Programme Area: Energy Storage and Distribution

Project: Network Capacity

Title: Performance of Onshore Multi-Terminal HVDC

Abstract:

This document reports the studies conducted to assess the performance and impact of multi-terminal High Voltage Direct Current systems integrated into the UK's onshore transmission system.

Context:

The Network Capacity research project identified and assessed new technology solutions that could enhance transmission and distribution capacity in the UK. It assessed the feasibility and quantified the benefits of using innovative approaches and novel technologies to provide improved management of power flows and increased capacity, enabling the deployment of low carbon energy sources in the UK. The project was undertaken by the management, engineering and development consultancy Mott MacDonald and completed in 2010.

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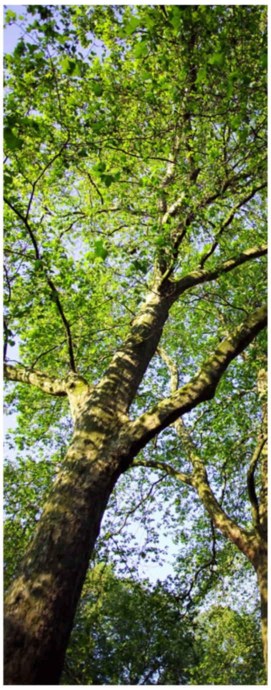


The ETI Energy Storage and Distribution Programme - Network Capacity Project

Work Package 2 Tasks 2&3 Final Report
Multi-Terminal HVDC - Integration Studies and Impact on UK Onshore Grid

December 2010
The Energy Technologies Institute (ETI)

Mott MacDonald

The ETI Energy Storage and Distribution Programme

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Content

1. Summary

1.1 Background

Mott MacDonald has been commissioned by the Energy Technologies Institute (ETI) to carry out the ETI's Network Capacity Project. This project is aimed at supporting the ETI's overall goal of accelerating the deployment of technologies that will help reduce greenhouse gas emissions and thus help achieve climate change goals. Specifically the project will assess the feasibility of two potential areas of development to improve the operation and increase the capacity of the UK onshore T&D systems. The outcome will be a thorough, coherent and well presented analysis that will enable the ETI to make informed decisions as to where future work in the programme should be directed.

- The first area of the project is focussed on the feasibility of applying new and existing power electronic technologies to provide enhanced management of network power flows in order to release more capacity within the T&D system.

- The second area concentrates on the technical feasibility of multi-terminal HVDC in the context of operation within the existing UK T&D system.

The work associated with both areas comprises an assessment of the credible options from these technologies in the context of power flow management including the benefits and also associated impediments to their development and deployment, and will provide guidance in respect of technology development opportunities. The work has been structured into two packages;

- Work Package 1 concentrates on the novel technologies with the potential to release capacity in the UK T&D networks. The work in this package comprises a literature review and modelling of the various technologies integrated into the networks to determine their effectiveness and requirements for such integration. It will also include analysis of environmental and social impacts, and of the barriers to development and deployment.

- Work Package 2 concentrates on the use of multi-terminal HVDC transmission and its integration within the existing UK T&D networks. The work in this package will comprise a feasibility assessment and detailed modelling of multi-terminal HVDC to assess its performance, impact and potential interactions arising from its use. It will also include analysis of the requirements for such integration, the benefits case for conversion of existing AC lines, and of the barriers to development and deployment.

1.2 Work Package 2 Task 2 and 3 Final Reports

Mott MacDonald commissioned TransGrid Solutions (TGS) to carry out studies on the integration of multi-terminal HVDC schemes into the UK grid as covered by the Work Package 2 Task 3 scope of work. The final report received from TGS is included as Appendix A. The report incorporates amendments to the report that have been made in response to ETI comments received on the draft report that was submitted in May 2010.

Mott MacDonald's final report on the impact of multi-terminal HVDC schemes on the UK onshore Grid covered by the Work Package 1 Task 3 Scope of Work is included as Appendix B. The report incorporates amendments to the report that have been made in response to ETI comments received on the draft report that was submitted in May 2010.

This task report is provided as separate stand-alone document. The final report for the project will consolidate and update the outputs from each of the individual task reports, including those covered by this report, in order to provide a coherent output that represents the integrated output from all of the work carried out.

Appendices

Appendix A. TransGrid Solutions Report : Assessment of Performance of Onshore HVDC Systems Integrated into the UK AC Grid

Engineering Support Services for:

Assessment of Performance of Onshore HVDC Systems Integrated into the UK AC Grid

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Report R1137.02.02

Work Package 2 - Task 2 Report

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Executive Summary

A high level performance assessment study has been undertaken to evaluate the technical feasibility of various on-shore two-terminal and three-terminal HVdc schemes when integrated into the existing UK grid in the year 2013/14. This assessment is part of a larger project being performed for The Energy Technologies Institute (ETI). ETI has identified the need for engineering studies to assess innovative approaches and technology solutions that could lead either:

- to the enhancement of the capacity of the existing onshore UK electricity transmission and distribution networks, or
- to the expansion of these networks by means other than the construction of new overhead line infrastructure,

and thereby enable the installation of substantially more renewable energy systems in the UK than the current T&D system can accommodate.

This study looked at integrating HVdc technology into the UK grid by converting existing HVac lines into HVdc lines in order to improve the transmission capacity in selected transmission corridors. The outcome of this study is a qualitative assessment that evaluates the performance of the system following the conversion of selected AC lines to Voltage Source Converter (VSC) HVdc and Line-Commutated Converter (LCC) HVdc, and makes a comparison with the performance of the system without the line conversions. Each line conversion scenario therefore compared three schemes: VSC HVdc, LCC HVdc and AC. Schemes were compared exclusively in terms of their relative impact on transmission system performance, rather than on aspects such as cost or environmental impact.

Three main scenarios were selected for study, with the first scenario looking at two options. The scenarios either convert existing HVac lines into HVdc lines or install back-to-back links on existing HVac lines. The goal was to enhance transmission capability across system boundaries B6, B7 and B9.

Transient stability and power flow analysis were performed to assess and compare the performance of the HVdc and AC schemes for the three scenarios. In addition, the Unit Interaction Factors (UIF) were calculated for generators nearby to the HVdc links to assess the potential for oscillatory interactions in the form of subsynchoronous resonance (SSR). Finally, a brief study to demonstrate the impact of HVdc lines on neighboring AC lines was performed.

Scenario 1 – Boundary B6
Scenario 1 investigated the potential for transmission capacity improvements in zones 6 and 7 across system boundary B6. The total power transfer being studied across boundary B6 was about 4.75 GW.

Option A – Conversion of the Double Circuit 400 kV AC line from Eccles to Stella West
Scenario 1A looked at converting the 400 kV AC double circuit Eastern interconnector into two two-terminal bi-polar HVdc links.

- Of the sixteen contingencies studied, there are three that are noteworthy for discussion:
  - Loss of the double circuit Eastern Interconnector (this is the line being converted)
  - Loss of the double circuit Western Interconnector
  - Loss of a portion of the double circuit Western Interconnector from Harker to Hutton.
- Loss of the Eastern Interconnector showed the same system performance for AC, VSC HVdc and LCC HVdc, namely the system becomes unstable. Whether the transmission line uses AC or HVdc technology, loss of the interconnector results in the same post-contingency situation.
- The system became unstable for the AC scheme following the loss of the Western Interconnector due to lack of available reactive power to support the high power transfers required of the Eastern Interconnector. For the same situation, both the HVdc options can use the fast power controllability inherent to HVdc to boost the power flowing in the Eastern Interconnector by use of a special protection system (SPS). Doing this allows the system to maintain stability for both the LCC and VSC HVdc options.

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- Loss of the double circuit AC line from Harker to Hutton resulted in a stable system response for the AC scheme. The HVdc schemes both required a similar SPS to boost power on the Eastern Interconnector following this contingency in order to avoid voltage collapse in the Stella West are for the LCC scheme, and to avoid thermal overloading of several transmission lines for the VSC scheme. The Eastern Interconnector as an AC line automatically adjusts/shares power flow when a neighboring AC line trips, however HVdc power will stay the same unless told to do otherwise, hence the need for the SPS to quickly adjust the power flow on the Eastern interconnector should it be converted to HVdc.
- The AC and HVdc transmission options showed similar capability to maintain system stability and give similar system performance for the remaining contingencies that were studied.

Based on the results presented above, both the VSC and LCC based HVdc options have a clear advantage over the AC option in terms of their ability to maintain system stability for loss of the Western interconnector, by using the fast power controllability inherent to HVdc.

However, it must be noted that the system is still unstable for loss of the Eastern Interconnector whether AC or HVdc technology is used. An obvious thought would be to convert both the Eastern and Western interconnectors to HVdc, so that in case of loss of either interconnector, an SPS could boost power in the other, and hopefully maintain system stability. However, converting both interconnectors to HVdc would fully isolate the Scottish Power network from the National Grid network, which is likely undesirable and would require a whole new set of studies.

A possible suitable option for installing HVdc on both the Eastern and Western interconnectors without isolating the Scottish Power and National Grid networks into two asynchronous systems would be to install HVdc on one circuit of each of the double circuit interconnectors and leave the other circuit as is. If only one of circuit of each double circuit interconnector is converted to HVdc, then the systems are still synchronous as they remain connected via one circuit of AC line for each double circuit interconnector. Back-to-back HVdc may be more desirable than converting the entire one circuit into a full HVdc link in order to avoid the operation of AC and HVdc on the same tower. Back-to-back HVdc is also simpler and less expensive option for this case. Back-to-back HVdc installed in series with an AC line could increase its power transfer capability as well as providing the ability to quickly control power flow on that line through the back-to-back HVdc link.

This led to the brief investigation of Option B for scenario 1.

Option B – Installation of back-to-back HVdc links on one circuit of both the Eastern and Western Interconnectors
Scenario 1B installed a back-to-back VSC HVdc link at Stella West on one circuit of the 400 kV double circuit AC Eastern interconnector, and a second back-to-back VSC link at Harker on one circuit of the 400 kV double circuit AC Western interconnector.

- Loss of the Western interconnector resulted in a stable system response.
- Loss of the Eastern interconnector caused a voltage collapse in the area around Strathaven and Elvanfoot along the Western interconnector, which resulted in system instability. Two 500 MVA synchronous condensers were required, one at Strathaven and one at Elvanfoot, in order to prevent the voltage collapse and maintain system stability. In addition to the reactive power support provided by the synchronous condensers, this contingency also relies heavily on the large reactive power capability of the VSC back-to-back HVdc link.

Based on the results presented above, the back-to-back VSCs at Stella West and Harker, along with two 500 MVA synchronous condensers, show potential as a feasible option of using HVdc technology to maintain system stability for the worst two contingencies: loss of the Eastern and Western interconnectors.

Scenario 2 – Boundary B7
Scenario 2 investigated the potential for transmission capacity improvements in zones 6, 7 and 8 across system boundary B7. The total power transfer being studied across boundary B7 was about 5.3 GW.

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Scenario 2 looked at converting the 400 kV double circuit AC line from Lackenby to Thornton into two two-terminal bi-polar VSC or LCC based HVdc links.

- Results of the analysis showed no significant benefit in converting the AC line to HVdc technology.
- The HVdc line from Lackenby to Thorton cannot assist to improve system stability following the loss of the Eastern or Western interconnector, which were the only two unstable contingencies of those being studied.
- The AC and HVdc transmission options showed similar capability to maintain system stability and resulted in a similar system performance for the remaining contingencies that were studied.

Based on the results presented above, there was no technical benefit found in converting the 400 kV double circuit AC line from Lackenby to Thornton into two two-terminal bi-polar VSC/LCC based HVdc links, although it was shown to be technically feasible.

Scenario 3 - Boundary B9

Scenario 3 investigated the potential for transmission capacity improvements in zones 10, 11 and 12 across system boundary B9. The total power transfer being studied across boundary B9 was about 13 GW.

Scenario 3 looked at converting the 400 kV double circuit AC line from Cottam to Eaton Socon to Wymondley into two three-terminal bi-polar VSC/LCC based HVdc links.

- Results of the analysis showed no significant benefit in converting the AC line to HVdc technology.
- The three-terminal HVdc line cannot assist to improve system stability following the loss of the Eastern or Western interconnector, which were the only two unstable contingencies of those being studied.
- The AC and HVdc transmission options showed similar capability to maintain system stability, however for one contingency the HVdc options resulted in thermal overloads of nearby transmission lines that were not overloaded in the AC option. The overloads could be mitigated by adjusting the post-contingency power transfer on the HVdc line, however this would either require an SPS or operator intervention.

Based on the results presented above, there was no technical benefit found in converting the 400 kV double circuit AC line from Cottam to Eaton Socon to Wymondley into two three-terminal bi-polar VSC or LCC based HVdc links, although it was shown to be technically feasible.

Summary of Conclusions

In final conclusion, of the three scenarios investigated, Scenario 1 involving system boundary B6 was the only scenario that showed potential benefit from the conversion of AC lines to HVdc. Boundary B6 is comprised of the 400 kV double circuit Eastern and Western interconnectors linking the Scottish Power network to the National Grid network. Converting the Eastern Interconnector to HVdc allowed the system to maintain stability following the loss of the Western interconnector, with use of the fast power controllability inherent to HVdc, as opposed to the existing system with AC interconnectors which resulted in system instability for the same contingency. However, loss of the Eastern interconnector, whether AC or HVdc, still resulted in system instability.

An attempt was made to find an HVdc solution for system boundary B6 that could solve the system instability for both loss of either the Eastern or Western interconnector. Installing a back-to-back VSC HVdc link on one circuit of each of the Eastern and Western interconnector double circuits, while leaving the other circuit unchanged showed potential benefit to the system. In this scenario, both interconnectors have an HVdc component with fast power controllability, while each interconnector still maintains one AC line to keep the Scottish and National Grid networks synchronized. The results were stable for loss of the Western interconnector, but resulted in voltage collapse along the Western interconnector for loss of the Eastern interconnector. It was found that two 500 MVA synchronous condensers, one at Strathaven and one at Elvanfoot, mitigated the voltage collapse and resulted in system stability being maintained.

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Scenarios 2 and 3 involving system boundaries B7 and B9 respectively both showed little benefit to converting AC lines to HVdc, although it was shown to be technically feasible. These particular system boundaries appear to have sufficient transmission capability for the powerflow case that was studied in this assessment.

In the studies performed on the UK grid that considered conversion of AC lines to DC, stability was always found to be the limiting factor, not thermal capacity. The conservative estimates of DC voltage and current, and hence DC thermal capacity, that were used in the study were sufficient for the studies. Even if the DC thermal capacity had been higher, the conclusions of the PSSE simulation studies would not have been changed.

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1. Introduction

The Energy Technologies Institute (ETI) has identified the need for engineering studies to assess innovative approaches and technology solutions that could lead either:

- to the enhancement of the capacity of the existing onshore UK electricity transmission and distribution networks, or
- to the expansion of these networks by means other than the construction of new overhead line infrastructure,

and thereby enable the installation of substantially more renewable energy systems in the UK than the current T&D system can accommodate.

The project is aimed at supporting the ETI's overall goal of accelerating the deployment of technologies that will help reduce greenhouse gas emissions and thus help achieve climate change goals. Specifically the project assesses the feasibility of two potential areas of development (below) to improve operation and increase the capacity of the UK onshore T&D systems.

- The first area of the project (work package 1) is focused on the feasibility of applying new and existing power electronic technologies to provide enhanced management of network power flows in order to release more capacity within the T&D system.

- The second area (work package 2) concentrates on the technical feasibility of multi-terminal HVDC in the context of operation within the existing UK T&D system.

This report focuses on the second task of work package 2. Task 2 of work package 2 undertakes a high level performance assessment study to evaluate various onshore two-terminal and three-terminal HVdc schemes when integrated into the existing UK grid in the year 2013/14. HVdc integration is carried out by converting existing HVac lines into HVdc lines in order to improve the transmission capability in selected transmission corridors. This assessment qualitatively compares the performance of Voltage Source Converter (VSC) HVdc and Line-Commutated Converter (LCC) HVdc with equivalent AC solutions. Schemes are compared exclusively in terms of their relative impact on transmission system performance, rather than on aspects such as cost or environmental impact. This report presents the outcome of this performance assessment study.

1.1. Selected HVac to HVdc Conversion Scenarios

Three main scenarios were selected for study, with the first scenario looking at two options. The scenarios either convert existing HVac lines into HVdc lines or install back-to-back links on existing HVac lines. The goal was to enhance transmission capability across system boundaries B6, B7 and B9.

- Scenario 1 – Boundary B6
    - Option A: Conversion of a 96 km, 400 kV double circuit AC line from Eccles to Stella West into two terminal VSC or LCC based HVdc links
    - Option B:: Installation of two back-to-back VSC links – the first back-to-back VSC link at Stella West on one circuit of the 400 kV double circuit AC line from Eccles to Stella West, and the second back-to-back VSC link at Harker on one circuit of the 400 kV double circuit AC line from Harker to Harker B.
- Scenario 2 – Boundary B7
    - Conversion of a 105 km, 400 kV double circuit AC line from Lackenby to Thornton into two terminal VSC or LCC based HVdc links
- Scenario 3 – Boundary B9
    - Conversion of a 135km and 37 km , 400 kV double circuit AC line from Cottam to Eaton Socon and Eaton Socon to Wymondley into three terminal VSC or LCC based HVdc links

Rationale behind the selection of these scenarios is provided in the scenario descriptions presented in sections 5.1, 6.1, 7.1 and 8.1

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1.2. Terms of Reference

The scope of work for this performance assessment is as follows:

- Acquire / develop detailed PSSE models of multi-terminal HVdc circuit components (e.g. HVdc converters, DC cable systems, transformers, AC and DC filters, control and regulation, etc) and of a complete multi-terminal HVDC link integrated into the existing AC system, complete with tuning for that system and appropriate control philosophy. The following models shall apply:
    - For the VSC technologies, an existing ABB model will be used.
    - For the LCC technology, the multi-terminal link will be limited to three terminals, and TransGrid Solutions' custom two time step model will be used.
- The development of converter station control models for T&D System Operator planning studies (steady state and dynamic conditions).
- The steady state and dynamic behavior of the integrated system (e.g. fault ride-through capability for both AC and DC side faults, steady state voltage and frequency performance, voltage and frequency stability).
- The new services and performance improvements delivered by the integrated system (e.g. reactive power control, power flow control, etc).
- The ability of the multi-terminal HVdc system to provide balancing of power flows between parallel lines.
- The identification and quantification of the impact of HVdc lines on neighbouring AC lines (and vice versa). This will include assessments (a) of any electromagnetic interactions between lines in close proximity, and (b) of any system behavioural interactions between lines connected close by on the network.
- The interactions (e.g. oscillations, sub-synchronous resonance, sub-synchronous torsional interaction, or other phenomena) between the multi-terminal HVdc system and the neighbouring power plants, phase shifting transformers and other AC network infrastructure.

Steady state analysis and dynamic stability analysis are performed using a year 2013/14 load flow model to study fifteen (16) contingencies including several DC contingencies.

1.3. Study Assumptions

The UK grid is exclusively an AC network with several HVdc links interconnecting the UK grid to other systems. These HVdc interconnectors have no influence on the present study and therefore those that were included in the system power flow were modeled with equivalent AC sources.

The 400 kV double circuit Eastern interconnector from Eccles to Stella West has a winter thermal rating of 3070 MVA, with the exception of one 8.36 km line section. This 8.36 km line section currently has a winter thermal rating of 1390 MVA. It is assumed that upgrading this line section would increase the winter thermal rating of this line section to meet the 3070 MVA rating of the rest of the line.

1.4. Study Tools

The primary study tool for this project is the PSSE V32 loadflow and stability software package which is an industry standard worldwide. PSSE was used to perform the steady state, short circuit and transient stability analysis as described in upcoming Section 4 on Study Methodology.

A secondary study tool for this project is the PSCAD V4 electromagnetic transients' software package. This software package is used for any of the studies that PSSE is not capable of performing. In this study, PSCAD is used to demonstrate the electromagnetic interaction between neighboring AC and DC lines.

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2. HVDC Models

2.1. Voltage Source Converter (VSC)

PSSE power flow and dynamic models are available from the PSSE standard model library to represent two-terminal VSC HVdc schemes, however there is no provision for multi-terminal VSC HVdc schemes. The standard PSSE library dynamic model (VSCDCT) is available to model a two-terminal VSC HVdc link, however after attempting to use the model it seemed to experience numerical stability issues under certain conditions.

For both of these reasons, a vendor-supplied PSSE model was obtained for use in this project. This model is capable of representing multi-terminal VSC HVdc links. This model has been validated by the vendor against a PSCAD model and was shown to provide accurate results [1]. The model is easy to use and is setup according to currently available VSC ratings.

The VSC model is set up to use ratings from a selected set of ratings available for commercial use. Because the VSC models are provided for use only with selected ratings, when setting up the VSC models for the various scenarios, the VSC model with the rating closest to the desired rating was selected. Therefore the exact desired VSC rating was not necessarily modeled if it was not available in the set of vendor-supplied model ratings. This is a modeling issue only. In reality, a VSC of any rating (not exceeding the maximum available rating) could be installed.

2.1.1. Power Flow

In PSSE power flow, the VSC HVdc link is modeled using an equivalent generator to represent the P, Q injection at each terminal. The power injections take the VSC converter and DC line losses into account. Negative power at a generator indicates rectifier operation, positive power indicates inverter operation.

These generators are connected to the grid through a transformer. AC filters are present on the VSC converter side of the transformer.

Please note in the power flow model that the AC voltage of 416 kV as seen on the VSC converter side of the transformer is representing the AC voltage, and not the DC voltage. The DC voltage of +/-320 kV is not seen is the power flow model; it is only used as a parameter in the dynamic model which can be seen in the PSSE dynamic data file (DYR).

Operating points are set to be within the P-Q capability curve shown in [1].
Please refer to the vendor-supplied PSSE model manuals [1] for further detailed information.

2.1.2. Dynamics

The VSC dynamic model represents the converter controls and includes the following:

- AC voltage control or reactive power control
- Active power control or DC voltage control
- Current output limitation
- Internal converter voltage limitations

In dynamics, the VSC converters are setup to control AC voltage. One of the converters uses DC voltage control while the other(s) control the active power.

The dynamics model also represents a DC line model connecting all VSC terminals, which allows the following actions by the user:

- Power ramping via the power order
- Converter blocking
- Modulation by an external control

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The model includes representation of fixed and variable converter losses.

Please refer to the vendor-supplied PSSE model manuals [1] for further detailed information.

2.2. Line Commutated Converter (LCC)

2.2.1. Power Flow

PSSE power flow models are available for the following line-commutated HVdc schemes:

- 2-terminal HVdc
- multi-terminal HVdc

In addition to the HVdc models, filters must be added as required to the converter buses. These filters are modeled as shunt capacitors. If higher system strength is required, synchronous condensers may also need to be added to the converter buses.

2.2.2. Dynamics

The standard PSSE library models typically used to represent HVdc schemes are response-type models, e.g. CDC4. These response-type models require the user to enter in many parameters related to the DC voltage and current recovery following disturbances. Essentially these models are pre-programmed to operate/recover in a pre-set manner and do not provide any indication of the commutation performance of the HVdc or how the DC controls will actually respond to the AC disturbance. This is a drawback to this type of model – it gives no indication of real DC controller response. Instead of running the simulation to see how the HVdc will respond, the user specifies how it will respond.

Of particular benefit to this project, TGS has developed a user written LCC HVdc model for PSS/E which allows the representation of the closed-loop HVdc controls as well as the HVdc line L/R dynamics. This custom developed model uses a two time-step approach in which the HVdc model is run at a smaller time-step than the rest of the PSS/E solution, thereby allowing the dynamics of the fast HVdc controls and of the HVdc line/cable to be modeled. This model has been shown to provide far superior results when compared to the standard library HVdc models available in PSS/E and other transient stability software packages.

Modeling details and validation details of two time-step model developed at TGS and compare it to the standard library response-type models and validate the model against PSCAD was documented in IEEE conference proceedings [2].

This two time step model was developed in-house by TGS and has been commercially used on a number of recent HVdc installations. Since the representation of the HVdc link(s) is key to this project, TGS made use of this model for these studies. It has been developed for both two-terminal and three-terminal line commutated converter HVdc links.

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3. AC System Model

3.1. Power Flow

The base case powerflow model used in this study assumes the representation of the winter peak demand scenario for year 2013/14 as indicated in the NGET Seven Year Statement 2009/2010. This is considered a position of the system sufficiently representative for achieving challenging operating conditions across several transmission corridors on the North-South axis. The forecast 61,981 MW peak demand was simulated in the model.

The model includes the HVdc interconnection with France represented as an equivalent AC generator of large inertia. Although expected to become operational soon, the Brit-Ned HVdc interconnection was not represented in the model due to uncertainty surrounding the forecast power exchanges. The Brit-Ned HVdc connection at Grain substation combined with the connection of the future E.On UK Plc's 1,290 MW power station would create a localised power circulation that it is thought would cause a negligible effect upon the system behaviour.

The HVdc Moyle interconnector between UK mainland and Northern Ireland has 250 MW rated capacity which was considered negligible from the perspective of the overall UK transmission system capacity. The HVdc interconnection was therefore not represented in this model.

The model also includes many of the future power stations using conventional fuel and conversion technology that are expected to produce power by 2013/14. These are (the list is alphabetical):

- Amlwch in system Zone 9, 270 MW unit effective capacity;
- Drakelow D in system Zone 11, 1,320 MW unit effective capacity,
- Grain Stage 2 in system zone 15, 860 MW unit effective capacity,
- Grain Stage 3 in system zone 15, 430 MW unit effective capacity,
- Pembroke Stage 1 in system zone 13, 800 MW unit effective capacity,
- Pembroke Stage 2 in system zone 13, 1,200 MW unit effective capacity,
- Port Talbot woodchip power station in system zone 13, 350 MW unit effective capacity,
- Sutton Bridge B in system zone 12, 1,305 MW unit effective capacity,
- West Burton B Stage 1 in system zone 10, 435 MW unit effective capacity,
- West Burton B Stage 2 in system zone 10, 435 MW unit effective capacity,
- West Burton B Stage 3, 435 MW unit effective capacity.

which gives an aggregate new capacity just under 8,000 MW to become available over the next three years.

No wind farms are represented in the model in the NGET area of the UK transmission system. Three wind farms, at Greater Gabbard, Thanet and Sheringham Shoal, are fairly close to completion and will be expected to deliver the full power before winter 2013/14. However these wind farms are connected to the Distribution Network Operators networks which are not directly represented in our dynamic model of the UK transmission system.

All other wind farm projects, having realistic chances of being commissioned and operational before the winter 2013/14, will be connected in the southernmost system zones that benefit from existing strong transmission interconnections. Their aggregate installed capacity will be just over 3,000 MW assuming the most optimistic scenario that all projects expected by the NGET to be operational before winter 2013/14 are delivered on time. Assuming a typical 40 % capacity factor the output of the aggregate offshore wind farms connected to the NGET transmission system will not exceed 1,200 MW.

In the context of an overall 55,900 MW NGET peak demand that is forecast to be supplied using approximately 4,200 MW import from Scotland and the balance from the conventional generators connected in the NGET section, the wind power may potentially represent approximately 2 % of the NGET generation that can be scheduled. The combined effect of the offshore wind farms connected to the NGET is therefore expected to have a negligible effect upon the dynamic performance of the UK

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transmission network in general and the NGET section of it in particular. Taking these facts into account a decision was made to not include the wind farms connected to the NGET section of the UK transmission system into the dynamic model.

All wind farms in operation or expected to be commissioned until winter 2013/14 and connected to the Scottish section of the UK transmission network were represented using suitable aggregations of the Wind Turbine Models available in the PSSTME. The aggregate power output of these wind farms equals nearly 2,900 MW which represents approximately 20.6 % of the generation scheduled in the Scottish section of the UK power system.

The onshore Scottish wind farms expected to be put in operation before winter 20013/14 will produce approximately 1,440 MW of the 2,900 MW aggregated wind power output represented in the model. That is, almost 49.5 % of the Scottish wind farms represented in the UK transmission system will become operational over the next three years.

3.2. Dynamics

The dynamic data used in this study represents generic PSS/E models for wind farms and conventional generators, including exciters and governors in the winter peak scenario of year 2013/14.

It is important to note that the dynamic representation used in this study is not a complete representation of real UK system data but rather a simplified generic representation of dynamic models.

The study is meant to demonstrate high level advantages and disadvantages of HVdc schemes, even if the dynamics model of the UK system does not represent actual UK system dynamic data.

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4. Study Methodology

The study methodology described in this section will be applied to each of the three scenarios being studied. For each scenario, the following types of studies are performed for the base case AC option as well as the two HVdc options, namely VSC and LCC based HVdc schemes:

STEADY STATE ASSESSMENT- PSS/E AC Contingency analysis
Steady state contingency analysis will discover the steady state voltage violations and thermal overloads in transmission lines and transformers. If violations exist in the HVdc options that do not exist in the AC option, mitigation measures need to be identified and evaluated. Alternatively, if the VSC or LCC HVdc options eliminate a violation, the analysis would demonstrate the performance improvements brought on by the HVdc schemes, such as active power control inherent to LCC and VSC HVdc schemes as well as reactive power control inherent to VSC HVdc schemes.

DYNAMIC ASSESSMENT- PSS/E dynamic simulation analysis
PSS/E dynamic simulation analysis of normal clearing three-phase AC faults and HVdc contingencies such as bipole blocking will demonstrate the dynamic behavior of each study scenario. This analysis will discover the transient, voltage and short term frequency stability performances of each scenario for the system contingencies.

PSCAD ELECTROMAGNETIC TRANSIENT STUDY
Electromagnetic interaction between neighboring AC and DC lies is demonstrated through a PSCAD electromagnetic transient study.

SUBSYNCHRONOUS RESONANCE (SSR) SCREENING
The risk for potential SSR between the controls of a nearby HVdc system and a generating unit can be calculaed using the Unit Interaction Factor (UIF) method [2]. The UIF is a measure of influence of HVdc controls on torsional mode stability [2]. Calculation of the UIF requires simple hand calculations involving the short circuit levels at the HVdc terminals. PSS/E short circuit assessment is used to get the short circuit levels at the HVdc terminals under various circumstances in order to be able to calculate the UIFs.

4.1. Study Criteria

The study presented in this report intends to demonstrate high level concepts such as increase in power transfer capacity and improvements in system dynamic performance that may arise from converting existing HVac lines to HVdc lines. For this reason, performances of HVdc scenarios are not compared with any specific system criteria but are rather compared directly to the performances of the HVac scenario. In a situation where the performance of the HVac scenario is unavailable to compare with the performance of the HVdc scenarios (for example, if the HVac scenario response is unstable), performance of the HVdc scenarios are evaluated on a case by case basis using engineering judgment. Finally, qualitative conclusions of advantages and/or disadvantages of the HVdc scenarios are drawn based on these comparisons.

4.2. Procedure: System Integration Studies

The following study procedures are used to carry out the assessment:

4.2.1. Power Flow setup

- Determine an initial rating for the HVdc system based on the power transfer requirements as well as the rating of the conductors of the existing HVac line that would be converted to HVdc. The initial rating may need to be adjusted several times based on a trial and error approach to obtain the desired steady state and dynamic performances.
- Calculate typical HVdc parameters and set-points based on the required rating.

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- Integrate the HVdc model(s) into the power flow cases.
- Add filters (shunt capacitors) to the PCC (Point of Common Coupling) buses for LCC models or to converter buses for VSC models.
- For LCC, calculate the Effective Short Circuit Ratio (ESCR) at the converter buses. As a general rule of thumb, if less than 2.5, synchronous condenser(s) may be required to increase the ESCR; however, the need for synchronous condensers will be verified during the transient stability analysis.

4.2.2. Steady State AC Contingency Analysis

Use PSSE activity ACCC to perform the steady state contingency analysis.

- Setup contingency (*.con), monitoring (*.mon) and subsystem (*.sub) files.
- Run the ACCC contingency analysis for all N-2 double circuit branch outages listed in Table 4-1.
- Analyze the output – record all thermal overloads and steady state voltage violations. As explained in section 4.1, this study does not follow any specific study criteria related directly to the GB system. Rather it uses the following general criteria to identify steady state voltage violations and thermal overloads.
    - A steady state voltage over 1.1 pu is recorded as an overvoltage violation and a steady state voltage under 0.9 pu is recorded as an undervoltage violation.
    - Steady state transmission overload above 100% of the Rate ‘A’ is recorded as a thermal overload.

4.2.3. Dynamic Simulation Study

Use the PSSE dynamics program to perform the dynamic simulation analysis.

- Create the required HVdc dynamics model(s), utilizing either the vendor-supplied VSC model or the TGS two time-step LCC model.
- Add the dynamics data related to the HVdc schemes to the rest of the network dynamic data.
- Run the system disturbances listed in Table 4-1 for each scenario, for the AC option as well as the HVdc options.
- Analyze the results – record the system performance for each disturbance.
- If the system performance of the HVdc scenarios are significantly poorer than that of the AC scenario, mitigation measures required to fix the issues are determined such that the system responses to all disturbances is acceptable. Mitigation measures could include modifying/optimizing HVdc control settings, adding an HVdc modulation control to damp a power system oscillation or to control frequency, implementing a special protection system using power control features available to HVdc, etc. In a rare occasion, adding dynamic voltage support and inertia using synchronous condensers may be evaluated.

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4.3. Contingencies

Table 4-1 provides the details of the system disturbances that are used to perform the steady state contingency analysis and the transient stability analysis for all of the scenarios. When a double circuit AC line is converted into one or multiple HVdc lines, all of the HVdc lines are tripped in order to represent a contingency equivalent to a double circuit AC line trip. These equivalent contingencies are utilized for contingencies 2, 7 and 14 in scenarios 1, 2 and 3, respectively.

Table 4-1 Contingencies studied for all four scenarios

	Contingency	Fault Location		Branch Outage			Comments
		Bus No. & Name	kV	From Bus	To Bus	Circuit	
1	WEST_IC	Harker (27025)	400	Harker (27025)	Moffat (27795)	1	
				Harker (27035)	Gretna (26955)	1	
2	EAST_IC	Eccles (26310)	400	Eccles (26310)	Stella West (28720)	1	This double cct line is converted to DC in SC1
				Eccles (26310)	Stella West (28725)	1	
3	S1_WEST_IC	Harker (5905)	400	Harker (5905)	Hutton (5915)	1	
				Harker (5905)	Hutton (5920)	1	
4	EAST_WEST_IC	Harker (5900)	275	Harker (5900)	Fourstones (760)	1	
				Harker (5895)	Stella West (5655)	1	
5	S1_EAST_IC	Stella West (13005)	400	Stella West (13005)	Spenymoor (13071)	1	
				Stella West (13010)	Spenymoor (13070)	1	
6	B7_EAST_IC_1	Norton (5600)	400	Norton (5600)	Osbaldwick (5085)	1	
				Norton (5600)	Osbaldwick (16150)	1	
7	B7_EAST_IC_2	Lackenby (5460)	400	Lackenby (5460)	Thornton (5100)	1	This double cct line is converted to DC in SC2
				Lackenby (5460)	Thornton (5095)	1	
8	Z8_C1	Thornton (5100)	400	Thornton (5100)	Creyke Beck (5350)	1	
				Thornton (5095)	Creyke Beck (5350)	1	
9	Z8_C2	Drax (5010)	400	Drax (5010)	Thornton (5100)	1	
				Drax (5005)	Thornton (5095)	1	
10	Z12_C1	Grendon (2975)	400	Grendon (2975)	Staythorpe (3165)	1	
				Grendon (2975)	West Burton (3205)	1	
11	Z12_C2	Enderby (2970)	400	Enderby (2970)	Ratcliffe (3135)	1	
				Enderby (2970)	Ratcliffe (3140)	1	
12	Z12_C3	Walpole (3005)	400	Walpole (3005)	Norwich Main (3000)	1	
				Walpole (3005)	Norwich Main (3000)	2	
13	Z12_C4	Pelham (2115)	400	Pelham (2115)	Burwell Main (2945)	1	
				Pelham (2115)	Burwell Main (2945)	2	
14	Z12_C5	Cottam (3105)	400	Cottam (3105)	Eaton Socon (2955)	1	One cct of this double cct line is converted to DC in SC3
				Cottam (3105)	Eaton Socon (2965)	1	
15	Z12_C6	Feckenham (3105)	400	Feckenham (3645)	Walham (2600)	1	
				Feckenham (3645)	Mlenty (2585)	1	
16	Z14_C1	Pelham (2115)	400	Pelham (2115)	Rye House (165)	1	
				Pelham (2115)	Rye House (175)	1	

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All 16 double circuit contingencies listed in Table 4-1 assume 7 cycle (140 ms) fault duration. Reclosing of the tripped circuits was not modeled for any of these contingencies.

4.4. Subsynchronous Resonance (SSR) Screening

Unit Interaction Factor is defined as (Power System Stability and Control by Prabha Kundur [17], page 1049):

$$UIF = \frac{MVA_{dc}}{MVA_g}\left(1 - \frac{SC_g}{SC_t}\right)^2$$

Where:

MVA_{dc} = MVA rating of the DC system

MVA_g = MVA rating of the generator

SC_t, SC_g = short-circuit capacity at the DC commutating bus (excluding AC filters) with and without the generator, respectively.

This is a Sub Synchronous Resonance screening index. The index is the product of two indicators of SSR; namely (a) the relative rating of the generator and (b) the electrical distance between the LCC HVdc converter terminal and the generating unit. The term within parentheses calculated in terms of system short circuit level is a measure of the electrical distance. The AC filters are removed from the network for the above calculations. It is recommended that further detailed studies be performed if the UIF is greater than 0.1. The index UIF is only an empirical formula for screening of SSR risk.

PSSE is used to calculate the short-circuit capacity at each HVdc terminal with and without each thermal generator in the vicinity.

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5. Scenario 1A: Two-Terminal HVdc: Eccles to Stella West

Scenario 1A investigates the potential for transmission capacity improvements in zones 6 and 7 across system boundary B6 by converting the 400 kV AC double circuit Eastern interconnector into two bi-polar HVdc links. The dashed line on the right hand side of Figure 5-1 shows the Eastern interconnector from Eccles to Stella West.

Figure 5-1 also shows the Western interconnector in the form of dashed line from Strathaven to Harker. These two interconnectors are the only two transmission lines connecting the Scottish transmission network to the National Grid Transmission network. They carry a total combined winter peak power transfer of 4750 MW in the power flow case being studied.

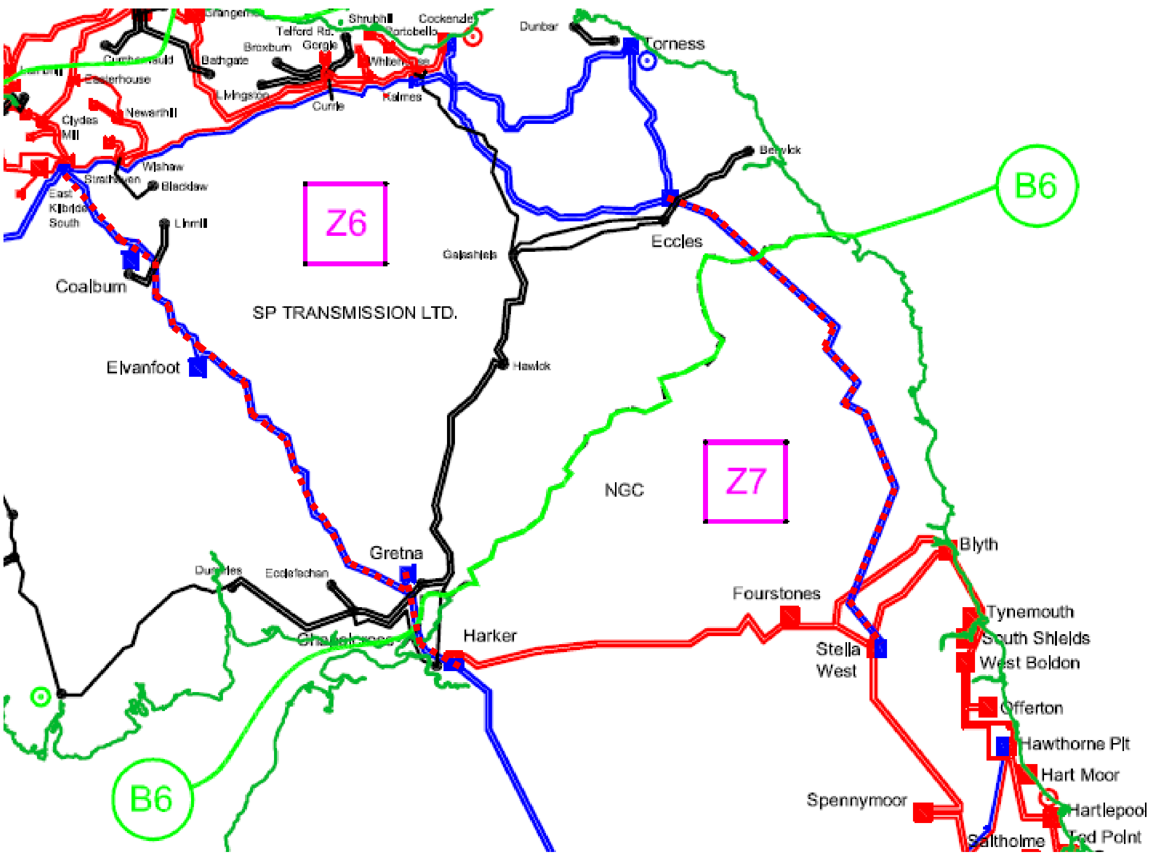

Figure 5-1 Eastern and Western interconnectors connecting zone 6 and 7 across system boundary B6.

The Eastern interconnector connects Eccles sub-station to Stella West sub-station through a 400 kV, dual circuit HVac overhead line. Both circuits of the double circuit HVac overhead line run on the same tower. The winter thermal rating of each of these individual circuits is 3070 MVA, except for an 8.36 km line section at the Eccles end. Each circuit of this 8.36 km line section only has a winter thermal rating of 1390 MVA. It is assumed this short line section could be upgraded to match the 3070 MVA rating of the rest of the line.

The Western interconnector connects Stratheven sub-station to Harker sub-station through a 400 kV, dual circuit HVac overhead line. Similar to the Eastern interconnector, both circuits of the Western interconnector also run on the same tower. Between Stratheven and Harker, the Western interconnector is tapped at three sub-stations (Coalburn, Elvanfoot, and Gretna) making the Western interconnector a multi-section line. At Coalburn and Gretna sub-stations, 275 kV and 132 kV lines connect to the Western

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interconnector through step-down transformers. The winter thermal rating of each of these sections is around 2000 MVA per single circuit of the double circuit line.

Please note that although both the Eastern and Western interconnectors are double circuit lines, the fact that the two circuits of each interconnector run on the same tower makes it possible that the entire Eastern or Western interconnector may be lost for a contingency involving a tower failure. Obviously, converting a double circuit interconnector to HVdc would not change this fact. Whether the double circuit line is an HVac or HVdc line, a common tower failure would result in loss of that entire interconnector.

5.1. Rationale for Selection of Line Conversion

The total thermal rating of the Eastern interconnector would be around 6000 MVA assuming that the 8.36 km line section at the Eccles end of the line could be upgraded to be equal to the rest of the line rating. The total thermal rating of the Western interconnector is around 4000 MVA. Therefore, the total combined thermal capacity of the Eastern and Western interconnectors is around 10,000 MVA.

The base case power flow used in this study has winter peak power transfer of 4750 MW across system boundary B6. Tripping the Eastern interconnector double circuit as a result of a tower failure would force the Western interconnector to carry the total power transfer. Similarly, tripping the Western interconnector would force the Eastern interconnector to carry the total power transfer. However, as shown in section 5.3, the system with the Eastern and Western interconnectors as HVac lines cannot survive the loss of either the Western or Eastern interconnector. The system becomes unstable after either of these two interconnectors trips. Therefore, the actual transmission capability across system boundary B6 is less than the winter peak power transfer of 4750 MW. In Scenario 1, the transmission capability across boundary B6 is expected to be improved by converting the existing HVac line(s) into HVdc line(s). The obvious candidates for AC to DC conversion are the Eastern and Western interconnectors.

The Eastern interconnector is a 400 kV HVac overhead line with two circuits running on the same tower. There are no sub-stations between Eccles sub-station and Stella West sub-station. Therefore, Scenario 1 investigates the conversion of both HVac circuits of the double circuit Eastern interconnector into two two-terminal bi-polar HVdc links with converter stations located at Eccles and Stella West.

It would also be possible to convert only one circuit of the double circuit Eastern interconnector to HVdc. However, doing this has two obvious disadvantages. The first is that only two conductors out of the three available conductors from the single HVac circuit could be employed in normal operation of the bi-polar HVdc link, as a bipolar HVdc link only uses two conductors and not three. The third redundant conductor could either be used as a metallic return path for mono-polar operation or be connected in parallel with one HVdc conductor (either positive or negative) to reduce transmission losses. However, this third conductor would not contribute towards the rating of the HVdc link and consequently the HVdc link would have a lower thermal rating than that of the original HVac circuit. The second disadvantage is the electro-magnetic interference that would occur between the HVac and HVdc lines running on the same tower. Although there are several HVac/HVdc hybrid schemes already in operation around the world, special designs are required for such schemes.

Similar to the Eastern interconnector, the Western interconnector is also a 400 kV, HVac overhead line with two circuits running on the same tower. However, there are two sub-stations between Strathleven sub-station and Harker sub-station where the Western interconnector is tapped to 275kV and 132 kV networks. Although a four or five terminal HVdc link could replace the Western interconnector, the following reasons make such multi-terminal HVdc link impractical:

1. The AC network at these tapped off sub-stations is weak without the connection of the 400 kV Western interconnector. This could pose a challenge for successful converter operation for an LCC HVdc scheme.

2. Power exchanges between the 400 kV Western interconnector and the 132 kV and 275 kV networks at the three tapped sub-stations are relatively small compared to the total power

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transfer in the Western interconnector. Therefore, the multi-terminal HVdc link would consist of terminals that are relatively small compared to the other terminals. Typically, the rating of the smallest terminal should at least be 15 % of the rating of the largest terminal for a multi-terminal LCC HVdc scheme.

Based on the above facts, the Eastern interconnector is the best choice of an existing HVac line that could be converted into an HVdc link in order to attempt to achieve improvement in transmission capability in zones 6 and 7 across system boundary B6. Both AC circuits of the Eastern interconnector will be converted to HVdc in order to avoid electro-magnetic interferences between the AC and HVdc lines and also to better utilize the available conductor capacity.

5.2. HVdc Ratings and Models Used

5.2.1. Rating of existing dual circuit 400 kV HVac Eastern interconnector

Parameters of the two sections of the double circuit 400 kV AC Eastern interconnector are listed in Table 5-1.

Table 5-1 Parameters of 400 kV AC double circuit eastern interconnector

Line Section	PSSE Bus names and numbers		Line Parameters on 100 MVA pu base			Line Rate A (MVA)	Conductor Rate A (kA)	Length (km)
	From Bus	To Bus	R	X	B			
1	ECCL40 (26310)	STWB4Q (28720)	0.00007	0.00137	0.05783	1390	2.006	8.36
	ECCL40 (26310)	STWB4R (28725)	0.00007	0.00137	0.05783	1390	2.006	8.36
2	STEW4C (13015)	STWB4Q (28720)	0.00076	0.01433	0.60460	3070	4.431	87.40
	STEW4D (13020)	STWB4R (28725)	0.00076	0.01433	0.60460	3070	4.431	87.40

Both line sections 1 and 2 are overhead transmission lines with two 400 kV three phase circuits running on the same tower. The total length of the Eastern interconnector is 95.76 km. The winter thermal rating (Rate A) of each of these two circuits is 1390 MVA and 3070 MVA for the two line sections, respectively. In this study, it is assumed that line section 1 could be upgraded to match the rating of line section 2 for both AC and HVdc scenarios. Therefore, a winter thermal rating of 3070 MVA (or 4.431 kA) is assumed for the entire Eastern interconnector. Autumn and summer ratings assumed for each of these two circuits are 2830 MVA (4.085 kA) and 2410 MVA (3.479 kA), respectively.

5.2.2. Rating of converted HVdc Eastern interconnector

By converting both AC circuits of the Eastern interconnector, there will be six conductors available with a 4.431 kA winter thermal rating. In order to calculate the power rating of the HVdc link, first the DC voltage rating of the DC link should be selected. There are many factors that influence the DC voltage rating of the converted DC line.

A DC conductor voltage equal to the peak phase voltage of the 400 kV AC line can certainly be applied to the existing conductors after changing only the conductor insulators but without changing the tower structure. However, real world case studies show higher DC voltages are usually possible for low to medium pollution conditions. Further details regarding the factors influencing the DC voltage and how to select the DC voltage for converting an AC line to DC are explained in the Work Package 2 Task 1 report.

The minimum DC conductor voltage is therefore calculated as:

$$\pm\sqrt{2}*\frac{400}{\sqrt{3}} = \pm 326 \text{ kV}.$$

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Therefore, ± 320 kV was selected at the rated DC voltage for both VSC and LCC converters. It should be noted that 320 kV is the voltage selected without looking into the tower details and design. A DC voltage optimization study would need to be performed at the design stage of the DC line to determine a suitable DC voltage considering the existing tower design and the right of way.

The DC current rating of a conductor in the converted line is higher than the AC current rating of the same line. This is because, unlike the ac power transmission, the skin effect and mutual effects between conductors are absent in the case of dc transmission. However, the exact increase in the DC current rating needs to consider the internal structure of the conductor. For example, ACSR conductors designed for AC transmission have a steel reinforced inner core. Commercially available ACSR conductors have a wide range of steel varying from as low as 6% to as high as 40% depending on the application, such as river crossing, overhead or ground wire installations. The steel core in these AC conductors is designed to provide tensile strength and typically has higher electrical resistance than the aluminium outer layer. Because of this, current tends to travel more in the outer layer than the inner layer, somewhat similar to the current distribution in an AC line caused by skin effect. Therefore, the DC resistance and the corresponding DC current rating of a converted line can only be determined after a careful analysis of conductor geometry. In the absence of the necessary data, a conservative estimation of DC current rating has been adopted for this study by assuming that the DC current rating is the same as the AC current rating for the converted transmission line.

If in the future the network topology of the UK grid is expanded sufficiently such that it is no longer limited by the stability issues observed in this study, then a more detailed investigation could be performed to determine a more exact DC voltage and current rating that would be possible for a given AC line converted to DC, taking into consideration the issues discussed including tower structure, pollution and conductor type. If future studies consider a less conservative DC thermal capacity for lines being converted from AC to DC, system studies would need to be performed to ensure that the AC system could in fact support the extra power flow associated with the higher DC thermal capacity, both from a steady state and stability point of view.

Table 5-2 tabulates the maximum possible power rating for the converted HVdc link based on the 320 kV DC voltage and minimum conductor dc current ratings in each season.

Table 5-2 Maximum rating of converted HVdc eastern interconnector

Season	AC Rating (MVA)	Maximum DC Rating (MW)	Increase in Power rating
Winter	3070*2 = 6140	320*4.431*2*3 = 8507	38.6 %
Autumn	2830*2 = 5660	320*4.085*2*3 = 7843	
Summer	2410*2 = 4820	320*3.479*2*3 = 6680	

The calculations in Table 5-2 show that the rating of the Eastern interconnector could be increased by 38.6 % by converting the interconnector from HVac to HVdc with a DC voltage of ±320 kV. As far as the thermal rating of conductors are concerned, the minimum DC power rating of 6680 MW is available in summer and a rating higher than 6680 MW is available in autumn and winter. Thus, the conductor DC power rating in any season is well over the 4750 MW required to transfer the total power through the Eastern interconnector when the Western interconnector is unavailable. Dynamic studies will demonstrate whether or not this is also feasible from a transient stability point of view.

It is important to note that the maximum power rating of an HVdc system is determined based not only on the conductor thermal rating, but also on the rating of other equipment associated with the HVdc system. Therefore the HVdc system would have a single rating for all seasons, unlike an AC line rating which changes from season to season.

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5.2.2.1. VSC Model

In the base powerflow case, the steady state power transfer in the Eastern interconnector is around 2.7 GW. However, when the Western interconnector is tripped, the Eastern interconnector should boost its power transfer to 4.75 GW in order to continue the total power transfer and maintain system stability. For this reason, the power rating of the Eastern interconnector should be at least 4.75 GW.

ABB has developed [1] VSC modules with voltage rated at ± 80 kV, ± 150 kV and ± 320 kV for various power ratings[1]. Modules rated at ± 320 kV have 405 MVA (0.63 kA), 796 MVA (1.24 kA) and 1216 MVA (1.90 kA) power ratings. The PSSE VSC model being used in this study is available at these ratings (but not at ratings in between). The highest power rating of a single converter module is limited by the current rating of the IGBT valves available today. However, VSC modules could be connected in parallel to obtain required power rating. Figure 5-2 shows the converter connection for the two VSC bi-poles utilized in the Scenario 1 case study. It is anticipated that converters with higher power ratings are available in the future, making it possible to realize this scheme with fewer parallel converters.

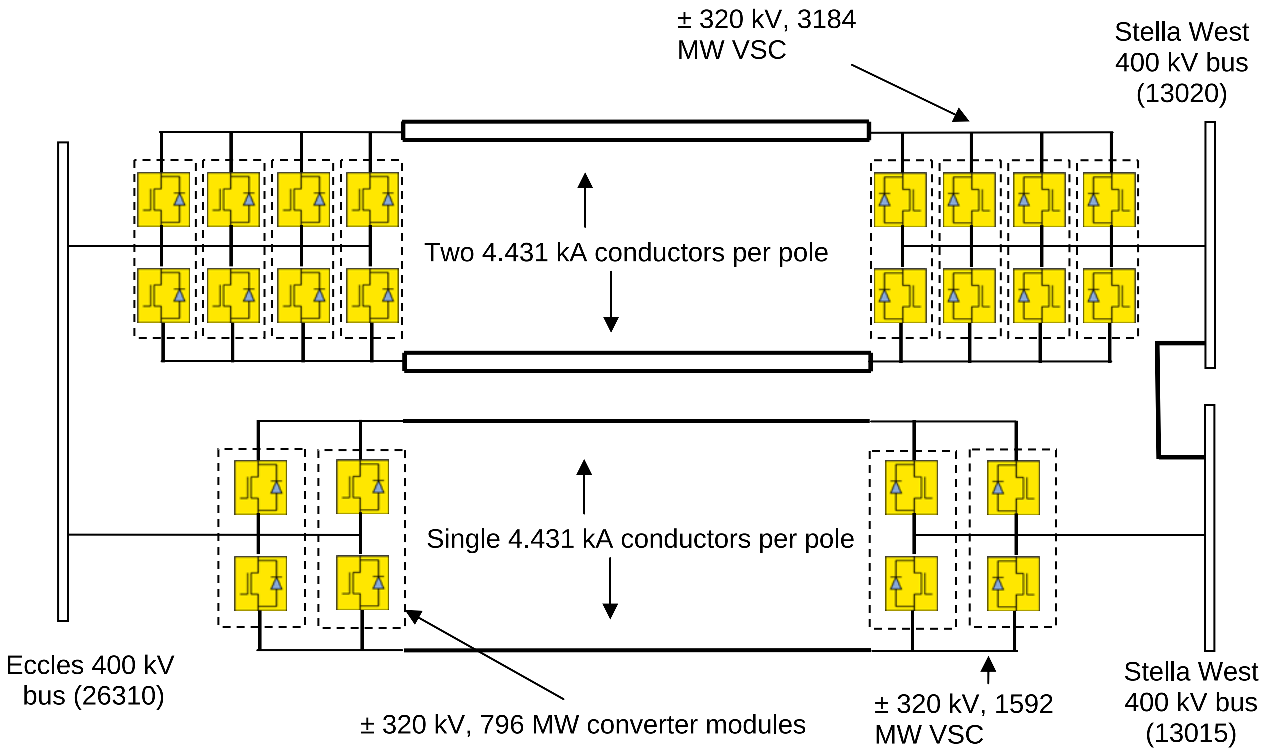

Figure 5-2 ± 320 kV, 796x2 MW and 796x4 VSC bi-poles in parallel at rectifier and inverter sides

These two parallel bi-poles utilize all six conductors available from converting the two three phase AC circuits, with two DC conductors per pole in the 3184 MW HVdc bi-pole and one DC conductor per pole in the 1592 MW HVdc bi-pole. As shown in Figure 5-2, the combined power rating of 4776 MW provided by the two parallel VSC bi-poles rated at 3184 MW and 1592 MW is thermally sufficient to boost enough power in the Eastern interconnector to compensate for the loss of the Western interconnector.

There are four 796 MW parallel converters at each end of the 3184 MW HVdc bi-pole and there are two 796 MW parallel converters at each end of the 1592 MW HVdc bi-pole. Note that Stella West 400 kV buses 13015 and 13020 are connected together by a zero impedance line.

The converter configuration shown in Figure 5-2 is one possible configuration that could be utilized to obtain the required rating. The number of modules connected in parallel at each converter station to

[1] Voltage of VSC modules could be higher than 320 kV. These ABB VSC modules are intended for use in applications involving DC cables and therefore DC voltage is limited by cable voltage rating.

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obtain the required power rating depends on the DC voltage selection and current rating of IGBT valves available in the future.

5.2.2.2. LCC Model

LCC utilizes thyristor valves in the converters. The maximum continuous current rating for a thyristor valve available today is around 5.5 kA. Consequently, the maximum power rating for an LCC bi-pole at ± 320 kV is about 3520 MW. In this case study, two LCC bi-poles in parallel were utilized to match the power rating of the two VSC bi-poles illustrated in section 5.2.2.1. Figure 5-3 shows the how two bi-poles are connected between Eccles 400 kV bus and Stella West 400 kV bus. Note that Stella West 400 kV buses 13015 and 13020 are connected together by a zero impedance line.

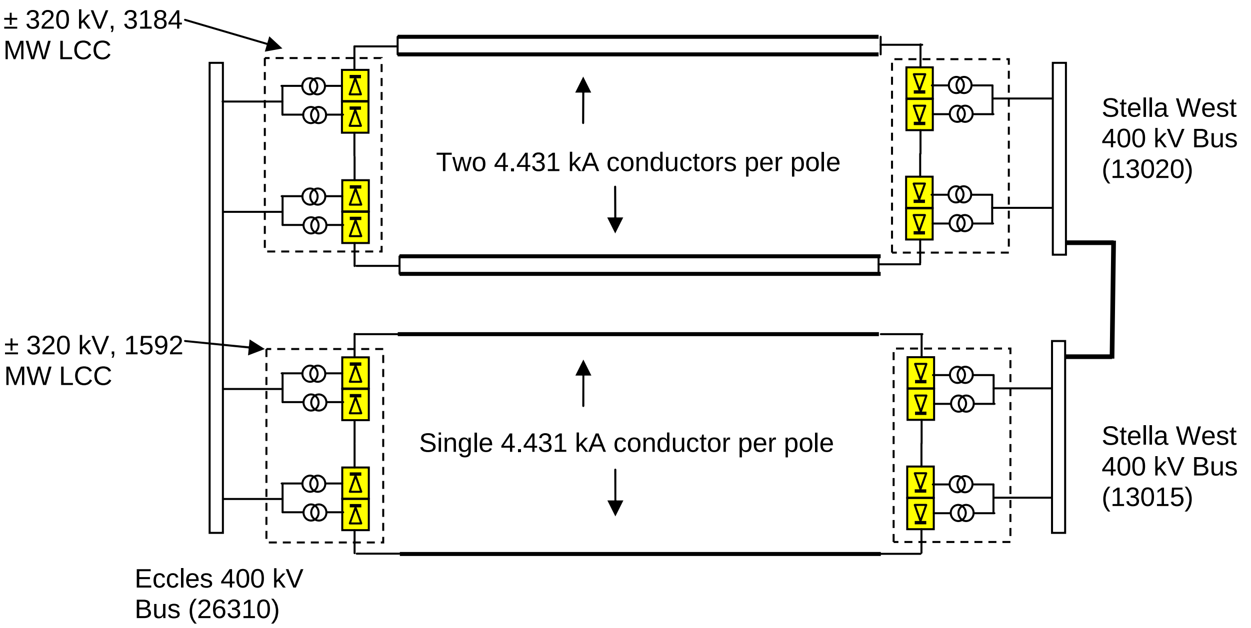

Figure 5-3 ± 320 kV, 1592 MW and 3184 MW LCC bi-poles

The two parallel bi-poles utilize all six conductors available from converting the two three phase AC circuits, with two conductors per pole in the 3184 MW HVdc bi-pole and one conductor per pole in the 1592 MW HVdc bi-pole.

The TGS two time step model [2] was used to model the LCC HVdc bi-poles in PSS/E dynamics.

5.2.3. Reactive power exchange with AC system

Voltage source converters have a large range of fast reactive power supply and absorption capability. The reactive power capability depends on the real power transmission. The vendor-supplied model used in this study has the typical per unit P-Q operating diagram shown in Figure 5-4 (figure taken from [1]]). This diagram demonstrates that when operating at a real power level near the MVA rating of the VSC, the reactive power capability is significantly less than if operating at a lower power level, in fact the reactive power capability shown in Figure 5-4 is near 0 MVAR at 1 pu real power. The reactive power can be controlled independently at each station. Please note that this P-Q diagram is typical and vendor-specific and does not necessarily reflect the P-Q operating curve of VSCs supplied by other vendors. Also note that the P-Q diagram refers to the converter only. There are filters located on the AC bus on the VSC side of the transformer which are not accounted for in the P-Q diagram. The rating of the filters depends on the rating of the converter, switching technology (Pulse Width Modulation or not), phase reactor etc. Each

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of the six 796 MVA VSC links modeled in this scenario has 119.4 MVAR of filters (capacitance). Therefore, the total capacity of the filters added at each end of the 3184 MW and 1592 MW VSC bi-poles are 477.6 MVAr and 238.8 MVAr, respectively.

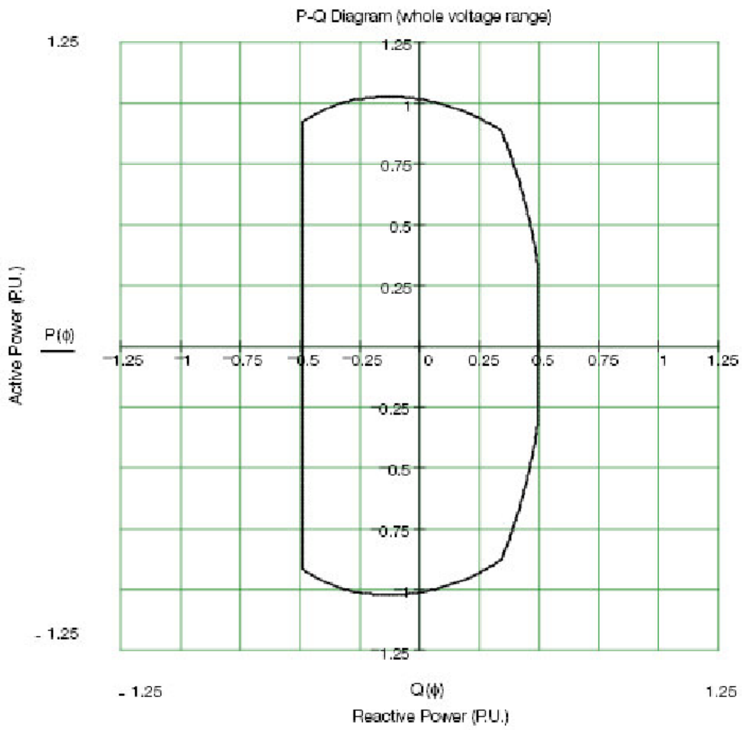

Figure 5-4 VSC P-Q diagram (converter only). Source: ABB.

Line-commutated converters typically consume reactive power in the range of 50-60% of the transmitted real power. LCC HVdc links are supplied with filters and capacitor banks, both for harmonic performance and for reactive power compensation. The LCC HVdc system is designed such that the reactive power exchanged with the AC system does not exceed a maximum level (which can be seen in the +/-Q band in Figure 5-5). Filters are switched on/off in order to maintain the reactive power exchange within the desired band, typically +/- 50 to100 MVAR depending on the filter bank size of a specific HVdc system, and depending on the reactive power consumption of the converter. An example P-Q diagram of an LCC HVdc system is shown in Figure 5-5.

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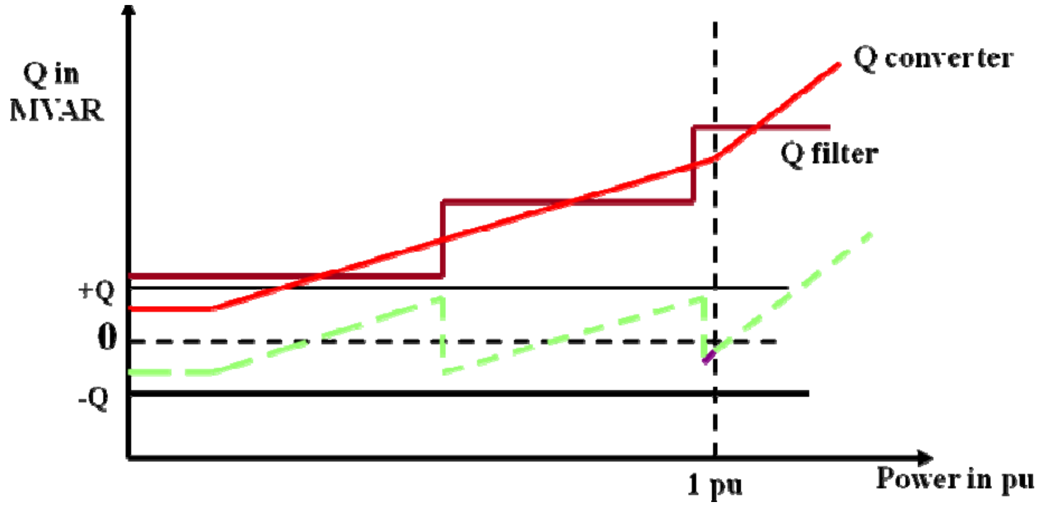

Figure 5-5 Typical LCC P-Q diagram including converter and filters. Green curve is reactive power exchanged with AC System. Red curve is the reactive power absorbed by the converter.

The two LCC HVdc bi-poles utilized in this Scenario 1 case study assumed a total filter rating of 55 % of the HVdc power rating.

An AC line loaded to its surge impedance loading will neither consume nor supply reactive power to the AC system. Operating below surge impedance loading, an AC line will supply reactive power; operating above surge impedance loading an AC line will absorb reactive power. Figure 5-6 below shows the P-Q diagram for one circuit of the double circuit AC line between Eccles and Stella West, assuming voltage at the two ends of the line are at 1.0 pu and that the effect of line resistance is negligible. The surge impedance loading (SIL) of the AC line is around 650 MW.

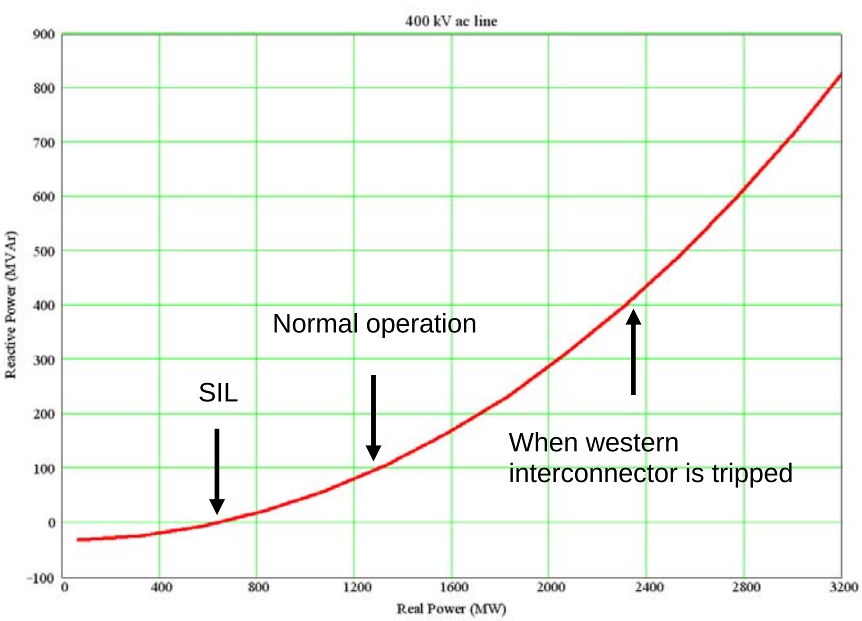

Figure 5-6: PQ diagram for 400 kV, 96 km long line

According to the PQ diagram, for one circuit of the double circuit Eastern interconnector AC line, about 100 MVAr/per circuit is absorbed from the system during normal operation and about 400 MVAr/per circuit would be absorbed from the system if the Western interconnector tripped, assuming the system was transiently stable and could reach this new operating point.

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5.2.4. AC System Strength at LCC HVdc Terminals

System strength is not as important an issue for VSC HVdc as it is for LCC HVdc.

Beyond the basic consideration of power transfer, there are a number of ways in which an LCC HVdc link and associated AC systems interact at the converter stations. As the strength of the AC system reduces, both in normal operation and as a result of contingencies, certain interactions tend to become more pronounced.[2] These interactions include:

- Recovery from AC and DC faults: For acceptable performance it is required that the DC system should recover from AC or DC faults without subsequent commutation failures. As a general guide, recovery to 90% of pre-disturbance power transfer within 100 to 300ms is desirable. As the Short Circuit Level (SCL) of the AC systems decreases, the effects of magnetizing inrush currents can become more pronounced, resulting in a slower recovery. Attempting to increase the speed of recovery can sometimes lead to the DC system drawing excessive reactive power from the AC network, resulting in a prolonged depression of the AC network voltage, particularly as the Short Circuit Ratio (SCR) of the AC systems decreases.

- Temporary Overvoltages: Temporary AC system overvoltages can occur at the HVdc terminals due to converter blocking, AC fault inception and clearing, DC faults, and other disturbances. The severity of these overvoltages increases as the SCR of the AC systems decreases.

- While it may be an issue for AC systems with higher SCRs also, the capacitive shunt compensation at the converter bus and the relatively high system inductance for low SCR AC systems results in a parallel resonance that might be close to the second harmonic. Such a resonance can result in harmonic voltages which are substantial relative to the magnitude of the fundamental during disturbances.

- Commutation Failures: It is a general requirement that the converter does not experience commutation failures for frequently occurring changes in the associated AC systems such as small voltage and phase deviations. As the SCR decreases, the likelihood of commutation failures occurring increases.

- Converter Reactive Power Element Switching: As the SCR decreases, the voltage sensitivity to changes in the reactive power increases and creates the potential for voltage changes within the AC network in the vicinity of the converter station when reactive power elements are switched.

- System Inertia: In addition to characterizing the AC system as having sufficient SCR, it is also necessary to consider the overall inertia of the system. In cases where overall system inertia is low, synchronous compensators can be used to increase the system SCR and help maintain AC system voltage and frequency.

Effective short circuit ratio (ESCR) is defined as follows:

ESCR = (Short circuit MVA at AC bus – MVA rating of filters)/Rated DC power

The CIGRE Guide for Planning DC Links Terminating at AC System Locations Having Low Short Circuit Capacities identifies the following categories of ESCR:

High	ESCR >2.5
Low	2.5 >= ESCR >= 1.5
Very Low	ESCR <1.5

[2] Guide for Planning DC Links Terminating at AC system Locations Having Low Short-Circuit Capacities, Part II: Planning Guidelines. CIGRE Working Group 14.07, IEEE Working Group 15.05.05, December 1997.

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Based on industry experience it can be stated that low or very low SCR in itself is not a technical limitation in the evaluation of an HVdc transmission option, but it must be recognized that decreasing SCR (and ESCR) results in overall decreased performance of the interconnected AC/DC systems. The effects of reducing ESCR on overall performance becomes even more pronounced for long HVdc cables.

ESCR is of more importance to HVdc inverters than to rectifiers, particularly with respect to stability issues and commutation failures. However, issues related to temporary overvoltages and HVdc filter switching apply equally to rectifiers and inverters.

It should be noted that an HVdc system itself does not contribute to the short circuit strength of the system, however a synchronous condenser installed with the HVdc system will increase the short circuit strength if deemed necessary by the studies.

System strengths at the converter buses were calculated and are summarized in Table 5-3 for the LCC HVdc option. Please note that the short circuit level of the Stella West 400 kV bus is calculated by connecting 400 kV buses 13015 and 13020.

Table 5-3 Short circuit levels at LCC terminal buses

LCC terminal	Short Circuit Strength (MVA)	SCR	ESCR
Eccles 400 kV bus (256310)	9060	1.9	1.4
Stella West 400 kV bus (13015+13020)	12555	2.6	2.1

Table 5-3 also tabulates the short circuit ratio (SCR) and effective short circuit ratio (ESCR) for the combined rating of 4776 MW. In the ESCR calculation, it was assumed that 55 % reactive power compensation is provided by the HVdc filters.

5.3. Performance Comparison

Performance of the VSC and LCC HVdc options for the Scenario 1 case study are compared with the performance of the base case AC system under the following categories.

- Steady State Transmission Losses
- Steady State AC Contingency Analysis
- Transient Stability and Dynamic Performance

5.3.1. Steady State Transmission losses

Losses resulting directly from the current flowing in the Eastern interconnector as a 400 kV double circuit AC line were calculated and compared with the losses in the VSC and LCC HVdc systems. According to the VSC manuals [1], each VSC converter has losses of 1.65% at nominal power rating, with 30% fixed losses and 70% variable plus the losses in the DC line. Typically, an LCC converter has losses of 0.80% at nominal power rating, with 10% fixed losses and 90% variable plus the losses in the DC line.

Table 5-4 tabulates conductor losses for all three transmission options as well as converter losses for the VSC and LCC options for two operating conditions.

It should be noted that very recent publications by VSC manufacturers indicate that VSC converter losses in the MMC type converters are almost comparable to losses in LCC converters. The 1.65% loss value used in this study for the VSCs is required by the PSSE VSC model as it is preprogrammed to use this value and cannot be changed by the user. For purposes of stability results, a loss value of 1.65% compared to 1% for example is not expected to have a significant impact on the results observed in this study. Of course, the lower losses would have a big impact on project economics, but that is beyond the scope of this report. Please note that the loss values presented in Table 5-4 are based on the VSC model and therefore correspond to a value of 1.65%.

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Table 5-4 Loss comparison for three transmission options

Transmission option	At Operating Point being Studied		
	Conductor Loss (MW)	Converter Loss (MW)	Total Loss (MW)
AC	29	-	29
VSC	16	110	126
LCC	16	45	61

During normal operation, the total transmission losses are smallest for the AC line and highest for the VSC option (almost 4 times the AC losses). Losses for the LCC option are almost half of the losses of the VSC option.

5.3.2. Steady State AC contingency Analysis

5.3.2.1. Diverged Contingencies

Steady state contingency analysis was performed for all 16 contingencies listed in Table 4-1 for all three transmission options, namely AC, VSC HVdc and LCC HVdc.

Converged post-contingency powerflow solutions could not be obtained for the case when the Eastern interconnector was represented as a 400 kV double circuit AC line for the following contingencies:

- Outage of the Western interconnector (WEST_IC)
- Outage of the Eastern interconnector (EAST_IC)

The Eastern and Western interconnectors are the only transmission lines connecting the ScottishPower Transmission Network in the north to the National Grid Transmission network in the south across the system boundary B6. Tripping of one of these interconnectors would cause the total power transfer of 4.75 GW across boundary B6 to flow in the other interconnector. This would result in very high reactive power demand at the terminals of the remaining interconnector. Refer to Figure 5-6 to see the increase in reactive power demand at the terminals of the Eastern interconnector when the Western interconnector is tripped. Because this reactive power demand could not be supplied with the limited reactive power resources available in the base case powerflow, a converged post-contingency powerflow solution could not be obtained.

Both the VSC and LCC HVdc options provide converged post-contingency powerflow solutions for loss of the Western interconnector (contingency WEST_IC), provided that a Special Protection System (SPS) is utilized to quickly boost DC power in the HVdc Eastern interconnector to compensate for the loss of power transfer in the Western interconnector.

Post-contingency powerflow solutions for loss of the Eastern interconnector (contingency EAST_IC) for the VSC and LCC HVdc options are identical to the post-contingency powerflow of the 400 kV double circuit AC line option. In all cases, a converged post-contingency powerflow solution could not be obtained.

In addition to loss of the Eastern interconnector, loss of the 400 kV double circuit AC line from Harker to Hutton (contingency S1_WEST_IC) did not have a converged post-contingency powerflow solution for the LCC HVdc option only. This was because an undervoltage collapse occurred in the Stella West area as a result of increased power flow in the Harker to Stella West 275 kV double circuit line. A similar powerflow increase in the 275 kV line was observed for the VSC HVdc option, however, the large reactive power supply capability of the VSC prevented voltage collapse in the Stella West area. In the case of the AC line option, voltage collapse around Stella West was not observed as the post-contingency powerflow in the Eccles to Stella West double circuit AC line (the Eastern interconnector) automatically increases to relieve the power transfer in the Harker to Stella West 275 kV double circuit line. Consequently, an SPS is required to boost the post-contingency power transfer in the Eastern interconnector for the LCC HVdc option to avoid voltage collapse near Stella West for loss of the double circuit 400 kV line between Harker and Hutton. Table 5-5 tabulates the SPS required for the Scenario 1 HVdc options.

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Table 5-5 SPS required for scenario 1A to prevent voltage collapse

Contingency	SPS	
	VSC Option	LCC Option
WEST_IC	Boost VSC power to compensate WEST_IC power transfer (i.e. boost power transfer from 2.7 GW to 4.7 GW)	Boost LCC power to compensate WEST_IC power transfer (i.e. boost power transfer from 2.7 GW to 4.75 GW)
S1_WEST_IC	-	Boost LCC power transfer from 2.7 GW to at least 3.4 GW

5.3.2.2. Steady State Voltage Violations

There were no overvoltage violations observed for the Scenario 1 transmission options, however, several undervoltage violations were observed for all three transmission options. These violations are tabulated in appendix A1. All undervoltage violations observed for the VSC and LCC HVdc options were also observed for the AC option. Hence, there are no new violations created by the VSC or LCC HVdc options. In fact, several undervoltage violations observed in the Stella West and Harker area for the AC option following loss of the 400 kV double circuit AC line from Harker to Hutton (contingency S1_WEST_IC) were not present for the VSC HVdc option. Thus, the VSC HVdc option has an advantage over the AC and LCC HVdc options due to its large inherent reactive power capability, which can assist in improving post-contingency undervoltages.

5.3.2.3. Steady State Thermal Overloads

There were a number of thermal overloads observed for all three transmission options. All of these thermal overloads were quite similar for all three transmission options, except for the thermal overloads caused by loss of the 400 kV double circuit Western interconnector and loss of the 400 kV double circuit AC line from Harker to Hutton (contingencies WEST_IC and S1_WEST_IC). The thermal overloads resulting from these two contingencies are listed in Table 5-6. A complete list of thermal overloads observed for scenario 1A is presented in Appendix B1.

Table 5-6 Thermal violations for contingencies S1_WEST_IC and WEST_IC

LINE NAME	RATING (MW)	CONTINGENCY	Percentage thermal violation		
			AC	VSC	LCC
5655*STEW2 275.00 16165 STEW2A 275.00 1	**570**	**WEST_IC**	**No solution**	**121.2**	**144.5**
26310 ECCL40 400.00 28855*TORN40 400.00 1	**1250**	**WEST_IC**	**No solution**	**121.7**	**121.7**
26310 ECCL40 400.00 28855*TORN40 400.00 2	**1250**	**WEST_IC**	**No solution**	**121.7**	**121.7**
760*FOUR20 275.00 5900 HARK2K 275.00 1	**855**	**S1_WEST_IC**	**-**	**122.7**	**-**
760*FOUR20 275.00 16165 STEW2A 275.00 1	**855**	**S1_WEST_IC**	**-**	**121.4**	**-**
4245 FORD4R 400.00 4925*DUBR4R 400.00 1	1040	S1_WEST_IC	112.8	111	113.1
4950 STSB4 400.00 4955*STSB4R 400.00 1	1000	S1_WEST_IC	113.6	112.3	113.8
5655 STEW2 275.00 5895*HARK2J 275.00 1	**775**	**S1_WEST_IC**	**-**	**134.8**	**-**
5655 STEW2 275.00 16165*STEW2A 275.00 1	**570**	**S1_WEST_IC**	**-**	**112.3**	**-**

The three thermal overloads observed for loss of the 400 kV double circuit Western Interconnector (contingency WEST_IC) are present only for the VSC and LCC HVdc options. However, it is not possible to determine whether these are new overloads caused by the HVdc options or if the same overloads would have been observed for the AC option if a post-contingency powerflow solution for the AC option

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had been possible. The AC option is unstable and does not have a converged post-contingency power flow solution for loss of the Western Interconnector.

Of the six thermal overloads caused by loss of the 400 kV double circuit AC line from Harker to Hutton (contingency S1_WEST_IC), the thermal overloads observed for the two 400 kV transmission lines (rows 6 and 7 of Table 5-6) are present for all three transmission options with nearly the same percentage violations, therefore the HVdc options do not impact these overloads. The other four thermal overloads observed on the four 275 kV transmission lines are present only for the VSC HVdc option. These thermal overloads arise as a result of increased power transfer from Harker to Stella West through the 275 kV network after tripping the Harker to Hutton double circuit 400 kV AC line (contingency S1_WEST_IC). These overloads could be relieved by boosting the post-contingency power transfer in the Eastern interconnector. Indeed, it was found that the same SPS that was utilized to prevent voltage collapse in the Stella West area for the LCC HVdc option (as shown in Table 5-5), could also be utilized for the VSC HVdc option to mitigate thermal overloads in the 275 kV network for the same contingency. Table 5-7 tabulates the updated SPS required for scenario 1A to mitigate voltage collapses and thermal overloads.

Table 5-7 SPS required for Scenario 1A

Contingency	SPS	
	VSC Option	LCC Option
WEST_IC	Boost VSC power to compensate WEST_IC power transfer (i.e. boost power transfer from 2.7 GW to 4.7 GW)	Boost LCC power to compensate WEST_IC power transfer (i.e. boost power transfer from 2.7 GW to 4.75 GW)
S1_WEST_IC	Boost LCC power transfer from 2.7 GW to at least 3.4 GW	Boost LCC power transfer from 2.7 GW to at least 3.4 GW

5.3.3. Transient Stability and Dynamic Performance

5.3.3.1. System Stability

Dynamic simulations were performed for all 16 contingencies listed in

Table 4-1 for all three transmission options, namely AC, VSC HVdc and LCC HVdc. Please refer to Appendix C1 for plots of system voltage, generator speeds, line powerflows, etc. for all 16 contingencies.

Provided that the SPSs listed in Table 5-7 were implemented, the system could maintain stability for the LCC and VSC HVdc options for all of the contingencies that were studied, with the exception of the loss of the 400 kV double circuit Eastern interconnector. Loss of the Eastern interconnector resulted in system instability for the AC and HVdc options. Loss of the Western interconnector resulted in system instability for the AC option only. .Table 5-8 lists the stability status of each transmission option for loss of the Eastern and Western interconnectors.

Table 5-8 Stability status of three transmission options

Contingency	AC Option	VSC HVdc Option	LCC HVdc Option
EAST_IC	Unstable	Unstable	Unstable
WEST_IC	Unstable	**Stable**	**Stable**

Contingency EAST_IC represents a tower failure of the double circuit Eastern interconnector at the Eccles end, causing all six conductors to be grounded at a location close to the Eccles 400 kV bus. The ground fault was cleared after 7 cycles by tripping both 400 kV AC circuits of the Eastern Interconnector at the Eccles and Stella West ends. The tripped AC circuits were not re-connected since the tower failure is a permanent fault. In dynamic simulations, this fault was modeled as follows.

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- AC option: A three phase-to-ground fault at the Eccles 400 kV bus cleared by tripping the two 400 kV AC circuits from Eccles to Stella West after 7 cycles.

- VSC HVdc option: This conductor to ground fault is a DC fault in both VSC HVdc bi-poles. When the DC conductors are grounded, the AC system at Eccles and Stella West feed the ground fault through the phase reactors, converters and the DC line. The vendor supplied VSC dynamic model does not provide a means to directly simulate DC faults, the user manual suggests dc faults to be modeled as ac faults through an impedance at both terminals. For that reason, a three phase-to-ground fault through a selected impedance was applied at each converter bus at Eccles and Stella West. The value of ground fault impedance at each end should include the impedance of the phase reactor, impedance offered by the converter and the impedance of the DC line between the fault location and the corresponding converter. For the sake of modeling simplicity and also to demonstrate worst conditions, the impedance of the converter and the DC line were neglected. Consequently, three phase-to-ground faults through the phase reactor impedance were applied at the Eccles and Stella West converter buses for both VSC bi-poles. These three phase-to-ground faults were cleared after 7 cycles, representing the fault clearing actions of AC breakers located on the primary side of the converter transformers.

- LCC HVdc option: An LCC converter isolates AC and DC sides during a conductor to ground fault on the DC side. Therefore, this conductor to ground fault on the DC lines was modeled as a double bi-pole block of LCC HVdc link, without any AC system fault.

It was observed that the AC option could not maintain transient stability following loss of the double circuit Eastern Interconnector (EAST_IC).The instability was caused by a voltage collapse initiated along the Western interconnector from Strathaven to Harker. Similarly, both the VSC HVdc and LCC HVdc options could not maintain transient stability for the same contingency. Indeed, this is to be expected as the post-contingency network is the same after tripping the Eastern interconnector, whether the Eastern interconnector uses AC or HVdc technology.

Contingency WEST_IC represents a tower failure of the double circuit Western interconnector close to the Harker 400 kV AC bus, causing a three phase-to-ground fault on both 400 kV AC double circuits. The ground fault is cleared by tripping the double circuit 400 kV line from Harker to Moffat and Gretna. This would cause the total power transfer of 4.75 GW across boundary B6 to flow in the Eastern interconnector. The SPS employed for the VSC and LCC HVdc options automatically boosts the power transfer in the HVdc Eastern interconnector when the Western interconnector is tripped. Figure 5-7 depicts the increase in power transfer in one circuit of the double circuit Eastern interconnector for all three transmission options. Note that the power transfer in the AC option also increases in a similar manner to the HVdc options; however, a short time later a voltage collapse along the Eastern interconnector causes a rapid decline in power transfer resulting in system instability. Figure 5-8 depicts the voltage collapse in the AC option at Stella West 400 kV following loss of the Western Interconnector (contingency WEST_IC). The HVdc options are both observed to maintain system stability.

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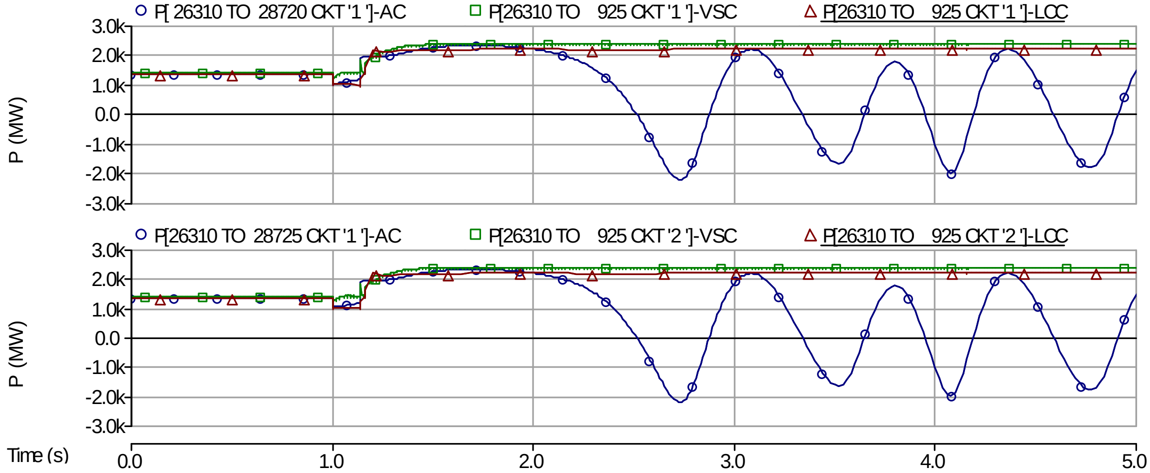

Figure 5-7 Boost in power transfer in Eastern interconnector following contingency WEST_IC. (Blue – AC, Green – VSC, Red – LCC)

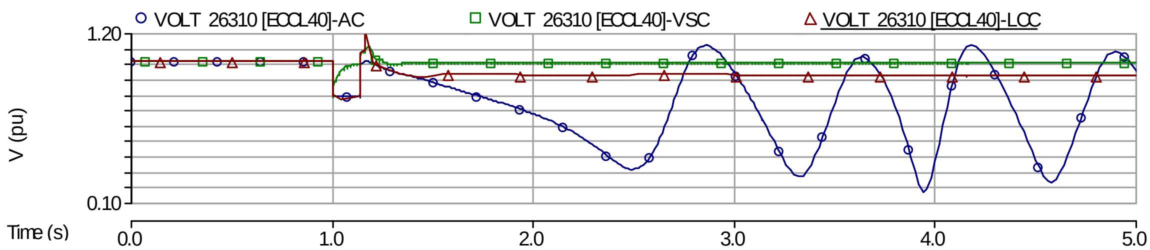

Figure 5-8 Voltage collapse at Stella West 400 kV bus for the AC option following contingency WEST_IC. (Blue – AC, Green – VSC, Red – LCC)

Based on the results presented above, both the VSC and LCC based HVdc options have a clear advantage over the AC option in their ability to maintain system stability for loss of the Western interconnector, with use of the fast power controllability inherent to HVdc.

Loss of the Eastern interconnector, however, results in system instability whether the Eastern interconnector uses AC or HVdc technology.

All three transmission options show similar capability to maintain system stability for all of the other 14 contingencies.

5.3.3.2. Transient Undervoltages / Overvoltages

AC system voltages were observed during the post fault period at buses rated 275 kV and above. Of the three transmission technologies, in most situations the VSC option showed superior voltage performance following a disturbance, while the AC and LCC options showed moderate voltage performances. The VSC option is inherently equipped with a large capacitive and inductive range of voltage control so it is not surprising that it shows better voltage performance.

Transient voltages up to 1.2 pu are typical in most power systems. Transient overvoltages above 1.2 pu were not observed for the AC or VSC HVdc options. Only the LCC HVdc option for loss of the Eastern Interconnector (contingency EAST_IC) had transient overvoltages slightly over 1.2 pu. Figure 5-9 depicts

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the voltages of all three transmission options for contingency EAST_IC at the 400 kV buses at Eccles and Stella West.

Please note that the system become unstable after the contingency EAST_IC as a result of inability of the Western interconnector to transfer increased amount of power to compensate the power transfer in EASTY_IC. However, as shown in scenario 1B, suitable transmission resource improvement in the area of the Western interconnector could result in increased transfer capability for the Western interconnector and hence prevent instability caused by contingency EAST_IC.

Focus of this report is to demonstrate the advantages and disadvantages of converting existing AC lines into DC lines. For this reason, mitigation of contingency EAST_IC is not investigated in scenario 1A study. However, transient overvoltage caused by contingency EAST_IC at Eccles and Stella West due to the filters connected at Eccles and Stella West converter buses at a full load rejection in both bi-poles are unlikely be affected by resource upgrades implemented to mitigate instability caused by contingency EAST_IC.   Thus, transient overvoltages caused by unstable contingency ESAT_IC are presented and discussed below.

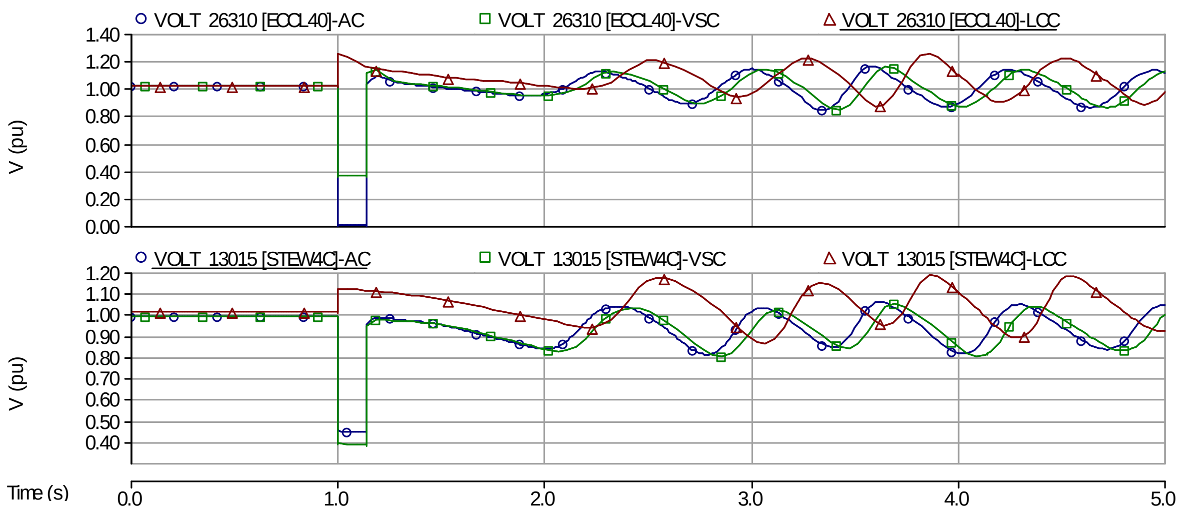

Figure 5-9 Transient overvoltage at Eccles and Stella West terminals for contingency EAST_IC (Blue – AC, Green – VSC, Red – LCC)

Contingency EAST_IC represents a tower failure on the Eastern interconnector close to Eccles and hence causes a DC line to ground fault on all six conductors of the Eastern interconnector as described in section 5.3.3.1. Consequently, a double bi-pole block of the Eastern interconnector would occur. This would reject almost 2.7 GW of power that was being transferred in the Eastern interconnector prior to the fault. If a double-bi pole block would not trip any of the HVdc filters that were in-service before the fault, presence of these filters would cause transient overvoltage depending on the strength of the AC system at Eccles and Stella West. The LCC HVdc link could be designed to ensure the filters would trip in such a situation to assist in reducing overvoltages.

Note that the transient overvoltage observed for the LCC option at Eccles is slightly higher than 1.2 pu whereas the transient overvoltage observed at Stella West is only slightly above 1.1 pu. This is to be expected as the short circuit strength at Eccles is slightly lower than the short circuit strength at Stella West.

Figure 5-10 depicts the worst transient undervoltage observed for the LCC HVdc option during the fault recovery period following the loss of the 400 kV double circuit line from Lackenby to Thronton after a three phase-to-ground fault at Lackenby 400 kV bus (contingency B7_EAST_IC_2). Note that the voltage

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at the Stella West inverter bus has a temporary dip for about one second during the fault recovery of the LCC HVdc option. Appropriate tuning of the HVdc controllers at the design stage would improve this temporary undervoltage.

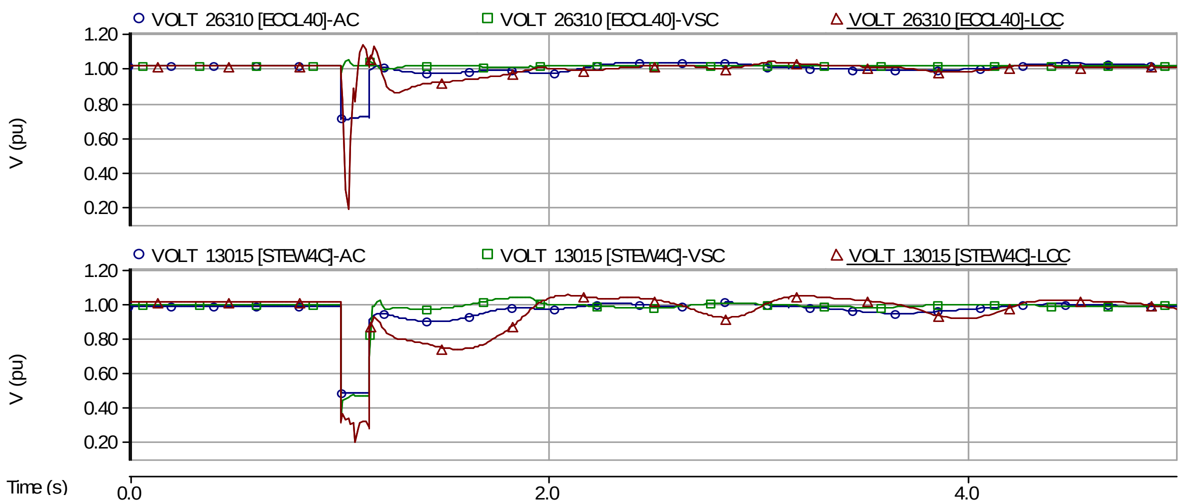

Figure 5-10 Transient undervoltage at Eccles and Stella West terminals for contingency B7_EAST_IC_2 (Blue – AC, Green – VSC, Red – LCC)

Figure 5-11 depicts the worst transient undervoltage observed for the AC option during the fault recovery period following the loss of the 400 kV double circuit line from Harker to Hutton after a three phase-to-ground fault at Harker 400 kV bus (contingency S1_WEST_IC). Loss of the Harker to Hutton 400 kV line diverts power through the 275 kV network from Harker to Stella West and Eccles to Stella West causing power oscillations and increased reactive power consumption in the area around Stella West. These power oscillations and the increase in reactive power consumption causes the voltage at the 400 kV Stella West bus to dip at first and then settle to a voltage just above 0.90 pu.

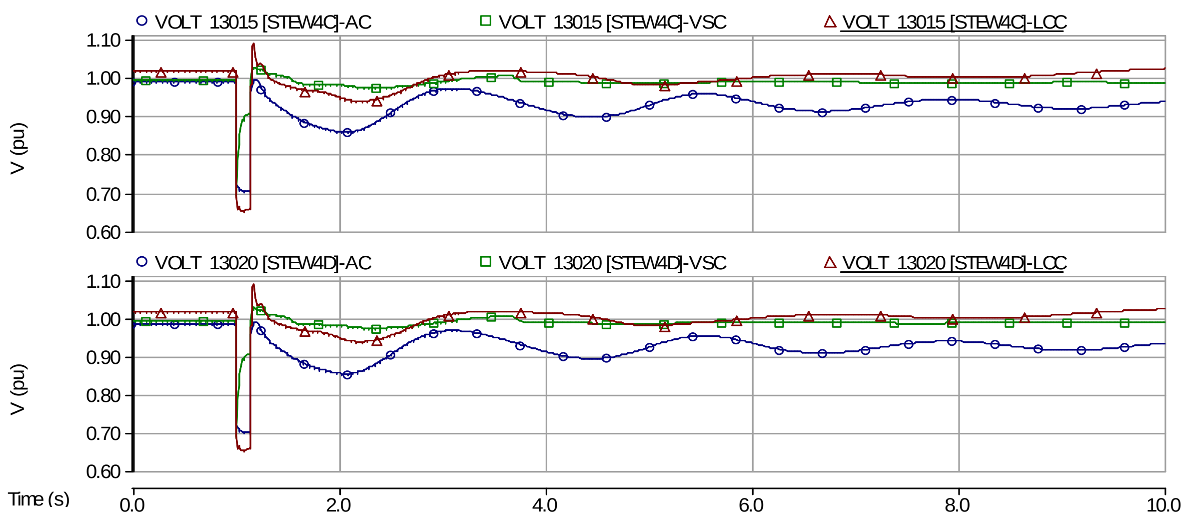

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Figure 5-11 Transient undervoltage at Eccles and Stella West terminals for contingency S1_WEST_IC (Blue – AC, Green – VSC, Red – LCC)

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5.3.3.3. System Frequency Performance

In transient stability programs such as PSS/E, the transmission system frequency is obtained from the derivative of the bus voltage angle. If there is a sharp change in the bus angle, the frequency might change infinitely. Therefore, there are filters associated with the frequency measurements. However, sometimes these filters are not enough to completely relieve these spikes in the frequency calculations, particularly if a fault has been applied in the area near to the frequency calculation. For this reason, generator speed quantities were mostly used to analyse frequency deviations as generator speeds are state variables which cannot change instantaneously and therefore should not give erroneous results.

For the power flow case that was studied, the AC, VSC HVdc and LCC HVdc transmission options did not show any transient underfrequency or overfrequency deviations outside of ± 0.5 Hz for any of the contingencies that were studied. All transient frequencies as measured by generator speeds were also within a ± 0.5 Hz frequency band.

5.3.3.4. System Damping

Plots of power oscillations inspected for various contingencies revealed that the three transmission options result in different damping levels depending on the contingency. Inspection of power oscillations also indicates that there is no clear evidence to substantiate which option has better system damping.

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5.4. SSR Screening

The UIF calculation described in the Study Procedures section is intended to screen for potential interaction between a conventional LCC HVdc system and generator shaft oscillation modes, known as subsynchronous resonance (SSR).

With LCC HVdc, any resonance frequency (f) on the DC side gets converted to f0+f and f0-f frequencies on the AC side.

Because VSC is a relatively new technology compared to LCC, there is less information available on the possibility of SSR with a VSC HVdc system. A simple test case was setup in PSCAD to test whether the same phenomenon occurred with VSC and results indicate that VSC may have the same potential as LCC to excite SSR.

There is also little information readily available on the possibility of SSR between a wind farm and an HVdc system. Because of this, the possibility cannot be excluded and it cannot be said for certain that the possibility does not exist. Should these HVdc options be further pursued it would be recommended to perform further studies to verify the possibility of SSR between HVdc terminals and wind farms in the Scottish Network along with the appropriate mitigation if deemed necessary.

Although the UIF screening calculations are intended to be used for LCC HVdc, the UIF was calculated for the VSC option as well in order to provide an indication of the potential need for detailed SSR studies. In order to calculate UIF index for the worst case scenario, the two parallel HVdc bi-poles (1592 MW and 3184 MW) between Eccles and Stella West were considered to be one single bi-pole with a combined rating of 4776 MW rating. The UIF index was calculated for all generators except salient pole generators in Zones 6 and 7. Table 5-9 and Table 5-10 summarize the results for the Eccles and Stella West terminals, respectively. Please refer Appendix D1 for complete table of UIF indices for scenario 1A.

Table 5-9 UIF Index calculated for Eccles converter terminal

Generator Bus umber	Generator ID	Generator Rating (MVA)	Converter Rating (MW)	Generator Bus Number		UIF
				System Intact	Generator out-of-service	
25915	1	222.3	4776.0	9525.8	9435.1	0.002
25915	2	71.6	4776.0	9525.8	9502.9	0.000
26210	1	34.0	4776.0	9525.8	9503.4	0.001
20470	**1**	**669.0**	**4776.0**	**9525.8**	**8292.2**	**0.120**
20475	**2**	**669.0**	**4776.0**	**9525.8**	**8292.2**	**0.120**
20245	1	610.0	4776.0	9525.8	9370.7	0.002
20250	2	610.0	4776.0	9525.8	9408.7	0.001
20065	1	300.0	4776.0	9525.8	9283.7	0.010

Table 5-10 UIF Index calculated for Stella West converter terminal

Generator Bus Number	Generator ID	Generator Rating (MVA)	Converter Rating (MW)	Short Circuit Level (MVA)		UIF
				System Intact	Generator out-of-service	
5395	1	660.0	4776.0	11977.8	11463.4	0.013
5400	1	650.0	4776.0	11977.8	11561.3	0.009
5535	1	350.0	4776.0	11977.8	11887.9	0.001
5540	1	350.0	4776.0	11977.8	11887.0	0.001
5555	1	170.0	4776.0	11977.8	11921.0	0.001
5715	1	130.0	4776.0	11977.8	11781.9	0.010
5720	1	130.0	4776.0	11977.8	11781.9	0.010

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All UIF calculations except for two 669 MVA generator units at Torness were below the threshold of 0.1. The two 669 MVA generator units at Torness have a UIF of 0.12, which is only slightly above the 0.1 threshold. Nevertheless, these two generators would be recommended for future study to determine the potential for SSR interaction with the HVdc terminal at Eccles.

5.5. Conclusions

Scenario 1A investigated the potential for transmission capacity improvements in zones 6 and 7 across system boundary B6. The total power transfer being studied across boundary B6 was 4.75 GW.

Scenario 1A looked at converting the 400 kV AC double circuit Eastern interconnector into two two-terminal bi-polar HVdc links.

The selection of AC circuits for conversion into DC links may occasionally raise challenges through the inclusion of different OHL towers along the circuit route. The different OHL towers are used typically for short distances along special passages. It is expected that these situations are managed during the engineering and design phase of the process. The economic impact on the conversion process costs is considered negligible.

The following conclusions can be made:

- Of the sixteen contingencies studied, there are three that are noteworthy for discussion:
  - Loss of the double circuit Eastern Interconnector (this is the line being converted)
  - Loss of the double circuit Western Interconnector
  - Loss of a portion of the double circuit Western Interconnector from Harker to Hutton.
- Loss of the Eastern Interconnector showed the same system performance for AC, VSC HVdc and LCC HVdc, namely the system becomes unstable. Whether the transmission line uses AC or HVdc technology, loss of the interconnector results in the same post-contingency situation.
- The system became unstable for the AC scheme following the loss of the Western Interconnector due to lack of available reactive power to support the high power transfers required by the Eastern Interconnector. For the same situation, both the HVdc options can use the fast power controllability inherent to HVdc to boost the power flowing in the Eastern Interconnector by use of a special protection system (SPS). Doing this allows the system to maintain stability for both the LCC and VSC HVdc options.
- Loss of the double circuit AC line from Harker to Hutton resulted in a stable system response for the AC scheme. The HVdc schemes both required a similar SPS to boost power on the Eastern Interconnector following this contingency in order to avoid voltage collapse in the Stella West area for the LCC scheme, and to avoid thermal overloading of several transmission lines for the VSC scheme. The Eastern Interconnector as an AC line automatically adjusts/shares power flow when a neighboring AC line trips, however HVdc power will stay the same unless told to do otherwise, hence the need for the SPS to quickly adjust the power flow on the Eastern interconnector should it be converted to HVdc.
- The AC and HVdc transmission options showed similar capability to maintain system stability and give similar system performance for the remaining contingencies that were studied.

Based on the results presented above, both the VSC and LCC based HVdc options have a clear advantage over the AC option in terms of their ability to maintain system stability for loss of the Western interconnector, by using the fast power controllability inherent to HVdc.

However, it must be noted that the system is still unstable for loss of the Eastern Interconnector whether AC or HVdc technology is used.

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6. Scenario 1B: Back-to-Back VSC HVdc at Stella West and Harker

Similar to scenario1A, scenario 1B investigates the potential for transmission capacity improvements in zones 6 and 7 across system boundary B6. As it was revealed in the scenario 1A study, the main challenge in increasing transmission capability across boundary B6 without building new transmission lines is to maintain system stability when either the Eastern or Western interconnector is tripped.

The Scenario1A study also concluded that the instability caused by tripping the Western interconnector could be effectively mitigated and power transfer could be continued without interruption if the existing 400 kV double circuit AC Eastern interconnector was converted into two parallel HVdc bi-poles utilizing either VSC or LCC HVdc technologies. However, AC to DC conversion of the Eastern interconnector could not help in maintaining stability when both HVdc bi-poles of the Eastern interconnector were tripped due to a common tower failure.

In the light of the findings presented in scenario 1A, scenario 1B investigates the potential for back-to-back HVdc links installed at Stella West and Harker to maintain system stability and to continue power transfer across boundary B6. Unlike scenario 1A, scenario 1B investigates only the impact of two contingencies: loss of the Eastern interconnector and loss of the Western interconnector (contingencies EAST_IC and WEST_IC) on the system steady state and dynamic performance. Also, out of the two HVdc technologies, only the feasibility of VSC HVdc technology for the back-to-back links is evaluated. Figure 6-1 shows the locations selected to install back-to-back VSC links.

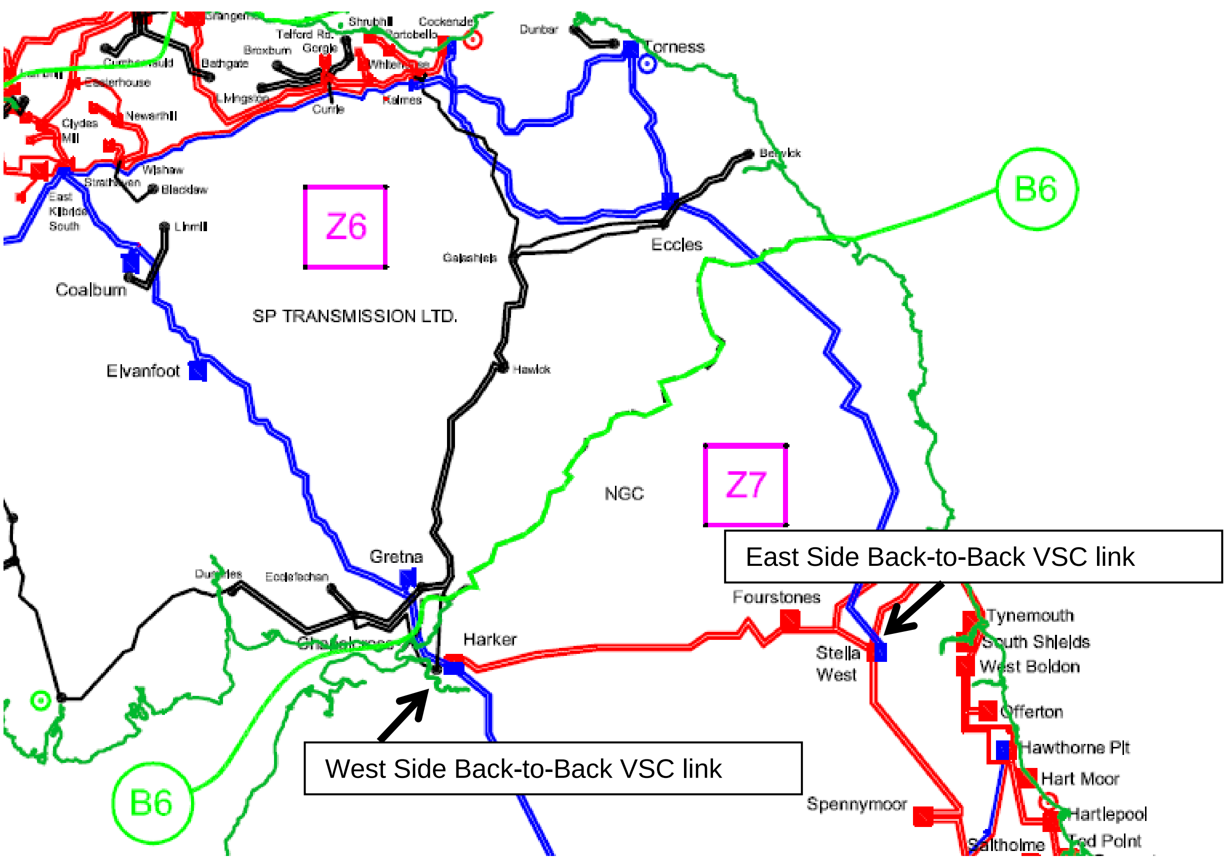

Figure 6-1 Location of East Side and West Side Back-to-back VSC links

At Stella West, the East side back-to-back VSC link is connected to the 400 kV Stella West bus on one circuit of the double circuit 400 kV Eastern interconnector. The other 400 kV circuit of the double circuit 400 kV Eastern interconnector remains unchanged. Similarly, the West side back-to-back VSC link is

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connected to one circuit of the double circuit 400 kV AC Western interconnector at Harker, with the other circuit remaining unchanged.

6.1. Rationale for Selection

Results of scenario 1A revealed that the instability caused by tripping the Western interconnector could be mitigated by converting the existing 400 kV AC Eastern interconnector into two parallel DC bi-poles. However, this conversion did not help to maintain stability if both bi-poles of the converted Eastern interconnector were tripped due to a common tower failure.

For this reason, it could be argued that not only the Eastern interconnector but also the Western interconnector should be converted into an HVdc link. However, as pointed out in section 5.1, the Western interconnector is tapped at several points, making the Western interconnector unsuitable as a two-terminal HVdc link. Also, the weak system strength of the AC system at the tapped locations makes the Western interconnector unsuitable for multi-terminal LCC HVdc technology. In addition, converting both Eastern and Western interconnectors would split the ScottishPower network and the National Grid network into two separate asynchronous systems. Splitting the systems into two asynchronous systems is likely undesirable and would require a whole new range of studies.

Therefore, a possible suitable option for installing HVdc on both the Eastern and Western interconnectors without isolating the Scottish Power and National Grid networks into two asynchronous systems would be to install HVdc on one circuit of each of the double circuit interconnectors and leave the other circuit as is. If only one of circuit of each double circuit interconnectors is converted to HVdc, then the systems are still synchronous as they remain connected via one circuit of AC line for each double circuit interconnector. Back-to-back HVdc may be more desirable than converting the entire other circuit into a full HVdc link in order to avoid the operation of AC and HVdc side by side on the same tower. Back-to-back HVdc installed in series with an AC line provides the ability quickly control power flow on that line through the back-to-back HVdc link.

Based on the above facts, installing back-to-back HVdc links in series with one circuit of the Eastern and Western interconnectors could potentially mitigate the instability caused by tripping the Eastern interconnector or Western interconnector.

The drawback of the back-to-back option compared to the full line AC to DC line conversion is that it would not increase the thermal capacity of the existing transmission lines. For that reason, the existing thermal ratings of the Eastern interconnector and Western interconnector would remain the same for the back-to-back option. That is, around 6000 MVA for the Eastern interconnector and around 4000 MVA for the Western interconnector. Since the thermal capacity of the Western interconnector is only about 4000 MW, many thermal overloads could be expected when the Eastern interconnector is tripped if the total system boundary B6 power transfer is 4.75 GW.

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6.2. Back-to-back VSC Model

In the base powerflow case, the steady state power transfers in the Eastern interconnector and Western interconnector are around 2.7 GW and 2.0 GW, respectively. However, when either of these interconnectors is tripped, the power transfer in the other interconnector must be boosted to around 4.75 GW in order to continue the total power transfer and maintain system stability. Three ABB VSC modules rated at ± 320 kV and 1216 MVA were utilized for each back-to-back VSC link to represent the back-to-back VSC option. Therefore, the combined power rating of each back-to-back VSC link was 3648 MVA. This rating is not optimized and further studies would be required to identify an optimized rating for the back-to-back HVdc links. Figure 6-2 and Figure 6-3 depict the VSC arrangement and show how each back-to-back VSC link is connected to the existing AC circuits.

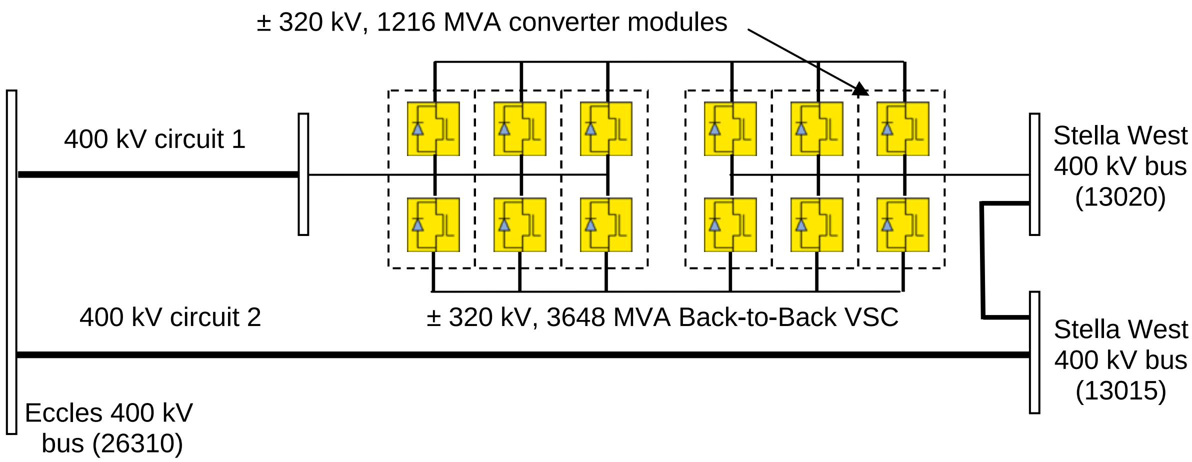

Figure 6-2: 1216x3 MVA back-to-back VSC HVdc link at Stella West

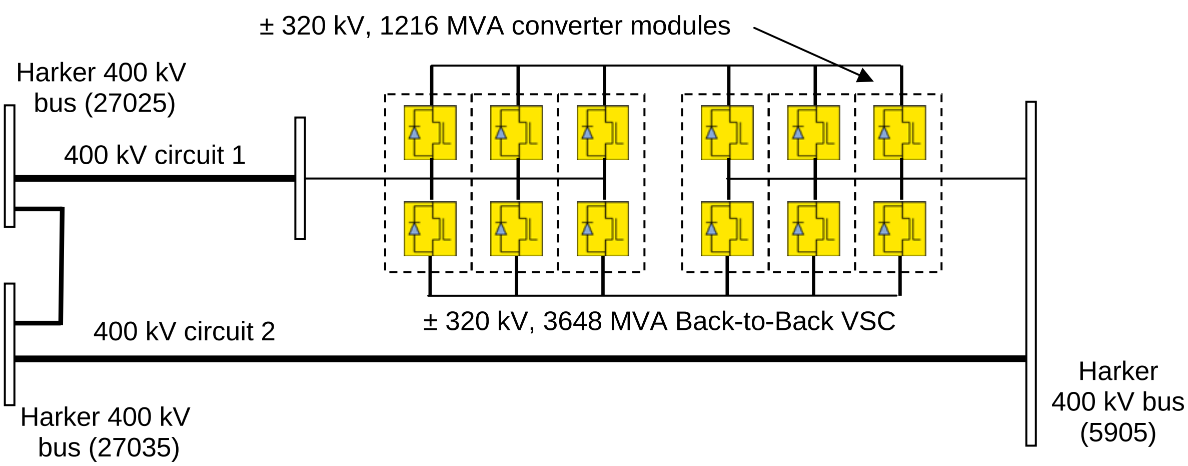

Figure 6-3: 1216x3 MVA back-to-back VSC HVdc link at Harker

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6.3. Steady State and Dynamic Performances

Performance assessment for secnario1B investigates the impact of the two worst case contingencies only: loss of the Eastern and Western interconnectors (contingencies EAST_IC and WEST_IC as given in Table 4-1). The performance of the two back-to-back VSC links on the Eastern and Western interconnectors should be similar to the scenario 1A case study for the rest of 14 contingencies tabulated in Table 4-1.

6.3.1. Steady State Transmission losses

According to the VSC manuals [1], each VSC[3] converter has losses of 1.65% at nominal power rating, with 30% fixed losses and 70% variable plus the losses in the DC line. Table 6-1 tabulates the power loss in the back-to-back VSC links on the Eastern and Western interconnectors.

Table 6-1 Converter losses for back-to-back VSC option

Location of the Back-to-back VSC link	Active Power Transfer (MW)	Converter Losses (MW)
Eastern Interconnector	1400	68
Western Interconnector	1150	63

During normal steady state operation in the particular powerflow case being studied, the total VSC converter losses are about 130 MW. Note that these converter losses are in addition to the losses in the AC transmission lines connected in series with the back-to-back VSC links. Therefore, the back-to-back VSC option results in approximately 130 MW higher losses compared to the AC option. Also, it is important to note that the converter losses are based on the 3648 MVA VSC rating that was assumed for the back-to-back VSC links. If the actual VSC rating were lower, the converter losses would be lower than 130 MW at this same operating point.

6.3.2. Steady State Contingency Analysis

6.3.2.1. Contingencies with Unconverged Solutions

Steady state contingency analysis was performed for loss of the Eastern and Western interconnectors (contingencies EAST_IC and WEST_IC) for the back-to-back VSC HVdc option. Post contingency powerflow solutions for both contingencies were obtained provided that the two SPSs listed in Table 6-2 were implemented.

Table 6-2 SPS utilized for back-to-back VSC HVdc operation

Contingency	SPS
	VSC Option
EAST_IC	Boost Western interconnector back-to-back power to compensate Eastern interconnector power transfer (i.e. boost power transfer from 1.2 GW to 2.8 GW)
WEST_IC	Boost Eastern interconnector back-to-back power to compensate Western interconnector power transfer (i.e. boost power transfer from 1.4 GW to 2.5 GW)

6.3.2.2. Steady State Voltage Violations

There were no overvoltage violations observed for the Scenario 1B back-to-back VSC HVdc option, however, there were a number of undervoltage violations. These violations are tabulated in appendix A2. These undervoltage violations would have been compared with the undervoltage violations recorded for the base case AC option, however the base case AC option did not have a converged post-contingency

[3] Recent publications by ABB and Siemens claim that the VSC converter losses have been reduced so that VSC losses are almost comparable to losses in LCC converters. Therefore, VSC converters with losses equal to LCC converter losses may be available in the future.

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powerflow solution for contingencies EAST_IC and WEST_IC. Therefore, the undervoltage violations that were observed for the back-to-back VSC HVdc option were compared with base case AC option undervoltage violations recorded for the rest of the 14 contingencies listed in Table 4-1**Error! Reference source not found.** Table 6-3 lists the undervoltage violations observed for the back-to-back VSC HVdc option if the violation was 1 % worse than the base case AC option or when there was a new undervoltage violation observed for the back-to-back VSC HVdc option that was not recorded for the base case AC option.

Table 6-3 Comparison of undervoltage violations for the back-to-back VSC HVdc option

Bus Name	AC Option	Back-to-back Option	
	All Converged Contingencies	EAST_IC	WEST_IC
11085 4314ZZ 400.00	-	0.89167	0.89884
11095 6247ZZ 400.00	-	0.89167	0.89884
11635 WWEY2P 275.00	-	0.89372	-
11665 WWEY2S 275.00	-	0.89056	-
25095 AUCH20 275.00	-	0.87491	-
25130 AYRR2Q 275.00	-	0.87396	-
25135 AYRR2R 275.00	-	0.87396	-
25770 COAL40 400.00	-	0.88403	-
25830 COYL20 275.00	-	0.87436	-
25845 COYW2S 275.00	-	0.87444	-
25850 COYW2T 275.00	-	0.87444	-
27350 KILS20 275.00	-	0.87574	-
27360 KILS40 400.00	-	0.88563	-
27365 KILT2Q 275.00	-	0.87534	-
27370 KILT2R 275.00	-	0.87534	-
27705 MAHI20 275.00	-	0.8748	-
27935 NECU20 275.00	-	0.87634	-
28605 STHA20 275.00	-	0.87707	-
28620 STHA40 400.00	-	0.87891	-

Note: Two 500 MVA synchronous condensers were added, one at Strathaven and one at Elvanfoot, to mitigate voltage collapse identified in the dynamic simulations, as is discussed in section 6.3.3. This voltage collapse was originated in the area of Strathaven to Elvanfoot along the Western interconnector. The undervoltage violations observed for the back-to-back VSC option as listed in Table 6-3 already assume these two synchronous condensers are in operation. This indicates that additional reactive power support beyond two 500 MVA synchronous condensers would be required for post-contingency operation when the Eastern interconnector is tripped. More details regarding these synchronous condensers and their impact of the system performance are presented in section 6.3.3.

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6.3.2.3. Steady State Thermal Overloads

There were a number of thermal overloads observed for the back-to-back VSC HVdc option. A complete list of thermal overloads observed for scenario 1B is presented in Appendix B2. These thermal overloads would have been compared with the thermal overloads recorded for the base case AC option, however the base case AC option did not have a converged post-contingency powerflow solution for contingencies EAST_IC and WEST_IC. Therefore, the thermal overloads observed for the back-to-back VSC HVdc option were compared with the base case AC option thermal overloads that were recorded for the rest of the 14 contingencies listed in Table 4-1. Table 6-4 summarizes the thermal overloads observed for the back-to-back VSC HVdc option if the overload was at least 3% higher than the overloads recorded in the base case AC option, or when there was a new thermal overload observed for the back-to-back VSC HVdc option that was not recorded for the base case AC option.

Table 6-4 Comparison of thermal overloads for back-to-back VSC HVdc option

Line Name	Line Rating (MW)	AC Option	Back-to-back Option	
		All Converged Contingencies	EAST_IC	WEST_IC
5655*STEW2 275.00 5895 HARK2J 275.00 1	775	-	110.3	-
5655*STEW2 275.00 16165 STEW2A 275.00 1	570	-	-	115.8
13005*STEW4A 400.00 13010 STEW4B 400.00 1	200	-	-	228.5
25770 COAL40 400.00 28620*STHA40 400.00 1	2010	-	120.7	-
25770*COAL40 400.00 26420 ELVA40 400.00 2	2210	-	108.2	-
26310*ECCL40 400.00 28855 TORN40 400.00 1	1250	-	-	125
26310*ECCL40 400.00 28855 TORN40 400.00 2	1250	-	-	125
26420 ELVA40 400.00 28620*STHA40 400.00 1	2210	-	108.8	-
26420*ELVA40 400.00 26955 GRNA40 400.00 1	2210	-	155.1	-
26955*GRNA40 400.00 27035 HAKB4B 400.00 1	2210	-	159.2	-
27360*KILS40 400.00 28620 STHA40 400.00 1	1390	-	108.6	-
28580 SMEA4Q 400.00 28620*STHA40 400.00 1	1390	-	144.5	-
28580*SMEA4Q 400.00 28855 TORN40 400.00 1	1250	-	160.5	100.3

The thermal overloads observed following the loss of the Western interconnector (contingency WEST_IC) are quite similar to those observed in scenario 1A with the exception of the 115.8 % and 100.3 % overloads observed on the 275 kV and 400 kV transmission lines, respectively.

Some of the thermal overloads observed following the loss of the Eastern interconnector (contingency EAST_IC) are to be expected as the power transfer (about 4750 MW) in the Western interconnector in the post-contingency period is greater than the thermal rating (about 4000 MVA) of the Western interconnector. There are two options that could be employed to mitigate some of these overloads. The first approach would obviously be to upgrade the overloaded lines so that the power transfer could continue following the loss of the Eastern interconnector. The other option would be to utilize the short term overload capability of transmission lines so that generation could be re-dispatched within the period allowed for the short term overload of transmission lines. Allowing short term overload would require further assessment by the transmission owners to rule out potential safety concerns.

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6.3.3. Transient Stability and Dynamic Performance

6.3.3.1. System Stability

The SPSs described in Table 6-2 were employed for tripping of either the Western interconnector or tripping of the Eastern interconnector. System stability was maintained following the loss of the Western interconnector (contingency WEST_IC); however, a voltage collapse initiated in the area from Strathaven to Elvanfoot along the Western interconnector caused system instability following the loss of the Eastern interconnector (contingency EAST_IC).

In order to mitigate the voltage collapse caused by loss of the Eastern interconnector, a total of two 500 MVA synchronous condensers were added, one at Strathaven and one at Elvanfoot. The size of these two synchronous condensers and their locations were not optimized in this study. A synchronous condenser model used in a previous study was employed at both locations. Please refer to Appendix C2 for plots of system voltage, generator speeds, line powerflows, etc. for contingencies WEST_IC and WEST_IC.

Moreover, it was found that adding the same synchronous condensers into the base case AC option did not prevent system instability in the AC base case for loss of either the Eastern or Western interconnector.

Figure 6-4 depicts the power transfer increase in each of the two circuits of the Eastern interconnector when the Western interconnector is tripped. The total power transfer in the Eastern interconnector prior to the contingency is about 2.7 GW, with about a 1.4 GW power transfer in the 400 kV AC circuit connected in series with the back-to-back VSC link and about a 1.3 GW power transfer in the other AC circuit. Following the loss of the Western interconnector, the power transfer in AC circuit connected to back-to-back VSC link increases from about 1.4 GW to 2.5 GW as a result of the SPS. Also, power transfer in the other AC circuit increases automatically so that the total power transfer in the Eastern interconnector increases from 2.7 GW to a total of 4.7 GW, thereby allowing the pre-contingency power transfer across boundary B6 to continue during post-contingency.

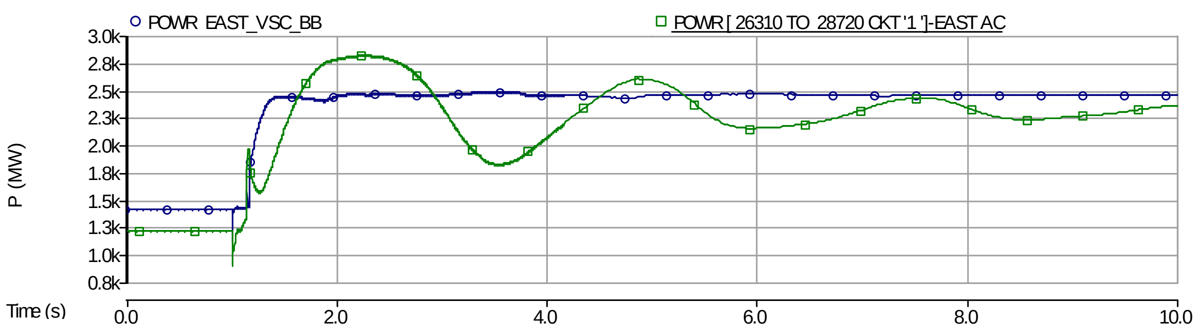

Figure 6-4 Increase in power transfer in Eastern interconnector for contingency WEST_IC (Blue – Circuit with Back-to-back VSC, Green – other AC circuit in parallel)

Figure 6-5 depicts the power transfer increase in each of the two circuits of the Western interconnector when the Eastern interconnector is tripped. The total power transfer in the Western interconnector prior to the contingency is about 2.1 GW, with about a 1.2 GW power transfer in the 400 kV AC circuit connected in series with back-to-back VSC link and about a 0.9 GW power transfer in the other AC circuit. Following the loss of the Eastern interconnector, the power transfer in the AC circuit connected to the back-to-back VSC link increases from about 1.2 GW to 2.8 GW as a result of the SPS. Also, power transfer in the other AC circuit increases automatically so that the total power transfer in Western interconnector increases from 2.1 GW to a total of 4.7 GW, thereby allowing the pre-contingency power transfer across boundary B6 to continue in post-contingency.

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Note as stated in the previous paragraph, this contingency requires the two 500 MVA synchronous condensers in order to maintain system stability.

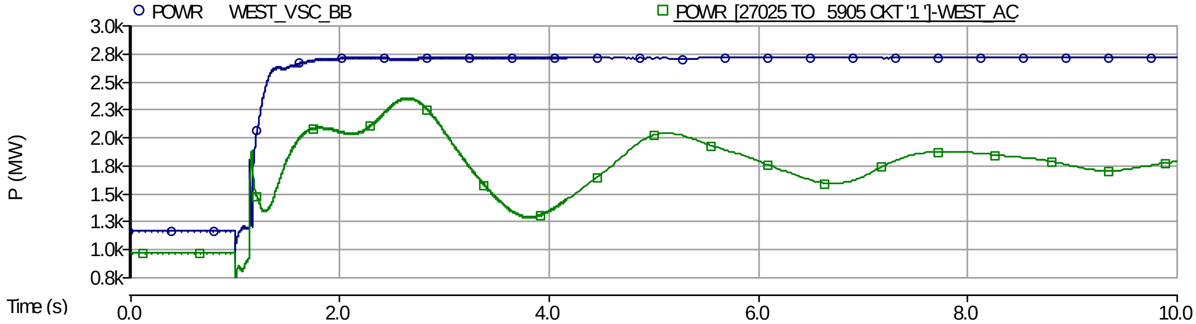

Figure 6-5 Increase in power transfer in Western interconnector for contingency EAST_IC (Blue – Circuit with Back-to-back VSC, Green – other AC circuit in parallel)

6.3.3.2. Reactive Power Support from the Back-to-Back VSC

An important and beneficial aspect of the back-to-back VSC option is the large amount of reactive power support that the VSC can supply to the AC network. Figure 6-6 depicts the dynamic reactive power support provided by the back-to-back VSC link at Harker during and following the loss of the Eastern interconnector (contingency EAST_IC).

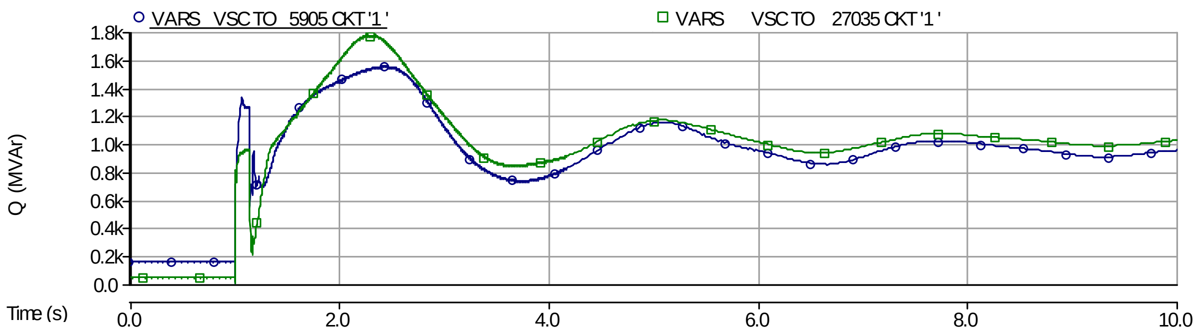

Figure 6-6 Reactive power injected into the AC system from the back-to-back VSC at Harker for contingency EAST_IC (Blue – VSC Q to Harker side, Green – VSC Q to Moffat and Gretna side)

Similarly, Figure 6-7 depicts the dynamic reactive power support provided by the back-to-back VSC at Stella West during and following the loss of the Western interconnector (contingency WEST_IC).

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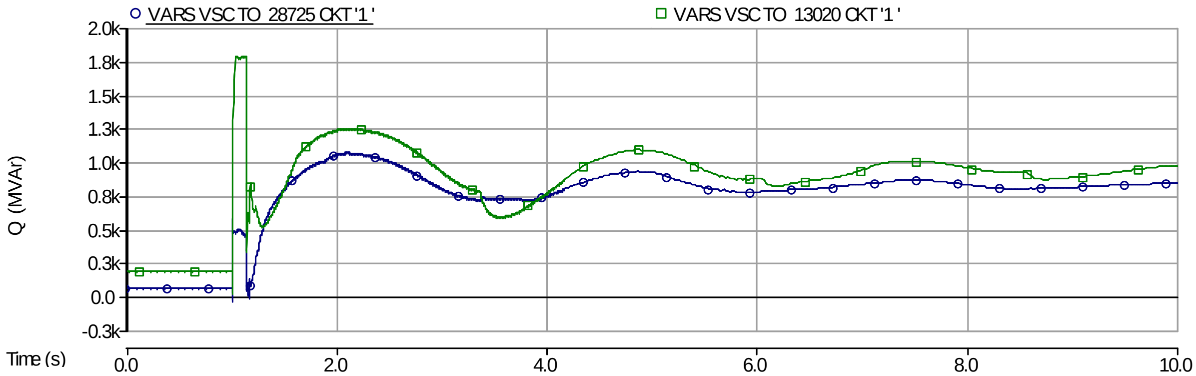

Figure 6-7 Reactive power injected into the AC system from the back-to-back VSC at Stella West for contingency WEST_IC (Blue – VSC Q to Eccles side, Green – VSC Q to Stella West side)

For both contingencies, the post-contingency reactive power injection from each side of the VSC link is close to1000 MVAr. It is imperative to note that without this reactive power support, the voltage around Stella West and Harker would collapse, causing system instability.

Figure 6-8 depicts the reactive power output of the synchronous condensers at Strathaven and Elvanfoot for loss of the Western interconnector (contingency WEST_IC). Note that the reactive power outputs of both synchronous condensers are slightly less during the post-contingency period compared to the reactive power outputs during the pre-contingency period. This is because the active power transfer is shifted from the west side network to the east side network during the outage of the Western interconnector, resulting in less demand for reactive power to maintain the voltage of the 400 kV network. This observation reveals that these two synchronous condensers hardly have any contribution to the fault recovery for loss of the Western interconnector.

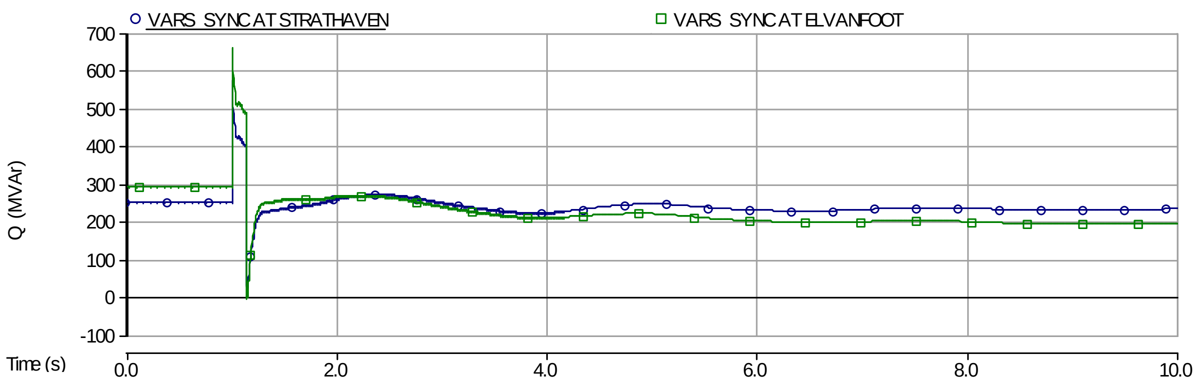

Figure 6-8 Reactive power output of synchronous condensers at Strathaven and Elvanfoot for contingency WEST_IC (Blue – Synchronous condenser at Strathaven, Green – Synchronous condenser at Elvanfoot)

Figure 6-9 depicts the reactive power outputs of the synchronous condensers at Strathaven and Elvanfoot for loss of the Eastern interconnector (contingency EAST_IC). Note that the reactive power outputs of both synchronous condensers are increasing rapidly during the fault recovery and settle close to 550 MVAr. Without this dynamic reactive power support, the voltage at Strathaven and Elvanfoot along the Western interconnector would collapse, resulting in system instability. Note that the reactive power support is required not only during transients but also during the steady state post-contingency operation.

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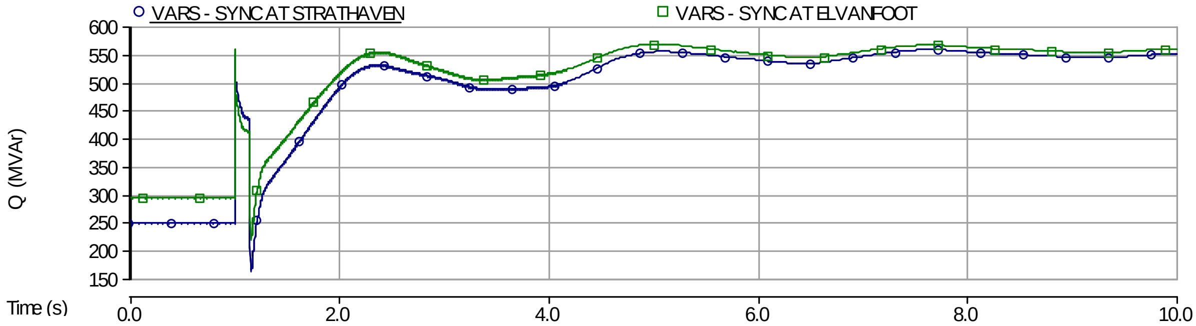

Figure 6-9 Reactive power output of synchronous condensers at Strathaven and Elvanfoot for contingency EAST_IC (Blue – Synchronous condenser at Strathaven, Green – Synchronous condenser at Elvanfoot)

The results presented above clearly indicate that loss of the Eastern interconnector is more severe than loss of the Western interconnector, requiring increased reactive power support in the Strathaven and Elvanfoot areas to transfer the increased amount of power in the Western interconnector following the loss of the Eastern interconnector.

6.3.3.3. Transient Undervoltages & Overvoltages

There were no transient overvoltages over 1.2 pu observed for scenario 1B. Figure 6-10 depicts the voltage at Elvanfoot, Strathaven and Stella West 400 kV buses for loss of the Western interconnector (contingency WEST_IC). Note that all of these voltages are above 0.95 pu during the post-contingency period.

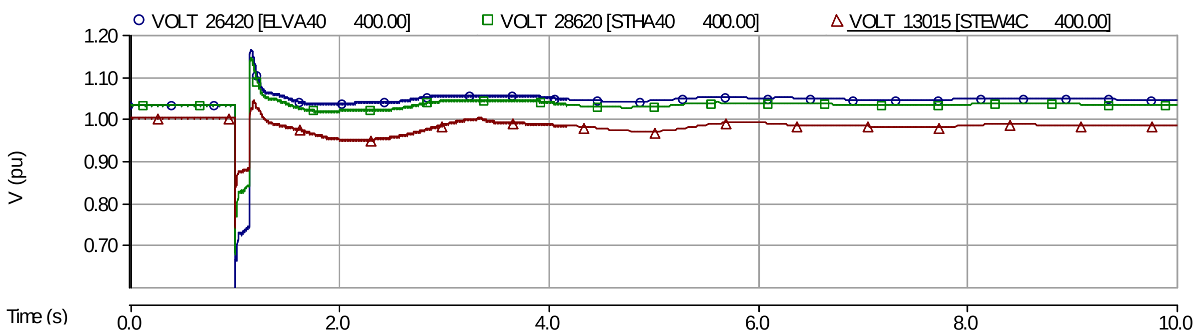

Figure 6-10 Voltage at Elvanfoot, Strathaven and Stella West for contingency WEST_IC

Figure 6-11 depicts the voltage at Elvanfoot, Strathaven and Harker 400 kV buses for loss of the Eastern interconnector (contingency EAST_IC). Note that the voltage at Harker was above 0.95 pu during the post-contingency period, however, voltages at Elvanfoot and Strathaven dip down almost to 0.8 pu during the fault recovery and then stabilize at about 0.95 pu. From this, it is clear that the without 500 MVA synchronous condensers at Elvanfoot and Strathaven, the voltage at Elvanfoot and Strathaven would drop below 0.8 pu, initiating a voltage collapse.

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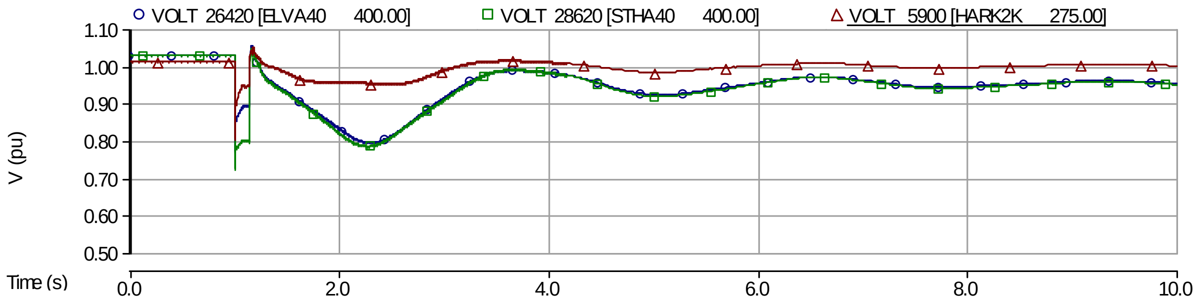

Figure 6-11 Voltage at Elvanfoot, Strathaven and Harker for contingency EAST_IC

In order to improve the transient undervoltage in the Elvanfoot and Strathaven area along the Western interconnector, a combination of dynamic and static reactive power support may be utilized.

6.3.3.4. System Frequency Performance

No transient underfrequency or overfrequency deviations outside of ± 0.5 Hz were observed for the two contingencies that were studied. All transient frequencies as measured by generator speeds were also within a ± 0.5 Hz frequency band.

6.3.3.5. System Damping

In general, plots of power oscillations inspected for loss of the Western and Eastern interconnectors (contingencies WEST_IC and EAST_IC) indicate that the back-to-back VSC HVdc option has adequate damping levels for power oscillations.

6.4. Conclusions

Because the results of Scenario 1A (conversion of the Eastern interconnector to HVdc) demonstrated that the system was still unstable for loss of the Eastern Interconnector whether AC or HVdc technology is used, Scenario 1B was created. An obvious thought would be to convert both the Eastern and Western interconnectors to HVdc, so that in case of loss of either interconnector, an SPS could boost power in the other, and hopefully maintain system stability. However, converting both interconnectors to HVdc would fully isolate the Scottish Power network from the National Grid network, which is likely undesirable and would require a whole new set of studies.

A possible suitable option for installing HVdc on both the Eastern and Western interconnectors without isolating the Scottish Power and National Grid networks into two asynchronous systems would be to install HVdc on one circuit of each of the double circuit interconnectors and leave the other circuit as is. If only one of circuit of each double circuit interconnector is converted to HVdc, then the systems are still synchronous as they remain connected via one circuit of AC line for each double circuit interconnector. Back-to-back HVdc may be more desirable than converting the entire one circuit into a full HVdc link in order to avoid the operation of AC and HVdc on the same tower. Back-to-back HVdc installed in series with an AC line provides the ability quickly control power flow on that line through the back-to-back HVdc link.

This led to the brief investigation of Option B for scenario 1.

Scenario 1B installed a back-to-back VSC HVdc link at Stella West on one circuit of the 400 kV double circuit AC Eastern interconnector, and a second back-to-back VSC link at Harker on one circuit of the 400 kV double circuit AC Western interconnector.

- Loss of the Western interconnector resulted in a stable system response.

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- Loss of the Eastern interconnector caused a voltage collapse in the area around Strathaven and Elvanfoot along the Western interconnector, which resulted in system instability. Two 500 MVA synchronous condensers were required, one at Strathaven and one at Elvanfoot, in order to prevent the voltage collapse and maintain system stability. In addition to the reactive power support provided by the synchronous condensers, this contingency also relies heavily on the large reactive power capability of the VSC back-to-back HVdc link.

Based on the results presented above, the back-to-back VSCs at Stella West and Harker, along with two 500 MVA synchronous condensers, show potential as a feasible option of using HVdc technology to maintain system stability for the worst two contingencies: loss of the Eastern and Western interconnectors.

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7. Scenario 2: Two-Terminal HVdc: Lackenby to Thornton

Scenario 2 investigates the potential for transmission capacity improvements in zones 7, 8 and 9 across system boundary B7 by converting the 400 kV AC double circuit Boundary-7 East Interconnector No 2 (B7_EAST_IC_2) into two bi-polar HVdc links. The dashed line on the right hand side of Figure 7-1 shows the B7_EAST_IC_2 interconnector from Lackenby to Thornton.

Figure 7-1 also shows the 400 kV AC double circuit Boundary-7 East Interconnector No 1 (B7_EAST_IC_1) from Norton to Osbaldwick, and the 400 kV AC double circuit interconnector from Harker to Hutton (S1_WEST_IC). These two interconnectors are the main transmission lines connecting Zone 7 with Zones 8 and 9. They carry a total combined winter peak power transfer of about 5230 MW in the power flow case being studied.

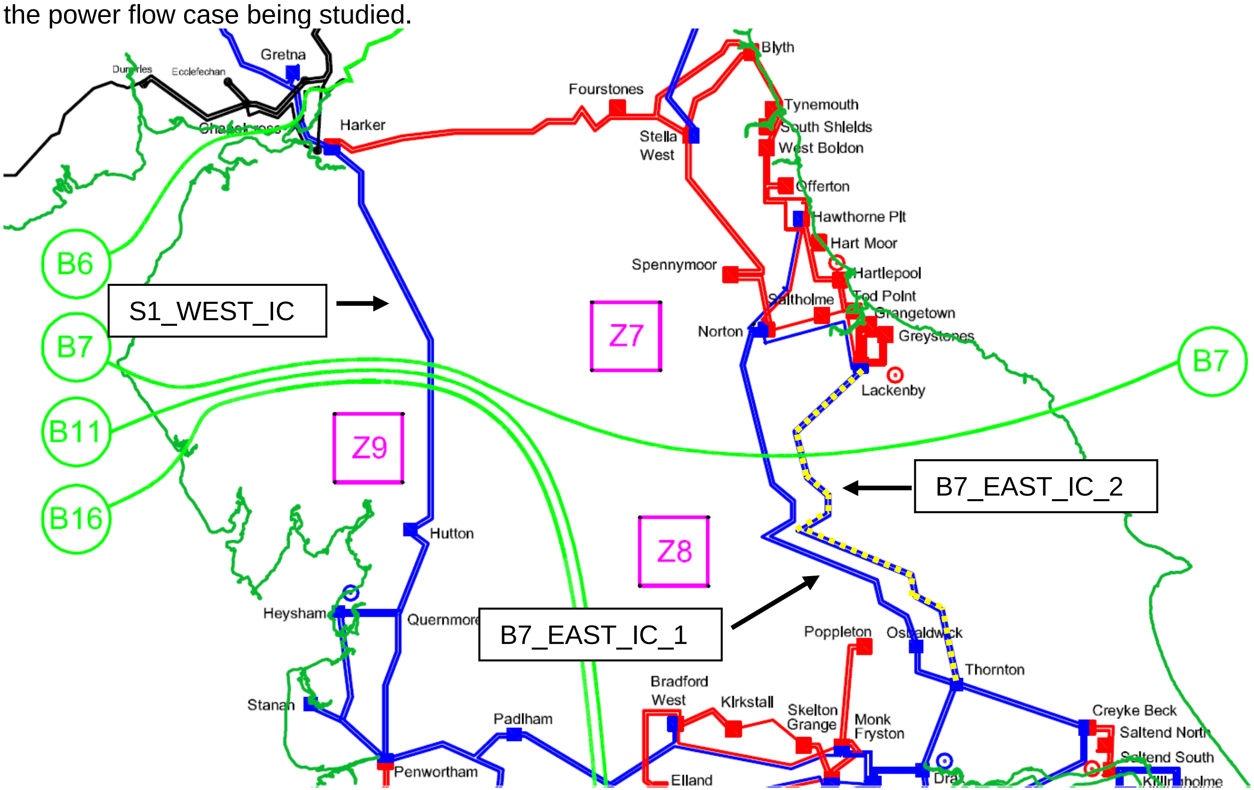

Figure 7-1 S1_WEST_IC, B7_EAST_IC_1 and B7_EAST_IC_2 interconnectors connecting zone 7 and 8, 7 and 9 across system boundary B7.

B7_EAST_IC_1 interconnector connects Norton sub-station to Osbaldwick sub-station through a 400 kV, dual circuit HVac overhead line. Both circuits of the double circuit HVac overhead line run on the same tower. The winter thermal rating of each of these individual circuits is 2010 MVA.

B7_EAST_IC_2 interconnector connects Lackenby sub-station to Thornton sub-station through a 400 kV, dual circuit HVac overhead line. Both circuits of the double circuit HVac overhead line run on the same tower. The winter thermal rating of each of these individual circuits is 2420 MVA. The length of the B7_EAST_IC_2 interconnector is about 105 km with 98.84 km of overhead line and 5.97 km of underground cable.

S1_WEST_IC interconnector connects Harker sub-station to Hutton sub-station through a 400 kV, dual circuit HVac overhead line. Both circuits of the double circuit HVac overhead line run on the same tower. The winter thermal rating of each of these individual circuits is 2520 MVA.

Please note that although all three interconnectors are double circuit lines, the fact that the two circuits of each interconnector run on the same tower makes it possible that the entire interconnector may be lost

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for a contingency involving a tower failure. Obviously, converting a double circuit interconnector to HVdc would not change this fact. Whether the double circuit line is an HVac or HVdc line, a common tower failure would result in loss of that entire interconnector.

7.1. Rationale for Selection of Line Conversion

The total combined thermal rating of the three interconnectors across boundary B7 would be around 7000 MVA. The base case power flow used in this study has winter peak power transfer of 5320 MW across system boundary B7. Tripping of one of the three double circuit interconnectors as a result of a tower failure would force the other interconnectors to carry the total power transfer.

Scenario 2 investigates converting the B7_EAST_IC_2 interconnector from Lackenby to Thornton into a two terminal DC line to see if there would be any potential improvement to system performance as a result of increasing transmission capability across boundary B7. Rationale behind selecting the B7_EAST_IC_2 interconnector instead of the other two interconnectors is because the B7_EAST_IC_2 interconnector connects two strong AC sub-stations, namely Lackenby and Thornton. Performance of an LCC HVdc link benefits from being connected to a strong AC network. The B7_EAST_IC_1 interconnector between Norton and Osbaldwick is also a suitable candidate; however, Thornton is a better location than Osbaldwick since Thornton is connected to both Drax and Creyke Beck 400 kV buses through strong 400 kV double circuit transmission lines. In the case of the S1_EAST_IC interconnector, Quernmore or Penwortham are better termination locations than Hutton. For this reason a three terminal HVdc link would be possible with terminals at Harker, Hutton and Quernmore. Also, a four terminal HVdc link would be possible from Harker to Penwortham with terminals at Harker, Hutton, Quernmore and Penwortham. However, power exchange between the Hutton 400 kV bus and the local AC network is quite small compared to the power transfer from Harker to Hutton and Hutton to Quernmore. Thereby, the three or four terminal HVdc link would consist of a terminal that is relatively small compared to the other terminals. Typically, the rating of the smallest terminal should at least be 15 % of the rating of the largest terminal for a multi-terminal LCC HVdc scheme.

Based on the above facts, the B7_EAST_IC_2 interconnector is the best choice for converting an existing HVac line into an HVdc link in order to attempt to achieve improvement in transmission capability across system boundary B7. Both AC circuits of the interconnector were converted to DC in order to avoid electro-magnetic interferences between the AC and DC lines and also to better utilize the available conductor capacity. Please refer to section 5.1 for a more detailed rationale behind why not only one circuit but both circuits of the B7_EAST_IC_2 interconnector were selected for conversion to DC.

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7.2. HVdc Ratings and Models Used

7.2.1. Rating of existing dual circuit 400 kV HVac B7_EAST_IC_2 interconnector

The B7_EAST_IC_2 interconnector has a cable section and an overhead section. Combined parameters of these two sections for each circuit of the double circuit 400 kV AC interconnector are tabulated in Table 7-1.

Table 7-1 Parameters of 400 kV AC double circuit B7_EAST_IC_2 interconnector

PSSE Bus names and numbers		Line Parameters on 100 MVA pu base			Circuit	Line Rate A (MVA)	Conductor Rate A (kA)	Length (km)
From Bus	To Bus	R	X	B				
THTO4J (5095)	LACK4 (5460)	0.00105	0.01772	1.34325	1	2420	3.493	104.81
THTO4K (5100)	LACK4 (5460)	0.00105	0.01772	1.34325	2	2420	3.493	104.81

The total length of the B7_EAST_IC_2 interconnector is 104.81 km. The winter thermal rating (Rate A) of each of these two circuits is 2420 MVA. Autumn and summer ratings assumed for each of these two circuits are 2420MVA (3.493 kA) and 2030 MVA (2.930 kA), respectively.

7.2.2. Rating of converted HVdc interconnector

By converting both AC circuits of the interconnector, there will be six conductors available with a 3.493 kA winter thermal rating. Similar to the scenario 1A study, ± 320 kV was selected as the rated DC voltage for both VSC and LCC converters. Please refer section 5.1 for the basis behind the selection of the DC voltage. Furthermore, it should be noted that 320 kV is the voltage selected without looking into the tower details and design. A DC voltage optimizing study would need to be performed at the design stage of the DC line to determine a suitable DC voltage considering the existing tower design and the right of way.

The dc current rating of a conductor in the converted line is higher than the ac current rating of the same line. For this reason, ac current rating could be considered as the minimum dc current rating for the converted transmission lines. Table 7-2 tabulates the maximum possible power rating for the converted HVdc link based on the 320 kV DC voltage and minimum conductor dc current ratings in each season.

Table 7-2 Maximum rating of converted HVdc B7_EAST_IC_2 interconnector

Season	AC Rating (MVA)	Maximum DC Rating (MW)	Increase in Power rating
Winter	2420*2 = 4840	320*3.493*2*3 = 6707	38.6 %
Autumn	2420*2 = 4840	320*3.493*2*3 = 6707	
Summer	2030*2 = 4060	320*2.930*2*3 = 5626	

The calculations in Table 7-2 show that the rating of the B7_EAST_IC_2 interconnector could be increased by 38.6 % by converting the interconnector from HVac to HVdc with a DC voltage of ±320 kV. As far as the thermal rating of conductors are concerned, the minimum DC power rating of 5626 MW is available in summer and a rating higher than 5626 MW is available in autumn and winter.

Thus, the DC power rating of the conductor in any season is well over the rating required to transfer the total power through the B7_EAST_IC_2 interconnector when one of the other two interconnectors is unavailable. It is important to note that the maximum power rating of an HVdc system is based not only on the conductor thermal rating, but also on the rating of other equipment associated with the HVdc system. Unlike conductors, ratings of the HVdc equipment do not depend on the season of the year. Dynamic studies will demonstrate whether or not this rating is also sufficient from a transient stability point of view.

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7.2.2.1. VSC Model

In the base powerflow case, the steady state power transfer in the B7_EAST_IC_1 and B7_EAST_IC_2 interconnectors were around 1.5 GW and 1.6 GW, respectively. The steady state power transfer in the S1_WEST_IC interconnector is about 2.2 GW. However, when one of these three interconnectors is tripped, the other two interconnectors should carry total power transfer of about 5.3 GW in order to continue the total power transfer and maintain system stability. For this reason, the power rating of the B7_EAST_IC_2 should be around 2.7 GW.

ABB has developed [1] VSC modules with voltage rated at ± 80 kV, ± 150 kV and ± 320 kV for various power ratings[4]. Modules rated at ± 320 kV have 405 MVA (0.63 kA), 796 MVA (1.24 kA) and 1216 MVA (1.90 kA) power ratings. The PSSE VSC model being used in this study is available at these ratings (but not at ratings in between). The highest power rating of a single converter module is limited by the current rating of the IGBT valves available today. However, VSC modules could be connected in parallel to obtain required power rating. Figure 7-2 shows the converter connection for the two VSC bi-poles utilized in the Scenario 2 case study. It is anticipated that converters with higher power ratings are available in the future, making it possible to realize this scheme with fewer parallel converters.

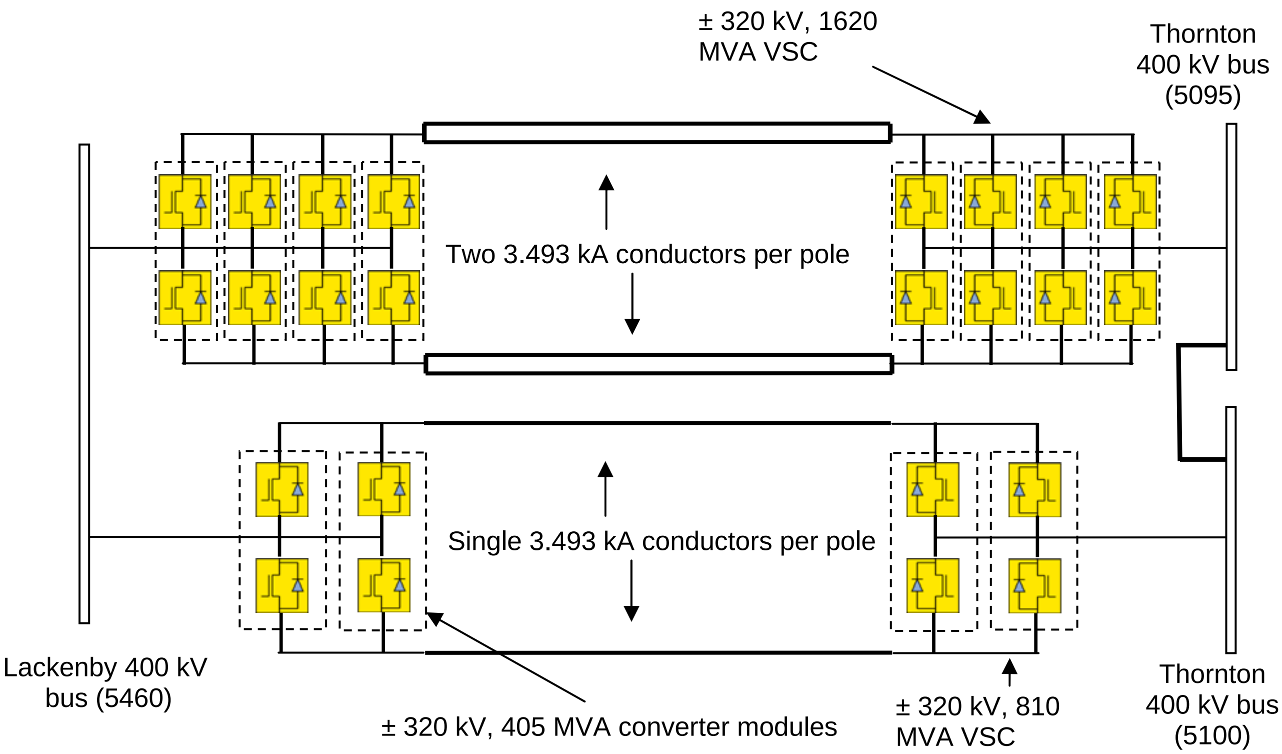

Figure 7-2 ± 320 kV, 405x2 MVA and 405x4 MVA VSC bi-poles in parallel at rectifier and inverter sides

These two parallel bi-poles utilize all six conductors available from converting the two three phase AC circuits, with two DC conductors per pole in the 1620 MVA HVdc bi-pole and one DC conductor per pole in the 810 MVA HVdc bi-poles. As shown in Figure 7-2, the combined power rating of 2430 MVA provided by the two parallel VSC bi-poles rated at 1620 MW and 810 MW is barely enough to compensate for the loss of either the S1_WEST_IC or B7_EAST_IC_1 interconnectors. However, the results presented in the rest of the Scenario 2 study will show that the combined rating of 2430 MVA of two parallel bi-poles is actually quite sufficient.

[4] Voltage of VSC modules could be higher than 320 kV. These ABB VSC modules are intended to use in applications involving DC cables and therefore DC voltage is limited by cable voltage rating.

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There are four 405 MVA parallel converters at each end of the 1620 MW HVdc bi-pole and there are two 405 MVA parallel converters at each end of the 810 MVA HVdc bi-pole. Note that Thornton 400 kV buses 5100 and 5095 are connected together by a zero impedance line.

The converter configuration shown in Figure 7-2 is one possible configuration that could be utilized to obtain the required rating. The number of modules connected in parallel at each converter station to obtain the required power rating depends on the DC voltage selection and current rating of IGBT valves available in the future.

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7.2.2.2. LCC Model

LCC utilizes thyristor valves in the converters. The maximum continuous current rating for a thyristor valve available today is around 5.5 kA. Consequently, the maximum power rating for an LCC bi-pole at ± 320 kV is about 3520 MW. In this case study, two LCC bi-poles in parallel were utilized to match the power rating of the three VSC bi-poles illustrated in section7.2.2.1. Figure 7-3 shows the how two bi-poles are connected between Eccles 400 kV bus and Stella West 400 kV buses. Note that Stella West 400 kV buses 13015 and 13020 are connected together by a zero impedance line.

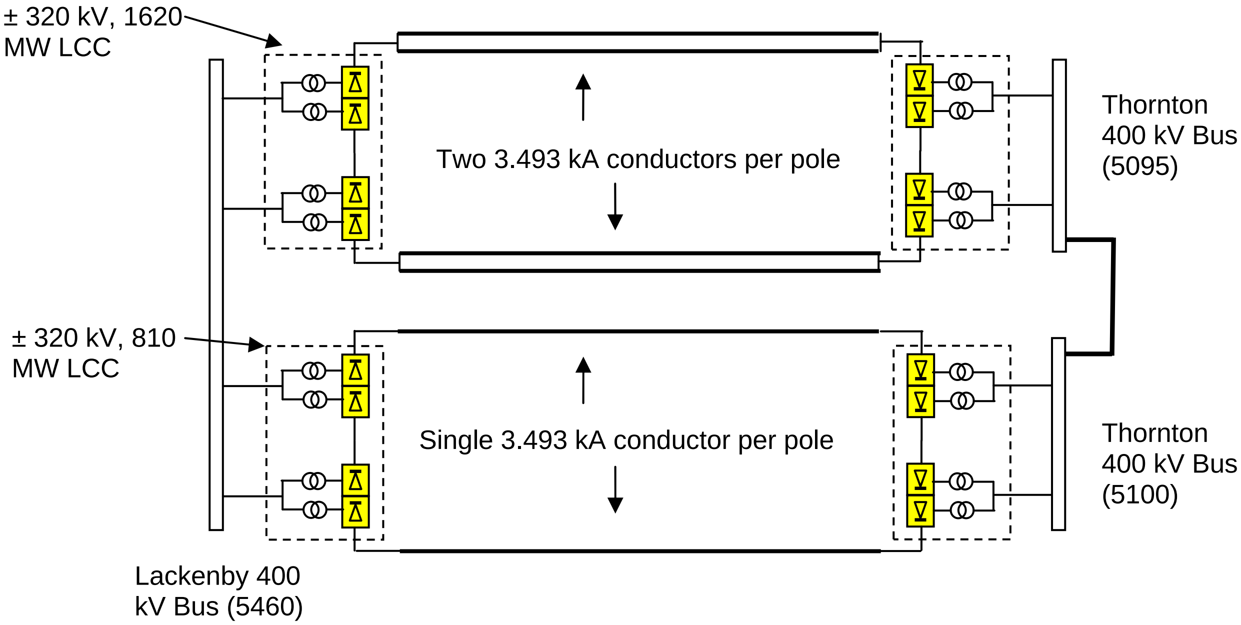

Figure 7-3 ± 320 kV, 810 MW and 1620 MW LCC bi-poles

The two parallel bi-poles utilize all six conductors available from converting the two three phase AC circuits, with two conductors per pole in the 1620 MW HVdc bi-pole and one conductor per pole in the 810 MW HVdc bi-pole.

The TGS two time step model [2] was used to model the LCC HVdc bi-poles in PSS/E dynamics.

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7.2.3. AC System Strength at HVdc Terminals

System strength is more of an issue for LCC HVdc than it is for VSC HVdc technology.

System strengths at the LCC converter buses were calculated and are summarized in Table 7-3 for the LCC HVdc option. Please note that the short circuit level of the Thornton 400 kV bus is calculated by connecting 400 kV buses 5100 and 5095.

Table 7-3 Short circuit levels at LCC terminal buses

LCC terminal	Short Circuit Strength (MVA)	SCR	ESCR
Thronton 400 kV bus (5095+5100)	37743	15.5	15.0
Lackenby 400 kV bus (5460)	15310	6.3	5.8

Table 7-3 also tabulates the short circuit ratio (SCR) and effective short circuit ratio (ESCR) for the combined rating of 2430 MW. In the ESCR calculation, it was assumed that 55 % reactive power compensation is provided by the HVdc filters. Both the Thornton and Lackenby terminals are considered to be strong.

7.3. Performance Comparison

Performance of the VSC and LCC HVdc options for the Scenario 2 case study are compared with the performance of the base case AC system under the following categories.

- Steady State Transmission Losses
- Steady State AC Contingency Analysis
- Transient Stability and Dynamic Performance

7.3.1. Steady State Transmission losses

Losses resulting directly from the current flowing in the B7_EAST_IC_2 interconnector from Lackenby to Thornton as a 400 kV double circuit AC line were calculated and compared with the losses in the VSC and LCC HVdc systems. According to the VSC manuals [1], each VSC converter has losses of 1.65% at nominal power rating, with 30% fixed losses and 70% variable plus the losses in the DC line. Typically, each LCC converter has losses of 0.80% at nominal power rating, with 10% fixed losses and 90% variable plus the losses in the DC line. Table 7-4 tabulates the conductor losses for all three transmission options as well as converter losses for the VSC and LCC options for two operating conditions.

Table 7-4 Loss comparison for three transmission options

Transmission option	At Operating Point being Studied		
	Conductor Loss (MW)	Converter Loss (MW)	Total Loss (MW)
AC	14.5	-	14.5
VSC	7	61	68
LCC	7	32	39

The total transmission losses are smallest for the AC line and highest for the VSC option (more than 4 times the AC losses). Losses for the LCC option are about half of the losses of the VSC option.

It should be noted that very recent publications by VSC manufacturers indicate that VSC converter losses in the MMC type converters are almost comparable to losses in LCC converters. The 1.65% loss value used in this study for the VSCs is required by the PSSE VSC model as it is preprogrammed to use this value and cannot be changed by the user. For purposes of stability results, a loss value of 1.65% compared to 1% for example is not expected to have a significant impact on the results observed in this study. Of course, the lower losses would have a big impact on project economics, but that is beyond the scope of this report. Please note that the loss values presented in Table 7-4 are based on the VSC model and therefore correspond to a value of 1.65%.

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7.3.2. Steady State AC contingency Analysis

7.3.2.1. Diverged Contingencies

Steady state contingency analysis was performed for the 16 contingencies listed in Table 4-1 for all three transmission options, namely AC, VSC HVdc and LCC HVdc.

Converged post-contingency powerflow solutions could not be obtained for all three transmission options for the following contingencies:

- WEST_IC (Outage of Western interconnector)
- EAST_IC (Outage of Eastern interconnector)

Please refer to section 5.3.2.1 under the Scenario 1 A case study for a detailed discussion regarding the reasons why it was not possible to obtain post-contingency powerflows for the above two contingencies.

7.3.2.2. Steady State Voltage Violations

There were no overvoltage violations observed for the Scenario 2 transmission options, however, several undervoltage violations were observed for all three transmission options. These violations are tabulated in Appendix A3. All undervoltage violations observed for the VSC and LCC HVdc options were also observed for the AC option. Hence, there are no new violations created by the VSC or LCC HVdc options. In fact, several undervoltage violations observed in the Stella West area for the AC option following the loss of the 400 kV double circuit AC line from Harker to Hutton (contingency S1_WEST_IC) were not present for the LCC or VSC HVdc options. Thus, both the LCC and VSC HVdc options have an advantage over the AC option due to the large inherent reactive power capability in the case of the VSC HVdc option and due to the reactive power support provided by the filters in the case of the LCC HVdc option, which can assist in improving post-contingency undervoltages.

7.3.2.3. Steady State Thermal Overloads

There were a number of thermal overloads observed for all three transmission options. However, all of these thermal overloads were almost the same (within 2 % of each other) for all three transmission options, except the case tabulated in Table 7-5. A complete list of thermal overloads observed for Scenario 2 is presented in Appendix B3.

Table 7-5 Thermal overloads with greater than 2 % difference between three transmission options

LINE NAME	RATING (MW)	CONTINGENCY	Percentage thermal violation		
			AC	VSC	LCC
5005 DRAX4J 400.00 5050*EGGB4J 400.00 1	2090	Z8_C1	109.9	-	-

The thermal overload tabulated in Table 7-5 indicates mitigation of an existing overload in base case AC option. This shows a very marginal benefit for the HVdc options compared to the AC option.

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7.3.3. Transient Stability and Dynamic Performance

7.3.3.1. System Stability

Dynamic simulations were performed for the 16 contingencies listed in Table 4-1 for all three transmission options, namely AC, VSC HVdc and LCC HVdc. System stability was maintained for all of the contingencies, with the exception of the loss of the 400 kV double circuit Eastern interconnector and the loss of the 400 kV double circuit Western Interconnector (contingencies EAST_IC and WEST_IC). Please refer to Appendix C3 for plots of system voltage, generator speeds, line powerflows, etc. for all 16 contingencies.

Interconnector B7_EAST_IC_2 is the existing double circuit AC line that has been converted into a DC line for Scenario 2. The contingency associated with tripping this interconnector is contingency B7_EAST_IC_2. This contingency represents a tower failure of Interconnector B7_EAST_IC_2 at the Lackenby end, causing all six conductors to be grounded at a location close to the Lackenby 400 kV bus. The ground fault was then cleared after 7 cycles by tripping Interconnector B7_EAST_IC_2 at the Lackenby and Thronton ends. The tripped AC circuits were not re-connected since the tower failure is a permanent fault. In dynamic simulations, this fault was modeled as follows:

- AC option: A three phase-to-ground fault at the Lackenby 400 kV bus cleared by tripping the two 400 kV AC circuits from Lackenby to Thronton after 7 cycles.

- VSC HVdc option: This conductor to ground fault is a DC fault in both VSC HVdc bi-poles. When the DC conductors are grounded, the AC system at Lackenby and Thronton AC system feed the ground fault through the phase reactors, converters and the DC line. The vendor supplied VSC dynamic model does not provide means to directly simulate DC faults, the user manual suggests dc faults to be modeled as ac faults through an impedance at both terminals. For that reason, a three phase-to-ground fault through a selected impedance was applied at each converter bus at Lackenby and Thronton. The value of ground fault impedance at each end should include the impedance of the phase reactor, impedance offered by the converter and the impedance of the DC line between fault location and the corresponding converter. For the sake of modeling simplicity and also to demonstrate worst conditions, the impedance of the converter and the DC line were neglected. Consequently, three phase-to-ground faults through the phase reactor impedance were applied at Lackenby and Thronton converter buses for both VSC bi-poles. These three phase-to-ground faults were cleared after 7 cycles, representing the fault clearing actions of AC breakers located on the primary side of the converter transformers.

- LCC HVdc option: An LCC converter isolates AC and DC sides during a conductor to ground fault on the DC side. Therefore, this conductor to ground fault on the DC lines was modeled as a double bi-pole block of three terminal LCC HVdc link, without any AC system fault.

Since all three transmission options could not maintain system stability for loss of the Eastern or Western interconnectors (contingencies EAST_IC and WEST_IC) and all three options could maintain system stability for the rest of 14 contingencies, both the VSC and LCC based HVdc options have no clear advantage over the AC option in their ability to maintain system stability. For this reason, it could be concluded that the AC and HVdc options perform similarly in terms of system stability.

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7.3.3.2. Transient Undervoltages & Overvoltages

AC system voltages were observed during the post fault period at buses rated 275 kV and above. Out of the three transmission technologies, in most situations the VSC option showed superior voltage performance following a disturbance, while the AC and LCC options showed moderate voltage performances. The VSC option is inherently equipped with a large capacitive and inductive range of voltage control so it is not surprising that it shows better voltage performance.

Transient voltages up to 1.2 pu are typical in most power systems. Transient overvoltages above 1.2 pu were not observed for all three options. Typically, transient overvoltages occur at the terminals of an LCC HVdc link during bi-pole block where total load rejection occurs at both ends while all the filters remain connected at the terminal AC buses. Figure 7-4 depicts the voltages of all three transmission options for contingency B7_EAST_IC_2 at the 400 kV buses at Lackenby and Thornton. Note that the highest transient voltage at the Lackenby and Thronton 400 kV buses are well below the 1.2 pu level. This is to be expected as the ESCR values calculated for the Lackenby and Thornton LCC HVdc terminals indicate a strong system.

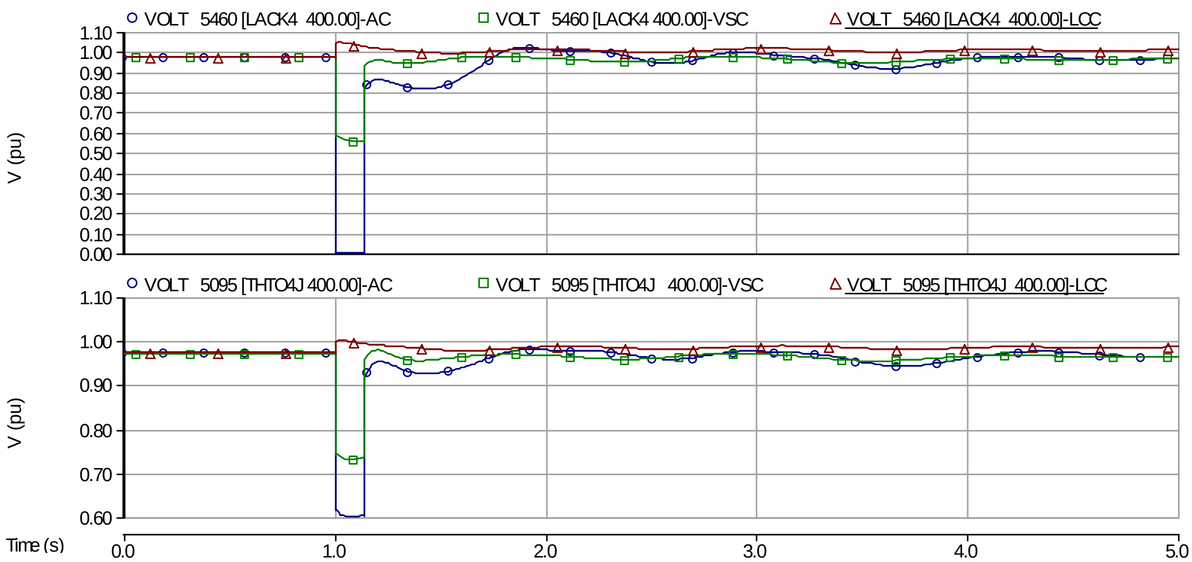

Figure 7-4 Transient overvoltage at Lackenby and Thornton terminals for contingency B7_EAST_IC_2 (Blue – AC, Green – VSC, Red – LCC)

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Figure 7-5 depicts the worst transient undervoltage observed for all three options during the fault recovery period of contingency S1_WEST_IC. Contingency S1_WEST_IC simulates tripping of the 400 kV double circuit line from Lackenby to Thronton after a three phase-to-ground fault at the Lackenby 400 kV bus. Note that the voltage at Stella West and Spenymoor buses have a temporary dip for about one second during the fault recovery of the all three options. This is due to the increases in reactive power demand in the Stella West and Spenymoor areas caused by temporary swings in power transfer during the diversion of power through the Stella West and Spenymoor corridor. Note that after the initial dip, the voltage at Stella West and Spenymoor recover to higher values, however these values are still low compared to the pre-contingency voltages. This shows that more reactive support is required in the Stella West and Spenymoor area for all three transmission options.

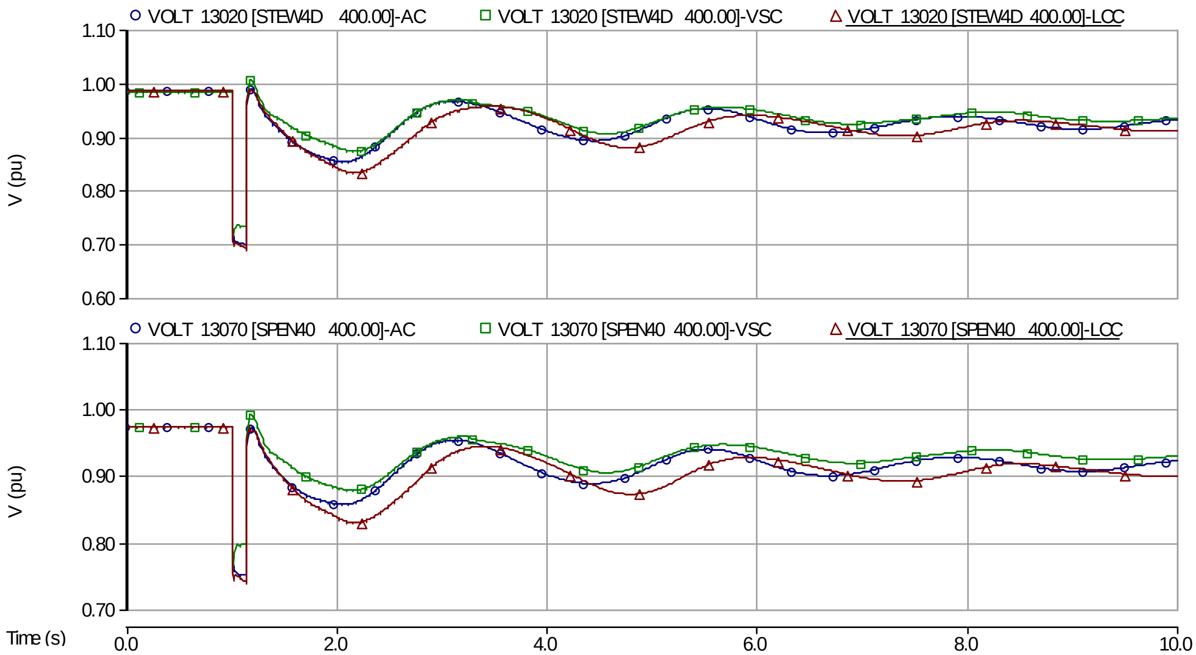

Figure 7-5 Transient undervoltage at Eccles and Stella West terminals for contingency S1_WEST_IC (Blue – AC, Green – VSC, Red – LCC)

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Figure 7-8 depicts the transient undervoltage observed for the VSC and LCC HVdc options during the fault recovery period of contingency B7_EAST_IC_1. Contingency B7_EAST_IC_1 simulates the tripping of 400 kV double circuit line from Norton to Osbaldwick after a three phase-to-ground fault at Norton 400 kV bus.

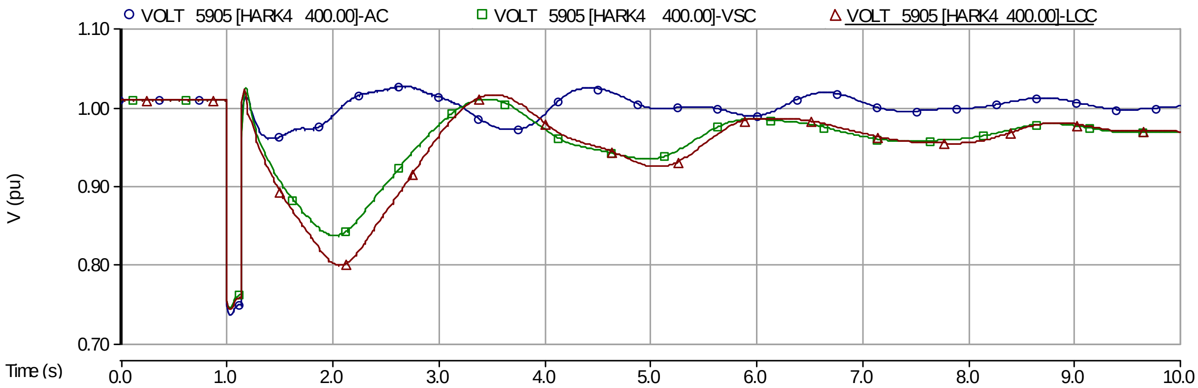

Figure 7-6 Transient undervoltage at Harker 400 kV bus for contingency B7_EAST_IC_1 (Blue – AC, Green – VSC, Red – LCC)

In the case of the AC option, tripping interconnector B7_EAST_IC_1 diverts power through 400 kV interconnector B7_EAST_IC_2 from Lackenby to Thornton and through the 275 kV network from Stella West to Harker. However, in both the VSC and LCC HVdc options, power transfer in interconnector B7_EAST_IC_2 remains unchanged and hence the increase in power transfer through the 275 kV network from Stella West to Harker is higher for the HVdc options when compared with the AC option. This increase in power transfer in the 275 kV network from Stella West to Harker increases the power transfer from Harker to Quernmore via Hutton.

Figure 7-7 shows the power oscillations and the increased power transfer in one circuit of double circuit S1_WEST_IC from Harker to Hutton for the HVdc options compared to the AC option.

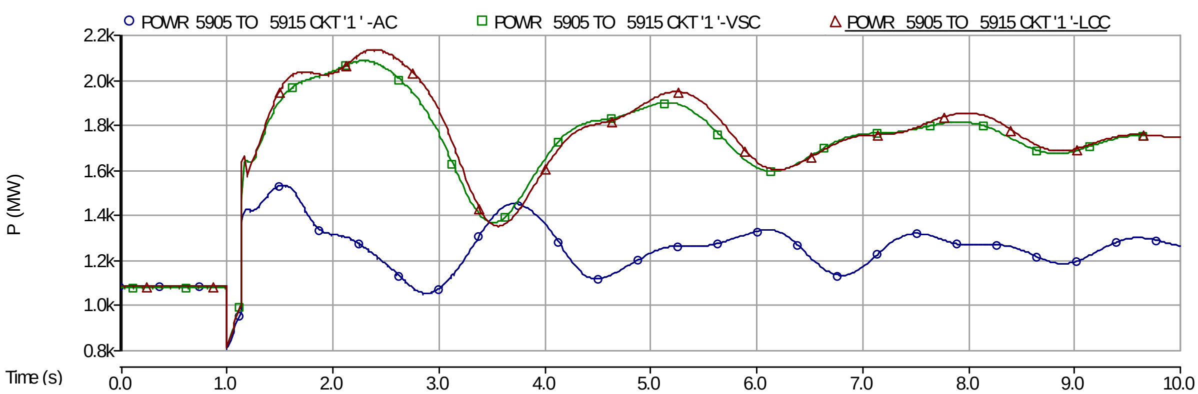

Figure 7-7 Power oscillations in S1_WEST_IC interconnector from Harker to Hutton for contingency B7_EAST_IC_1 (Blue – AC, Green – VSC, Red – LCC)

Note that the huge power swing that occurs during the fault recovery period causes the dip in voltage in the Harker and Hutton areas due to the increased demand for reactive power. In order to mitigate the voltage dip in the Harker and Hutton areas, an SPS was implemented to boost power in the HVdc converted interconnector B7_EAST_IC_2 for contingency B7_EAST_IC_1. Figure 7-8 shows the voltage at the Harker 400 kV bus for contingency B7_EAST_IC_1 when the power transfer in

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interconnector B7_EAST_IC_2 was boosted to 1.0 pu (2430 MW) in both bi-poles for both the VSC and LCC HVdc options.

Note that the dip in voltage at the Harker 400 kV bus has been improved in Figure 7-8 for both HVdc options. This observation indicates that by boosting power transfer in B7_EAST_IC_1 beyond 1.0 pu (2430 MW for both parallel bi-poles) for several seconds during fault recovery could quite possibly prevent the voltage dip at Harker for both HVdc options. Therefore, designing the HVdc systems a higher rating may be beneficial if either of the two Scenario 2 HVdc schemes would be built.

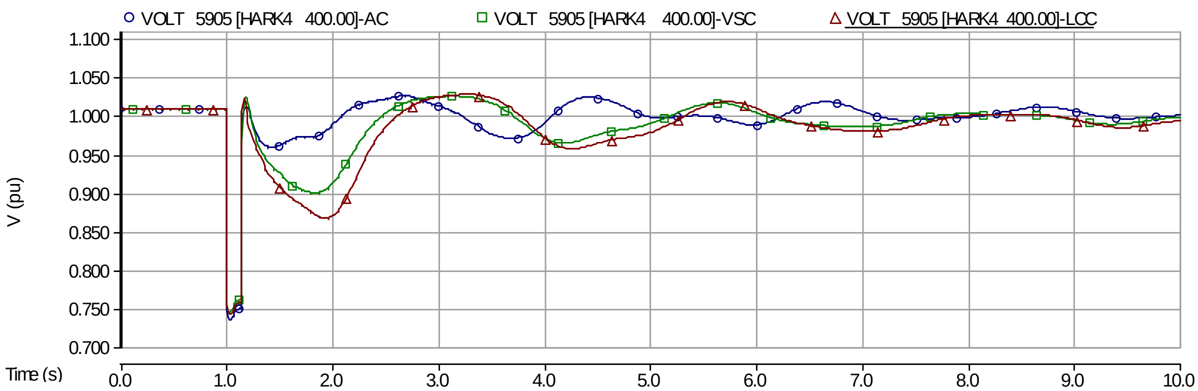

Figure 7-8 Improvement in transient undervoltage at Harker 400 kV bus for contingency B7_EAST_IC_1 when SPS was utilized to boost power in B7_EAST_IC_1 interconnector (Blue – AC, Green – VSC, Red – LCC)

7.3.3.3. System Frequency Performance

In transient stability programs such as PSS/E, the transmission system frequency is obtained from the derivative of the bus voltage angle. If there is a sharp change in the bus angle, the frequency might change infinitely. Therefore, there are filters associated with the frequency measurements. However, sometimes these filters are not enough to completely relieve these spikes in the frequency calculations, particularly if a fault has been applied in the area near to the frequency calculation. For this reason, generator speed quantities were mostly used to analyze frequency deviations as generator speeds are state variables which cannot change instantaneously and therefore should not give erroneous results.

For the power flow case that was studied, the AC, VSC HVdc and LCC HVdc transmission options did not show any transient underfrequency or overfrequency deviations outside of ± 0.5 Hz for any of the contingencies that were studied. All transient frequencies as measured by generator speeds were also within a ± 0.5 Hz frequency band.

7.3.3.4. System Damping

Plots of power oscillations inspected for various contingencies revealed that the three transmission options result in different damping levels depending on the contingency. Inspection of power oscillations also indicates that there is no clear evidence to substantiate which option has better system damping.

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7.4. SSR Screening

The UIF calculation described in the Study Procedures section is intended to screen for potential interaction between a conventional LCC HVdc system and generator shaft oscillation modes, known as subsynchronous resonance (SSR).

With LCC HVdc, any resonance frequency (f) on the DC side gets converted to f0+f and f0-f frequencies on the AC side.

Because VSC is a relatively new technology compared to LCC, there is less information available on the possibility of SSR with a VSC HVdc system. A simple test case was setup in PSCAD to test whether the same phenomenon occurred with VSC and results indicate that VSC may have the same potential as LCC to excite SSR.

There is also little information readily available on the possibility of SSR between a wind farm and an HVdc system. Because of this, the possibility cannot be excluded and it cannot be said for certain that the possibility does not exist. Should these HVdc options be further pursued it would be recommended to perform further studies to verify the possibility of SSR between HVdc terminals and wind farms in the Scottish Network along with the appropriate mitigation if deemed necessary.

Although the UIF screening calculations are intended to be used for LCC HVdc, the UIF was calculated for the VSC option as well in order to provide an indication of the potential need for detailed SSR studies. In order to calculate UIF index for the worst case scenario, the two parallel HVdc bi-poles (810 MW and 1620 MW) between Lackenby and Thornton were considered to be a single bi-pole with a combined rating of 2430 MW rating. The UIF index was calculated for all generators except salient pole generators in Zones 7, 8, 9, 10 and 11. Please refer Appendix D3 for complete table of UIF indices for scenario 2. Table 7-6 and Figure 7-6 summarize the results for the Lackenby and Thornton terminals, respectively.

Table 7-6 UIF Index calculated for Lackenby converter terminal

Generator Bus umber	Generator ID	Generator Rating (MVA)	Converter Rating (MW)	Generator Bus Number		UIF
				System Intact	Generator out-of-service	
5395	1	660.0	2430.0	14647.4	14104.8	0.005
5400	1	650.0	2430.0	14647.4	13897.2	0.010
5535	1	350.0	2430.0	14647.4	14065.6	0.011
5540	1	350.0	2430.0	14647.4	14061.0	0.011
5930	1	190.0	2430.0	14647.4	14642.6	0.000
5555	1	170.0	2430.0	14647.4	14269.6	0.010
5495	1	160.0	2430.0	14647.4	14402.6	0.004
5500	1	160.0	2430.0	14647.4	14403.4	0.004
5505	1	160.0	2430.0	14647.4	14403.5	0.004
5510	1	160.0	2430.0	14647.4	14402.6	0.004
5515	1	200.0	2430.0	14647.4	14372.1	0.004
5520	1	160.0	2430.0	14647.4	14402.0	0.004
5525	1	160.0	2430.0	14647.4	14401.4	0.004
5530	1	160.0	2430.0	14647.4	14401.4	0.004
5715	1	130.0	2430.0	14647.4	14570.9	0.001
5720	1	130.0	2430.0	14647.4	14570.9	0.001

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Table 7-7 UIF Index calculated for Thornton converter terminal

Generator Bus Number	Generator ID	Generator Rating (MVA)	Converter Rating (MW)	Short Circuit Level (MVA)		UIF
				System Intact	Generator out-of-service	
5045	1	700.0	2430.0	35806.6	34989.41	0.002
5035	1	700.0	2430.0	35806.6	34990.39	0.002
5040	1	700.0	2430.0	35806.6	34993.16	0.002
5025	1	700.0	2430.0	35806.6	35136.34	0.001
5020	1	700.0	2430.0	35806.6	35137.75	0.001
5030	1	700.0	2430.0	35806.6	35142.34	0.001
5070	1	510.0	2430.0	35806.6	35303.37	0.001
5075	1	520.0	2430.0	35806.6	35306.18	0.001
5060	1	530.0	2430.0	35806.6	35398.13	0.001
35505	1	410.0	2430.0	35806.6	35456.7	0.001
35510	1	410.0	2430.0	35806.6	35456.7	0.001
35515	1	410.0	2430.0	35806.6	35456.7	0.001
5065	1	530.0	2430.0	35806.6	35414.47	0.001

All UIF calculations were below the threshold of 0.1. For this reason, there are no generator units flagged for future study to determine the potential for SSR interaction.

7.5. Conclusions

Scenario 2 investigated the potential for transmission capacity improvements in zones 7, 8 and 9 across system boundary B7. The total power transfer being studied across boundary B7 was about 5.2 GW.

Scenario 2 looked at converting the 400 kV double circuit AC line from Lackenby to Thornton into two two-terminal bi-polar VSC/LCC based HVdc links.

- Results of the analysis showed no significant benefit in converting the AC line to HVdc technology.
- The HVdc line from Lackenby to Thorton cannot assist to improve system stability following the loss of the Eastern or Western interconnector, which were the only two unstable contingencies of those being studied.
- The AC and HVdc transmission options showed similar capability to maintain system stability and resulted in a similar system performance for the remaining contingencies that were studied.

Based on the results presented above, there was no technical benefit found to converting the 400 kV double circuit AC line from Lackenby to Thornton into two two-terminal bi-polar VSC/LCC based HVdc links, although it was shown to be technically feasible.

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8. Scenario 3: Three-Terminal HVdc: Cottam to Eaton Socon and Eaton Socon to Wymondley

Scenario 3 investigates the potential for transmission capacity improvements in zones 10, 11 and 12 across system boundary B9 by converting the 400 kV AC double circuit number 5 in Zone 12 (Z12_C5), into two bi-polar, three-terminal HVdc links. The dashed line in Figure 8-1 shows circuit Z12_C5 from Cottam to Eaton Socon and Eaton Socon to Wymondley.

Figure 5-1In addition, Figure 8-1 shows the following 400 kV AC double circuits.

1. Zone-12 circuit No 1 (Z12_C1) from Staythorpe to Grandon and Grandon to Sundon. Winter peak power transfer in this circuit is about 3.0 GW.
2. Zone-12 circuit No 2 (Z12_C2) from Ratcliffe to Enderby and Enderby to Patford Bridge and Patfort Bridge to East Claydon. Winter peak power transfer in this circuit is about 2.7 GW.
3. Zone-12 circuit No 3 (Z12_C3) from Walpole to Norwich Main and Norwich Main to Branford. Winter peak power transfer in this circuit is about 1.9 GW.
4. Zone-12 circuit No 4 (Z12_C4) from Walpole to Burwell Main and Burwell Main to Pelham. Winter peak power transfer in this circuit is about 2.8 GW.

Winter peak power transfer on circuit Z12_C5 is about 2.5 GW. Thereby, these five double circuit 400 kV AC lines carry a total combined winter peak power transfer of about 13 GW across boundary B9 in the power flow case being studied.

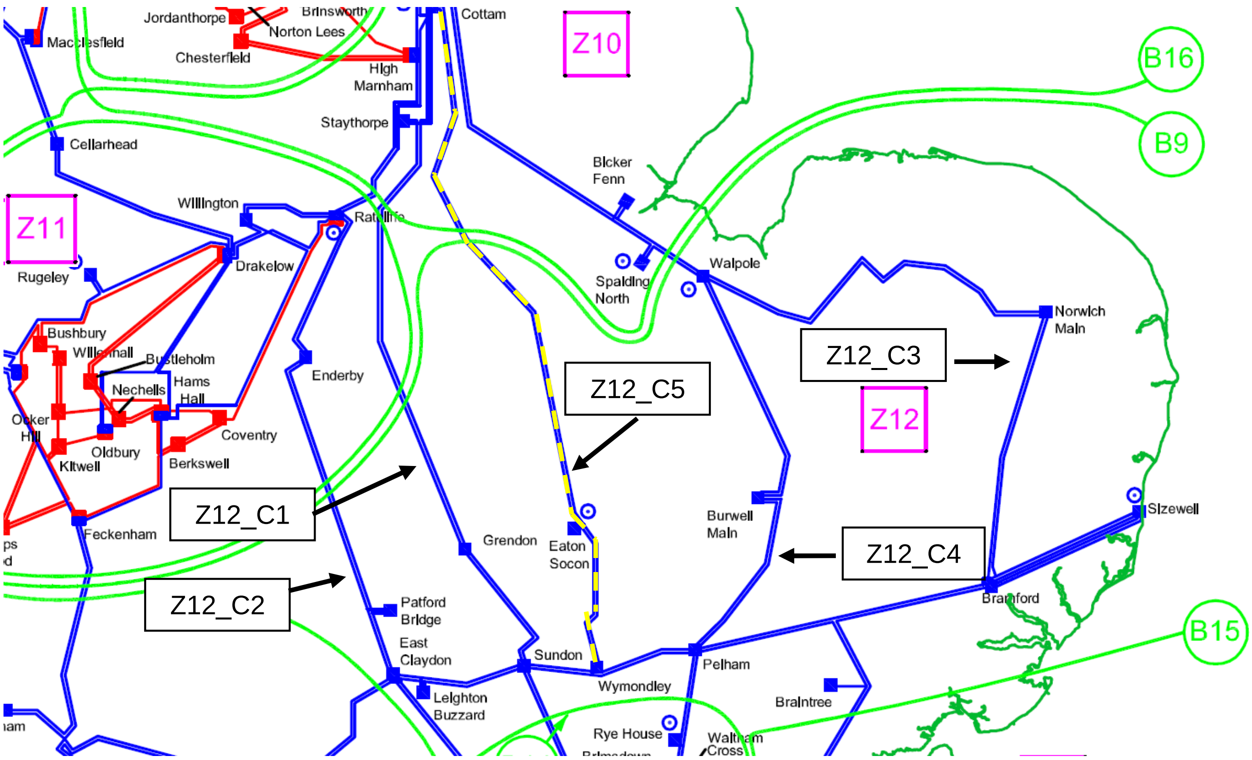

Figure 8-1 Zone 12 400 kV double circuits connecting zone 10 and 12 across system boundary B9.

Please note that although all five circuits are double circuit lines, the fact that the two circuits of each interconnector run on the same tower makes it possible that the entire interconnector may be lost for a contingency involving a tower failure. Obviously, converting a double circuit interconnector to HVdc would not change this fact. Whether the double circuit line is an HVac or HVdc line, a common tower failure would result in loss of that entire interconnector.

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8.1. Rationale for Selection of Line Conversion

The total combined power transfer in the five 400 kV circuits across boundary B9 in the winter peak case being studied is about 13 GW. Tripping of one of the five double circuit lines as a result of a tower failure would force the other circuits to share the pre-contingency power transfer that was being transferred by the tripped circuit. In addition to high power transfer, highly meshed AC network connections across boundary B9 makes the conversion of one of five AC circuits into three-terminal DC link a suitable scenario to study AC and multi-terminal HVDC interactions. Selecting other circuits located elsewhere in the UK transmission system would not have granted any additional contributions to the learning curve of the interactions of the multi-terminal HVDC link with AC system.

The Scenario 3 study investigates whether converting the Z12_C5 double circuit line into a three-terminal DC line would have any potential to improve system performance by increasing transmission capability across boundary B9. The rationale behind selecting the Z12_C5 double circuit line out of the five double circuit lines across boundary B9 is because the terminal locations of line Z12_C5, namely, Cottam, Eaton Socon and Wymondley, have suitable short circuit capacities for successful operation of a three-terminal LCC HVdc link. Other four double circuit lines have at least one terminal location where the short circuit strength is unsuitable for the operation of a three-terminal LCC HVdc link.

Based on the short circuit strength available at the midpoint (Eaton Socon), the Z12_C5 double circuit line is the best choice of an existing HVac line that could be converted into a three-terminal HVdc link in order to attempt to achieve improvement in transmission capability across system boundary B9. Both AC circuits of the interconnector were converted to DC in order to avoid electro-magnetic interferences between the AC and DC lines and also to better utilize the available conductor capacity. Please refer section 5.1 for the rationale behind why not only one circuit but both circuits of the Z12_C5 double circuit line were selected for the conversion.

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8.2. HVdc Ratings and Models Used

8.2.1. Rating of existing 400 kV HVac Z12_C5 dual circuit

Z12_C5 is a double circuit 400 kV AC line connecting Cottam to Wymondley with a tap at Eaton Socon. Parameters of circuit Z12_C5 are tabulated in Table 8-1.

Table 8-1 Parameters of 400 kV AC double circuit B7_EAST_IC_2 interconnector

PSSE Bus names and numbers		Line Parameters on 100 MVA pu base			Circuit	Line Rate A (MVA)	Conductor Rate A (kA)	Length (km)
From Bus	To Bus	R	X	B				
COTT4 (3105)	EASO4 (2955)	0.00148	0.02229	0.91004	1	2780	4.013	135.3
COTT4 (3105)	EASO4R (2965)	0.00148	0.02229	0.91004	1	2780	4.013	135.3
EASO4 (2955)	WYMO4 (2140)	0.0004	0.00606	0.024736	2	2780	4.013	36.5
EASO4R (2965)	WYMO4 (2140)	0.0004	0.00606	0.024736	2	2780	4.013	36.5

The total length of circuit Z12_C5 is 171.8 km. The winter thermal rating (Rate A) of each of these two circuits is 2780 MVA. Autumn and summer ratings assumed for each of these two circuits are 2570 MVA (3.709 kA) and 2220 MVA (3.204 kA), respectively.

8.2.2. Rating of converted HVdc eastern interconnector

By converting both AC circuits of Z12_C5, there will be six conductors available with a 4.013 kA winter thermal rating. Similar to the Scenario 1A study, ± 320 kV was selected at the rated DC voltage for both VSC and LCC converters. Please refer section 5.1 for the basis behind the selection of the DC voltage. Furthermore, it should be noted that 320 kV is the voltage selected without looking into the tower details and design. A DC voltage optimizing study would need to be performed at the design stage of the DC line to determine a suitable DC voltage considering the existing tower design and the right of way.

The dc current rating of a conductor in the converted line is higher than the ac current rating of the same line. For this reason, ac current rating could be considered as the minimum dc current rating for the converted transmission lines. Table 8-2 tabulates the maximum possible power rating for the converted HVdc link based on the 320 kV DC voltage and minimum conductor dc current ratings in each season.

Table 8-2 Maximum rating of converted HVdc Z12_C5 circuit

Season	AC Rating (MVA)	Maximum DC Rating (MW)	Increase in Power rating
Winter	2780*2 = 5560	320*4.013*2*3 = 7705	38.6 %
Autumn	2570*2 = 5140	320*3.709*2*3 = 7121	
Summer	2220*2 = 4440	320*3.204*2*3 = 6152	

The calculations in Table 8-2 show that the rating of the Z12_C5 circuits could be increased by 38.6 % by converting the double circuit line Z12_C5 from HVac to HVdc with a DC voltage of ±320 kV. As far as the thermal rating of conductors are concerned, a minimum DC power rating of 6152 MW is available in summer and a rating higher than 6152 MW is available in autumn and winter.

Thus, the conductor DC power rating in any season is well over the rating required to transfer the total power through Z12_C5 when one of the other four circuits is unavailable (2.5 GW existing power transfer in circuits Z12_C5 + 3.0 GW which is the highest power transfer in any parallel circuit). It is important to note that the maximum power rating of an HVdc system is based not only on the conductor thermal rating, but also on the rating of other equipment associated with the HVdc system. Unlike conductors, ratings of the HVdc equipment do not depend on the season of the year. Dynamic studies will demonstrate whether or not this HVdc rating is also sufficient from a transient stability point of view.

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8.2.2.1. VSC Model

In the base powerflow case, the steady state power transfer in circuit Z12_C5 is about 2.5 GW. The highest power transfer in any of the circuits that are in parallel with circuit Z12_C5 in the Zone 12 corridor is about 3.0 GW in circuit Z12_C1. When one of the five 400 kV double circuits is tripped, the other four circuits will share the power transfer. On the other hand, circuit Z12_C5 that is converted to HVdc could carry the total power that was being transferred in the circuit that tripped. If the latter option is desired, the rating of the HVdc link should be selected to be around 5.5 GW to account for the 2.5 GW existing power transfer in Z12_C5 circuit and the 3.0 GW power transfer in circuit Z12_C1.

ABB has developed [1] VSC modules with voltage rated at ± 80 kV, ± 150 kV and ± 320 kV for various power ratings[5]. Modules rated at ± 320 kV have 405 MVA (0.63 kA), 796 MVA (1.24 kA) and 1216 MVA (1.90 kA) power ratings. The PSSE VSC model being used in this study is available at these ratings (but not at ratings in between). The highest power rating of a single converter module is limited by the current rating of the IGBT valves available today. However, VSC modules could be connected in parallel to obtain the required power rating. Figure 8-2 shows the converter connection for the two VSC bi-poles utilized in the Scenario 3 case study. It is anticipated that converters with higher power ratings are available in the future, making it possible to realize this scheme with fewer parallel converters.

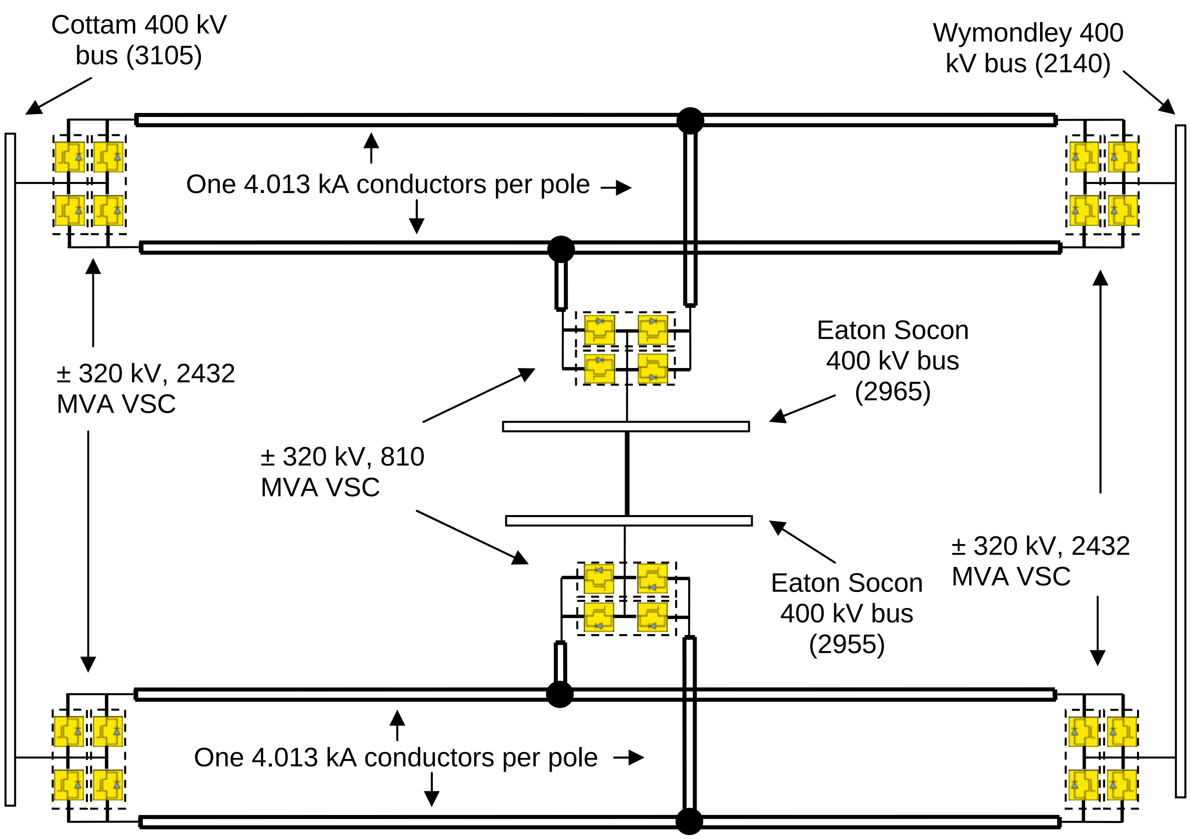

Figure 8-2 ± 320 kV, two parallel three terminal VSC HVdc links between Cottam, Eaton Socon and Wymondley

[5] Voltage of VSC modules could be higher than 320 kV. These ABB VSC modules are intended to use in applications involving DC cables and therefore DC voltage is limited by cable voltage rating.

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These two parallel bi-poles utilize only four out of six conductors available from converting the two three phase AC circuits, with one DC conductor per pole in the 2432 MVA three terminal HVdc bi-pole. In order to obtain the required rating (2432 MVA), only one conductor per pole is sufficient and therefore only four conductors are needed. The remaining two conductors could be used as metallic returns for two bi-poles or could be connected in parallel with (+)ve and (-) ve conductors of one bi-pole to reduce transmission power loss.

As shown in Figure 8-2, the combined power rating of 4864 MVA provided by the two parallel VSC bi-poles rated at 2432 MVA allows about 2.3 GW extra capacity to boost the majority of the power transfer through the HVdc link when any of the parallel circuits are tripped. In fact, the results presented in the rest of the Scenario 3 study will show that the combined rating of 4864 MVA is more than required to cater to the power transfer needs. Note that Eaton Socon 400 kV buses 2955 and 2965 are connected together by a zero impedance line. Please note that the ratings selected for the HVdc links are not optimized and simply serve the purpose of demonstrating advantages that could be obtained by converting HVac line Z12_C5 to an HVdc line.

The converter configuration shown in Figure 8-2 is one possible configuration that could be utilized to obtain the required rating. The number of modules connected in parallel at each converter station to obtain the required power rating depends on the DC voltage selection and the current rating of IGBT valves available in the future.

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8.2.2.2. LCC Model

LCC utilizes thyristor valves in the converters. The maximum continuous current rating for a thyristor valve available today is around 5.5 kA. Consequently, the maximum power rating for an LCC bi-pole at ± 320 kV is about 3520 MW. In this case study, two LCC bi-poles in parallel were utilized to match the power rating of the two VSC bi-poles illustrated in section 8.2.2.1. Figure 8-3 shows how the two three-terminal bi-poles are connected between Cottam 400 kV bus, Eaton Socon 400 kV bus and Wymondley 400 kV buses. Note that Eaton Socon 400 kV buses 2955 and 2965 are connected together by a zero impedance line.

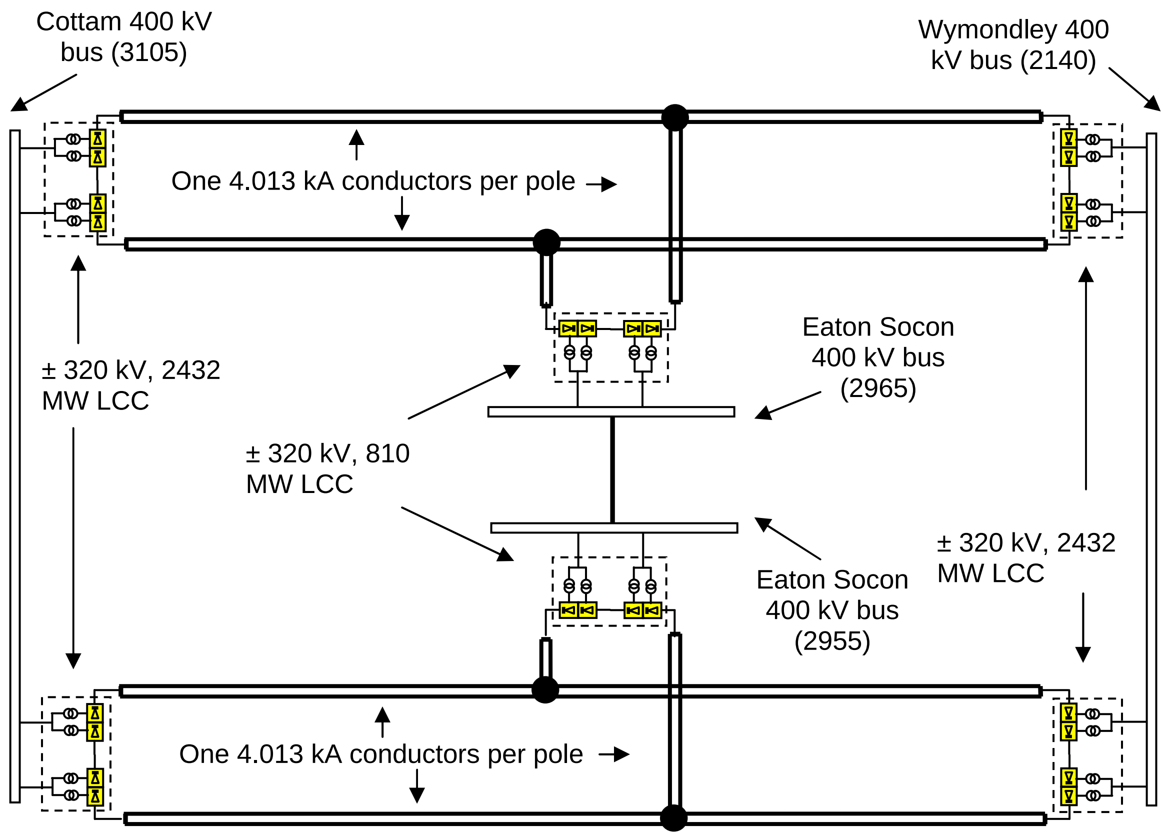

Figure 8-3 ± 320 kV, two parallel three terminal LCC HVdc links between Cottam, Eaton Socon and Wymondley

Similar to the VSC model, these two parallel bi-poles utilize only four out of six conductors available from converting the two three phase AC circuits, with one DC conductor per pole in the 2432 MW three terminal HVdc bi-pole. The remaining two conductors could be used as metallic returns for the two bi-poles or could be connected in parallel with (+) ve and (-) ve conductors of one bi-pole to reduce transmission power losses.

The TGS two time step model [2] was used to model the LCC HVdc bi-poles in PSS/E dynamics.

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8.2.3. AC System Strength at HVdc Terminals

System strength is not as important an issue for VSC HVdc as it is for LCC HVdc.

System strengths at the LCC converter buses were calculated and are summarized in Table 8-3 for the LCC HVdc option. Please note that the short circuit level of the Eaton Socon 400 kV bus is calculated by connecting 400 kV buses 2955 and 2965.

Table 8-3 Short circuit levels at LCC terminal buses

LCC terminal	Short Circuit Strength (MVA)	Combine rating of Converters (MW)	SCR	ESCR
Cottam 400 kV bus (3105)	25647	4864	5.3	4.7
Eaton Socon 400 kV bus (2955+2965)	3501	1620	2.2	1.6
Wymondley 400 kV bus (2140)	33035	4864	6.8	6.2

Table 8-3 also tabulates the short circuit ratio (SCR) and effective short circuit ratio (ESCR) for the combined rating of 4864 MW at Cottam and Wymondley and 1620 MW at Eaton Socon. In the ESCR calculation, it was assumed that 55 % reactive power compensation is provided by the HVdc filters.

8.3. Performance Comparison

Performance of the VSC and LCC HVdc options for the Scenario 3 case study are compared with the performance of the base case AC system under the following categories.

- Steady State Transmission Losses
- Steady State AC Contingency Analysis
- Transient Stability and Dynamic Performance

8.3.1. Steady State Transmission losses

Losses resulting directly from the current flowing in circuit Z12_C5 as a 400 kV double circuit AC line were calculated and compared with the losses in the VSC and LCC HVdc systems. According to the VSC manuals [1], each VSC converter has losses of 1.65% at nominal power rating, with 30% fixed losses and 70% variable plus the losses in the DC line. Typically, each LCC converter has losses of 0.80% at nominal power rating, with 10% fixed losses and 90% variable plus the losses in the DC line. Table 8-4 tabulates conductor losses for all three transmission options as well as converter losses for the VSC and LCC options for two operating conditions.

Table 8-4 Loss comparison for three transmission options

Transmission option	At Operating Point being Studied		
	Conductor Loss (MW)	Converter Loss (MW)	Total Loss (MW)
AC	71	-	71
VSC	27	130	157
LCC	27	32	59

The total transmission losses are smallest for the AC line and highest for the VSC option (more than 4 times the AC losses). Losses for the LCC option are about one third of the losses of the VSC option.

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It should be noted that very recent publications by VSC manufacturers indicate that VSC converter losses in the MMC type converters are almost comparable to losses in LCC converters. The 1.65% loss value used in this study for the VSCs is required by the PSSE VSC model as it is preprogrammed to use this value and cannot be changed by the user. For purposes of stability results, a loss value of 1.65% compared to 1% for example is not expected to have a significant impact on the results observed in this study. Of course, the lower losses would have a big impact on project economics, but that is beyond the scope of this report. Please note that the loss values presented in Table 8-4 are based on the VSC model and therefore correspond to a value of 1.65%.

8.3.2. Steady State AC contingency Analysis

8.3.2.1. Diverged Contingencies

Steady state contingency analysis was performed for the 16 contingencies listed in Table 4-1 for all three transmission options, namely AC, VSC HVdc and LCC HVdc.

Converged post-contingency powerflow solutions could not be obtained for all three transmission options for following contingencies:

- WEST_IC (Outage of Western interconnector)
- EAST_IC (Outage of Eastern interconnector)

Please refer to section 5.3.2.1 under the Scenario 1 A case study for a detailed discussion regarding the reasons behind why it was not possible to obtain post-contingency powerflows for the above two contingencies.

8.3.2.2. Steady State Voltage Violations

There were no overvoltage violations observed for the Scenario 3 transmission options, however, several undervoltage violations were observed for all three transmission options. These violations are tabulated in Appendix A4. All undervoltage violations observed for the VSC and LCC HVdc options were also observed for the AC option. Hence, there are no new violations created by the VSC or LCC HVdc options. In fact, several undervoltage violations observed in the vicinity of boundary B9 for the AC option following loss of the 400 kV double circuit AC Z12_C6 were not present for the LCC or VSC HVdc options. Thus, both the LCC and VSC HVdc options have a slight advantage over the AC option due to the large inherent reactive power capability in the case of the VSC HVdc option and due to the reactive power support provided by the filters in the case of the LCC HVdc option, which can assist in improving post-contingency undervoltages.

8.3.2.3. Steady State Thermal Overloads

There were a number of thermal overloads observed for all three transmission options. However, all of these thermal overloads were almost the same (within 2 % of each other) for all three transmission options, except the cases tabulated in Table 8-5. A complete list of thermal overloads observed for Scenario 3 is presented in Appendix B4.

Table 8-5 Thermal violations with at least 2 % difference in percentage overload

VIOLATION NUMBER	LINE NAME	RATING (MW)	CONTINGENCY	Percentage Overload (%)		
				AC	VSC	LCC
1	400*WIMB2 275.00 11475 3487ZZ 275.00	240	System intact	139.4	137.9	135.9
	400*WIMB2 275.00 11475 3487ZZ 275.00	240	Z12_C6	**146.7**	137.9	135.9
2	400*WIMB2 275.00 11485 3583ZZ 275.00	180	System intact	177.3	175.3	172.7

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	400*WIMB2 275.00 11485 3583ZZ 275.00	180	Z12_C6	**186.4**	175.3	172.7
3	1390*RAYL4 400.00 10035 5435ZZ 400.00 1	240	System intact	102.2	102.5	**106.1**
	1390*RAYL4 400.00 10035 5435ZZ 400.00 1	240	Z12_C3	102.2	104.6	**106.1**
4	2975 GREN4 400.00 3165*STAY4 400.00 1	2010	Z12_C2	-	106.6	**108.7**
5	3140 RATS4K 400.00 3170*STAY4R 400.00	2010	Z12_C1	100.2	120	**122.9**

Thermal violation numbers 1 and 2 tabulated in the first four rows of Table 8-5 show two cases where the VSC and LCC HVdc options have very slightly reduced an existing thermal overload compared to the base case AC option. Thermal violation number 3 shows a case where the VSC and LCC HVdc options have slightly worsened an existing thermal overload compared to the base case AC option.

Thermal violation numbers 4 and 5 tabulated in the last two rows of Table 8-5 show two cases where the VSC and LCC HVdc options have produced new thermal violations which can be mitigated by utilizing the two SPSs tabulated in Table 8-6.

Table 8-6 SPS required for Scenario 3

Contingency	SPS
	VSC/ LCC HVdc Options
Z12_C1	Increase HVDC power at Cottam terminal (3105) by 1000 MW
Z12_C2	Increase HVDC power at Cottam terminal (3105) by 550 MW

8.3.3. Transient Stability and Dynamic Performance

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8.3.3.1. System Stability

Dynamic simulations were performed for the 16 contingencies listed in Table 4-1 for all three transmission options, namely AC, VSC HVdc and LCC HVdc. System stability was maintained for all of the contingencies, with the exception of the loss of the 400 kV double circuit Eastern interconnector and the loss of the 400 kV double circuit Western Interconnector (contingencies EAST_IC and WEST_IC). Please refer to Appendix C4 for plots of system voltage, generator speeds, line powerflows, etc. for all 16 contingencies.

Circuit Z12_C5 is the existing double circuit AC line that has been converted into an HVdc line in Scenario 3. The contingency associated with tripping of this line is contingency Z12_C5. This contingency represents a tower failure of circuit Z12_C5 at the Cottam end, causing all six conductors to be grounded at a location close to the Cottam 400 kV bus. The ground fault was then cleared after 7 cycles by tripping circuit Z12_C5 at the Cottam, Eaton Socon and Wymondley ends. The tripped AC circuits were not re-connected since the tower failure is a permanent fault. In dynamic simulations, this fault was modeled as follows.

- AC option: A three phase-to-ground fault at the Cottam 400 kV bus cleared by tripping the two 400 kV AC circuits from Cottam to Eaton Socon after 7 cycles. It is assumed that there are circuit breakers located at the Cottam and Eaton Socon ends of the 400 kV AC line so that an AC fault at the Cottam end could be isolated by tripping only the Cottam to Eaton Socon section of circuit Z12_C5.

- VSC HVdc option: This conductor to ground fault is a DC fault in both VSC HVdc bi-poles. When the DC conductors are grounded, the AC system at Cottam, Eaton Socon and Wymondely feed the ground fault through the phase reactors, converters and the DC line. The vendor supplied VSC dynamic model does not provide means to directly simulate DC faults, the user manual suggests dc faults to be modeled as ac faults through an impedance at both terminals. For that reason, a three phase-to-ground fault through a selected impedance was applied at each converter bus at Cottam, Eaton Socon and Wymondely. The value of ground fault impedance at each end should include the impedance of the phase reactor, impedance offered by the converter and the impedance of the DC line between fault location and the corresponding converter. For the sake of modeling simplicity and also to demonstrate worst conditions, the impedance of the converter and the DC line were neglected. Consequently, three phase-to-ground faults through the phase reactor impedance were applied at Cottam, Eaton Socon and Wymondely converter buses for both VSC bi-poles. These three phase-to-ground faults were cleared after 7 cycles, representing the fault clearing actions of AC breakers located on the primary side of the converter transformers.

- LCC HVdc option: An LCC converter isolates AC and DC sides during a conductor to ground fault on the DC side. Therefore, this conductor to ground fault on the DC lines was modeled as a double bi-pole block of three terminal LCC HVdc link, without any AC system fault.

Please note that the SPSs tabulated in Table 8-6 were also applied in the dynamic simulations. However, these SPSs merely prevent thermal overloads and were found to have no significant impact to system stability.

Since all three transmission options could not maintain system stability for loss of the Eastern or Western interconnectors (contingencies EAST_IC and WEST_IC) and all three options could maintain system stability for the rest of 14 contingencies, both the VSC and LCC based HVdc options have no clear advantage over the AC option in their ability to maintain system stability. For this reason, it could be concluded that the AC and HVdc options perform similarly in terms of system stability.

8.3.3.2. Transient Undervoltage\ Overvoltages

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AC system voltages were observed during the post fault period at buses rated 275 kV and above. Out of the three transmission technologies, in most situations the VSC option showed superior voltage performance following a disturbance, while the AC and LCC options showed moderate voltage performances. The VSC option is inherently equipped with a large capacitive and inductive range of voltage control so it is not surprising that it shows better voltage performance.

Transient voltages up to 1.2 pu are typical in most power systems. Transient overvoltages above 1.2 pu were not observed for the AC or VSC HVdc options. Only the LCC HVdc option for loss of circuit Z12_C5 (contingency Z12_C5) had transient overvoltages close to but still less than 1.2 pu. Figure 8-4 depicts the voltages of all three transmission options for contingency Z12_C5 at the 400 kV buses at Cottam, Eaton Socon and Wymondley.

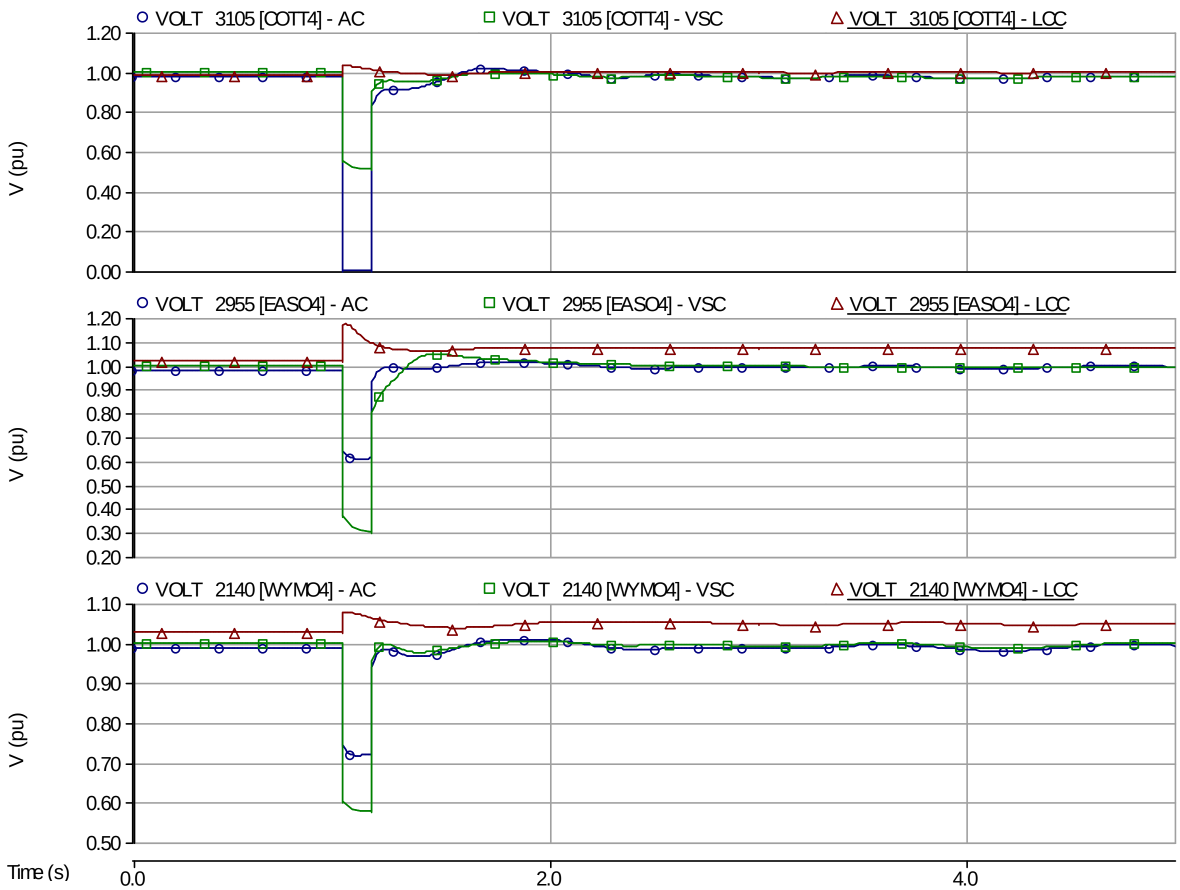

Figure 8-4 Transient overvoltage at three terminals for contingency Z12_C5
(Blue – AC, Green – VSC, Red – LCC)

Contingency Z12_C5 represents a tower failure on circuit Z12_C5 close to Cottam and hence causes a DC line to ground fault on all six conductors of circuit Z12_C5 as described in section 8.3.3.1.

Consequently, a double bi-pole block of the three-terminal HVdc would occur. This would reject almost 2.5 GW of power that was being transferred on circuit Z12_C5 prior to the fault. If a double-bi pole block would not trip any of the HVdc filters that were in-service before the fault, presence of these filters would cause a transient overvoltage depending on the strength of the AC system at Cottam, Eaton Socon and Wymondley. The LCC HVdc link could be designed to ensure the filters would trip in such a situation to assist in reducing overvoltages.

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Note that the transient overvoltage observed for the LCC option at Cottam and Wymindley are lower than 1.1 pu whereas the transient overvoltage observed at Eaton Socon is close to 1.2 pu. This is to be expected as the ESCRs at Cottam and Wymondley are much higher than at the ESCR at Eaton Socon.

The VSC HVdc option has equal or better undervoltage performance compared to the AC option. The LCC HVdc option has equal or slightly worse undervoltage performance compared to the AC option. Figure 8-5 depicts the worst transient undervoltage observed for the LCC HVdc option. This undervoltage occurred during the fault recovery period of contingency Z12_C1. Contingency Z12_C1 simulates tripping of the 400 kV double circuit line from Grendon to Staythorpe and West Burton after a three phase-to-ground fault at Grendon 400 kV bus. Note that the voltage at the Eaton Socon rectifier bus has a temporary dip for about a fraction of a second during the fault recovery of the LCC HVdc option. Appropriate tuning of the HVdc controllers at the design stage would likely improve this temporary undervoltage.

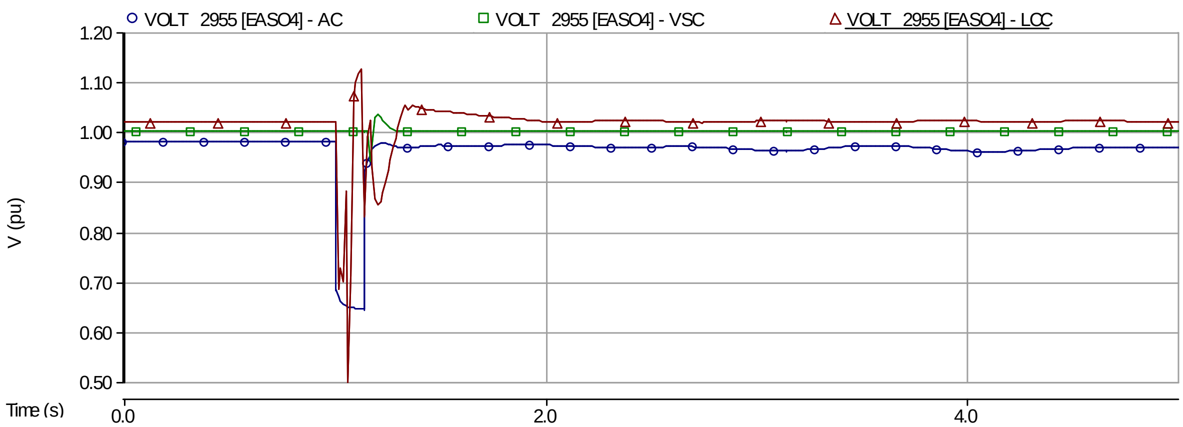

Figure 8-5 Transient undervoltage at Eaton Socon terminal for contingency Z12_C1 (Blue – AC, Green – VSC, Red – LCC)

8.3.3.3. System Frequency Performance

In transient stability programs such as PSS/E, the transmission system frequency is obtained from the derivative of the bus voltage angle. If there is a sharp change in the bus angle, the frequency might change infinitely. Therefore, there are filters associated with the frequency measurements. However, sometimes these filters are not enough to completely relieve these spikes in the frequency calculations, particularly if a fault has been applied in the area near to the frequency calculation. For this reason, generator speed quantities were mostly used to analyse frequency deviations as generator speeds are state variables which cannot change instantaneously and therefore should not give erroneous results.

For the power flow case that was studied, the AC, VSC HVdc and LCC HVdc transmission options did not show any transient underfrequency or overfrequency deviations outside of ± 0.5 Hz for any of the contingencies that were studied. All transient frequencies as measured by generator speeds were also within a ± 0.5 Hz frequency band.

8.3.3.4. System Damping

Plots of power oscillations inspected for various contingencies revealed that the three transmission options result in different damping levels depending on the contingency. Inspection of power oscillations also indicates that there is no clear evidence to substantiate which option has better system damping.

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8.4. SSR Screening

The UIF calculation described in the Study Procedures section is intended to screen for potential interaction between a conventional LCC HVdc system and generator shaft oscillation modes, known as subsynchronous resonance (SSR).

With LCC HVdc, any resonance frequency (f) on the DC side gets converted to f0+f and f0-f frequencies on the AC side.Because VSC is a relatively new technology compared to LCC, there is less information available on the possibility of SSR with a VSC HVdc system. A simple test case was setup in PSCAD to test whether the same phenomenon occurred with VSC and results indicate that VSC may have the same potential as LCC to excite SSR.

There is also little information readily available on the possibility of SSR between a wind farm and an HVdc system. Because of this, the possibility cannot be excluded and it cannot be said for certain that the possibility does not exist. Should these HVdc options be further pursued it would be recommended to perform further studies to verify the possibility of SSR between HVdc terminals and wind farms in the Scottish Network along with the appropriate mitigation if deemed necessary.

Although the UIF screening calculations are intended to be used for LCC HVdc, the UIF was calculated for the VSC option as well in order to provide an indication of the potential need for detailed SSR studies. In order to calculate UIF index for the worst case scenario, the two parallel HVdc bi-poles (2432 MW, 810 MW and 2432 MW each) between Cootam, Eaton Socon and Wymondley were considered to be one single bi-pole with a combined rating of 4864 MW, 1620 MW and 4864 MW at each terminal. The UIF index was calculated for all generators except salient pole generators in Zones 9,10,11,12,13 and 14. Please refer Appendix D4 for complete table of UIF indices for scenario 3.

Table 8-8 and Table 8-9 summarize the results for the Cottam, Wymondley and Eaton Socon terminals, respectively.

Table 8-7 UIF Index calculated for Cootam converter terminal

Generator Bus umber	Generator ID	Generator Rating (MVA)	Converter Rating (MW)	Generator Bus Number		UIF
				System Intact	Generator out-of-service	
3120	1	530.0	4864.0	24436.5	23095.1	0.028
3125	1	530.0	4864.0	24436.5	23095.1	0.028
3115	1	530.0	4864.0	24436.5	23130.0	0.026
3110	1	520.0	4864.0	24436.5	23142.8	0.026
3175	1	520.0	4864.0	24436.5	23808.4	0.006
3180	1	520.0	4864.0	24436.5	23808.4	0.006
3185	1	520.0	4864.0	24436.5	23808.4	0.006
3190	1	520.0	4864.0	24436.5	23808.4	0.006
5200	1	270.0	4864.0	24436.5	24176.9	0.002

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Table 8-8 UIF Index calculated for Wymondley converter terminal

Generator Bus Number	Generator ID	Generator Rating (MVA)	Converter Rating (MW)	Short Circuit Level (MVA)		UIF
				System Intact	Generator out-of-service	
195	1	310.0	4864.0	31305.2	30964.0	0.002
185	1	190.0	4864.0	31305.2	31095.4	0.001
180	1	190.0	4864.0	31305.2	31103.6	0.001
190	1	190.0	4864.0	31305.2	31104.1	0.001
1420	1	660.0	4864.0	31305.2	31002.3	0.001
1425	1	660.0	4864.0	31305.2	31005.7	0.001

Table 8-9 UIF Index calculated for Eaton Socon converter terminal

Generator Bus Number	Generator ID	Generator Rating (MVA)	Converter Rating (MW)	Short Circuit Level (MVA)		UIF
				System Intact	Generator out-of-service	
35435	**1**	**530.0**	**1620.0**	**3589.3**	**2298.0**	**0.396**
2995	**1**	**270.0**	**1620.0**	**3589.3**	**2724.9**	**0.348**
2985	**1**	**230.0**	**1620.0**	**3589.3**	**2891.1**	**0.267**
2990	**1**	**230.0**	**1620.0**	**3589.3**	**2888.8**	**0.268**

As shown in Table 8-7, Table 8-8 and Table 8-9 ll UIF calculations were below the threshold of 0.1, with the exception of four generator units. These four generator units at Little Barford Power Station have a UIF above the 0.1 threshold. These generator units are powered by a gas fired combined cycle prime mover and therefore, these four generators would be recommended for future study to determine the potential for SSR interaction with the HVdc terminal at Eaton Socon.

8.5. Conclusions

Scenario 3 investigated the potential for transmission capacity improvements in zones 10,11 and 12 across system boundary B9. The total power transfer being studied across boundary B9 was about 13 GW.

Scenario 3 looked at converting the 400 kV double circuit AC line from Cottam to Eaton Socon to Wymondley into two three-terminal bi-polar VSC/LCC based HVdc links.

- Results of the analysis showed no significant benefit in converting the AC line to HVdc technology.
- The three-terminal HVdc line cannot assist to improve system stability following the loss of the Eastern or Western interconnector, which were the only two unstable contingencies of those being studied.
- The AC and HVdc transmission options showed similar capability to maintain system stability, however for one contingency the HVdc options resulted in thermal overloads of nearby transmission lines that were not overloaded in the AC option. The overloads could be mitigated by adjusting the post-contingency power transfer on the HVdc line, however this would either require an SPS or operator intervention.

Based on the results presented above, there was no technical benefit found to converting the 400 kV double circuit AC line from Cottam to Eaton Socon to Wymondley into two three-terminal bi-polar

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VSC/LCC based HVdc links, although it was shown to be technically feasible. However, it should be noted that the conversion of HVac to HVdc may become a viable alternative for the connection of large offshore wind farms that are expected to be deployed during the Round 3 developments

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9. Conclusions on the Performance of HVDC in the UK Grid

Of the three scenarios investigated, Scenario 1 involving system boundary B6 was the only scenario that showed potential benefit from the conversion of AC lines to HVdc. Boundary B6 is comprised of the 400 kV double circuit Eastern and Western interconnectors linking the Scottish Power network to the National Grid network. Converting the Eastern Interconnector to HVdc allowed the system to maintain stability following the loss of the Western interconnector, with use of the fast power controllability inherent to HVdc, as opposed to the existing system with AC interconnectors which resulted in system instability for the same contingency. However, loss of the Eastern interconnector, whether AC or HVdc, still resulted in system instability.

An attempt was made to find an HVdc solution for system boundary B6 that could solve the system instability for both loss of either the Eastern or Western interconnector. Installing a back-to-back VSC HVdc link on one circuit of each of the Eastern and Western interconnector double circuits, while leaving the other circuit unchanged showed potential benefit to the system. In this scenario, both interconnectors have an HVdc component with fast power controllability, while each interconnector still maintains one AC line to keep the Scottish and National Grid networks synchronized. The results were stable for loss of the Western interconnector, but resulted in voltage collapse along the Western interconnector for loss of the Eastern interconnector. It was found that two 500 MVA synchronous condensers, one at Strathaven and one at Elvanfoot, mitigated the voltage collapse and resulted in system stability being maintained.

Scenarios 2 and 3 involving system boundaries B7 and B9 respectively both showed little benefit to converting AC lines to HVdc, although it was shown to be technically feasible. These particular system boundaries appear to have sufficient transmission capability for the powerflow case that was studied in this assessment.

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10. Interactions between DC Lines and Neighboring AC Lines

Adding a DC line to an existing AC transmission system can significantly increase the power transfer capability of a transmission corridor. The resulting hybrid system has significant coupling between the AC and DC circuits, not only because of the electromagnetic coupling of the circuits but also from the fact that they may share the same sending end and receiving end AC systems [3-7]. The major interaction issues between the AC-DC systems, reported in published materials are summarized in the following sections. Some of the interactions were demonstrated using a model of a 400kV, 900 km same tower AC-DC hybrid transmission system simulated in PSCAD/EMTDC. The hybrid transmission line was modeled using a detailed frequency dependent model. The changes in the tower configuration are illustrated in Figure 10-1.

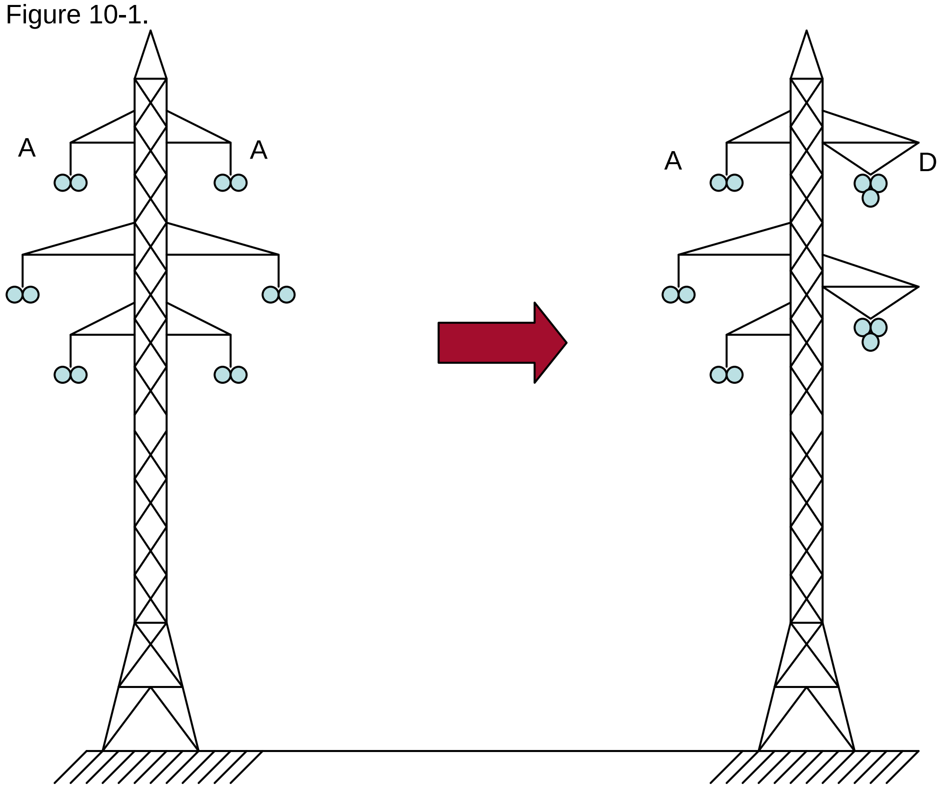

Figure 10-1 AC tower modification for AC-DC hybrid transmission

10.1. Steady State Induction Issues

One important issue with the parallel AC-DC lines is the fundamental frequency (50Hz) current inductions in the DC line due to electromagnetic coupling with the neighboring AC lines. The induced current has a significant effect on the system operation. To demonstrate the coupling effect between AC and a DC lines sharing the same right of way a hypothetical 400kV DC line that is installed on the same tower as a 400kV AC line is simulated in PSCAD electromagnetic transient simulation program. Figure 10-2 shows the induced voltage and current ripples in the DC line.

As can be seen a considerable 50Hz component appears in the DC current due to the coupling with the adjacent AC line. The switching action of the DC converters demodulates the fundamental frequency ripple into direct current and second harmonic components at the secondary side of the converter transformer [3].

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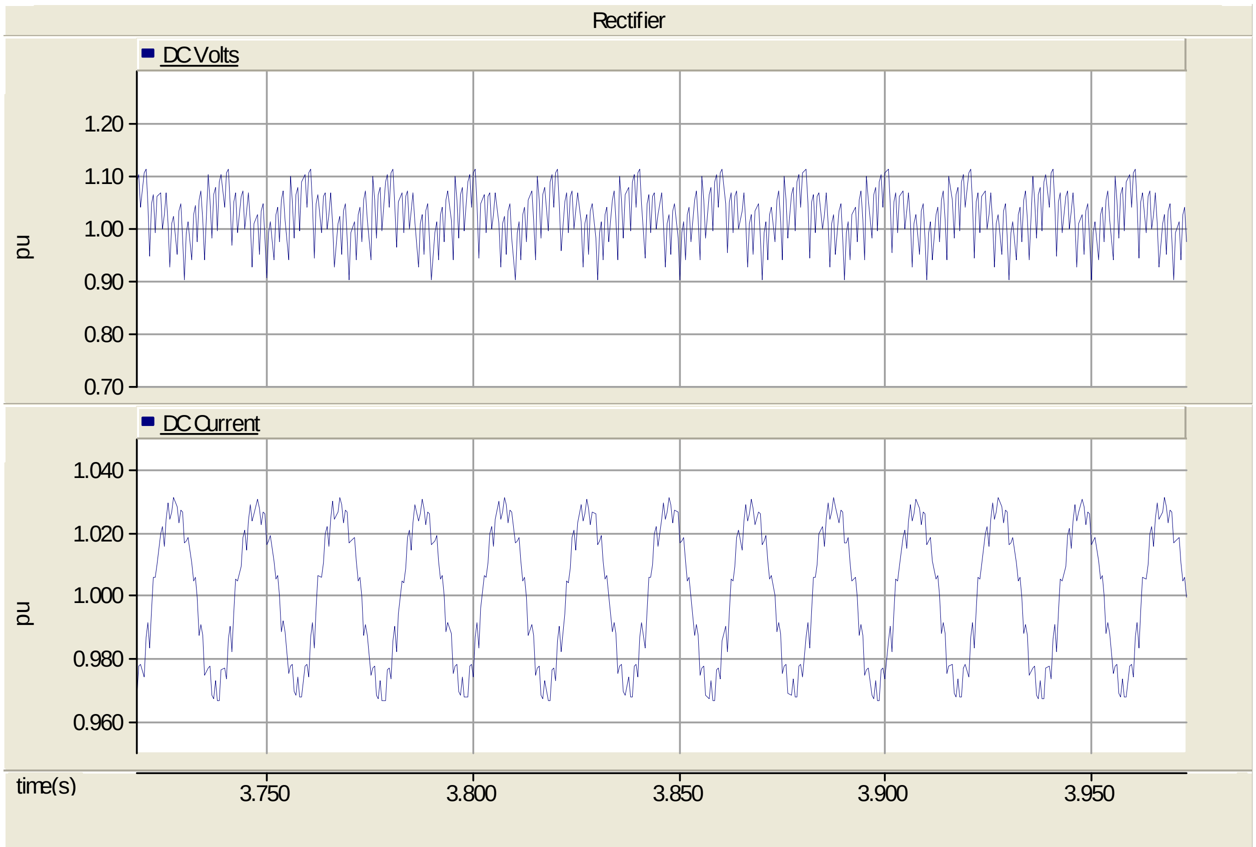

Figure 10-2: Fundamental frequency (50Hz) ripples induced in DC voltage and current by neighboring AC lines

Presence of DC offsets in the currents causes asymmetric (half cycle) saturation of the converter transformers [3]. A small amount of DC component in the converter transformer can cause a significant effect on the saturation. The continuous saturation may cause the loss of life of the transformer and high audible noise. The asymmetric saturation produces a wide spectrum of harmonics, which can pose difficulties in designing filters in the AC side and the DC side. Especially, the second harmonic component appeared in the AC side due to demodulation of fundamental frequency ripple in the DC current and the saturation of the converter transformers has to be removed. The fundamental component ripple in the DC lines may cause inaccurate measurements of voltages and currents as well as CT saturation. This has to be taken into account in designing the control and protection scheme of the HVdc system.

The magnitude of the 50 Hz component in the DC current depends on the span between the AC circuit and the DC circuit. For the simulated case, the rms value of the 50 Hz component was 2.1% of the DC current when the minimum distance between the AC and DC conductors was 16 m. When the minimum distance between the conductors was increased to 60 m, the 50 Hz component was only 0.55% of the DC current. Further increase in the span would reduce the induced current to lower values.

The steady state fundamental frequency ripple in the DC current should be kept as low as 0.1% of the converter rating to avoid the adverse effects discussed above [3]. A number of techniques are available to reduce the induced fundamental frequency component current. The DC side blocking filters and the transposition of the AC conductors are two methods that can significantly reduce the fundamental frequency ripple current [4].

Figure 10-3 shows the same AC-DC hybrid transmission system depicted in Figure 10-2, when the AC circuit was transposed at five locations along the line. Compared to the non-transposed case (Figure 10-2), this case shows less fundamental frequency ripples in the DC current. The fundamental frequency

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component was reduced from 2.1% to 1% after transposition. This can be further reduced by increasing the number of transposition locations.

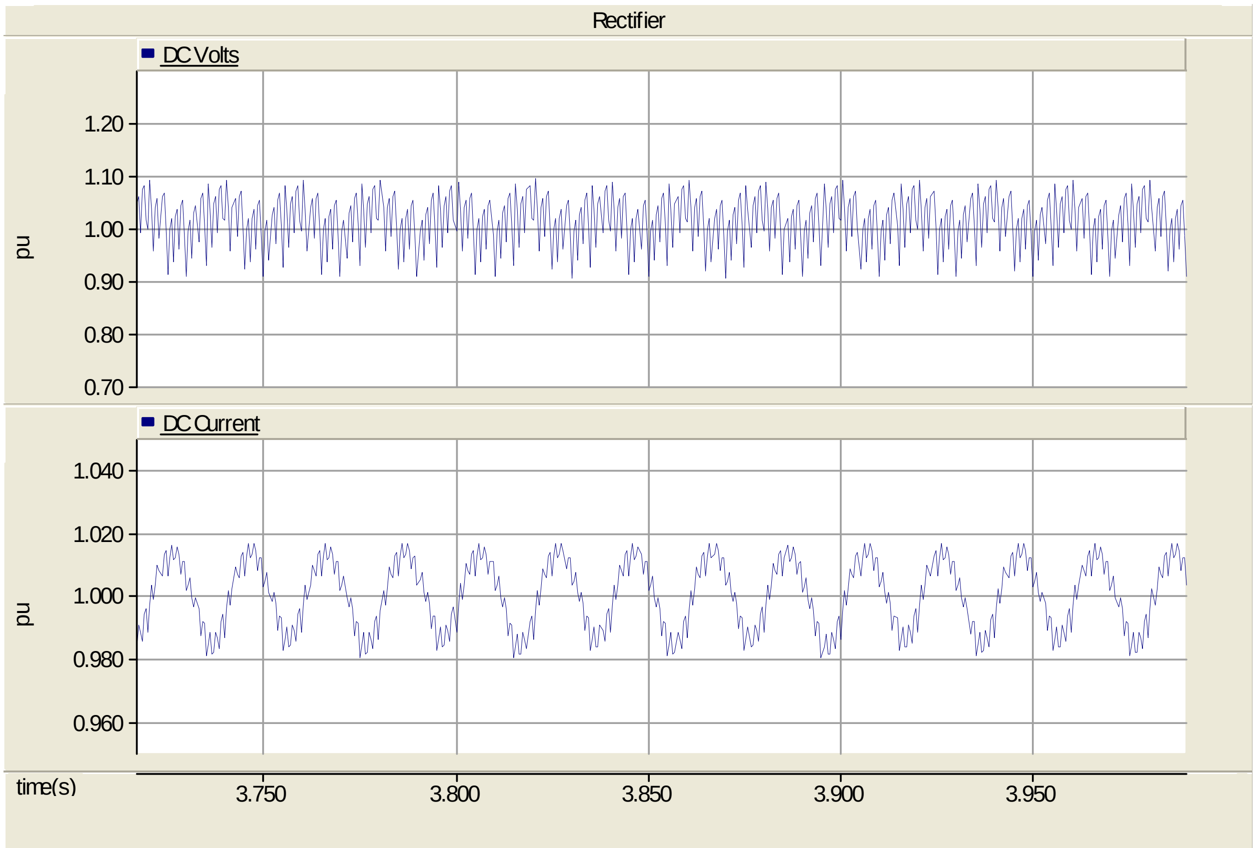

Figure 10-3: DC voltage and current for a 400kV same tower AC-DC hybrid transmission system when AC circuit was transposed at 5 locations along the line.

Figure 10-4 shows the DC voltage and current for a 400kV same tower AC-DC hybrid transmission system, when the 50 Hz blocking filters are employed in the DC side. Compared to the non-transposed case (Figure 10-2), this case shows almost zero fundamental frequency ripples in the DC current. The fundamental frequency component was reduced from 2.1% to 0.05% after adding the filters.

In addition to these mitigation options, modulation controllers can be added into the HVdc controllers to minimize the fundamental frequency ripple in the DC current. However, such a controller does not remove the DC current component from all converter transformers. Alternatively, firing angle modulation can be used to eliminate the DC current component in the converter transformer. This method is effective in reducing the converter transformer DC current, but it introduces a noticeable amount of non-characteristic harmonics, a combination of AC line transposition and firing angle modulation can effectively remove the DC current component in the converter transformer without creating an unacceptable level of non-characteristic harmonics [7].

In summary, the fundamental frequency ripple in the DC current can cause a significant effect on the HVDC system and neighboring AC system. However, the ripple can be significantly reduced by using AC circuit transposition, blocking filters or firing angle modulation.

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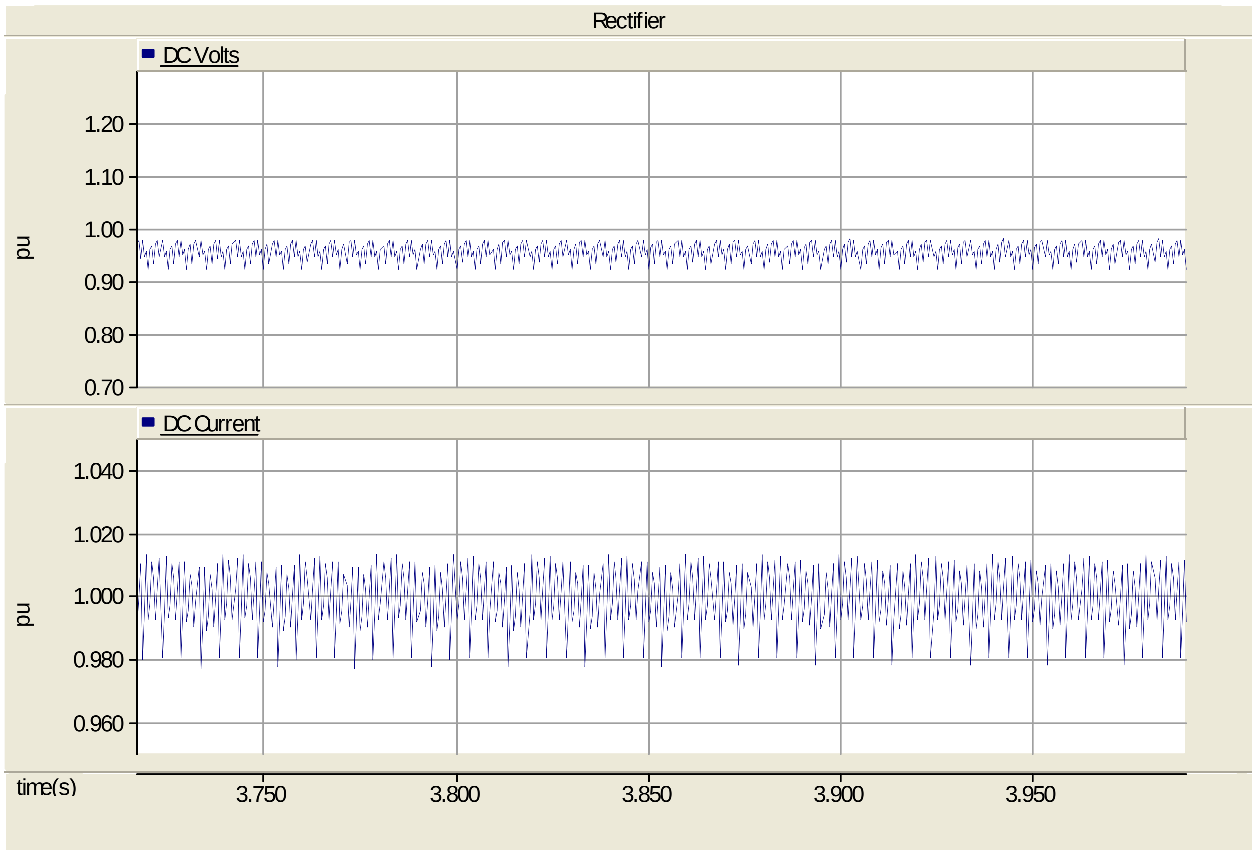

Figure 10-4: DC voltage and current for a 400kV same tower AC-DC hybrid transmission system, when the 50 Hz blocking filters are added in the DC side.

10.2. Transient Overvoltages

Transient overvoltages may occur in AC and DC lines following faults in the AC-DC parallel transmission systems [4]. In general, the transient overvoltages can be observed in AC and DC transmission systems regardless of the proximity of the lines. However, the magnitudes of transient overvoltages can be higher for AC-DC hybrid transmission systems [4]. In addition to the AC faults and DC faults, AC to DC conductor contact faults are also possible in these systems. Seven possible fault conditions: (1) AC single line to ground faults, (2) AC line to line ground faults, (3) AC line to line faults, (4) AC three phase to ground faults, (5) AC-DC conductor contact faults, (6) AC-DC conductor to ground contact faults and (7) DC conductor to ground faults have been analyzed in [4] using detailed electromagnetic transient simulations. The fault analysis has been done for a 230-250 kV AC-DC hybrid transmission system connected to an AC system with two different strengths. The strong and weak configurations had 6800 MVA and 1700 MVA short circuit levels respectively. The short circuit ratios (SCR) at the HVdc were 11.36 and 2.84 respectively. The following conclusions related to the transient overvoltages are highlighted in [4].

- The overvoltages depend on the strength of the AC system.

- The higher transient overvoltages can be observed for AC line to line faults, AC single line to ground faults and AC-DC conductor to ground faults. The magnitudes of the transient overvoltages in the DC lines increase with a decrease in AC system strength.

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- In the AC line, the magnitudes of the transient overvoltages increase with a decrease in AC system strength for the faults involving AC conductors only. For AC-DC contact faults and DC lines faults, the overvoltages in the AC system are smaller for weaker systems.

- The transposition of AC conductors significantly reduces the transient overvoltages in both AC line and DC line.

10.3. Corona Effect

The influence of corona generated space charge from the DC conductors is appreciable for same tower hybrid AC-DC transmission systems [5]. The corona charges in the DC line may produce significant magnitudes of direct current components in the AC conductors. Such currents may cause the saturation of power transformers and measuring transformers connected to the AC line. Appropriate transposition of the AC conductors may be used, if necessary, to reduce these currents.

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11. Multi-terminal HVDC Interactions in Power Systems

The HVdc systems may interact with the other dynamic devices such as generators and FACTS devices in the power systems. Some of the major interaction phenomena are discussed in this section.

It should be noted that the nature of the interaction phenomena is common to two-terminal and multi-terminal HVdc systems. The issues may be slightly more complicated with a multi-terminal, not necessarily because it is multi-terminal, but simply because there are more terminals, possibly in the near vicinity of each other. For example, if two terminals of a multi-terminal link are nearby to each other and the potential for SSR with a nearby generator exists, the issue may be more complicated than if there were a single HVdc terminal nearby.

11.1. HVDC – Generator Electromechanical Interactions

The HVdc controllers may affect the damping of some electromechanical oscillation modes of the generating plants [8-9]. These oscillations are either local oscillations among generator units close to the HVdc terminals or inter-area oscillations of a large portion of the power system.

The HVdc controller parameters can be modified to improve the damping of electromechanical modes affected by the HVdc. Especially, damping controllers can be incorporated with the HVdc controllers to damp out some troublesome electromechanical modes in the power system [9-12]. A modulation signal, which is provided by an auxiliary controller, is added into the rectifier or inverter primary controllers to improve the damping of some selected electromechanical modes. The speed of a nearby generator or the AC system frequency can be used as an input to the auxiliary controller.

The HVdc-generator electromechanical oscillations can be analyzed using conventional small signal stability analysis software. The dynamic performance can be studied using a transient stability simulation or detailed electromagnetic transient simulation.

11.2. HVDC - Generator-Turbine Torsional Interactions

Some HVdc systems may interact with tightly coupled generator-turbine systems, which have torsional oscillations. The torsional oscillations may occur in thermal generating plants with multi-mass turbine systems. These mechanical shaft oscillations usually lie in the subsynchronous frequency range (0 to fundamental frequency) and therefore, commonly known as subsynchronous oscillations/resonances (SSO or SSR). The HVdc controllers may interact with the generator-turbine units to cause the instabilities in these torsional modes. Especially, the rectifier current/power controller contributes into these instabilities.

In some practical cases, torsional instabilities caused by HVdc-generator-turbine interactions have been reported. In the Square Butt project in North Dakota, the rectifier current controller interacted in an adverse way with an 11.5 Hz torsional mode of an adjacent generator-turbine unit [13]. Again in North Dakota, the investigations carried out in the Coal Creek HVdc station have indicated some possibility of a torsional instability at a 19 Hz torsional mode associated with a nearby generator-turbine unit [14].

Although the HVdc controllers may cause torsional instabilities in generator-turbine units, they can also be utilized to improve the damping of the torsional modes. A subsynchronous damping controller (SSDC) can be included in the rectifier current/power controller as an auxiliary controller to improve the damping of some of the torsional modes associated with neighboring generator-turbine units [9,15].

The torsional interactions between the HVdc systems and generator-turbine units cannot be accurately analyzed using conventional transient stability or small signal stability analysis software, which use the simplified representation of the AC network (admittance matrix model). An electromagnetic transient simulation or small signal stability analysis including AC network dynamics [9] should be used instead. A

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sensitivity analysis can be performed using Unit Interaction Factor (UIF) calculations to find the HVdc-generator-turbine systems, which may cause the torsional interactions. More details about UIF calculations are given in Section 4.7.

The following demonstration shows the detailed analysis of torsional interactions between the HVdc systems and the generator turbine units. An electromagnetic transient simulation was used to observe the system behavior and an in-house built small signal stability model including the network dynamics was used to analyze the torsional modes quantitatively.

11.2.1. Demonstration of Torsional Interactions using a small test system

A demonstration has been performed using PSCAD/EMTDC to show HVdc-generator-turbine torsional interactions. The CIGRE benchmark HVdc test system was modified as shown in Figure 11-1. A synchronous generator with a multi-mass turbine unit was connected at the rectifier side AC bus to supply half of the P-Q requirement of the rectifier. The generator-turbine parameters were selected as in the IEEE first benchmark model for SSR studies.

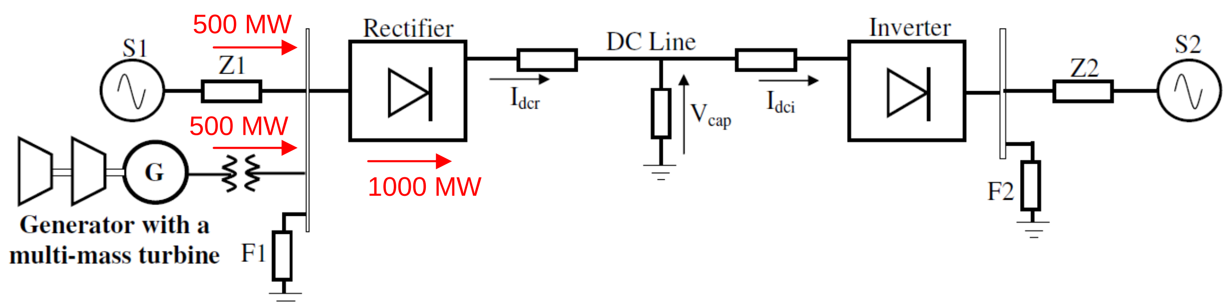

Figure 11-1 Small test system used to demonstrate HVdc-generator-turbine torsional interactions.

The generator speed for a small disturbance in the power system is shown in Figure 11-2. The torsional modes, seen in the figure have almost zero damping since the generator mechanical damping was ignored in the model. A small signal stability analysis of the model showed that there were three torsional modes of frequencies 16 Hz, 25 Hz and 32 Hz, observable in the generator speed.

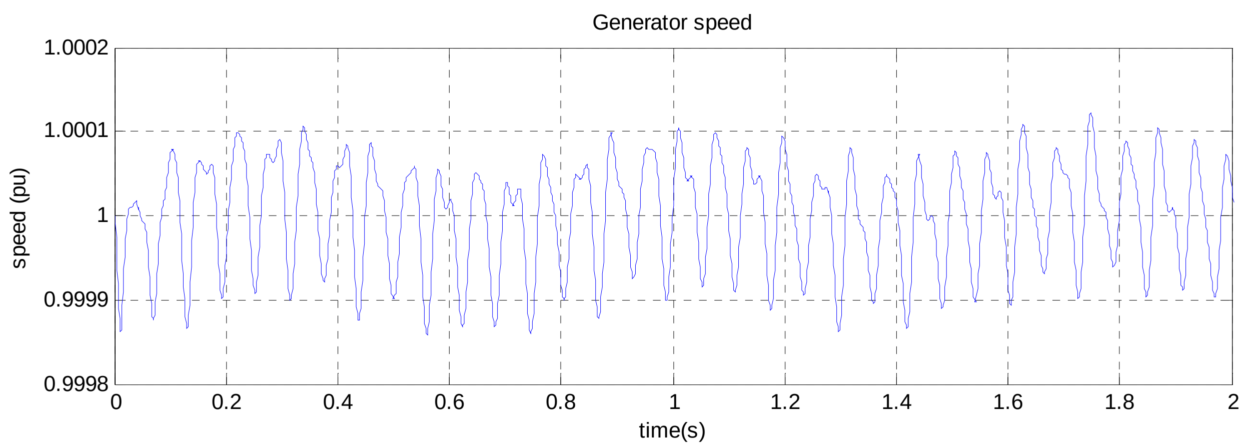

Figure 11-2 Torsional oscillations in generator speed under nominal conditions.

The torsional modes in the generator-turbine unit were sensitive to the HVdc rectifier current controller gains. When the rectifier PI controller proportional gain was 0.11 and the time constant was 4.5 ms, the torsional mode at 16 Hz was unstable. The resultant generator speed is shown in Figure 11-3. A rapid increase in 16 Hz oscillations can be observed in the figure.

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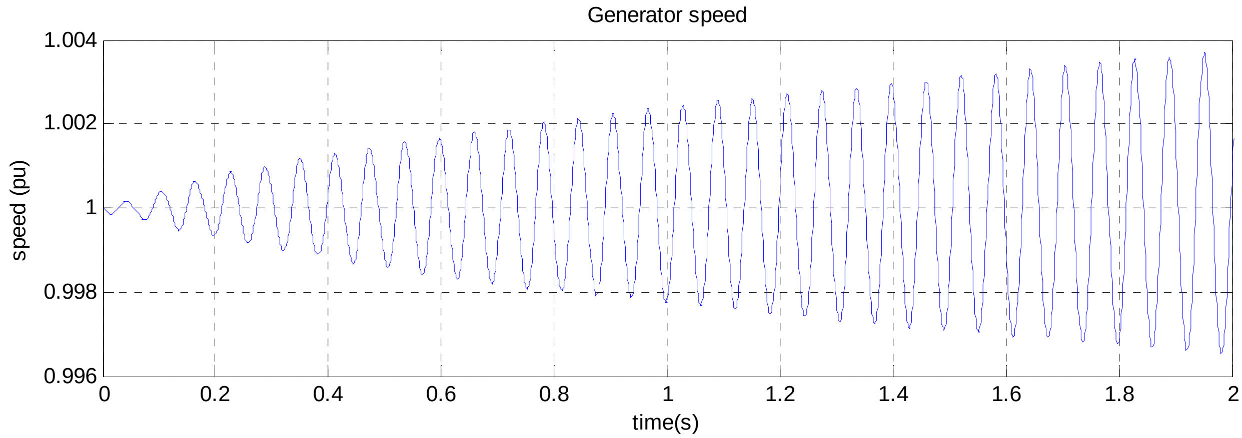

Figure 11-3 Torsional oscillations in generator speed when rectifier current controller gains were changed.

The above analysis showed that the HVdc controllers can cause the instability of the generator-turbine torsional modes. In contrast, the HVdc controllers can be used to damp out the oscillations of the generator. A subsynchronous damping controller (SSDC) was added to the rectifier current controller as shown in Figure 11-4. The SSDC gains were tuned to damp out the three torsional modes using small signal stability assessment. Figure 11-5 shows the generator speed for the same disturbance as in Figure 11-2, after adding the SSDC. The torsional oscillations were damped out quickly by the SSDC as can be seen in Figure 11-5.

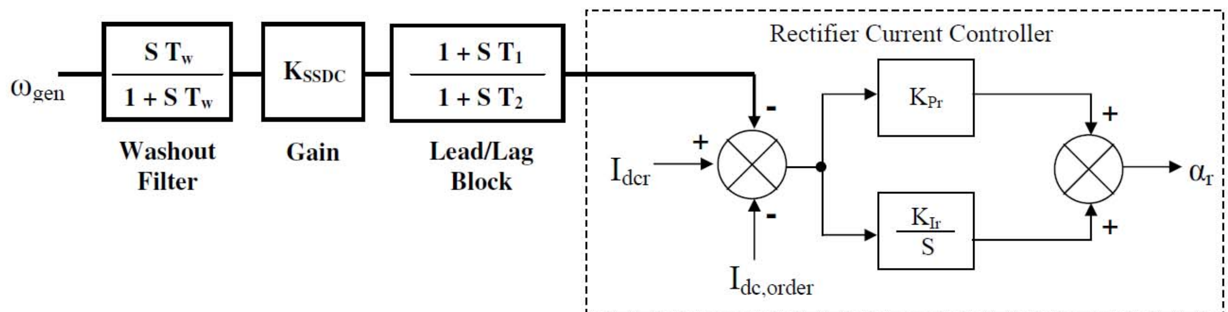

Figure 11-4: Subsynchronous damping controller attached to the rectifier current controller.

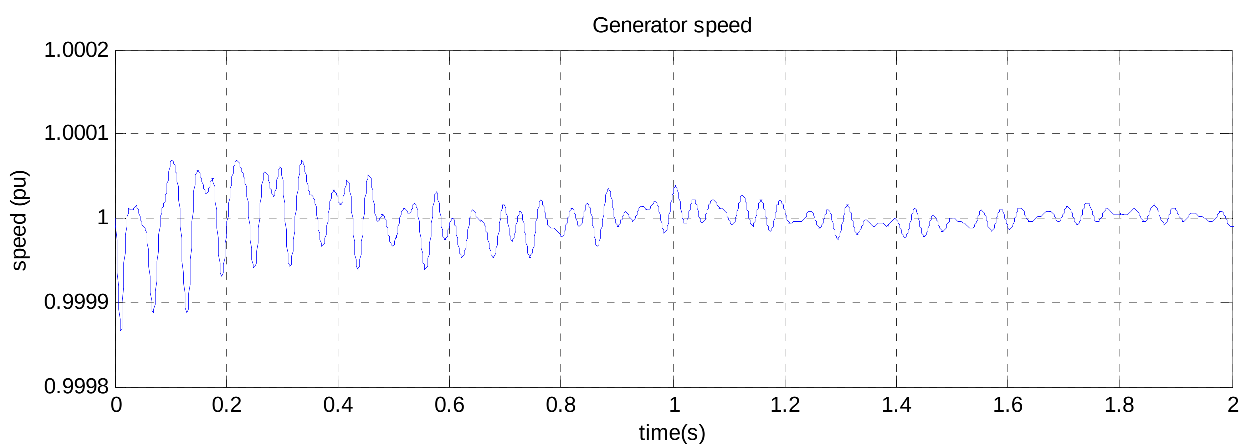

Figure 11-5: Torsional oscillations in Generator speed when a subsynchronous damping controller is connected at rectifier current controller.

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11.3. Multi-infeed HVDC Interactions

When more than one HVdc inverters are connected to a power system within close proximity, they are considered as “multi-infeed HVdc systems”. In multi-infeed HVdc systems, the HVdc links may interact with each other as well as with other dynamic devices in the power system. The DC lines and the HVdc controllers participate in these interactions and the strength of interactions depends on the proximity of the HVdc terminals [16]. These facts should be considered when designing HVdc controllers for multi-infeed HVdc systems. The interactions can be observed in electromagnetic transient simulations and the small signal stability assessment with proper models can be used for quantitative analysis at steady state [9,16].

11.4. Harmonic Resonances

The HVdc systems produce a significant amount of higher order harmonics (characteristic harmonics) in the AC to DC conversion process. If there is low impedance in the AC side for one of the characteristic harmonics, a resonance may occur in the system. Although such a behavior is very rare in practical systems, the possibilities should be analyzed using AC system frequency scans.

11.5. Other Possible Interactions

The controllers of the dynamic devices such as FACTS devices installed close to the HVdc terminals may interact with the HVdc controllers. The electromagnetic transient simulations and small signal stability assessment of the models can be used to identify these possibilities.

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Appendix

List of appendices:

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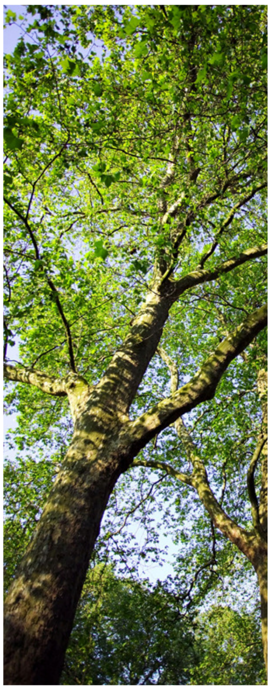
Appendix B. Mott MacDonald Report : Impact of new onshore multi-terminal HVDC


ETI Network Capacity Project

Work Package 2 Task 3: Evaluation of Impact of New Onshore Multi-Terminal HVDC

July 2010

Energy Technologies Institute (ETI)

Mott MacDonald

ETI Network Capacity Project

Work Package 2 Task 3: Evaluation of Impact of New Onshore Multi-Terminal HVDC

July 2010

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Content

1. Introduction

In order for the UK to achieve its targeted deployment of renewable energy by 2020, the Energy Technologies Institute (ETI) has commissioned an engineering investigation into the use of various Flexible AC Transmission System (FACTS) devices and onshore HVDC technologies which will provide additional capacity on the existing HVAC transmission network whilst avoiding the construction of new overhead lines.

The scope of work guiding this Work Package 2 Task 3 work is as follows:

- Assess the potential impact of new onshore multi-terminal HVDC systems on renewable energy deployment in the UK, and the consequent impacts on UK CO_2 emissions and security of supply.

- Assess the benefits case for the conversion of existing AC lines to DC operation in terms of through-life cost, performance, CO_2 reduction potential and impact on security of supply.

Irrespective of whether the onshore HVDC scheme is configured as a point-to-point link or a multi-terminal subsystem, the potential impacts as described above and the benefits case for converting HVAC lines to HVDC operation is considered to be similar, as a multi-terminal link is functionally simply an extension of a point-to-point link. As such when assessing particular impacts, a comparison will be made between the various HVDC technologies (Line Commutated Converter and Voltage Source Converter) but not between a point-to-point HVDC link and a multi-terminal HVDC configuration.

2. Impact of Onshore HVDC

The impact of an onshore HVDC scheme will be assessed under the following criteria:

- Reasons for converting from HVAC to HVDC
- Onshore HVDC Performance
- Benefits case of HVAC to Onshore HVDC Conversion
- Lifecycle cost comparison between HVAC and HVDC
- Renewable deployment facilitation with possible CO_2 emission reduction

2.1 Reasons for Converting From HVAC To HVDC

The reason for investigating the use of onshore HVDC schemes (point-to-point or multi-terminal) within this study is to create additional capacity on existing transmission corridors to allow for the connection of renewable generation, as stipulated in the UK 2020 renewable energy deployment targets. The use of onshore HVDC is being investigated due to the lack of available capacity on the existing transmission system to accommodate the required renewable generation, as well as the lengthy consenting requirements and land availability constraints characteristic to acquiring new transmission corridors.

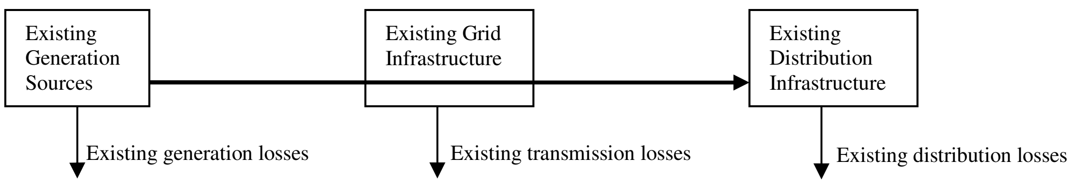
2.2 Onshore HVDC Performance

This section covers performance of HVDC schemes from an operational perspective i.e. losses, reliability and security of supply rather than from a steady-state / dynamic performance perspective i.e. power quality, HVAC-HVDC response and system interface, fault performance and system stability. The steady state and dynamic performance benefits are the subject of the Work Package 2 Task 2 report within this study.

2.2.1 System Losses

A summary of the losses in a typical electrical utility network can be seen in the schematic diagram below:

Figure 2.1: Summary of losses incurred with electrical utility networks



Since the overall objective is to evaluate the conversion of an existing HVAC transmission circuit to an onshore HVDC scheme, this section will illustrate simplified overall losses (focusing mainly on power losses due to current flow excluding corona losses and dielectric losses) on typical HVAC transmission links and HVDC schemes of similar ratings. The losses [1] can be seen listed in Table 2.1. It is noted that although the HVAC transmission loss data is based on North American 500 kV HVAC transmission systems, the comparison provided between HVDC and HVAC losses is equally relevant to the UK.

Table 2.1: Transmission Losses For HVAC and HVDC Operating At Full Rating

			LINE			CONVERTER	TOTAL			
Transmission Method	Voltage	Criteria	100 km	300 km	600 km		100 km	300 km	600 km	Conductor Information
Single Circuit Overhead Line	HVAC 500 kV	Rated Power	3000 MW	3000 MW	2000 MW	N/A	3000 MW	3000 MW	2000 MW	3 x ACSR “Falcon” per phase
		% Loss	**1.6 %**	**4.7 %**	**6.3 %**	**-**	**1.6 %**	**4.7 %**	**6.3 %**	
Double Circuit Overhead Line	HVAC 500 kV	Rated Power	6000 MW	6000 MW	4000 MW	N/A	6000 MW	6000 MW	4000 MW	3 x ACSR “Falcon” per phase
		% Loss	**1.6 %**	**4.7 %**	**6.3 %**	**-**	**1.6 %**	**4.7 %**	**6.3 %**	
Bipole LCC Overhead Line	HVDC ± 500 kV	Rated Power	3000 MW	3000 MW	3000 MW	3000 MW	3000 MW	3000 MW	3000 MW	2 x ACSR “Bluebird” per pole
		% Loss	**0.8 %**	**2.4 %**	**4.7 %**	**1.4 %**	**2.2 %**	**3.8 %**	**6.1 %**	
Bipole VSC Overhead Line	HVDC ± 200 kV	Rated Power	600 MW	600 MW	600 MW	600 MW	600 MW	600 MW	600 MW	2 x ACSR “Falcon” per pole
		% Loss	**1.3 %**	**4.0 %**	**8.0 %**	**3.0 %**	**4.3 %**	**7.0 %**	**11.0 %**	
Bipole LCC Overhead Line	UHVDC ± 800 kV	Rated Power	6400 MW	6400 MW	6400 MW	6400 MW	6400 MW	6400 MW	6400 MW	5 x ACSR “Curlew” per pole
		% Loss	**0.5 %**	**1.6 %**	**3.2 %**	**1.4 %**	**1.9 %**	**3.0 %**	**4.6 %**	

Source: “Assessment and Analysis of the State-Of-the-Art Electric Transmission Systems with Specific Focus on High-Voltage Direct Current (HVDC), Underground or Other New or Developing Technologies,” [1]

According to the National Grid Seven Year 2010 [4], approximately 10 out of a total of 461 NG overhead line circuits exceed 100 km in length with the longest circuit having a total length of 218 km [4]. As can be seen from the above table, even though HVDC has lower overhead line and cable losses as compared to HVAC of a similar rating, converter losses for HVDC schemes will often, particularly in the case of VSC systems due to higher switching losses, increase the total transmission loss to greater than the equivalent HVAC loss even during operation at high power levels.

2.2.2 Reliability

With any system, its reliability is determined by the reliability of all its critical components. The reliability of an HVDC scheme can be improved at the design phase by incorporating redundancy in the critical components that form part of the HVDC link. The critical components are [1]:

- Thyristor/IGBT valves
- Control system
- Cooling system
- Auxiliary power supplies
- AC harmonic filters

Reliability can be improved by storing adequate levels of critical spares and the use of preventative and predictive maintenance routines coordinated with periods of low forecast network loading. In general, most overhead line faults are due to factors (i.e. lightning, mechanical and thermal failures) which are independent of the operation (i.e. HVAC or HVDC). In the case of a monopolar HVDC scheme, a fault would result in the entire link being out of service. However, a bipolar HVDC scheme with a metallic earth return could still operate at half the power rating if one pole should be out of service due to a fault.
As such, the reliability of the overhead line itself can be assumed to remain the same after HVDC conversion provided the conversion is done correctly and does not introduce additional failure modes. Since the overhead line reliability is common to both HVAC and HVDC scenarios, it has been excluded from this analysis and the focus will be on the reliability of the converter stations since these additional components will impact the overall reliability of the HVDC scheme.
The following reliability table was generated using data obtained from [1]:

Table 2.2: Typical HVDC Converter Reliability Statistics

Reliability Criteria	LCC (Monopole)	LCC (Bipole)	VSC
Forced outage rate	3 outages per year	6 outages per year (100% power) 0.05 outages per year (minimum of 50% power)	1 - 2 outages per year (100% power)
Forced unavailability	0.3% to 0.5%	0.6% to 1.0% (100% power) 0.003% (minimum of 50% power)	0.3% to 0.5% (100% power)
Scheduled unavailability (mostly due to maintenance)	< 1.0%	< 2.0% (100% power) < 0.1% (minimum of 50% power)	< 0.4% (100% power)
Availability	98.5%	> 97% (100% power) 99.9% (minimum of 50% power)	> 99.0% (100% power)
Life Expectancy	40 years	40 years	40 years

Source: "Assessment and Analysis of the State-Of-the-Art Electric Transmission Systems with Specific Focus on High-Voltage Direct Current (HVDC), Underground or Other New or Developing Technologies," [1]

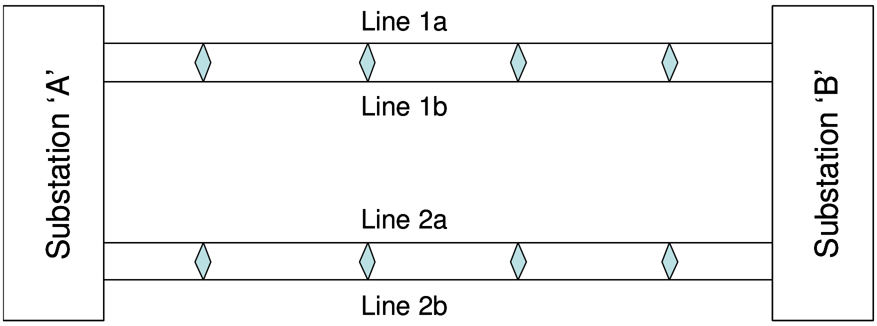
2.2.3 Security of Supply

This assessment of HVDC performance with regards to security of supply is based on the requirements of the National Electricity Transmission System Security and Quality of Supply Standard (SQSS).

2.2.3.1 Definition of a Typical UK Transmission Link

This assessment is based on a link in the UK transmission system formed by two double circuit 400 kV lines, i.e. providing a total of four circuits. It is assumed that there are no parallel system connections. This analysis assumes that power transfer capability is constrained solely by the thermal capacity of the line (which is often used as an argument for HVAC to HVDC conversion). In practice power transfer may be constrained by stability limits, which will tend to improve the case for HVDC conversion.

Figure 2.2: Sketch of a typical 400 kV UK transmission link



UK 400 kV line construction is based on two groups of tower designs. The first is suitable for stringing with twin conductors and generally uses L2 or L8 type towers. The second is suitable for stringing with quad conductors and generally uses L6 or L12 type towers.

HVAC line capability for various standard conductor systems is detailed in NG Technical Guidance Note TGN(E)026. The highest capacity systems in general use can be summarised as follows:

- L2/L8 Towers

Conductor system is twin 'Matthew' 620mm^2 GZTACSR (sometimes referred to as 'GAP' conductor) with a rated temperature of 170˚C.

Table 2.3: 400 kV L2/L8 double circuit twin conductor overhead line ratings

Rating Type	Per Circuit Rating [MVA]	Current [A]
Winter Post-Fault Continuous Rating	3100	4480
Summer Post-Fault Continuous Rating	2960	4270

Source: Table I2 of TGN(E)026

- L6/L12 Towers

Conductor system is triple 'Arucaria' AAAC with a rated temperature of 75˚C.

Table 2.4: 400 kV L6/L12 double circuit triple conductor overhead line ratings

Rating Type	Per Circuit Rating [MVA]	Current [A]
Winter Post-Fault Continuous Rating	3820	5510
Summer Post-Fault Continuous Rating	3320	4790

Source: Table H45 of TGN(E)026

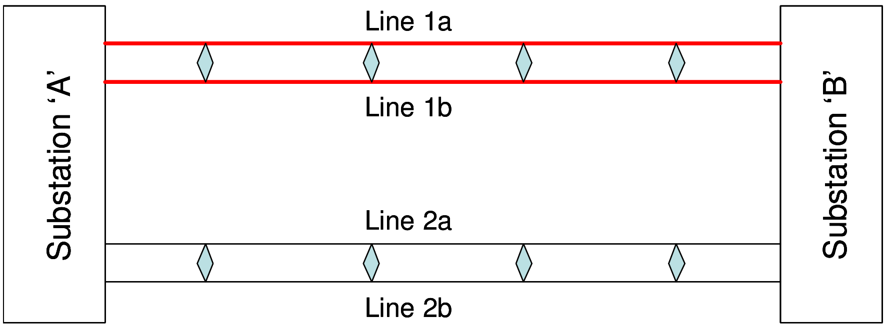
2.2.3.2 Pre-Fault Capability of HVAC Link

The link is assumed to form part of the Main Interconnected Transmission System (MITS); its design capacity is therefore defined by the requirements of Section 4 of the SQSS.

At Average Cold Spell (ACS) peak demand (i.e. in winter conditions), the transfer capacity of the link must be planned such that, starting with an intact system, following the secured event of a fault outage of a double circuit line there shall be no unacceptable overloading of any primary transmission equipment.

The capability of the link is therefore determined by the following post-fault configuration (circuits shown red are subject to fault outage):

Figure 2.3: Sketch of a typical 400 kV UK transmission link with an unplanned 400 kV double circuit outage

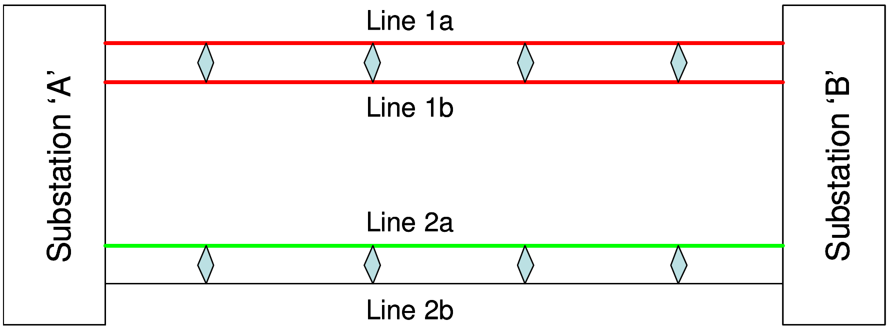


The winter capacity of the link (after any short term post-fault reconfiguration) is thus 2 x 3100 = 6200 MVA for L2/L8 towers and 2 x 3820 = 7640 MVA for L6/L12 towers.

At other times (generally outside the winter period), the transfer capacity of the link must be planned such that, starting with a system depleted by a planned outage, following the secured event of a fault outage of a double circuit line there shall again be no unacceptable overloading of any primary transmission equipment.

The capability of the link is therefore determined by the following post-fault configuration (circuits shown red are subject to fault outage, circuits shown in green are subject to planned outage):

Figure 2.4: Sketch of a typical 400 kV UK transmission link with both planned and unplanned 400 kV double circuit outages



The summer capacity of the link (after any short term post-fault reconfiguration) is thus 2960 MVA for L2/L8 towers and 3320 MVA for L6/L12 towers.

In practice, the NG transmission system is often operated such that the pre-fault loading on the overhead line circuits exceeds the long term post-fault capability. In this case the short term overload capacity of the HVAC system is exploited after the fault has occurred to allow power transfers to be reduced (e.g. by automatic tripping of generating plant through an 'Operational Tripping' scheme or instructing reductions in generation output).

The maximum allowable loss of generation is defined by the 'infrequent load loss limit', currently limited to 1320 MW but propose to increase to 1800 MW. There is the potential for summer power transfers over the link of up to 1800 + 2960 = 4760 MVA for L2/L8 towers or 1800 + 3320 = 5120 MVA for L6/L12 towers.

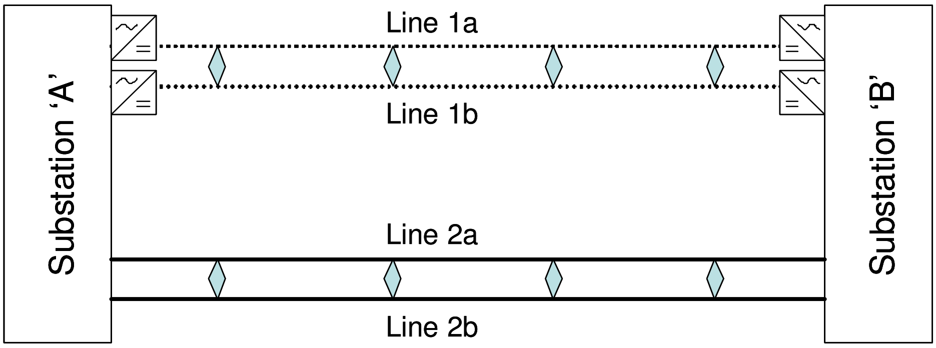
Using the L6/L12 capability as an example, a transfer of 5120 MVA represents a pre-fault loading of 1710 MVA per circuit (5120 MVA/3 – one circuit on planned summer outage). Based on overload capabilities detailed in TGN(E)026, the single line available post-fault could support this transfer for at least 5 minutes post-fault. Since this gives very little opportunity for manual post-fault intervention, we would judge that the load reduction would have to be achieved by an operational tripping scheme.

However, a reduction of pre-fault power transfer to 3870 MVA would allow 20 minutes for manual intervention. Dynamic loading techniques could be used to increase this transfer capability in operational timescales.

2.2.3.3 Effect of Adding 2x HVDC Links

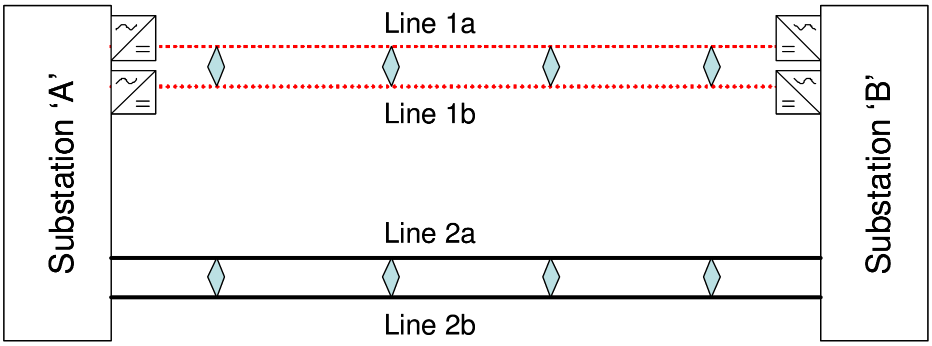
The preferred option for replacing HVAC connections in the example link would be to convert 1x double circuit line to HVDC operation. This is illustrated in the following diagram:

Figure 2.5: Sketch of a HVDC and 400 kV HVAC UK transmission link



This would have no impact on the power transfer capacity as the SQSS requirements dictate that there should be no overloading following a fault outage of a double circuit overhead line. The winter post-fault configuration would thus be as follows:

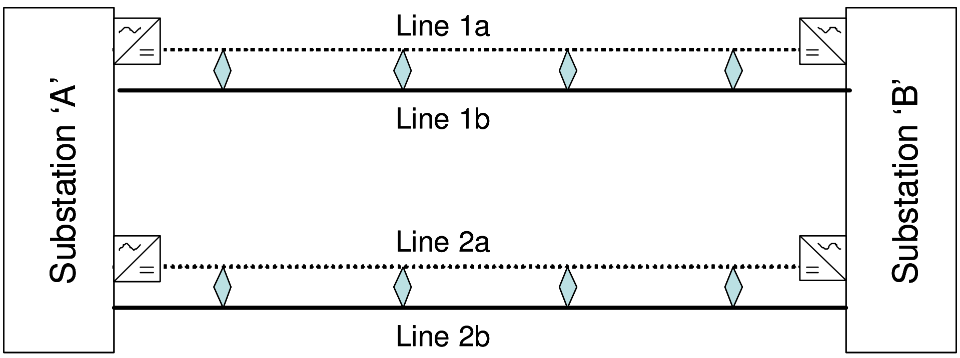
Figure 2.6: Sketch of a HVDC and 400 kV HVAC UK transmission link with an unplanned outage



This is no different from the winter post-fault capability provided by 4x HVAC links, consequently the HVDC links offer little benefit (other than improved control of power flows).

A better solution operationally would be as follows:

Figure 2.7: Sketch of a combined HVDC and 400 kV HVAC UK transmission link



The winter post-fault configuration would thus leave lines 1a/1b in service (or 2a/2b) giving a total transfer capacity for L6/L12 towers of 3820 MVA + rating of 1x HVDC link. Any short term overloading would be carried solely by the single HVAC circuit remaining in service.

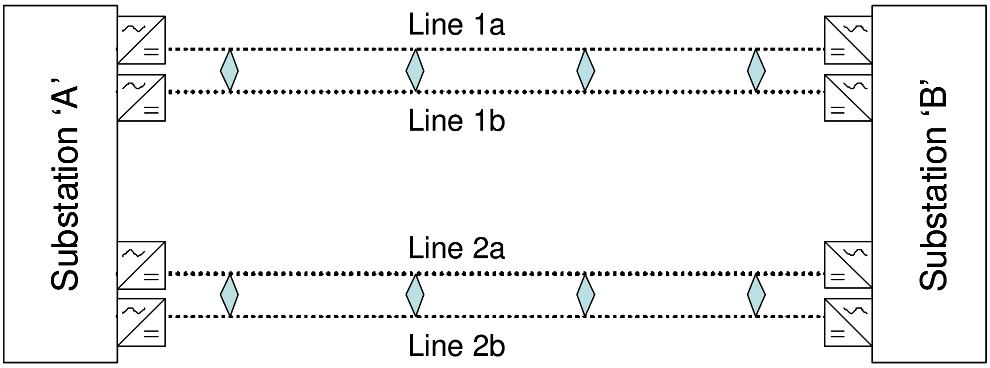
It should be noted that the capability of each HVDC link would have to exceed 3820 MW (L6/L12 towers) or 3100 MW (L2/L8 towers) to provide any capacity enhancement.

In summer conditions, with a planned outage on line 2a and a fault outage on line 1a/1b, only the single HVAC line 2b would remain in operation. The post-fault capacity is thus no greater than for the HVAC only link described in section 2.2.3.2.

2.2.3.4 Effect of Adding 4x HVDC Links

The configuration can be illustrated as follows:

Figure 2.8: Sketch of a HVDC UK transmission link



Assuming HVDC circuits of equal capability, the winter post fault capacity is dictated by the rating of two links. Again, the capability of each HVDC link would have to exceed 3820 MW (L6/L12 towers) or 3100 MW (L2/L8 towers) to provide any capacity enhancement.

The summer post-fault capability is dictated by the rating of a single link. Typical LCC HVDC overload ratings are as follows [1]:

- 30% for five seconds without redundant cooling.
- 10% for two hours without redundant cooling.
- 20% for two hours with redundant cooling.
- 10% continuous with redundant cooling.

Higher LCC HVDC temporary overload ratings have been reported, for example the Intermountain scheme in the United States is understood to have a 67% overloading capability for 6 s. However this timeframe is still less than the HVAC line overload capabilities discussed earlier, providing much less flexibility in post-fault intervention.

Typical VSC HVDC overload capability is approximately 5% during times of low ambient temperatures [1].

Since HVDC transmission offers limited overload capability then any pre-fault transfer in excess of the rating of a single HVDC link would have to be subject to an operational tripping scheme.

2.2.3.5 General Comment on HVDC Circuits

As outlined above, very high HVDC circuit ratings (4GW+) would be required to achieve an improvement on the theoretical capacity of an existing 400 kV UK HVAC link. This is significantly in excess of present VSC developments and would dictate the use of bi-polar LCC converters to replace each individual circuit of a double circuit HVAC link. This would impact severely on the land take at each terminal substation and costs would be high. Typical onshore HVDC (LCC) converter station sizes are as follows:

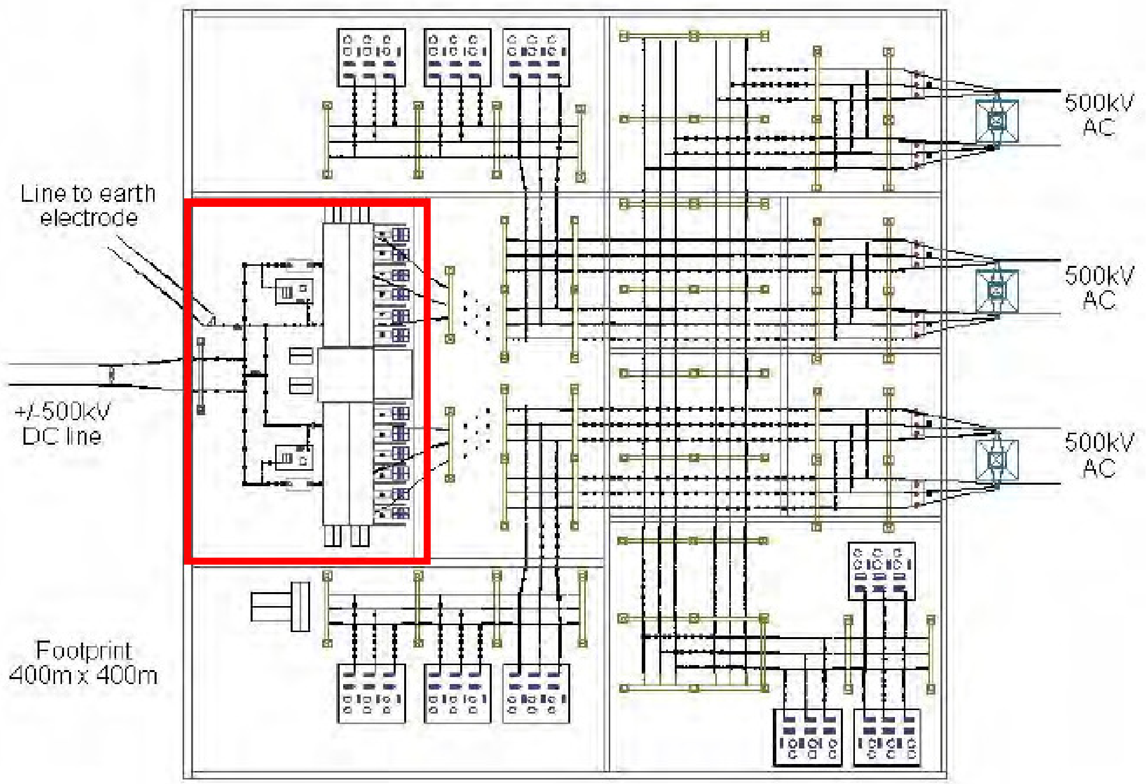
Table 2.5: Onshore HVDC (LCC) Converter Station Footprints

LCC Converter Station Rating	Length [m]	Width [m]	Height [m]
± 500 kV 3000 MW Bipole	400	400	21
± 600 kV 4000 MW Bipole	400	400	22

Source: "Assessment and Analysis of the State-Of-the-Art Electric Transmission Systems with Specific Focus on High-Voltage Direct Current (HVDC), Underground or Other New or Developing Technologies," [1]

An example can be seen in the layout illustrated below:

Figure 2.9: Typical Layout Of A ±500 kV 3000 MW LCC Converter Station (outlined red area includes converter transformers, valve buildings and DC area).



Source: "Assessment and Analysis of the State-Of-the-Art Electric Transmission Systems with Specific Focus on High-Voltage Direct Current (HVDC), Underground or Other New or Developing Technologies," [1] For interest, typical HVDC (VSC) power ratings and footprints are shown below:

Table 2.6: Onshore HVDC (VSC) Converter Station Footprints

VSC Converter Station Rating	Length [m]	Width [m]	Height [m]
± 200 kV 350 MW	80	32	13
± 200 kV 700 MW	90	65	16
± 300 kV 1000 MW	110	75	24

Source: "Assessment and Analysis of the State-Of-the-Art Electric Transmission Systems with Specific Focus on High-Voltage Direct Current (HVDC), Underground or Other New or Developing Technologies," [1]

It is also worth noting that a 4 GW link would draw/inject in excess of 4000 A at the 400kV HVAC connection. 400 kV switchgear ratings are generally limited to 4000 A and, whilst higher currents can be accommodated, this adds to the complexity of the installation (5 kA GIS has been specified by NG to terminate triple Arucaria circuits).

Whilst it is recognised that HVDC circuits offer greater controllability than their HVAC counterparts and may not be limited by stability constraints, they may only be justified where practical loadings on HVAC links are severely compromised by system topology.

2.3 Lifecycle cost comparison between HVAC and HVDC

This study considers the modification of an existing HVAC transmission link to operate as an onshore HVDC link. An exact lifecycle cost for this complex scenario would be very difficult to calculate, as it would depend on many case-specific factors. A high-level formula is however provided below which could be used:

HVDC Conversion Lifecycle Costs = Conversion Cost + Operational and Maintenance Costs + Losses

For evaluation purposes, the overhead line installation and dismantling costs are not considered, assuming that this would have been accounted for as part of the cost evaluation of the existing HVAC overhead line.

In order to operate an existing HVAC overhead line as a HVDC link, converter stations are required on either end. The below table provides estimated capital costs, which will form part of the conversion costs, for converter stations based on required ratings:

Table 2.7: Typical LCC Converter Station Costs (Rectifier plus Inverter)

Voltage [kV]	Bipolar Rating [MW]	Total Cost [US$ million]
± 500	1000	170
± 500	2000	290
± 500	3000	420
± 500	4000	680
± 600	3000	450 – 460
± 800	3000	510

Source: Impacts of HVDC lines on the economics of HVDC projects, Cigré 388 [2]

The current maximum VSC HVDC converter station rating is 1000 MW. Based on this, a ± 320 kV VSC HVDC converter station pair (rectifier plus inverter) would cost approximately US$277 million. This figure covers equipment directly related to the converter station (i.e. DC converter, transformers and AC filters), but not costs associated with additional HVAC switchyard equipment. Installation and civil work are covered, assuming good ground conditions and existing access. This figure includes a 20% addition to allow for project management and engineering.

The rest of the conversion costs will comprise of the costs associated with the modification of the existing HVAC overhead line to allow for HVDC operation (a detailed explanation of HVAC to HVDC overhead line conversion can be seen in the ETI Work Package 2 Task 1 report – "Feasibility of Onshore HVDC Systems Integrated into the UK AC Grid.")

Typically, the following overhead line components will be assessed and may have to be modified for HVDC use:
- Tower structural strength and foundation loadings – this may not be affected because it is assumed that the existing HVAC conductors will be reused in the HVDC scheme.
- Insulation levels and clearances – this will depend on the HVDC voltage selected.
- Conductor spacing within a bundle – this may need to be modified to reduce HVDC corona effects.
- Capability of the earth wire to act as a metallic return.

The overhead line conversion cost is estimated to be approximately 75% of a new overhead line cost. For example, if a UK 400 kV HVAC double-circuit overhead line was converted to a bipole HVDC overhead line, this conversion would cost approximately US$1.13 million per km (a new 400 kV HVAC double-circuit overhead line costs approximately US$1.58 million per km).

Typically the annual operational and maintenance (O&M) costs of an HVDC scheme are approximately 2% of the total scheme cost [2]. When analysing the O&M costs of a HVAC to HVDC conversion, the overhead line O&M costs are likely to remain the same but there will be additional O&M costs due to the addition of the converter stations.

Losses are discussed in section 2.2.1 of this report.

2.4 Benefits case of HVAC to Onshore HVDC Conversion

From section 2.2.3, it can be seen that the post fault HVAC ratings on the UK 400 kV overhead line circuits are currently in excess of 4 GW which means that any additional capacity that could be provided by the conversion to an onshore HVDC scheme is very likely to be uneconomic. Other than the potential additional capacity, a conversion to HVDC could provide the following benefits that are not offered by the existing HVAC transmission overhead line [1]:
- Real and reactive power flow control: power flow in HVDC systems can be predetermined and is independent of phase relationships, avoiding inadvertent overloading or under-utilisation as may occur in HVAC systems.
- Loss of HVAC transmission lines can be automatically compensated by reduction in power through the HVDC link, to match the capability of the remaining in-service HVAC transmission network.
- Damping of electro-mechanical oscillations.
- Suppression of sub-synchronous resonances.

- Following a load rejection on the network, a limitation of temporary over-voltage can be achieved by the HVDC link by the rapid absorption of reactive power.
- Frequency limit control can be initiated, if normal operating limits are exceeded.
- Reduced transmission losses
- No impacts on fault levels: HVDC links provides negligible contribution to the short circuit levels in the connected systems, which may be desirable depending on the application. HVAC Faults and oscillations do not transfer across HVDC interconnections.

Other often mentioned benefits of HVAC to HVDC conversion such as enabling long distance power transmission, eliminating reactive power flows from long HVAC cable circuits and enabling asynchronous system connections are not considered to be applicable to this study focused on onshore UK transmission.

A more economical solution which could provide additional capacity may be to install a lower rated HVDC cable link in parallel with the existing HVAC transmission overhead line; however this is not part of the current scope of this report.

2.5 Renewable energy deployment facilitation with possible CO_2 emission reduction

By utilising the onshore HVDC schemes (LCC or VSC), additional capacity can be created on the existing UK transmission grid. In order to meet UK renewable energy targets, the idea is to supply this additional network capacity by offshore wind generation. Based on a CO_2 emission reduction figure of 430g CO_2/kWh quoted by Renewable UK [3] (previously known as BWEA), the approximate CO_2 savings can be calculated for the amount of wind generation supplied. The formula is shown below:

Annual wind energy emission reduction [grams CO_2]	=	HVDC availability factor **x** Capacity created by HVDC which is to be filled by wind generation [kW] **x** hours in a year **x** CO_2 emission reduction for wind generation [grams CO_2/kWh]

The assumptions for the above calculation are as follows:

- 430g CO_2/kWh wind generation CO_2 emission reduction value which has been calculated by Renewable UK
- The additional capacity created by the HVDC scheme is completely supplied by wind generation for the entire year. If the generation dispatch varies, this formula can only be used for the portion of the additional capacity supplied by wind generation.
- HVDC availability factors can be seen in section 2.2.2.

An example of a CO_2 emission reduction calculation is as follows:

In a particular scenario, an additional transmission capacity of 1 GW is created by using an onshore HVDC scheme with an availability factor of 0.98. If this additional 1 GW was to be met using wind generation, the anticipated annual CO_2 emission reduction could be:

Annual emission reduction [grams CO_2] = 0.98 x 1,000,000 kW x 8760 hours x 430 g CO_2/kWh

= 3.69×10^{12}g CO_2

= 3.69 million tonnes CO_2

3. Conclusions

This report has focused on evaluating the impact of replacing an existing HVAC transmission circuit with an HVDC scheme. As can be seen in section 2.2.3, the required post-fault ratings, for a UK 400 kV double circuit transmission corridor, are in excess of 4 GW. In complying with SQSS specifications, there is negligible benefit of attempting to increase this transmission corridor capacity by replacing it with an onshore HVDC scheme primarily due to economic reasons. The benefits of using an onshore HVDC scheme could be maximised by installing a lower rating (<4 GW) onshore HVDC cable link in parallel with an existing transmission corridor. However the impact of this application has not been studied as part of this report.

Appendices

References:

[1] “Assessment and Analysis of the State-Of-the-Art Electric Transmission Systems with Specific Focus on High-Voltage Direct Current (HVDC), Underground or Other New or Developing Technologies,” Stantec, 23 December 2009.

[2] Cigré Report – “Impacts of HVDC Lines on the Economics of HVDC Projects,” 388, Working Group B2/B4/C1.17, August 2009.

[3] Renewable UK website, (http://www.bwea.com/edu/calcs.html), data obtained on 27 April 2010.

[4] National Grid Seven Year Statement 2010 website, (http://www.nationalgrid.com/uk/Electricity/SYS), data obtained on 28 May 2010.

Glossary

A	Ampere
AAAC	All Aluminium Alloy Conductor
AC	Alternating Current
BWEA	British Wind Energy Association
CO_2	Carbon Dioxide
ETI	Energy Technologies Institute
FACTS	Flexible Alternating Current Transmission System
GW	Gigawatt (1 000 000 000 watt)
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
Km	Kilometre (1 000 metres)
kV	Kilovott (1 000 volts)
LCC	Line Commutated Converter
MW	Megawatt (1 000 000 watt)
SQSS	Security and Quality of Supply Standard
TGN	Technical Guidance Note
UK	United Kingdom
VSC	Voltage Source Converter