackman method and uses the discounting Social Time Preference Rate (STPR) which is from the Government Green Book (generally 3.5%). The operating cost is also discounted with the same values.

Summary

In this work, the performance of SC, STATCOM and H-SC has been validated and the benefit of a 140 MVA H-SC at Neilston location has been evaluated, in terms of boundary transfer capability, compared with other options. The boundary transfer capabilities obtained from power system analysis has been used to carry out Cost Benefit Analysis (CBA), using BID3 tool.

For most of the scenarios, the increase in boundary transfer capabilities are similar for all options, however, in certain scenarios, H-SC and SC & STATCOM together options provided more increase in boundary capabilities. The capital cost of the H-SC is lower than SC & STATCOM together option. Hence H-SC provided more cost benefit compared with other options with the ETYS 2017 background.

With the ETYS 2017 background, not all NOA 2018-19 reinforcement options are considered. Assuming NOA 2018-19 options are also in place, the amount of generation constraint required is reduced and hence the cost savings are reduced.

The capital cost for SC / STATCOM / H-SC obtained from ABB is used for the CBA analysis. The cost benefit analysis has been carried for the assets' life period of 40 years. For this work, it was possible to complete CBA analysis with one hour time steps and the sensitivity of increasing time step to 3 hours to save the running time was not carried out.

The operating mode of H-SC is assumed as both SC and STATCOM are available and operating in automatic voltage control mode. This mode of operation will provide dynamic reactive power, SCL and inertia at all time and hence would be preferred mode of operation. However, in this mode of operation, the power losses due to SC and STATCOM would be high.

H-SC functions such as Power Loss Minimisation (PLM) will reduce the power losses in the steady state condition. This will be the additional benefit of H-SC in comparison with the SC and STATCOM together without hybrid control option.

This work is to show the benefits that could be achieved by H-SC at Neilston location and is not sufficient to suggest investment in an H-SC. In order to determine whether H-SC investment is an economical investment, it should be compared against other competing options, through NOA process.

Further Work

This report analysed the performance of SC, STATCOM and H-SC and evaluated the benefit of a 140 MVA H-SC at Neilston location. The benefit of H-SC is compared against other options such as SC/ STATCOM/Combined SC and STATCOM.

The initial works on power loss calculation have been carried out and will be further explored in the future works to profile the power loss incurred by H-SC.

Following the actual installation of H-SC at Neilston, trial data will be collected and will be compared with the study results for validation purpose. Through this evaluation benefits of H-SC at Neilston location will be completed through both system analysis and trial.

Following this, the benefit of higher rated H-SC at Neilston location will be evaluated. Then further analysis will be carried out by considering H-SCs at different locations in the GB system, to evaluate the benefit of H-SC / SC. These results will be provided as input to CBA analysis to determine the economics of H-SC on the wider GB network.

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Glossary of Terms

Abbreviation	Definition
AVR	Automatic Voltage Regulator
BAU	Business as Usual
CBA	Cost Benefit Analysis
CION	Connected Infrastructure Options Notes
CR	Community Renewables
CSC	Current Source Converter
FES	Future Energy Scenario
H-SC	Hybrid Synchronous Compensator
HVDC	High Voltage Direct Current
ISM	Inertia Support Maximisation
NGESO	National Grid Electricity System Operator
NOA	Network Option Assessment
NPV	Net Present Value
OEL	Over Excitation Limiter
PLM	Power Loss Minimisation
PV	Present Value
RDP	Regional Development Programme
RoCoF	Rate of Change of Frequency
SC	Synchronous Compensator
SCL	Short Circuit Level
SOF	System Operability Framework

SQSS	Security and Quality of Supply Standards
STATCOM	Static Compensator
STPR	Social Time Preference Rate
SWW	Strategic Wider Works
TOV	Transient Over Voltage
UV	Under Voltage
VSM	Virtual Synchronous Machine

Appendix A – Cost Benefit Analysis Specification SDRC 2.1

1. Introduction

The NIC Phoenix innovation project aims are to design and deploy a Hybrid Synchronous Compensator (H-SC) and evaluate the potential benefits of the device. This report describes the approach to the cost benefit analysis work that is part of the Phoenix project. It begins by recapping GB electricity system operability challenges and the potential benefits offered by H-SCs in meeting these challenges.

Power system analysis and cost benefit assessment will be carried out to assess the value of the H-SC that will be trialled at Neilston 275kV substation on SPT's transmission network. The results of these trials will enable the validation of the system study results that will be an input to the cost benefit analysis. Through power system analysis the benefits of H-SC at Neilston will be compared against other options including the installation of a synchronous compensator (SC) or a static compensator (STATCOM) in isolation.

The power system and cost benefit models developed through the work at Neilston will then be used to assess the value of H-SC installation at other locations on the GB transmission network.

The results of the power system analysis and cost benefit assessment will enable the Phoenix project to determine what consumer value is feasible through the wider deployment of H-SCs. This will help the NETSO and wider stakeholders to determine and design the commercial service framework to encourage the effective use of H-SCs alongside other solutions to meet operability challenges.

2. Background

GB Operability Challenges

The amount of conventional synchronous generation is declining in the GB electricity system due to the planned closure of coal and nuclear power stations as well as due to the increasing amount of solar and wind power generation being connected to transmission and distribution networks. The declining amount of synchronous generation on the network, reduces the fault level, also known as Short Circuit Level (SCL) of the system, that will have an impact on dynamic voltage management, power quality and the reliable operation of protection. The significant reduction of synchronous generation also reduces the level of system inertia, which will have an impact on frequency containment, Rate of Change of Frequency (RoCoF) and system stability.

Potential H-SC Benefits

The H-SC consists of a Synchronous Compensator (SC) and a STATic COMpensator (STATCOM) with an innovative hybrid control mechanism to maximise the benefits from both the SC and STATCOM. The SC has rotating mass and could provide Short Circuit Level (SCL) contributions, reactive power support and inertia to the system. A SC is similar to a synchronous generator without any active power (MW) contribution. The STATCOM provides steady state and dynamic reactive support to the system but does not have ability to provide fault level contribution and inertia.

The installation of H-SCs on the electricity system could provide the following benefits to the Electricity System Operator:

a) SCs and STATCOMs are both able to provide reactive power support in steady state conditions. For certain system boundaries, the installation of a H-SC or H-SCs would provide reactive power support and could potentially increase the boundary transfer capabilities.

b) SCs and STATCOMs are both able to provide dynamic reactive power capabilities. For particular system boundaries, the installation of a H-SC or H-SCs could provide dynamic reactive support and could improve the voltage stability limit/voltage collapse limit.

c) The amount of fault current contribution by H-SCs would increase the Short Circuit Level (SCL) of the system. The increase in SCL could improve the operation of High-Voltage Direct Current (HVDC) links by reducing the likelihood of commutation failure of Current Source Converter (CSC) type HVDC links. This could potentially improve the thermal, voltage and angular stability limits for certain boundaries.

d) The inertia contribution from a H-SC or H-SCs could improve the angular stability limit for certain boundaries. The inertia contribution from H-SCs could impact the Rate of Change of Frequency (RoCoF) and frequency nadir limits and as a result H-SCs could reduce the amount of generation which is constrained to meet the RoCoF and maximum infeed loss limit for the given scenario.

The above benefits that could be obtained from H-SCs will be analysed using a well-established Cost Benefit Analysis (CBA) method that has been adopted to use in this project. The value of using H-SCs to provide these benefits will be compared with other technologies. This work will initially focus on an H-SC installation at Neilston so that the CBA results can be checked through the trial H-SC installation. This will allow the models and assumptions to be fine-tuned.

Having done this verification of the H-SC model and the CBA methodology, the installation of H-SCs at other GB sites will be tested. This will include variation of the Neilston H-SC design, discussed in section 5, that would provide different levels of reactive power support, fault levels or inertia more suited to the system needs in other locations.

<u>Potential H-SC Benefits Not Factored into CBA</u>

In addition to the benefits that will be quantified through the CBA work, H-SCs could provide other benefits to the GB network. For example, the fault level contribution from a H-SC or H-SCs could improve the residual voltage level and fault ride through capabilities of generation connected to the DNO network. The increase in fault level contribution from the H-SC would also reduce the requirement to change the protection settings (otherwise required if there is not enough system fault infeed). H-SCs could also improve the power quality of the system (harmonics, power oscillation damping) and the restoration capability of the system.

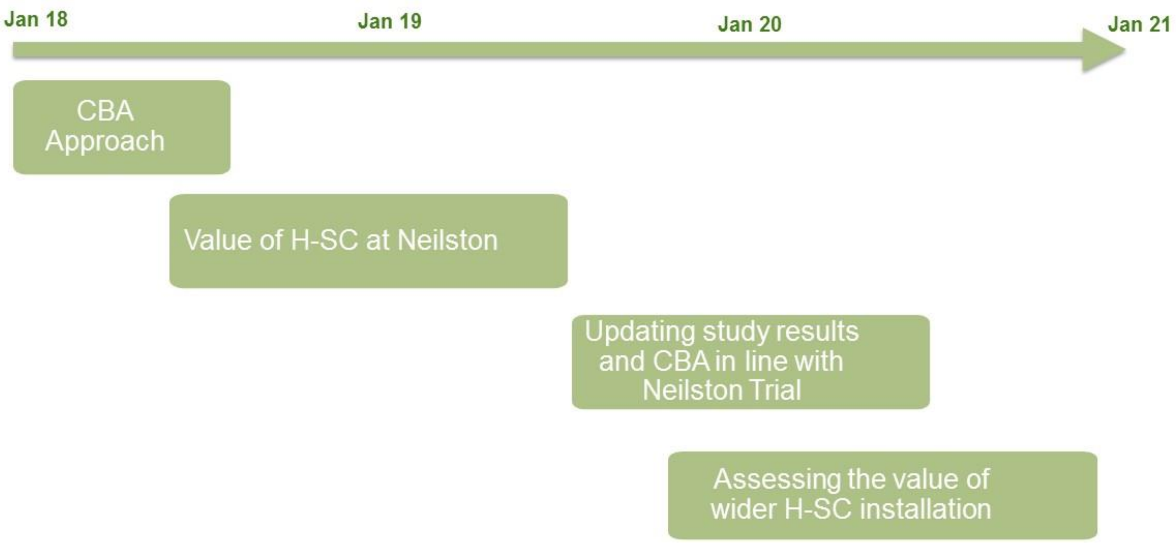
It should be noted that whilst some qualitative assessment will be provided on these benefits (for example indicative increases in distribution level fault levels will be considered), these additional benefits will not be analysed or quantified in the proposed CBA method.

3. CBA Methodology

Timeline

The H-SC value assessment will follow the timeline shown in Figure 1.

Figure 1 – Broad Timeline for CBA Work



There are 4 phases of CBA work. After the overall approach and methodology has been established (this report), the second phase of work will focus on quantifying potential benefits for the ongoing H-SC installation at Neilston 275kV substation.

The third phase of work will take results from trials of the installed H-SC to ensure that the H-SC model and CBA methodology are accurately representing H-SC performance and benefits.

A final phase of work will be carried out in parallel with the third phase. Having validated the H-SC model and the CBA methodology, this will identify other potential locations for H-SCs and assess the value of installing H-SCs at these locations.

Throughout the CBA work, results will be shared with a Commercial Working Group that is being established to inform the H-SC value assessment and the related work to develop appropriate commercial service arrangements.

In each phase of the work, the study results will be regularly reviewed. If it is clear that particular options are of limited value, the programme of studies will be adjusted to ensure effective use of study time.

Power System Analysis

A key part of the CBA method is carrying out detailed power system analysis studies to understand how the installation of H-SCs (or other options) will improve power system performance and capability to increase power system transfers. To order analyse the potential benefits from H-SCs, the following assessments will be carried out:

a. Thermal limit

b. Steady state voltage limit

c. Short Circuit Level
d. Transient stability limit
e. Voltage stability limit
f. Frequency and RoCoF limit

To determine the benefit of a H-SC at Neilston 275kV, the above assessments will initially be carried out for the Scotland to England & Wales boundary transfer (generally known as the "B6" boundary). The assessments (a) to (e) will provide the MW transfer limits for the B6 boundary and the assessment (f) will provide the maximum infeed loss allowable for the whole system. The assessments carried out to determine the boundary transfer will meet the criteria set out in the Security and Quality of Supply Standard (SQSS)[9].

The actual H-SC is planned to be installed at Neilston in summer 2019. The analysis outlined will be carried out for year 2019 and for two other years when major generation background changes are likely to materially impact the Scotland to England & Wales (B6) boundary transfer capability. The following network backgrounds will be considered to analyse the benefit of H-SC at Neilston:

1. For 2019 network – The trial H-SC will be installed at Neilston in 2019
2. For 2023 network – Assumed closure of Hunterston nuclear generation[10]
3. For 2027 network – Assumed closure of Torness nuclear generation[11] [12]

For the above network backgrounds, analysis will be carried out for both winter peak and summer minimum (solar peak) periods using the 2017 Future Energy Scenarios (FES) Consumer Power demand and generation background. This will enable a more accurate profile of the year round B6 boundary transfer limits to be established for the CBA model.

The boundary transfer values obtained from the winter peak and summer minimum demand conditions will be used to extrapolate the boundary transfer capabilities for other demand and generation scenarios and hence build up year round boundary transfer limits. To extrapolate the values even more accurately, additional sensitivity studies may be carried out to determine the boundary transfer limits for other system demand conditions.

The transfer limits calculated through the power system analysis will be used as inputs to a year round cost benefit analysis that is further described below.

Key Assumptions for Power System Analysis

In carrying out the power system analysis to support the CBA, several assumptions are made. These are outlined below together with checks that will be carried out to firm up assumptions and increase confidence in the CBA results.

H-SC Power System Model – ABB will be providing a detailed model of the H-SC at Neilston including the control system. This will be used in the PowerFactory representation of the GB network that the NETSO already uses for its day to day operational planning. The H-SC performance through this model will initially be compared with more established models for

[9] https://www.nationalgrid.com/uk/electricity/codes/security-and-quality-supply-standards?code-documents
[10] https://www.edfenergy.com/energy/power-stations/hunterston-b
[11] Torness nuclear closure is expected in year 2030. The network model is available only up to 2027, as part of Electricity Ten Year Statement (ETYS) studies.
[12] https://www.edfenergy.com/energy/power-stations/torness

SCs and for STATCOMs to gain confidence that the H-SC is being represented accurately. ABB will be providing the generic SC and StTATCOM models to carry out this analysis.

The results obtained using the H-SC model will also be compared to results from the trial installation at Neilston when these are available. The H-SC model will be adjusted if required in collaboration with ABB. This process to ensure accurate equipment models are in place is one that is familiar to the NETSO when new types of generation or other technology are connected to the GB network.

Power System Analysis Study Background – the background of generation and demand used to assess power transfer limits will be based on the 2017 FES Consumer Power background. This background is the most onerous of the FES backgrounds in terms of reduced levels of synchronous generation on the GB electricity system.

For each year and season studied, a generation and demand background consistent with the FES Consumer Power background will be used. The network representation used in the PowerFactory model will be a full dynamic model of the GB transmission network including all transmission connected generation and equipment.

Comparison Studies at Neilston

For comparison purposes, in the second phase of CBA work, the cost benefit of the H-SC at Neilston will be compared against other options that could resolve the same system issues. Analysis will be carried out for the following study cases:

1. Counterfactual case - base case without other solutions implemented to the network
2. With addition of Hybrid Synchronous Compensator (H-SC)
3. With STATCOM
4. With Synchronous Compensator (SC)
5. With SC and STATCOM at Neilston (but without the innovative control scheme).

Inputs to CBA Model

The boundary power transfer limits obtained from the power system analysis will be provided as input to a separate CBA tool to quantify the system benefit of the H-SC. In addition to the power system analysis and CBA carried out for the installation at Neilston, assessments will be carried out to determine the benefit of different H-SC specifications (e.g. variation in ratings of H-SC, SC and STATCOM ratio) and H-SCs installed at alternative locations on the network (please refer to section 5).

The CBA tool is the BID3 assessment tool that is already used by the NETSO to carry out other cost benefit assessments in established industry processes. An example template of this input to the CBA tool is shown in Table 1.

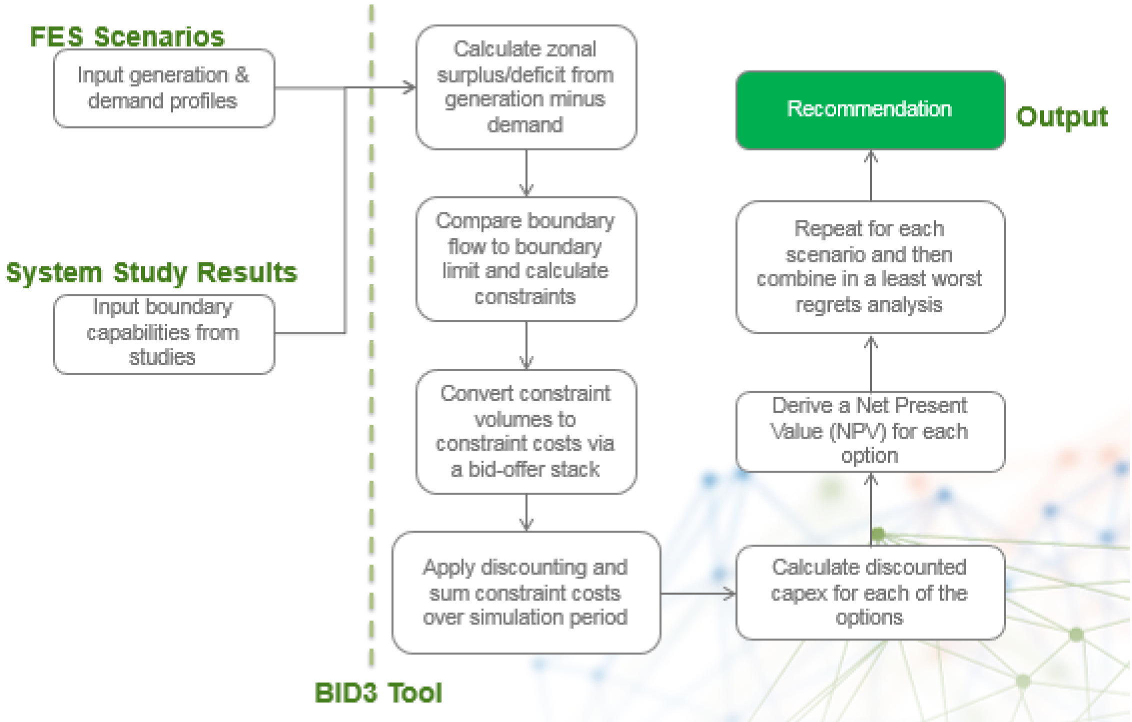
Table 1 - CBA Input Template

Boundary Limits	Scenarios	Study Cases				
	2019 Winter Peak	Without any changes	With H-SC	With SC	With STATCOM	With SC & STATCOM at one Node
Thermal Limit						
SCL at Hunterston						
Steady state voltage limit						
Transient Stability						
Voltage Stability						
Frequency / RoCoF limit						
	2019 Summer Minimum	Without any changes	With H-SC	With SC	With STATCOM	With SC & STATCOM at one Node
Thermal Limit						
SCL at Hunterston						
Steady state voltage limit						
Transient Stability						
Voltage Stability						
Frequency / RoCoF limit						

Other inputs to the CBA tool include the installation cost, maintenance cost, availability factors and life expectancy for each technology. Using these inputs, the CBA tool will calculate the economic benefit of installing a H-SC or other options to increase boundary transfer capabilities and meets the criteria set out in SQSS. The CBA tool will enable comparison of H-SC and other solutions over a specified period taking account of generation that would be constrained on or off because of power transfer limits.

The CBA tool will be capable out of carrying out the economic analysis over a study period of many years built up by modelling discrete 1 hour time steps. It will have the capability to model generators' availability and unavailability rather than assuming that all generators remain connected and uniformly scaling generator outputs to change boundary flow values. Figure 2 illustrates the overall CBA methodology.

Figure 2 - Cost Benefit Assessment Methodology



Key Assumptions for Cost Benefit Assessment

In addition to the assumptions made for power system analysis, further assumptions are made for the CBA. Some of the key assumptions are discussed below:

1. **H-SC Capital and Maintenance Costs** – accurate assumptions for these costs will be agreed with project partners (including ABB) and, where these are not commercially confidential, they will be tested with the Commercial Working Group. Sensitivity analysis will be carried out to test a reasonable range of costs.
2. **Time Granularity of CBA Analysis** – it is proposed to model one hour time steps in the CBA tool as previous experience indicates that this time step will provide an accurate representation of costs. Depending upon the study results, it may be possible to increase the time step (e.g. three hours) to save the running time for CBA analysis.
3. **H-SC Operating Regime** - the H-SC will have several operating modes based on how the SC and STATCOM elements are used to support the network. For the cost benefit assessment, the boundary transfer limits with the H-SC in place will be based on the mode where both SC and STATCOM could provide variable reactive power based on voltage condition and SC also could provide fault infeed and inertia to the system. Based on our assessment to date we believe this is most effective mode of operation and will be confirmed based on power system studies.
4. **FES Scenarios** – The system studies to determine the boundary limits will be based on FES Consumer Power scenario. However, in cost benefit analysis Net Present Value (NPV) of each option will be analysed for all four FES scenarios.

Limitations of H-SC Assessment

A Synchronous Compensator (SC) in isolation or as part of an H-SC could be provided by a new asset or by converting a mothballed or existing power station to SC operation. These approaches will have different costs. The proposed CBA studies do not include a case covering the conversion of a mothballed or existing power station to SC. The CBA methodology could accommodate the assessment of such solutions if these are shown to be viable options and if system models and cost data are made available.

4. More General Background to Cost Benefit Analysis Approach

The Economics Assessment Team within the System Operator have developed several methods for performing cost benefit analysis of network developments for a number of different purposes, including the Network Options Assessment (the NOA), Strategic Wider Works assessments (SWWs) and Connected Infrastructure Options Notes (CIONs).

Despite elements of each of these methods being unique, there is a common approach applied to determine which solution represents the most economical option for the GB consumer, taking into consideration uncertainty and characteristics of private sector investment in public services and infrastructure.

Step 1: Define a counterfactual case. This will be used as a base case to compare any additional costs or savings available when considering each of the possible options. Identifying benefits available when comparing to a counterfactual is often termed the Savings Approach.

Step 2: Forecast the level of constraint (boundary limit) for each of the options, following technical studies which determine the extent of constraint on the network and the extent that each option impacts the constraint[13].

Step 3: Find the Present Value (PV) of the cost (capex) of each of the options (provided by the proposer of the option) by applying the Spackman Method[14]. This method involves amortising the cost of the investment, taking into consideration the cost of financing the investment at the Weighted Average Cost of Capital (WACC) for the company proposing to deliver the option. This finance adjusted capex is then discounted at the Social Time Preference Rate (STPR).

Step 4: Find the PV of the savings per option by first deducting the constraint costs of the counterfactual case from the option case to give a saving or cost for the option when compared to the counterfactual. Summing these savings over the life of the option and discounting the value by the STPR yields the PV of savings for each option.

Step 5: Find the Net Present Value (NPV) of each option by deducting the PV capex from the PV savings.

Step 6: Create a matrix of the NPVs across all of the options and scenarios modelled and then perform a Least Worst Regret analysis to identify the preferred option[15].

[13] There are a variety of inputs required to get the constraint forecasting model to work correctly and to make this efficient a large number of these are standardised and validated annually. Some of the inputs for BID3 include:

- Plant & interconnector capacities and availability
- Generation profiles for renewables such as tidal, solar and wind based on weather years
- Fuel prices (including carbon prices)
- Demand levels by zone and weather based profiles

[14] The Joint Regulators Group on behalf of UK's economic and competition regulators recommend a discounting approach that discounts all costs (including financing costs as calculated based on a Weighted Average Cost of Capital or WACC) and benefits at the Social Time Preference Rate (STPR). This is known as the Spackman approach.

[15] For further information on Least Worst Regret analysis, refer https://www.nationalgrid.com/sites/default/files/documents/NOA%20Methodology%20Review%202017.pdf

5. Wider Analysis of H-SC Ratings and Locations

In addition to the power system analysis and CBA carried out for the installed H-SC at Neilston, additional assessments will be carried out to test the value of different H-SC specifications and of H-SC installations at other locations. This work will be shared with and informed by discussions in the Commercial Working Group.

H-SC Variations

The following variations in H-SC specifications will be investigated for sensitivity studies only:

1. **Rating of H-SC:** The proposed H-SC at Neilston 275kV has reactive capability of -105 / +140 Mvar and an inertia constant (H) in the range of 1s. The analysis will be repeated by scaling the capability of H-SC, for example to provide higher reactive capability and inertia capability.
2. **SC and STATCOM rating Ratio:** The trial H-SC is based on 1:1 ratio, i.e., SC and STATCOM has the same reactive power rating. The proposed CBA will also analyse the benefit of having a different ratio (such as the SC having a rating 3 times as much as the STATCOM rating and so on).

To carry out these assessments, ABB will be providing a generic H-SC model that allows scaling of size and reactive power range. To analyse the above variations, the change in capital cost, maintenance cost and possible changes in availability factors need to be provided as inputs to the CBA tool.

Wider System Needs and Potential Locations

Based on the future system needs identified through studies such as the System Operability Framework (SOF) and Regional Development Programmes (RDP), and through operational experience, further system analysis will be used to assess the use of H-SCs for other geographical locations. For these locations, a suitable boundary, network background and changes in generation details will be selected and the CBA methodology will be repeated to analyse the potential benefit of H-SC technology.

With many potential H-SC sites, there will be potential change in SCL and inertia of the system. As the CBA model and methodology is limited to assessing one system boundary at a time, there will be limitations as to assessing the combined effect of multiple H-SC installations across different geographical locations. At this stage, we are not planning to carry out assessments on the combined effect of multiple H-SCs installed on different parts of the GB system. However, if there is potential value in installing multiple H-SCs on one side of a transmission boundary, this will be considered during the project.