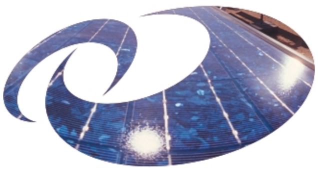
Assessment of the Grid Connection Options for the Scottish Islands

Highlands and Islands Enterprise



27th March 2007

CONFIDENTIALITY (Confidential or not confidential):	Not-Confidential
Project No.:	**5258**
Project Name:	**Assessment of the Grid Connection Options for the Scottish Islands**

UNIT APPROVAL	Name	Date
WRITTEN BY:	TNEI Services Limited	27/11/06
ISSUED BY:	TNEI Services Limited	
APPROVED BY:	TNEI Services Limited	27/03/07

REVISION HISTORY RECORDS

Revision	Date	Creation / Update summary
Draft	12/11/06	For Discussion
Rev 1	27/11/06	For Discussion
Rev 2	15/12/06	Final Review
Rev 3	15/03/07	Final Release
Rev 4	27/03/07	For Publication

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Glossary

AC Alternating Current

ARODG Access Reform Options Development Group

BETTA British Electrical Trading and Transmission Arrangements

CSC Current Sourced Converter

CUSC Connection and Use of System Code

DNO Distribution Network Operator

DGUoS Distributed Generation Use of System

DTI Department of Trade & Industry

FSL Final Sums Liability

GBSO Great Britain System Operator

GRT Gross Register Tonnage

GSP Grid Supply Point

GW GigaWatt (1,000,000 kW)

HIE Highlands and Islands Enterprise

HVAC High Voltage Alternating Current

HVDC High Voltage Direct Current

ICPC International Cable Protection Committee

kV KiloVolt (1,000 V)

MVA MegaVoltAmpere (1,000 kVA)

MW MegaWatt (1,000 kW)

NGT National Grid Transco

NGET National Grid Electrical Transmission Limited

NIE Northern Ireland Electricity

Ofgem The Office of Gas and Electricity Markets

RETS Renewable Energy Transmission Study

RPZ Registered Power Zone

RO Renewables Obligation

ROC Renewables Obligation Certificate

s185 Section 185 of the Energy Act 2004

SHETL Scottish Hydro Electric Transmission Limited

SNH Scottish Natural Heritage

SO System Operator

SPTL Scottish Power Transmission Limited

SQSS Security and Quality of Supply Standard

SYS Seven Year Statement

TEC Transmission Entry Capacity

TIRG Transmission Investment for Renewable Generation

TO Transmission Owner (equivalent to Transmission Licensee)

TNUoS Transmission Network Network Use of System

VSC Voltage Sourced Converter

Executive Summary

1. The Highlands and Islands of Scotland represent the greatest density of renewable energy resource in the UK. Extreme tidal, wave and wind regimes continue to attract developers seeking to install tidal, wind and wave energy conversion technologies that could make very significant contributions to the UK's energy requirements and climate change targets.

2. We are reminded through the media on an almost daily basis that time is of the essence and by publications such as the Stern Report that the grave implications of inactivity will be economic as well as climatic.

3. This report was commissioned by the Highlands and Islands Enterprise (HIE), in conjunction with Scottish Executive, Shetlands Islands Council, Orkney islands Council and Comhairle nan Eilean Siar, to consider the issue of the connection of the main Scottish Island groups to the mainland network. The report is based on current estimates for wind generation of 1000MW on the Western Isles, 600MW on Shetland, 200MW on Orkney and the 1000MW Beatrice offshore wind-farm in the Firth of Moray.

4. By necessity this report deals with a range of complex issues to arrive at recommendations in relation to how the strategic wind resources of the Scottish Islands could be connected primarily into the GB transmission network.

5. Fundamentally this report illustrates the dynamics and complexity of the variable factors that converge to protract the process of installing and connecting renewable energy generation assets.

Policy and Regulatory Comments

6. Several policy and regulatory issues are identified as having a constraining effect:

7. a) The uncertainties surrounding the process of gaining planning consent for wind farms make the provision of resources for connection risky and politically sensitive. This is a Catch-22 scenario where to de-risk the wind generation development; grid access must be available. Similarly to de-risk the transmission investment; the wind generation developments must be certain.

8. b) Whilst it is regarded as good practice, it is very rare for the submission or determination of applications for wind farms and their associated connections to concur. It is common that a condition placed on the consent for one is reliant on the consent for the other; this ensures that a connection is not put in place for generation that is later denied consent, and that generation is not constructed without an option for connection. A parallel approach to these applications could significantly reduce development timelines although it would increase the risks associated with funding this up-front development activity. Given the potential benefits to developers, this approach could also serve to improve the extent to which they begin to work together. There would be significant strategic benefits to be had from a third party underwriting the costs associated with gaining planning consent for connections.

9. c) Currently there is a total of 12GW of primarily wind generation projects with connection offers in Scotland. The proposed 'shake up' by the Great Britain System Operator with the move towards increased levels of User Commitment will be beneficial in terms of clearing out 'shelved' projects and giving a truer picture of projects in the 'pipeline'. This process should provide far greater clarity in relation to the true requirement for mainland grid reinforcement, as well as releasing more capacity to provide additional potential projects with firm connection offers.

10. d) Conversely, whilst beneficial to those parties involved with providing grid connections, the provision of significant financial User Commitments in the form of the Final Sums Liability represents significant risks to developers, given the uncertainties surrounding gaining planning consent.

11. e) Given the commercial incentive to bring wind farms on stream, the "Connect and Manage" approach considered by the Access Reform Options Development Group may also enable large projects to be developed and commence partial generation earlier than would be the case if waiting for full infrastructure works to commence.

12. f) Additional generation could be introduced to the grid through Transmission Entry Capacity (TEC) trading. When a generator is not fully utilising its TEC allowance, another party could be given non-firm or short-term access rights via an exchange mechanism. This arrangement could enable greater utilisation of the network and enable projects to be brought on stream earlier. However current lead times for TEC trading make it impractical for wind generation. An additional barrier to trading exists in the disparities in compliance between previous Scottish Grid Code and new GB SQSS.

13. g) Through the Transmission Investment for Renewable Generation (TIRG) review, Ofgem categorised investments required for the uptake of renewable generation in Scotland as Baseline, Incremental and Additional. Baseline projects are funded through the TIRG revenue allowance arrangements. The other two categories did not attract immediate funding as a result of higher perceived risks. Several projects in these two categories are viewed as critical for the rapid development of the renewable resource in Scotland.

14. h) As is discussed later, whilst the Beauly-Denny line upgrade and the minor Scotland – England inter-connector upgrades have been classified as Baseline, the findings of this study suggest that there is a strong strategic argument for categorising other onshore reinforcement work as Baseline. Priority candidates would be Beauly-Dounreay upgrade, Beauly-Blackhillock re-conductoring, Beauly-Keith upgrade and Keith-Kintore-Tealing 400kV ring. Without this level of onshore upgrading, offshore connections become unviable and consenting times fall out of sync.

15. i) Transmission Network Use of System (TNUoS) charges could represent a significant problem for Island projects and this represents another significant area of uncertainty. Of benefit to projects in the short term is the newly introduced "Plugs" model that now includes substation costs within the TNUoS payment scheme, meaning that generators do not have to pay this additional, significant up-front cost. The uncertainty surrounding the calculation and level of the TNUoS charges when applied to the Islands is a point of key concern.

16. j) In terms of the potential geographically related variations in transmission charges enabled by section 185 of the Energy Act 2004, the reduced figures could help facilitate island developments but the prospect of 5-year reviews introduces uncertainty and therefore risk. Again, the uncertainty surrounding how the s815 legislation will actually be implemented is also a point of concern.

17. k) Finally, although the benefits to the GB renewable targets are significant, Island wind projects are high risk and finance hungry. The current review of the ROC mechanism, and the prospect of a banding mechanism that reduces the incentives for onshore generators, adds an additional uncertainty to slow down the development process.

Connection Options

18. In relation to technology, the report outlines the pros and cons of employing AC and HVDC transmission technology. The final conclusions are that a combination of the two represent the most effective solution.

19. Three key factors emerge from the initial high-level connection analysis:

20. a) Due to the increasing utilisation factors on the existing transmission network, there are now few locations where significant levels of generation can connect without triggering reinforcements.

21. b) For low capacity factor generation such as wind, it is more difficult to justify long connections due to the low connection asset utilisation. If there is sufficiently low correlation between different sources of renewable generation, i.e. wind versus wave, then this will increase the utilisation of the link but there will be constraints during periods of high generation.

22. c) Crucially, the majority of the proposed island generation is "commercially firm" with respect to the most serious onshore transmission constraint, the Scotland-England inter-connector. This immediately removes a large commercial avoided-cost value for the business case justifying a long bypass link.

23. The Scotland/England inter-connector currently only has a firm capacity of 2.2GW, so given the 12GW of connection agreements in Scotland this represents a considerable constraint. The TIRG upgrades that have been identified and sanctioned will take capacity up to 3.3GW, and SPTL has requested additional funds from Ofgem to investigate routes for a third inter-connector.

24. There appears to be little commercial benefit in pursuing alternative grid connections into England or Wales since most Island project developers already

have firm connection offers that are not dependant on Scotland/England Inter-connector capacity.

25. Existing constraints on the Irish network plus the existing capacity in the Moyle inter-connector and the potential Dublin/Wales inter-connector mean there is little benefit in establishing a link with Ireland.

26. An inter-connector to Norway is less unlikely but there is no targeted incentive to generate from renewable sources in Norway and an inter-connector linked primarily to wind power would not resolve the demand/supply balance problems they are encountering. Furthermore, a fundamental issue is that an inter-connector to Norway could at times represent an additional burden on the Scottish network.

Orkney

27. For a 200MW connection from Orkney into the GB network, the fastest and least cost option is a 132kV AC subsea cable connection. This could run from Skail Bay on Orkney Mainland to Murckle Bay to the East of Thurso. The onshore connections to the generation sites on Orkney and to Dounreay substation on the Scottish mainland would be run as either overhead lines or underground cables.

28. This option would also have the shortest timeframe associated with it, allowing firm access to the network from 2011 and possible short-term access from 2010. The estimated capital connection cost of this option is £47M, which gives a TNUoS charge of £30/kW/yr including the estimated s185 reduction.

29. A joint connection linking Orkney and Shetland to Keith was the only other short-listed connection option that was considered in detail for Orkney. This was found to be less beneficial, more expensive and more complex than the direct AC connection.

Shetland

30. For a 600MW connection from Shetland into the GB network, the fastest and least cost option would be a +/-300kV VSC HVDC subsea cable connection from Shetland to Keith. This could run from West Voe of Skellister on Shetland to Cullen Bay on Mainland Scotland. The on-shore sections could be under-grounded to the most suitable site for a converter station, which is anticipated to be at the Keith substation on the mainland.

31. This option would also have the shortest timeframe associated with it, allowing the first 250 MW of generation to gain access to the network from 2012. The estimated capital connection cost of this option is £300M, which gives a TNUoS charge of £42/kW/yr including the estimated s185 reduction.

32. Connections to Cockenzie, Hawthorn Pit, Humberside and Walpole were also considered but a connection of this length for the sole purpose of wind generation export was found to be an inefficient use of an expensive asset. The connection to Thurso was not considered further because there would be insufficient capacity unless a new line was constructed from Dounreay to Beauly.

33. An alternative to onshore reinforcements would be to connect the Shetland generation into the Scottish System via a direct link. Then a 'Bulk Transfer'

connection would be established from Peterhead into England as the third Scotland-England inter-connector for the whole GB network.

34. To avoid replacement of the existing generation, any planned interconnection would need to comprise at least two independent circuits in order to provide the necessary security of supply for the existing demand customers.

Western Isles

35. For a 1000MW connection from the Western Isles into the GB network, the fastest and least cost option would be a +/-150kV VSC HVDC subsea cable connection from Lewis to Beauly. The cable could run from Chubag Bay on Lewis to Ardmair Bay near Ullapool and then continue with VSC HVDC underground cable to the Beauly substation. The cable on Lewis could be run underground from the landfall to an appropriate site for the converter station.

36. This option would also have the shortest timeframe associated with it, allowing the first 250 MW of generation to access the network from 2011. The estimated capital connection cost of this option is £287M, which gives a TNUoS charge of £33/kW/yr including the estimated s185 reduction.

37. The other short-listed connection options for the Western Isles considered were Dalmally via Oban, Hunterston, and Deeside. Connections to Anglesey and Pembroke were also considered, but the available capacities at these points in the network are very dependent on other generation connections. This means that the increased cost of connection was highly unlikely to be outweighed by increases in available network capacity.

Beatrice Offshore Windfarm

38. The fastest and least cost option considered for the 1,000MW connection from the Beatrice offshore windfarm into the GB network is a multiple 132kV subsea cable connection. This could land at Cullen bay and continue from there with an overhead line connection to the Keith Substation. The estimated capital connection cost of this option is £59M, which gives a TNUoS charge of £26/kW/yr including the estimated s185 reduction.

Key Recommendations

39. The Island groups should be treated as entities rather than as the individual schemes that already have significant capacity in the GB queue. A single large connection would provide a stronger signal and lobbying position to the process than several smaller and potentially competing schemes. The stakeholders in the report are well placed to facilitate this merging of applications. The GBSO has indicated that it would look favourably on such a sharing of transmission access.

40. It is clear that the greater the extent to which uncertainty can be reduced and information shared, the easier progress will become for all parties. In particular TEC sharing could represent a significant opportunity for bringing 'The Lewis Wind Farm' on line ahead of time without undue discrimination. There would seem to be a role for an organisation to facilitate this process and deal with the potentially complex, contractual issues of bringing parties together.

41. There is a high degree of regulatory uncertainty surrounding the connection and charging arrangements that will be applied to the Scottish Islands. Decisions need

to be made quickly as to how security factors will be calculated for subsea links, what the applicable TNUoS charge methodology might be, how s185 will be implemented and whether TEC trading can actually be utilised in Scotland by renewable generators.

42. Timing is a critical factor and there is a clear requirement for the critical paths for Island developments to be established and examined and then a strategic programme developed.

43. The current proposals for competition in offshore transmission have an obvious benefit if there are licensees who are highly experienced in the delivery of offshore transmission projects. As this is not the case for the three UK TOs, the scope for significant cost or time-savings may be limited to their ability to negotiate commercial terms with suppliers, or their ability to achieve planning consent rapidly and manage projects efficiently. These proposals are not viewed as providing any significant acceleration in the connection of the Scottish Island projects.

44. Increasing User Commitment can be considered as a positive move to reduce uncertainty from the transmission owner's perspective. However, it is unlikely to resolve the timing uncertainty for the generation developments. This is because it does not address the potential delay issues associated with the consenting, sanctioning and construction of the transmission infrastructure.

45. Table 5.1 highlights the key barriers facing a number of the key Island projects. It is not being suggested that infrastructure should be physically constructed ahead of definite demand; however, the key delays for the majority of transmission investments are the consenting process and the securing of necessary wayleaves. A mechanism to secure wayleaves and consents ahead of time, perhaps at an increased level of financial risk, would dramatically reduce the time to develop infrastructure and would significantly reduce the uncertainty facing generation developers. This would be an extension of the TIRG Incremental category based on reasonable expectation rather than avoided constraint costs.

1 Introduction

1.1 Background

The Highlands and Islands Enterprise (HIE), in conjunction with Scottish Executive, Shetlands Islands Council, Orkney Islands Council and Comhairle nan Eilean Siar, commissioned TNEI Services Ltd in July 2006 to investigate the technical and economic feasibility of the connection of large tranches of renewable generation on the main Scottish Island groups to the mainland transmission network. Renewable energy is one of a number of priority sectors that have been identified as being of key strategic importance to the development of the region's economy.

The study scope comprised an analysis of the likely connection points, offshore cable routes and an assessment of the reinforcement options on the onshore transmission network. A key aspect was to investigate the timescales of the various options and how these interact with the island based projects currently being developed.

The existing interconnections between the islands and the Scottish mainland where present are insufficient to accept the anticipated level of generation capacity being proposed. In addition, there are a number of deep reinforcement works required within the Scotland and England transmission systems that will be required. The timescales associated with these deep reinforcements are long, and so the study investigated a number of alternative connection options that might accelerate the connection of island schemes.

The study investigated connections based on the current estimates for renewable generation for the main Island groups. These are:-

- 1000MW on the Western Isles
- 600MW on Shetland,
- 200MW on Orkney,
- 1000MW associated with the Beatrice offshore wind farm[1].

This report outlines the identified the potential grid connection options including locations, cable routes, technologies, regulatory issues and associated costs and comparative timescales.

As part of this study, consultations were held with the following organisations to obtain the latest information in addition to a number of existing reports:

- Scottish Hydro Electric Transmission (SHETL) - transmission network owner
- Scottish Power Transmission (SPTL) - transmission network owner
- National Grid Transco (NGT) - transmission network owner and GB system operator
- Statnett – Norwegian Transmission Network Owner

[1] Brief from HIE

- Northern Ireland Electricity (NIE) - Northern Ireland Network Owner
- Ofgem - Electricity Network Regulator
- DTI – Department of Trade and Industry
- Scottish and Southern Generation - Generation owner and wind farm developer
- AMEC & British Energy – Developer behind "The Lewis Windfarm"
- Airtricity - Developer behind SuperGrid offshore wind farms
- ABB - technology provider
- Areva – technology provider
- Highland and Islands Enterprise – study stakeholder
- Shetland Islands Council – study stakeholder
- Orkney Islands Council – study stakeholder
- Comhairle nan Eilean Siar – study stakeholder
- Scottish Executive – study stakeholder
- Scottish Natural Heritage – statutory body for Scottish natural heritage

In addition, a study was commissioned by TNEI with JP Kenny to investigate the sub-sea routing issues associated with the short-listed options. This information has contributed to Sections 5, 6 and 7.

1.2 Assessment Methodology

The methodology used to assess the feasibility of offshore grid connection options is as follows.

- The main Scottish island groups are defined as Western Isles, Orkney and Shetland.

- The viable connection options for the three island groups are largely dictated by the location of suitable subsea cable routes and the existence of sufficient grid capacity at the proposed landfalls. Once these factors were established, it was necessary to perform a technology selection based on the cable route, required interconnection capacities, and the characteristics of the grid at both ends of the link.

- The cable routing used a geographic constraint mapping analysis to determine the possible subsea cable routes. The analysis considered key routing constraints including physical, engineering, environmental, and third party interactions. Unsuitable landfalls (e.g. due to distance from suitable grid infrastructure, or involving excessive time delays or high reinforcement costs) were excluded from further analysis.

- Consultations were held with the three UK transmission network owners (SHETL, SPTL and NGT) and the GB system operator (NGT). Contact was also made with SONI, Eirgrid and Statnett to assess the grid connection possibilities within Northern Ireland, the Republic of Ireland, and Norway respectively.

A key aspect was to assess the impact that the planned and possible reinforcements to the Scotland and England Transmission network may have on the offshore grid options. For example, if one or more of the existing bottlenecks are resolved quickly, then a shorter and more cost effective cable route may be more viable.

- Subsea connection scenarios were then created and cost estimates developed. These scenarios were used to form the short-list of connection options for each island group including consideration of any joint connection possibilities. The short-listed options were developed in more detail and are discussed later in the report. Some of the more significant scenarios that did not make the short-list are described briefly in Appendix C together with reasons for their rejection.

1.3 Report Overview

Section 2 of this report provides some of the background to the existing connection applications and offers, and the issues surrounding the connection queue. Background information from existing studies is also included.

Section 3 undertakes a connection assessment considering the local network connection issues within the SHETL, SPTL and NGET networks, as well as the deeper system impact and reinforcement issues that may exist. Options for connection to Norway's Statnett network or Northern Ireland's NIE network are also assessed. The various options are discussed with details of the most suitable technological solutions and any associated constraints.

Section 4 discusses the associated costs and connection timeframes for the available options and provides an assessment of the most suitable options for the economic and timely connection of the various schemes. This includes connection costs, anticipated transmission use of system costs and any other significant economic benefits associated with the connection option.

Section 5 contains a summary of the proposed options and details the recommendations of study.

2 Renewable Generation Connections in Scotland

This section discusses the current Renewable Generation connection situation in Scotland and considers the connection offers that have been presented to the various developers on the Scottish Islands. The aim of this discussion is to clearly identify the actual position of individual schemes within the wider context.

Scotland has seen a significant increase in generation connection applications, driven primarily by the excellent wind resource. The Renewable Obligation has served to encourage this activity. However, the existing transmission network in Scotland and Northern England was not designed for this level of generation and so it requires reinforcement and/or augmentation.

2.1 BETTA and "The GB Queue"

The British Electricity Trading and Transmission Arrangements (BETTA) were implemented on 1 April 2005. They created, for the first time, a fully competitive British-wide wholesale electricity market by integrating the transmission networks of England, Wales and Scotland.

This significantly eased the large-scale development of renewables in Scotland. Under previous arrangements, the Scottish domestic market had limited demand, and access to the larger market in England and Wales was expensive because of charges and access limitations on the Scotland/England interconnectors[1].

BETTA provided Scottish generators with access to a wider market as well as the opportunity to get the best price for their output[2]. However, the limited network capacity between Scotland and England can result in constraints for generators in Scotland, and this can lead to market distortion. As part of the transition period, a cut-off date was established whereby generators accepting commercial terms for connection before 1st January 2005 would not be commercially disadvantaged due to physical constraints in the England and Wales network nor by constraints on the Scotland/England interconnectors. (I.e. such generators would be commercially "firm".)

Essentially, if such a generator was subsequently constrained due to lack of network capacity outside of Scotland, then it would be commercially compensated under the standard market mechanisms. This means that such generators possess a commercially firm connection even if they do not enjoy a physically firm connection.

All generation connection agreements received by the Great Britain System Operator (GBSO) are placed in a queue (The GB Queue) in strict order by date on which the developer formally accepted the connection offer. Those offers accepted earliest are typically contingent on fewer reinforcements than those accepted later.

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[1] Email with NGT

[2] www.ofgem.gov.uk

This is a matter of on-going discussion, in particular with ARODG[1]. This is because there are some generation projects in the queue that may find it difficult to obtain planning consent. These projects may indirectly block the connection of other generation projects that are further down the queue but that may be more straight-forward to consent. The worst case would be a project in a position to start construction, network capacity still being available, but it is unable to connect due to the commercial terms of its connection offer.

The above paragraphs describe the current situation, however, there are proposals that could change this. One of these, CUSC amendment proposal (CAP) 131 as discussed in Section 2.4, proposes that new generators should provide a stronger user commitment signal, which could have implications for the composition of the GB queue.

2.2 Current Situation in Scotland

Currently there are a total of 12.1 GW of accepted connection offers for connection in Scotland under the pre-BETTA regulations. The vast majority of these applications are for wind power generation[2].

Of the offers, a total of 7.7 GW is with SHETL, and the remaining 4.4 GW is with SPTL. The existing SHETL transmission network can only accommodate approximately 1.5 GW of new renewable generation without reinforcement[3].

In 2003, the DTI initiated some preliminary studies to investigate the transmission system reinforcements required to accept increasing amounts of renewable generation. The Renewable Energy Transmission Study (RETS) identified the transmission system reinforcement costs associated with installation of up to 6 GW of renewable energy generation in Scotland. It was clearly recognised that the provision of this infrastructure was crucial in ensuring that the generators are able to make a contribution to meeting the Government 2010 targets for renewable energy generation.

The RETS report of June 2003 produced by the three transmission licensees (SHETL, SPT, NG) assessed the connection of 2GW, 4GW and 6GW of additional renewable generation in Scotland and recommended the staged reinforcements required to accommodate this[4].

SHETL studies have indicated that the most effective, economic and efficient way of increasing the network capacity in its system is to upgrade the existing Beauly-Denny corridor from 132 kV to 400/275 kV (400 kV on one side and 275 kV on the other to facilitate interconnection with the rest of the system at Errochty and Braco). The application for consent under section 37 of the

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[1] “A framework for considering reforms to how generators gain access to the GB electricity transmission system”, April 2006, ARODG

[2] Consultation with SHETL

[3] Consultation with SHETL & SPTL

[4] http://www.dti.gov.uk/files/file18060.pdf

Electricity Act 1989 for this upgrade was submitted and has been referred to a Public Inquiry that is scheduled to start on 1st February 2007. If permission is granted in 2008 the works will then take approximately 3 years to build, so completion will not be achieved until at least 2011. This reinforcement will allow up to a total of 3000 MW of generation to be connected in the Northern SHETL region.

The further reinforcements that have been identified by SHETL as the most effective way of increasing the network capacity are shown in Table 2.1.

Order	**Line**	**Upgrade required**	**Anticipated date of completion**	**SHETL capacity for new renewable generation after completion**
1	Beauly - Dounreay	Second Circuit on existing towers	2010	Additional connection capacity for the North of Scotland as far as Beauly
2	Beauly – Denny	New 400/275kV route replacing existing 132kV route	2011	2.5GW
3	Beauly – Blackhillock	Re-conductoring	2013	3.0GW
4	Beauly - Keith	Rebuild at 400kV one of the three existing routes between Beauly and Keith/Blackhillock	2015	4.2 GW
5	Keith – Kintore - Tealing	Creation of 400 kV ring by operating existing routes at 400kV	2015	5.2 GW

Table 2.1 Anticipated Reinforcements Required in the SHETL Region[1]

Scottish Power Transmission indicated that in addition to planned changes to the substation at Sloy and the part of the Beauly-Denny upgrade that is located in their area, fewer reinforcements are required in their Transmission area to accommodate these connections. Re-conductoring of some of the existing lines and some reactive power compensation may be required dependent upon where the generation chooses to connect[2].

There is a significant requirement for reinforcement of the Scottish Power network where it interconnects with England. This is because the Scotland/England inter-connector currently only has a firm capacity of 2.2GW. With the additional 12GW of connection agreements in Scotland, there will be

[1] Consultation with SHETL

[2] Consultation with SPTL

significant constraints on these lines from Gretna to Harker and then on to Hutton, and from Eccles to Stella West[1].

The reinforcements that have been identified by SPTL and NGET as the most effective way of increasing the network capacity are shown in Table 2.2.

Line	Upgrade required	Anticipated date of completion	Interconnector capacity after completion
Eccles – Stella West Strathaven – Harker Blyth – Stella West	Re-conductoring Upgrade to 400kV Upgrade to 400 kV	2010	2.8 GW
Strathaven - Harker Northeast Ring Heysham Ring	Reactive Compensation Upgrade to 400kV Upgrade to 400kV	2012	3.3 GW

Table 2.2 Anticipated Reinforcements Required in the Scotland-England Inter-connector[2]

No further reinforcements to increase the capacity beyond 3.3 GW have yet been detailed or approved by Ofgem. However, if and when additional capacity is required, then it is likely that an additional inter-connector will need to be built, either onshore or offshore.

The reactive compensation work proposed by SPTL is being considered by Ofgem. SPTL has also requested additional funds for the pre-engineering works of a third inter-connector. These funds would enable SPTL to investigate proposed routes, costs and environmental issues, but would not go as far submission of the Section 37 application for consent.

2.3 Island Connection Offers

At present there are six major projects with a total of 2226MW of booked GB Queue capacity on Island groups under consideration. These projects are shown in Table 2.3, along with the dates that the capacities are likely to be available. These dates only consider the onshore reinforcements and may be subject to delays due to consenting issues. This table was valid as of 7/12/06, although it is understood that some of these connection dates have now been pushed back due to delays with the Beauly-Denny upgrade.

[1] Consultation with SPTL and NGET

[2] Consultation with SPTL and NGET

User	Station Name	Location	TEC	Applicability
Beinn Mhor Power Ltd	Eishken Estate	Isle of Lewis	300 MW	31-Oct-10
Fairwind (Orkney) Ltd	Fairwind Ltd	Orkney	126 MW	31-Oct-10
SSE Generation Limited	Beatrice Wind Farm	Forth of Moray	1000 MW	TBC
SSE Generation Limited	North Nesting Wind	Shetland	250 MW	30-Dec-12
SSE Generation Limited	Parc (South Lochs) Wind	Isle of Lewis	250 MW	31-Oct-09
Viking Energy Ltd	Viking Wind Farm	Shetland	300 MW	11-Oct-14

Table 2.3 Comparison of anticipated Island capacity requirements against capacity already booked in the GB Queue[1]

The anticipated requirements for the Scottish Islands are shown in Table 2.4 against the capacity already booked and the shortfall that will be need to be secured or otherwise managed.

	Anticipation	GB Queue	Shortfall
Orkney	200 MW	126 MW	74 MW
Shetland	600 MW	550 MW	50 MW
Western Isles	1000 MW	550 MW	450 MW
Beatrice Offshore Windfarm	1000 MW	1000 MW	0 MW

Table 2.4 Comparison of anticipated Island capacity requirements against capacity already booked in the GB Queue

The map in Appendix A shows the connection options and reinforcements discussed in this section along with the other options that are considered later in this report.

2.3.1 Orkney

There have been several applications for connection of generation on Orkney, the largest of which is the Fairwind project. The total generation connection requirements have triggered the requirement for reinforcement of the existing subsea links to the Scottish mainland. The connection of the majority of this

[1] http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/tectrading/

generation is therefore dependent on completion of those works, as well as other Scottish mainland reinforcements[1].

The Orkney based projects have a total of 126MW of accepted generation capacity in the GB Queue. The accepted offer(s) are all based on a connection to the mainland network at Thurso. The connection capacity will not be available at Thurso until the following network reinforcements are complete:

1) Beauly-Denny line upgrade

2) Beauly-Dounreay line reconductoring

As the main application(s) were pre-BETTA, the connection(s) are not commercially dependent upon reinforcements to the Scotland/England inter-connectors or reinforcements within England.

Orkney has recently become the site of a Registered Power Zone (RPZ). This will allow the active management of the existing system and the existing 33kV cable circuits to the Scottish mainland. The active management maximises the renewable generation that can be connected on Orkney without requiring reinforcement of these cable links. The RPZ approach has only allowed 15MW of additional generation capacity to be connected bringing the total maximum generation capability to 45MW.

If the planned generation on Orkney reduces but is still more than the 15MW of new capacity available under the RPZ, then a new sub-sea cable will be required. The degree of reinforcement of the existing links to the mainland depends on the amount of additional capacity that is required[2].

If the total additional generation is less than 40MW, then it is likely that only an additional 33kV cable could be justified in terms of cost. Capacity requirements greater than this would require at least two 33kV cables, and so a 132kV cable is likely to be more cost effective. The installation of a 132kV cable would also provide significantly more additional capacity (90-180MW) than the corresponding two 33kV cables (40-60MW).

2.3.2 Shetland

There have been several applications for connection from prospective generators on Shetland, amongst these are the following projects:

- North Nesting (250MW)
- Viking (350MW)

There is no existing electrical connection between Shetland and the Scottish mainland or any other mainland networks[3]. All major schemes are therefore

[1] http://www.nationalgrid.com/uk/Electricity/SYS/ and SHETL consultation

[2] SSE Power Distribution RPZ annual report (www.ofgem.gov.uk)

[3] http://www.nationalgrid.com/uk/Electricity/SYS/ and SHETL consultation

dependent on the establishment of a sub-sea connection to the mainland as well as mainland network reinforcements. The Shetland based projects have a total of 600MW of capacity in the GB Queue. The accepted offers are based on connections at Thurso and Keith. The first half of connection capacity will not be available until the following network reinforcements are complete[1]:

1) Beauly-Denny line upgrade

2) Beauly-Blackhillock line reconductoring

3) Second circuit on the Beauly-Dounreay line

The second half of connection capacity will not be available until the following additional network reinforcements are complete[2]:

1) New Beauly-Keith line

2) Completion of 400kV SHETL ring

Both applications were pre-BETTA and therefore are not commercially dependent upon reinforcements to the Scotland/England inter-connectors or reinforcements within England.

SHETL has indicated that, because of the sequence of applications, original connection offers were made based on separate links from Shetland to Thurso and Blackhillock. Given that both offers were accepted, a more optimal combined Shetland link to Blackhillock/Keith is currently under consideration.

2.3.3 Western Isles

There have been several applications for connection from prospective generators on the Western Isles, amongst these are the following projects:

- South Lochs (250MW)
- Eishken (300MW)

The other major scheme, "The Lewis Windfarm" (650MW), will also be seeking a connection but has not yet submitted any connection application[3]. Therefore, as the situation stands, it will join at the back of the GB queue and so will be dependent on the known network reinforcement requirements as well as any Scotland/England inter-connector constraints.

There is an existing 33kV electrical connection between the Western Isles and the Scottish mainland via the 132kV overhead line across Skye. This is insufficient for the major projects proposed. All major schemes are dependent on the establishment of a sub-sea connection to the mainland as well as mainland network reinforcements. The Western Isles based projects have a

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[1] Consultation with SHETL

[2] Consultation with SHETL

[3] Consultation with 'The Lewis Windfarm' developers

total of 550MW of capacity in the GB Queue. The accepted offers are based on connections at Ullapool. The connection capacity will not be available until the following network reinforcements are complete, in addition to the new circuits from Lewis through to Beauly[1]:

1) Beauly-Denny line upgrade

2) Beauly-Blackhillock line reconductoring

The existing 550MW of accepted offers were pre-BETTA and therefore are not commercially dependent upon reinforcements to the Scotland/England inter-connectors or reinforcements within England. The additional required generation capacity for the Lewis Windfarm is not yet in the GB Queue. Therefore, at this stage, it is likely to be dependent on completion of the 400kV SHETL ring as well as possible upgrades to the Scotland / England inter-connector and parts of the England network[2].

2.3.4 Beatrice Offshore Wind-farm

There has been an application for a 1000 MW generation connection from an offshore wind-farm located in the Moray Firth[3].

This application was pre-BETTA and is therefore not commercially dependent upon reinforcements to the Scotland/England inter-connectors or reinforcements within England.

The Beatrice project holds a place in the GB queue, but the timescale for connection is beyond the period covered by National Grid's Seven Year Statement. The connection capacity is unlikely to be available until at least the following network reinforcements are complete, in addition to the new circuits connecting to the mainland:

1) Beauly-Denny line upgrade

2) Beauly-Blackhillock line reconductoring

3) New Beauly-Keith line

4) Completion of 400kV SHETL ring

2.4 Changes to the GB Queue

Currently, the GBSO is trying to 'shake the tree' by requiring generators to demonstrate their commitment to connecting. It is proposed that this will take the form of a User Commitment. This is described in the CUSC amendment proposal CAP 131.

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[1] Consultation with SHETL

[2] Consultation with SHETL

[3] http://www.nationalgrid.com/uk/Electricity/SYS/ and SHETL consultation

The CAP131 proposal requires the developer to put up £1/kW each year (to a maximum of £3/kW) prior to the Transmission Owner gaining consents for the reinforcement work. Once consents have been obtained, the developer will need to provide 1.5 times the final TNUoS charges for the connection in the 1st year, 3 times this TNUoS charge in the 2nd year, 4.5 times in the 3rd year and 6 times in the 4th year.

Although at present developers are required to provide a bond to cover the Final Sums Liabilities of their connection, the proposed User Commitment may require significantly more financial commitment 'up front'. A number of developers with existing connection agreements have indicated that their projects are either no longer economically viable, or are unlikely to obtain planning permission. Therefore, it is anticipated that they will either reduce their connection capacity or relinquish it altogether if such a user commitment becomes compulsory.

It is proposed that capacity made available by generators reducing or relinquishing their requirements would be offered to the next connecting party in the queue[1]. If they are in a position to accept an advancement of their expected connection date, then the capacity will be allocated to them, and their capacity offered in turn to the next party. Otherwise, it will be offered to the next party in the queue until a taker is found. If the capacity made available is less than the capacity required by the next party, then they will be offered a split connection with part of their capacity being made available earlier than the rest.

There is still debate on the issue of whether a development's planning status should affect its position in the queue for connection. At one stage, consideration was being given to a 'scorecard' system that tried to the rank the various projects (ARODG). However, little support was shown for this arrangement as it was considered to be very difficult to implement without discrimination[2].

There are also proposals from the Access Reform Options Development Group (ARODG) relating to a limited "connect and manage" approach[3]. Under this principle there would be scope to permit new renewable schemes to connect and generate to a managed extent after consent had been secured for the dependent system reinforcements, but before the reinforcements were necessarily complete. This proposal is to be the subject of a more formal industry proposal under the Connection and Use of System Code (CUSC).

[1] 'Proposal for managing access to the GB transmission system for existing users under BETTA: conclusion document', National Grid, July 2005

[2] "A framework for considering reforms to how generators gain access to the GB electricity transmission system", April 2006, ARODG

[3] "A framework for considering reforms to how generators gain access to the GB electricity transmission system", April 2006, ARODG

2.5 Regulatory issues affecting the Scottish Islands

It is important to understand the roles and responsibilities of the key industry participants, including the DTI, the regulator OFGEM, and the transmission and distribution companies. This is because their designated responsibilities and licence conditions have a significant impact on the way they treat all generation connections onto the Great Britain grid.

In March 2006, the Government announced that offshore electricity transmission would be subject to a price control regime. Regulation is being developed to allow electricity generated from offshore renewable sources to be transferred to onshore networks via a transmission connections. Ofgem and the DTI are developing proposals, which may have a potential impact on the Beatrice project[1].

The regulatory framework that will apply to Island connections is currently undecided. Therefore any assumptions about the applicable regulatory framework should be viewed in this light.

Ofgem also manages the Renewables Obligation but has stated clearly that it is outside of Ofgem's legal vire to provide a subsidy to renewable (or any other) generators.

The following are some of the key regulatory issues and proposed changes that either have had, or are likely to have, an impact on the Scottish Island connections.

2.5.1 Transmission Investment for Renewable Generation (TIRG)

In the last price controls in 2000, no allowances were provided for investment in transmission capacity required to accommodate increased levels of renewable generation. This was due to the significant uncertainty of both the likely level and pattern of the emerging renewable generation. The established incentives for investing to meet transmission user requirements also required adjustment given the introduction of BETTA.

Subsequently, it was felt that if the funding of transmission investment was not addressed before the next main price controls in 2006, it could hamper the transmission investment required to meet this demand. Consequent delays in the connection of new renewable generation would affect the ability to meet the RO. This could have a negative commercial impact on consumers, and so some form of mitigation was required.

The TIRG consultation process began in October 2003. This process was intended to consider the investment issues faced by the three licensed transmission owners. It was also to help determine whether each of the investment projects put forward by the transmission licensees could be justified in terms of reducing the cost of network constraints and transmission losses.

[1] http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/17689_199_06.pdf

Subsequently, the various transmission investment projects were categorised by the regulator, Ofgem, as follows[1]:

'Baseline' – these were projects that appeared to be clearly justifiable in terms of savings, constraints and other costs;

'Incremental' – these were projects where there was some uncertainty regarding the savings;

'Additional' – these were projects where there was significant uncertainty in terms of savings and a high risk to GB consumers. The risk was that the GB consumers might end up bearing the cost of assets that may not in the end be required.

Baseline projects would be funded through the TIRG revenue allowance arrangements. Incremental and Additional investment, however, could be considered at the next transmission price control review in 2006.

In the context of this study, the key projects that were classified as 'Baseline' were the Beauly-Denny line upgrade, and the preliminary inter-connector upgrades between Scotland and England.

At the time, Ofgem categorised the new connections to the Scottish Islands and some of the other SHETL planned reinforcements as 'Additional'. This is until such time as the parties triggering the reinforcements were prepared to underwrite the development costs.

2.5.2 Security Factors and Connection Charges

As part of its consultation on GB charging arrangements, the GBSO brought forward proposals for a "Plugs" model for connection charging. This is where the Plug comprises the single-user connection assets between the user and the grid substation. Substation assets would be no longer classed as connection assets, but instead would be classed as infrastructure and so their costs would be recovered via the TNUoS charge. Also, dedicated spurs to generators would also be classed as infrastructure[2].

These shallow connection charges significantly reduce the charges that generators would have to pay up front to connect to the transmission network. Ofgem considers that shallow connection charging arrangements promote effective competition. This is because they ensure that parties are not disadvantaged on the basis of when and where they connect to the network.

If the existing onshore arrangement applied to the islands, then new connections to the islands would be classed as infrastructure and would be recovered via the TNUoS charge. This would mean that island customers would pay the same charge whether they accepted a double circuit connection that meets the requirements of the Security and Quality of Supply Standard (SQSS)

[1] http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/9631_28804.pdf

[2] http://www.nationalgrid.com/uk/Electricity/

or requested a single circuit design variation connection and accepted the associated uncompensated access restrictions[1].

For the Scottish Island connections, the costs associated with the provision of additional circuits is so high that it may be more cost efficient to reduce the level of security provided, i.e. fewer circuits. Therefore the GBSO is currently consulting on the best way of changing the TNUoS charges to reflect the savings associated with reduced security connections through to the affected generators[2].

2.5.3 TNUoS Charges and s185

The calculation of the locationally varying element of TNUoS takes into account the cost of the circuit infrastructure required to cope with both intact and secured outage conditions. The secure outage condition is determined by applying the locational security factor[3].

Given the requirement for relatively stable cost messages, connection points are assigned to zones. The zonal marginal km are converted into costs and hence a tariff by multiplying by the annuitised value of the transmission infrastructure capital investment required to transport 1MW over 1km derived from the projected cost of 400kV overhead line and the locational security factor. Circuit expansion factors are used to model other circuit types (e.g. 275kV underground cable).

At present there are no expansion factors in use for undersea cables and so, to derive a tariff for the Scottish Islands, unit costs of the relevant undersea cable technology needed to be based on quotations from suppliers and previous project costs[4].

Due to the potentially high TNUoS charges that would result for the Scottish Islands, the Energy Act 2004 included Section 185 that introduces the concept of a reduction in TNUoS for these areas.

No specific detail was provided and so at present there are two options being discussed for the implementation of this reduction in TNUoS charges[5]:

(a) 50% of the value above £25/kW

(b) 50% of value above the highest existing charging zone (£20.52 for Northern Scotland)

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[1] http://www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc/

[2] http://www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc/

[3] 'Statement of the connection charging methodology', April 2006, NGT

[4] Consultation with NGT (GBSO)

[5] Consultation with NGT and SHETL

Therefore, if the full TNUoS charge for an Island Zone was £45/kW, then:

(a) the reduced charge would be £35.00/kW

(b) the reduced charge would be £32.76/kW

2.5.4 Firm / Non- Firm Connections

Generators that do not have any Transmission Entry Capacity (TEC) do not have any rights to export energy on to the transmission network. There are currently a number of short-term TEC products (Short term TEC and Limited Duration TEC) available. These products allow generators to connect and export prior to their enduring TEC becoming available. Generators with TEC have 'commercially firm' access rights, and these proposals would allow 'commercially non-firm' access rights.

These short-term access rights would allow a generator to connect to the network and export energy as long as capacity is available in operational timescales without exacerbating transmission constraints. It should be noted that these products are 'firm', albeit for a defined time period. 'Non-firm' products (where access can be withdrawn without compensation) are not seen as useful to users at this stage[1].

This could allow a more efficient use of the transmission network as it would allow more generation to access the network prior to completion of the required reinforcements. If more access were released by the GBSO ahead of the completion of the necessary reinforcements, then this would cause an increase in transmission constraint costs. Under the current arrangements these constraint costs would ultimately be picked up by electricity consumers.

However, the existing TEC trading arrangements still involve too much lead-time for any TEC trading based on wind forecasting to be of significant short-term use for most wind farms. There is also an unresolved issue for generation in Scotland with regards to the TEC exchange rate that would be applicable[2].

Due to the BETTA transitional arrangements, the Scottish system is not compliant with the GB SQSS due to the Scotland/England inter-connector constraints. Therefore, the TEC trading exchange rate between parties within Scottish transmission networks would be zero. There is obviously an issue that needs to be resolved for TEC trading between generators with TEC under the previous Scottish grid code and generators with TEC or connecting under the GB SQSS[3].

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[1] http://www.nationalgrid.com/uk/Electricity/gbagreements/

[2] http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/stfirm/

[3] Consultation with NGT (GBSO)

A final issue regarding non-firm connection is the level of generation that could be affected by a single unplanned network outage. At present the GB system carries 1320MW of primary response, which corresponds to the largest loss of a single source of generation that can be economically justified. A present, it is unlikely that the GBSO would allow for a level of generation greater than 1320MW to be connected in a non-firm manner behind a single point of failure. This means that the total non-firm generation in Scotland would be have to be less than 1320MW due to the Scotland / England inter-connector constraint[1].

2.5.5 Planning Consents

Each renewable energy generation project will require planning permission at the local authority level. Installations greater than 50MW will also require consent from the Secretary of State under Section 36 of the Electricity Act.

Consent is required for any overhead lines above 20kV under Section 37 of the electricity act.

As local planners will be looking at the full picture of how the schemes considered in this report are to be connected; developers are faced with a difficult decision:

- Should the developers wait until the required connections and reinforcements have been planned and consented under Section 37 before applying for consent for their project?

- Or should they apply for consent for their project with the risk that the connection options are not available if the Section 37 consent is not granted?

The first option requires a connection application and the associated final sums liabilities or user commitment. This involves significant financial commitment in advance of knowledge of whether their project will get consent.

The second option risks developers spending a significant amount of time and money getting permission for a project that can never connect.

[1] Consultation with NGT (GBSO)

3 Options for Connections

3.1 Overview

The initial phase of the study reviewed the GB transmission network through consultation with the relevant TOs. This identified suitable locations where it would be possible to connect a significant capacity from a subsea connection. This information, along with a view on possible network reinforcements, was fed into some preliminary analysis to produce a short-list of possible connection options for the island generation.

The short-list of includes those connections offered to the Island schemes, as discussed in Section 2. A number of the other locations on the short-list have the advantage of either a) avoiding capacity constraints in the network, or b) attracting lower Transmission Network Use of System (TNUoS) Charges.

As well as those options that were short-listed, a large number of other options were considered but they are not discussed in detail here. This is because they either have significantly higher TNUoS charges with no additional timescale benefits, or are not technically feasible with current technology.

The short-listed options are all shown on the map in Appendix A and are discussed further below.

Three key factors came out of the initial high-level analysis:

1) Due to the increasing utilisation factors on the existing transmission network, there are now few locations where significant levels of generation can connect without triggering reinforcements.

2) For low capacity-factor generation such as wind, it is more difficult to justify long connections due to the low connection asset utilisation. If there is sufficiently low correlation between different sources of renewable generation sharing a single transmission route, i.e. wind versus wave, then this might increase the utilisation of the link, albeit at the cost of some generation shedding.

3) Crucially, the majority of the island generation is “commercially firm” with respect to the most serious onshore transmission constraint - the Scotland-England inter-connector. This immediately removes a large commercial avoided-cost value from any justification of a long bypass link.

3.1.1 Cable Utilisation and Generation Diversity

The TNUoS charge is a fixed charge for the kW capacity of a generation connection. As this represents a fixed overhead for a generation project, a high utilisation of the connection is important to keep the cost per kWh to an affordable minimum.

To give an example of the effect of low utilisation, a 300 MW wind-farm on one of the Scottish Islands with a capacity factor of 40% may be expected to pay TNUoS charges of around £40/kW/year. The wind-farm will produce about 1,051,000 MWh of electricity and would pay £12,000,000 in annual charges. This equates to £11.41/MWh, which is a reasonably high percentage of the expected revenue from this generator.

As a comparison, a conventional generator located on the same Scottish Island with a utilisation factor of 90% would still have to pay the same high TNUoS charges, but would produce more MWh of electricity (2,365,200 MWh), so the cost per unit produced is only £5.07/MWh.

A similar wind-farm to the one described above, located on the mainland with a lower capacity factor of 30% will have lower TNUoS charges of up £20.52/kW/year leading to £6,156,000 of annual charges. It will produce about 788,400 MWh of electricity, bringing the unit cost to £7.81/MWh.

Increasing the diversity between generation sources is a possible way of increasing the utilisation of a network asset. The Scottish Island groups also possess significant wave and tidal energy resources, so there is the potential to improve connector utilisation by diversification of generation types.

The maximum increase in utilisation of the connector will be achieved if there is no correlation between the generation sources. The maximum utilisation is then calculated using a standard statistical approach that assumes the sources are independent variables, i.e. $u = \sqrt{c_1^2 + c_2^2}$. Therefore, if a wind-farm is 100MW with a capacity factor (c_1) of 40% and a nearby wave-farm is also 100MW with a capacity factor of 30% (c_2), the maximum utilisation of a 100MW connector might be 50% - higher than could be achieved by either generator on its own.

This increase in connector utilisation comes at the expense of increased energy shedding during high generation conditions. This may have a significant impact on the economics of the individual generation schemes and so needs to be considered carefully.

With wind, wave and tidal energy sources, it is likely that there is a non-zero correlation within a specific geographical area. As the degree of correlation increases, the connector utilisation will decrease and amount of energy shedding will increase. The only way to determine with any confidence the degree of correlation and potential energy shedding would be to perform a statistical analysis on generation profiles synthesised from measured data.

3.2 Mainland Grid Connections

3.2.1 Grid connections into Scotland

Each of the following connection options for the Island groups has been selected because it either:

a) provides the shortest practical offshore connection links or,

b) bypasses some or all of the required onshore reinforcements within the Scottish network.

The timescales and costs for the connection options are discussed and compared in Section 5 and associated Appendices.

1) Beauly
2) Cockenzie
3) Dalmally
4) Dounreay
5) Keith
6) Hunterston
7) Peterhead
8) Thurso

3.2.2 Grid connections into England and Wales

Each of the following options could potentially by-pass some or all of the required onshore reinforcements within the GB network, including the Scotland/England Inter-connector upgrades. This may allow more generation on the mainland to connect without increasing the level of constrained generation.

1) Deeside
2) Hawthorn Pit
3) Humberside
4) Walpole
5) Pembroke
6) Wylfa
7) Generic SouthWest
8) Generic SouthEast

In general, connections directly into the England or Wales networks yield little or no additional commercial benefit to island generators. This is because the majority of the projects are already in possession of connection agreements, which are not dependent on the Scotland/England inter-connector capacity.

There are two circumstances under which these connection options may yield benefits:

a) if they enable generators not already in the GB queue to obtain commercially firm connections

b) if they can yield significant timescale advantages by bypassing other long-lead-time transmission reinforcements.

The timescales and costs for these alternatives are discussed and compared in Section 5 and associated Appendices.

3.2.3 Grid connections into Northern Ireland and the Republic of Ireland

Discussions with Northern Ireland Electricity (NIE) and Eirgrid have indicated that there is little interest in promoting the connection of further wind generation into their systems as there is already a significant amount connecting into the relatively small island network.

They also indicated that a second inter-connector to Scotland would not provide any significant advantage, as the existing Moyle inter-connector is currently not fully utilised. There are future plans for a Dublin to North Wales inter-connector, however this is still only at the feasibility study stage and there is only limited publicly available information.

3.2.4 Grid connections into Norway

Discussions with the Norwegian System Operator, Statnett have indicated that there may be interested in an inter-connector from Scotland into its system.

Statnett indicated that such an inter-connector would be used as a method of balancing power both on a day-to-day basis and also on a more long-term energy contract basis.

In Norway, almost all the electricity is generated by hydroelectric power stations whereas, in the GB system, electricity is primarily based on thermal generation (coal, oil, gas or nuclear power). Each of these systems has their weaknesses and strengths; Norway cannot store fuel, so instead, water is stored in reservoirs. This allows the system to generate a lot of power over a short period of time, but it does not store sufficient water to maintain a high level of production over a long period of time.

The GB system, being predominantly a thermal based system, is in the opposite situation. The limiting factor here is establishing a production capacity that is large enough to match the highest consumption peaks. Also, with significant contributions expected from wind power in the future, the GB thermal plants may be required to provide higher levels of power balancing services than has previously been the case.

In recent years, the Norwegian power capacity has proven to be less than desired, especially on cold winter days with a high level of consumption. Norway has also gone from being an annual nett exporter of electrical energy to a predictable annual nett importer.

Statnett publications indicate that despite the current hold on the planned North Sea inter-connector and the installation of NorNed, an inter-connector with the Netherlands, there is still interest in another inter-connector with a predominately thermal network such as the GB system.

Previous studies by SKM for Tennet and Statnett on the NorNed inter-connector indicated that a 600MW inter-connector between Norway and the Netherlands could generate trade margins with a value of up to £60 million per year.

It is understood that the North Sea inter-connector that was planned between the North East of England and Norway was unsuccessful due to political rather than commercial, economic, technical or environmental concerns. With

Shetland as a mid point for this inter-connector some of these political issues may be negotiable.

A connection from Shetland directly to Norway is not seen as the most beneficial option for the generators in Shetland as Norway does not currently have any renewable obligation certificates (or equivalent) that provide incentives to renewable generation. Some system of green certificates to reward new renewable generation is going to be introduced, but Statnett could not clarify whether such certificates would be available to generators located outside of Norway.

It is anticipated that any possible inter-connector between Norway and Scotland would be operated such that the electricity generated by the Shetland wind turbines would be entered into the GB market (and so receive ROCs). The inter-connector could then be used for additional flows between GB and Norway depending on market conditions.

The main factor that should be taken into account with this inter-connector option is that with the existing constraints in the SHETL network, a connection to Norway could create additional burdens on the Scottish network. It may, though, on some occasions be beneficial, as export into Norway may partially relieve some constraints on the network, even if the power generated by the wind farms on Shetland is directed towards Norway rather than into an already constrained grid.

Further analysis of the utilisation of an inter-connector would need to be undertaken and discussions arranged with the TOs, the GBSO, and Ofgem to determine the way that it would be owned, financed and operated.

3.3 Orkney Islands Connections

The scenario being considered for Orkney is for the connection of an additional 200MW of generation. The short-listed connection options for Shetland are as follows:

1. Dounreay via Thurso
2. Joint connection with Shetland to Keith via Cullen

3.3.1 Orkney to Dounreay with landfall at Thurso

Technology Choices

A 132kV AC cable connection is the most suitable for a 200MW connection from Orkney to the mainland network. This is because the connection distance of 60km is sufficiently short to make it technically viable and cheaper than an HVDC scheme. Possible AC connection options include:

1) 2 x 100MW, 132 kV AC
2) 2 x 180MW, 132 kV AC

The first option would achieve the required capacity with some security of supply. However, as a large proportion of the connection cost is in the design, installation, and substation alterations, then option 2 would incur only a small incremental cost over option 1. This would also provide a higher degree of security. The required link capacity and length means that an HVDC link is unlikely to be economic or to be able to provide the same degree of security.

Offshore Routing

As the eventual location of the planned generation on Orkney is not known, the location of the landfall has been assumed to be on to the Orkney Mainland. Onshore connections to the eventual generation sites will need to be provided from this location.

A major factor to consider during cable routing in this area are the extremely high tidal currents, which predominate within Scapa Flow, Hoy Sound and the Pentland Firth. Any routing through Scapa Flow would necessitate transit across the Pentland Firth and the Outer Sound where spring tidal rates of between 6 and 10 knots occur together with overfalls and eddies which are extremely treacherous. Routing West through Hoy Sound will also encounter tidal flows in excess of 5kts and should be avoided.

The most feasible route appears to be to make a crossing from Orkney Mainland to Hoy in the area of Bring Deeps (four other telecommunication cables make this crossing) and then to route by Land across Hoy to Rackwick on the Western side of the Island of Hoy prior to an offshore route to Thurso passing clear to the West of the Pentland Firth where tidal streams would be expected to be less than 3 knots.

The land crossing on Hoy would cause significant issues as a National Scenic Area covers North Hoy. Hoy is also designated as a Special Area of Conservation and Special Protection Area.

The area to the West of Hoy is a restricted area to be avoided by vessels of more than 5000 G.R.T to avoid the risk of pollution. This applies to laden tankers and all other vessels carrying hazardous cargoes. It is also recommended that laden tankers not bound to or from Flotta and Scapa Flow should not transit the Pentland Firth against the tide or in restricted visibility or other adverse weather conditions.

An alternative, and Scottish Natural Heritage's preferred option, avoiding the additional land crossing on the Isle of Hoy, would be to route the Orkney landfall clear to the North of Hoy Sound[1]. This would increase the overall route length and so increase the expense. The nearest viable alternative would be Skail Bay. It is understood that BT have commissioned a cable route survey between Dunnet Bay and Skail Bay in the Orkneys. This is the route that would be recommended for further studies.

All cable routing areas would need to consider a number of European Protected Species such as dolphins, porpoises and whales.

Potential Landfalls

Four Potential Landfalls have been identified based on physical suitability. Two are on the island side and two on the UK mainland side.

[1] Consultation with SNH

There is also a potential landfall at Rackwick on the island of Hoy where there is an existing telecommunications cable. Landfall locations are sparse in this area and Rackwick is one of the few locations offering a small but exposed beach rather than a cliff coastline. If this location was chosen then landfalls would also be required on the other side of Hoy and on the Orkney Mainland Island but as four telecoms cables already make this crossing then suitable landfalls should be available.

The Bay of Skail is situated approximately 7½ miles (12kms) north of Hoy sound on the Orkney mainland and is the first available location where a cable landfall is possible. This site is also the planned landfall location for a BT cable.

Melvich Bay is the preferred landfall location on the Scottish mainland side due to proximity to a land connection to the grid near Dounreay.

The OS map extract in Figure 3.1 indicates that a suitable beach area exists there, allowing cable burial. It should have a reasonable degree of shelter. There is a small sand dune area beyond the upper beach at the head of the Halladale River. SNH have stated that unnecessary destabilising of the sand dunes will need to be considered during any detailed route assessment, and appropriate precautions taken.

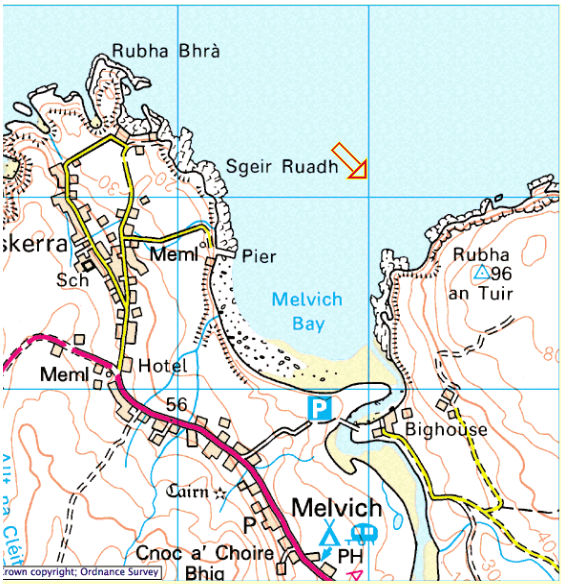

Figure 3.1 OS Map Extract - Melvich Landfall Option

The UKAEA undertakes an extensive beach monitoring programme using sophisticated vehicular radiation detection systems. Since 1999, these systems have regularly monitored five local beaches: Sandside, Crosskirk, Brims, Scrabster and Thurso. These are situated between 3 km west (Sandside) and 13 km east (Thurso) of Dounreay. Reassurance surveys of Melvich beach, some 10 km west of Dounreay, have been carried out on two occasions together with an extensive survey of Dunnet beach, approximately 23 km east of Dounreay. Cable landfall installation will undoubtedly be a sensitive subject anywhere in the vicinity of Dounreay, particularly in connection with disturbance to the seabed as a result of cable dredging and trenching work.

An alternative sheltered landfall site exists some 3 miles to the East of Thurso in Murkle Bay. This site is shown in Figure 3.2. The bay is a small inlet on the

South side of Dunnet Bay offering a sandy beach landing with agricultural land behind the beach. The bay already hosts a landfall to another telecommunications cable and alternative landing sites would appear to be plentiful within Dunnet Bay subject to any additional issues raised for environmental or tourism reasons.

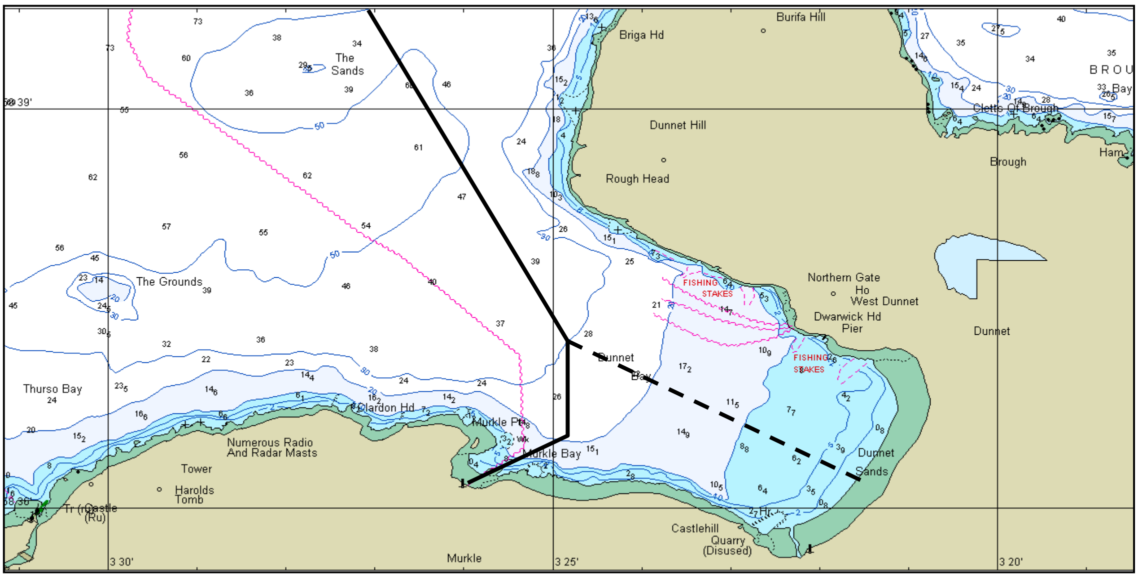

Figure 3.2 Muckle Bay Potential Landfall

In addition, the Farice-1 telecommunications cable was installed in January 2004. The cable runs between Seydisfjordur, Iceland – Funningsfjordur and the Faroe Islands - Dunnet Bay, Scotland. It is understood that this cable enters the bay on the NE side and a crossing would probably be required.

Fishing stakes to the North of the bay would also need to be avoided. Similar environmental concerns would be likely to be raised with respect to seabed disturbance relating to the possible existence of radioactive particles as in Melvich.

Onshore Routes

Landfall sites at either Melvich or Muckle Bay would require further onshore connections to the Dounreay site. This could either be via 132 kV overhead lines on lattice towers or if required (and economically justified) by underground cabling. As the installation of buried AC cable is significantly more expensive than overhead line then Ofgem would require a clear business case for the under-grounding of this section of line.

There are a number of environmental and or landscape designations that would need to be avoided:

Strathy Point AGLV, Dunnet Head AGLV, Dunnet Links SSSI, River Thurso SSSI, River Thurso SAC, Pennylands SSSI, Holborn Head SSSI, North Caithness Cliffs SPA, Ushat Head SSSI, Sandside Bay SSSI.

Onshore Reinforcements

Once this connection has reached the Dounreay substation, the generators will only have firm access to the network once some of the deeper onshore reinforcements have been completed. The generation on Orkney that is in the GB queue is reliant on the upgrade of the Beauly-Denny line as well as the reinforcement of the existing Beauly-Dounreay line. Any subsequent development greater than 10MW per site would be reliant on all of the above upgrades as well as the re-conductoring of the Beauly- Blackhillock line and the building of the new Beauly-Keith line, the creation of the 400 kV ring and upgrades to the Scotland/England interconnector.

Any potential additional developers would need to approach the GBSO to determine if short-term TEC products could be made available for their connection prior to all the required onshore reinforcements being completed.

3.3.2 Orkney/Shetland to Keith with landfall at Cullen

A joint connection linking Orkney and Shetland to Keith was the only other short-listed connection option that was considered in detail for Orkney. This is discussed in Section 3.4.3.

3.4 Shetland Islands Connections

The scenario being considered for Shetland is for the connection of an additional 600MW of generation. The short-listed connection options for Shetland are as follows:

1. Bergen (Statnett, Norway)

2. Keith

3. Orkney and then a joint connection on to Keith

Connections to Cockenzie, Hawthorn Pit, Humberside and Walpole were also considered but a connection of this length for the sole purpose of wind generation export was found to be an inefficient use of an expensive connection.

The connection to Dounreay via Thurso was not considered further because there would be insufficient capacity available at Dounreay, for a connection of 600MW, unless a new line was constructed from Dounreay to Beauly. This would be unlikely to result in a shortening of timescales or reduction in cost.

An alternative to onshore reinforcements would be to connect the Shetland generation into the Scottish System via a direct link. Then a ‘Bulk Transfer’ connection would be established from Peterhead into England. This would be a more efficient use of the connection asset as it would constitute a third Scotland-England inter-connector for the whole GB network.

In all cases, it was assumed that both projects in Shetland will co-ordinate their connection activities and request the transfer the connection offer of the smaller development from Dounreay to Keith. This approach would remove the delays and costs associated with the second circuit from Dounreay to Beauly.

It should be noted that the existing generation facility on Shetland is nearing the end of its economic life and needs either a complete refurbishment or replacement. With the development of renewable generation on the island and connections to the Scottish Mainland then it is possible that some of this expense may be avoidable. There is additional generation at the Oil Terminal – Sullom Voe - that could provide a small amount of back up generation.

To avoid replacement of the existing generation, any planned interconnection would need to comprise at least two independent circuits in order to provide the necessary security of supply for the existing demand customers. This is to ensure that quality of supply (voltage and frequency) can be maintained in the event of loss of a connection to the Scottish Mainland.

3.4.1 Shetland to Keith with landfall at Cullen

Technology Choices

A VSC based HVDC scheme is the most suitable for a 600MW connection from Shetland to a mainland network. This is because the connection distance of 300km is significant and the island network is very weak relative to the connection capacity. An AC cable option would not be suitable for this distance. Possible VSC HVDC connection scenarios include:

1) 2 x 300MW, ±300 kV DC
2) 2 x 500MW, ±300 kV DC
3) 1 x 600MW, ±300 kV DC

The multiple cable options would provide some security of supply, and would also allow for a staged installation if appropriate. If only a single link was installed, then the replacement of the existing conventional generation on Shetland could not be avoided. The impact of this on the investment case will be discussed further in Section 5.

Offshore Routing

The seabed for much of the route is expected to consist of a veneer of coarse sands and shells with outcrops of gravel. Gravel areas may well be environmentally sensitive and restrictions are in place to protect potential herring spawning grounds particularly in the outer Moray Firth. Government requirements with respect to seabed sampling or any seabed installation work will be an integral part of any survey or construction licence issued.

The approach to the South Moray coast avoids the Southern Trench where water depths in excess of 200 metres may be encountered.

The route crosses two in-service telecommunications cables, the Tat14 (Sprint) and the Atlantic Crossing 1 (AC1). In addition the out of service Tat 10b would also be crossed together with the main 30” 209km oil Trunkline which transports oil from the Piper field to the Talisman operated Flotta terminal.

There are Annex 1 habitats around the East Coast of Shetland, but Scottish Natural Heritage (SNH) has indicated that the cable could be routed so that it would not have a negative effect on them.

All cable routing areas would need to consider a number of European Protected Species such as dolphins, porpoises and whales, especially the Moray Firth Dolphins SAC and the cumulative impacts on these SACs as a consequence of other proposals e.g. the proposed Beatrice windfarm and oil/gas installations will also have to be considered.

Finally, the Moray Firth contains military firing practice areas, which could pose potential problems when laying the cable, especially if there are any unexploded munitions.

Potential Landfalls

Three Potential Landfalls have been identified based on physical suitability - one on the island side and two on the mainland side.

The West Voe of Skellister on Shetland is a sandy bay sheltered from most directions with road access at the head of the beach. A landing site here would be located close to the proposed wind farm development sites.

Cullen is the eastern of two potential landfalls identified on the South Moray coast. The bay offers shelter from all winds with a southerly component.

An alternative landfall has been identified further to the west in Spey Bay although this may be more environmentally sensitive than Cullen. This is because there is a SSSI designation on the western side of the Bay, with much of the bay also designated as a Site of Interest to Natural Science. The least environmentally sensitive area of Spey Bay is likely to be the beach at Portgordon as it has fewer designations associated with it.

The landfall at Cullen is shown in Figure 3.3.

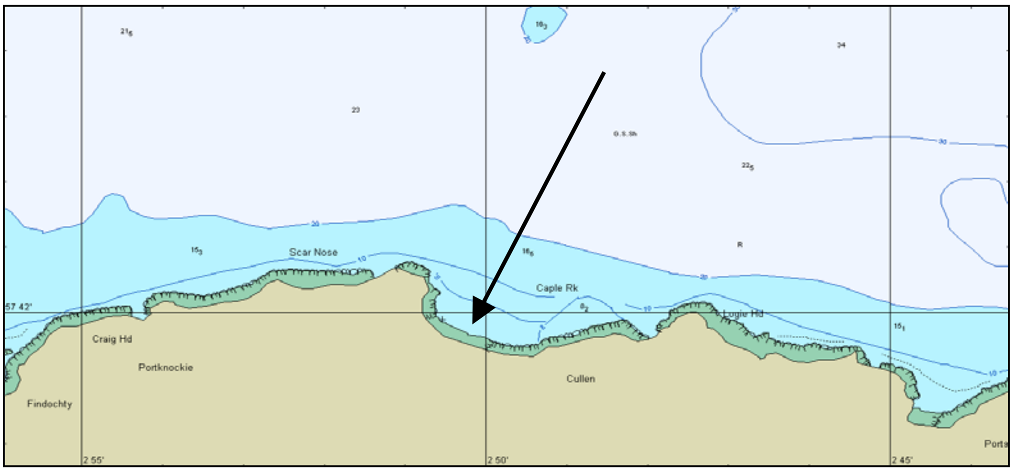

Figure 3.3 Landfall Option - Cullen

Onshore Routes

The route from Cullen / Spey Bay to Keith can mostly follow the existing B roads – the B9018 or B9016 - by burying the HVDC cable in the road verges. This will avoid the need for overhead lines in a relatively sensitive area.

There are a number of environmental and or landscape designations that would need to be avoided during any detailed route design: River Spey SAC, Spey Bay

SSSI, Spey Bay SINS, Garden and Designed Landscape near Fochabers, The Cullen Bay AGLV, and the Cullen Conservation Area.

Onshore Reinforcements

Once the connection has been established between Shetland and the Keith substation, the Shetland generation will only have firm access (TEC) to the network once some of the deeper onshore reinforcements have been completed. The reinforcements required are dependent on the position of each generation development in the GB Queue.

The first block of TEC is reliant on the upgrade of the Beauly-Denny line, the addition of a second circuit on the Beauly-Dounreay line and the re-conductoring of the Beauly-Blackhillock line. The Beauly-Dounreay reinforcements may not be required if the connections are combined and the connection is moved to Keith rather than Dounreay.

The second block of TEC is reliant on all of the same reinforcements as well as the construction of the new Beauly-Keith line and the completion of the SHETL 400 kV ring.

If this connection route were chosen then the developers could enter into talks with the GBSO to determine if any short-term TEC products could be made available for their connection prior to all the required onshore reinforcements being completed.

3.4.2 Shetland to Keith and Norway

Technology Choices

This connection considers a combined generation connection and inter-connector between Scotland and Norway. The connection from Shetland to Scotland will cater for the 600MW of generation to be exported from Shetland along with 400MW from Norway to Scotland via Shetland.

In the event of an outage on the connection to Scotland, the connection to Norway would provide an alternative route for import and export of power for the Islands. The 400MW of capacity between Norway and Scotland could be traded independently of the Shetland generation, thereby increasing the inter-connector utilisation.

The links between Shetland and Scotland and Shetland and Norway would both be approximately 300km in length. For this distance and considering the weak island mid-point VSC HVDC is the most suitable technology. The scenario considered involves a 1000MW ±300 kV DC link from Shetland to Keith, and a 400MW ±300 kV DC link from Shetland to Norway.

An AC cable would not be suitable at this distance. Moreover, the Shetland network characteristics are not suitable for AC connection, or the inter-connector power-flow control requirements.

Offshore Routing

The routing and landfalls for the Shetland-to-Keith part of the route has been discussed in section 3.4.1. The route and landfalls for the Shetland to Norway part of the route has not yet been investigated. This is because discussions with Statnett have not yet identified the most suitable location for connection into its network. However, it is believed that a suitable connection might be located somewhere between Bergen in the North and Stavanger in the South.

Onshore Reinforcements

As discussed in the previous option, once this connection has reached the Keith substation, the generators will only have firm access to the network once some of the deeper onshore reinforcements have been completed.

This connection option does have the advantage that if the network in Scotland is fully constrained, then there may be potential for some of the generation to be sold into the Norwegian network. Any renewable generation sold into Norway would not be eligible for ROCs. However, there may in future years be a similar product or possible carbon trading revenue.

Statnett stated that major reinforcements would not be expected for the connection of a 400 – 600 MW inter-connector in the Fjordland part of the Norwegian network.

The commercial and regulatory arrangements for the inter-connector would need to be the subject of further study, and they are discussed in section 3.1.3.

3.4.3 Shetland to Keith via Orkney

Technology Choices

This connection scenario investigates the option of connecting Shetland and Orkney into the same point on the mainland network. The proposed connections will be in a triangle configuration with the following VSC HVDC $\pm$300kV links. The link capacities take advantage of the standard block sizes available from a specific equipment supplier. It may be possible to eliminate one of the HVDC converter stations on Orkney if a multi-terminal HVDC link is practicable.

Shetland to Keith	300km	1 x 500MW
Shetland to Orkney	200km	1 x 500MW
Orkney to Keith	125km	1 x 500MW

Under normal operating conditions, generation can flow from Shetland directly to Keith and via Orkney, picking up the generation from Orkney on the way. In the event of a fault in one of these connections, then the generation from both Islands would still be able to flow in the other connection, but with a reduced capacity available.

The use of smaller capacity HVDC links would be difficult due to the length of the link. The multiple cable option also provides a reasonable level of security of supply for the Island networks. This approach allows for the staged installation of the inter-connectors as capacity is required. If only one link was installed then the replacement of the existing generation on Shetland could not be avoided.

An AC cable would not be suitable for this distance.

Offshore Routing

The routing for this connection would follow the a similar routing as described for the previous option, except that an additional land-fall will be required either on the East coast of the Orkney mainland or on South Ronaldsay.

Potential Landfalls

Potential Landfalls on the Orkney mainland would possibly be into Deer Sound, although this has been identified by SNH as a sensitive bird area. There are also sensitive sand dune systems in the area and a number of Sites of Local Nature Conservation Importance located in this area.

An alternative landfall on South Ronaldsay would be at Newark Bay. However this location has a number of Sites of Local Nature Conservation Importance and a SSSI at Denwick. A detailed search for marine and offshore sensitivities has not been undertaken in this area.

Onshore Reinforcements

Once this connection has been established to the Keith substation, the generation will only have firm access to the network once some of the deeper onshore reinforcements have been completed. The reinforcements required depend on the position of generation development in the GB Queue.

All developments on the Islands that are in the GB Queue are dependent on the Beauly-Denny line upgrade. If the Orkney connection is changed from Dounreay to Keith, then it would not be dependent on the reinforcement of the Dounreay to Beauly line.

The first block of TEC would probably be available once the Beauly-Denny line upgrade has been completed. The second block of TEC would be available once the Beauly-Blackhillock line has been re-conductored. The third block of TEC would only be available once the new Beauly-Keith line and the SHETL 400kV ring had been completed.

If this connection route were chosen then these developers could enter into talks with the GBSO as the system operator to determine if short-term TEC products could be made available for their connection prior to all the required onshore reinforcements being completed.

3.5 Western Isles Connections

The scenario being considered for the Western Isles is the connection of an additional 1000MW of generation. The short-listed connection options for the Western Isles are as follows:

1. Lewis to Beauly via Ullapool
2. Dalmally via Oban
3. Hunterston
4. Deeside

Connections to Wylfa (Anglesey) and Pembroke were also considered, but the available capacities at these points in the network are very dependent on other generation connections. This means that the increased cost of connection was highly unlikely to be outweighed by increases in available network capacity. This is especially the case as this connection would see a low utilisation due to the low capacity factor of wind generation.

A connection to the Northern Ireland Electricity (NIE) network was also considered, but with the current very high level of wind generation applications in Northern Ireland and the Republic of Ireland, an additional connection of this size was unlikely to be feasible or achieve any timescale improvements.

3.5.1 Lewis to Beauly with landfall at Ullapool

Technology Choices

A VSC based HVDC scheme is the most suitable for a 1000MW connection from Lewis to the mainland network. This is because the connection distance of 80km would be very long for subsea AC transmission, and the island network is very weak relative to the connection capacity. Possible VSC HVDC connection scenarios include:

1) 3 x 350MW, ±150 kV DC
2) 2 x 500MW, ±150 kV DC

The multiple cable options would provide some security of supply, and would also allow for a staged installation based on when capacity was required.

Offshore Routing

The various offshore routing options between Stornoway and Ullapool are shown in Figure 3.4. These are based on two potential landfalls close to Stornoway and two potential landfalls close to Ullapool. Offshore route lengths vary between 79.2 km (Chubag Bay to Ullapool) and 83.0 km (Gress to Ardmair).

The cables would have to cross the North Minch in water depths of up to 120m. Seabed sediments are likely to be mixed - predominantly sands, mud, shells and gravel. Areas of rock outcrops would need to be considered in a detailed routing study with the final route selected providing a minimum of 1 metre of surficial sediment where possible.

The North Minch area is designated as a military practice area with submarines exercising both on the surface and submerged. Liaison with the Navy would be essential during offshore operations.

In addition, there is likely to be one or more marine SPA proposals for the Minch. There are also mammalian wildlife issues within the Minch and around the Summer Isles. These will require detailed consideration during any EIA application.

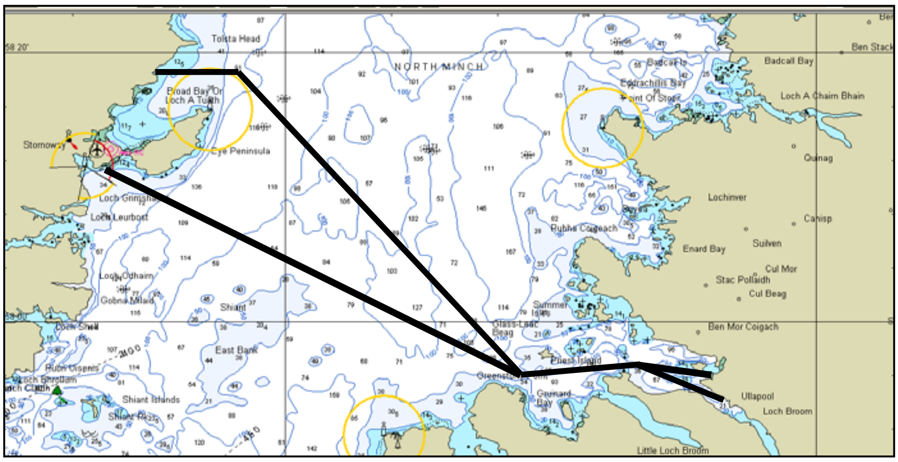

Figure 3.4 Offshore Route Options – Stornoway to Ullapool

The Beaufort Dyke, a deep water trench located just North of the Isle of Man between Scotland and Ireland, has been used in the past as a dumping ground by the Ministry of Defence. It measures more than 50 km long and 3.5 km wide, and there is reported to be in the region of 1.17 million tonnes of explosives dumped there. Sea disposal of munitions continued until 1972 when agreements were reached in two International Conventions to control the dumping of materials at sea.

In 1995 large numbers of incendiary devices were discovered around the coastline of the Firth of Clyde and adjacent areas. The discovery of these stranded devices coincided with the laying of a submarine gas pipeline linking Scotland to Northern Ireland. The gas pipeline passes to the North of the Beaufort's Dyke explosives disposal site. Whilst the study area in the North Minch lies significantly to the North of the Beaufort Dyke, there is still a risk of encountering explosives and incendiary devices during route surveys and the subsequent cable installation. As a result, special procedures would be required to ensure the appropriate actions are taken if ordnance is encountered.

Potential Landfalls

Three Potential Landfalls have been identified based on physical suitability - two on the island side and one on the mainland side.

Chubag Bay and Gress are the preferred locations on the island as they offer sandy bays with deep water relatively close to shore.

Chubag Bay lies approximately 2¼ miles SE of Stornoway and offers good shelter from all sectors apart from the South. The landfall indicates that a sandy beach and foreshore area is available with a potential for an onshore route link through farmland with road access close by at Holm.

An alternative landfall has been located approx 1.5 miles NE of Gress on the northern side of Broad Bay and 8 mile NE of Stornoway however, this is located in the Gress Saltings SSSI and impacts to this designation will need to be avoided if possible.

Cable or network links from the windfarms to either landfall points on Lewis will also need to minimise risk to birds and avoid potential impacts to the Lewis Peatlands SPA, SAC and Ramsar. The presence of abundant hydrology and hard geological strata mean that under-grounding will be a very expensive option. However detrimental impacts to the South Lewis, Harris and North Uist NSA will also need to be minimised.

Ardmair is the preferred location on the mainland as it avoids the congestions of Loch Broom and Ullapool itself.

Ardmair bay is situated approximately 2¾ miles NNW of Ullapool and to the North of the entrance to Loch Broom. The bay appears to offer a good landfall opportunity with the A384 road at the head of the beach. The close locality of Priest Island SPA and presence of marine mammalian fauna will need consideration during any detailed cable routing, as will the presence of shellfish and salmonoids.

Onshore Routes

The route from Ardmair to Beauly can mostly follow the existing A road – the A835 - by burying the HVDC cable in the road verges. This will avoid the need for overhead lines and new rights of way across relatively remote terrain. However, an underground line from Ardmair to Beauly would cross numerous watercourses, posing technical problems. In addition, some of the watercourses contain important populations of freshwater pearl mussels, which could be negatively impacted depending on the crossing method chosen. This route also runs through a Wild Land Search Area although as the proposed route is next to the road this is unlikely to impact upon the route choice.

There are a number of designations that will have to be taken into account when choosing the final route for this option including: NSA's to the north and south of Loch Broom (Wester Ross & Assynt-Coigach NSAs); Beinn Dearg SPA and SAC; Fannich Hills SAC; Ben Wyvis SAC & SPA; Loch Ussie SAC; Conon Islands SAC; Inner Moray Firth SPA; Rubha Dunan, Cailleach Head; Creag Chorcurach, An Teallach, Dundonnell Woods and Corrieshalloch SSSIs; and the North Highland AGLV covering Beinn Dearg and Fannich Hills.

Onshore Reinforcements

Once the connection has been established to the Beauly substation, the generation will only have firm access (TEC) to the network once some of the deeper onshore reinforcements have been completed. The reinforcements required depend on the position of generation development in the GB Queue.

The first block of TEC would probably be available once the Beauly-Denny line upgrade has been completed. The second block of TEC would be available once the Beauly-Blackhillock line has been re-conductored. These two blocks would provide for a total of 550MW of TEC against the anticipated requirement of 1000MW. At this stage any additional TEC allocation is likely to require completion of the 400kV SHETL ring as well as any reinforcements required to the Scotland/England inter-connector.

If this connection route were chosen then any developers not in the GB queue would need to enter into talks with the GBSO to determine if any short-term

TEC products were available. This would be necessary for them to start generation prior to the required onshore reinforcements being completed.

3.5.2 Lewis to Oban and on to Dalmally

Technology Choices

A VSC based HVDC scheme is the most suitable for a 1000MW connection from Lewis to the mainland network. This is because the connection distance of 180km is not practicable for subsea AC transmission, and the island network is very weak relative to the connection capacity. The VSC HVDC connection scenario considered is:

1) 2 x 500MW, ±150 kV DC

This multiple cable option would provide some security of supply, and would also allow for a staged installation based on when capacity was required.

Offshore Routing

A potential route linking South Harris with Oban has been identified with a landfall in South Harris and several potential landfall sites close to Oban on the Scottish Mainland (Figure 3.5). The South Harris landfall is adjacent to an existing telecommunications cable at Loch Geocrab.

As discussed in Section 3.5.1 any impacts to the proposed Minch SPA and marine mammalian fauna will need careful consideration as will the submarine exercise area in the Minch.

Routing through the sound of Mull is technically feasible, although may be challenging. A preliminary route is shown in Figure 3.6. Special attention will be needed when routing through the overfalls in the Firth of Lorne and the extremely rocky NW approaches to the sound (highlighted in red circles on the drawing). Routing has been developed to minimise the effects of tidal currents as far as possible. On-bottom cable stability will be a major problem in this area and installation costs are likely to be very high. During detailed route design notice would need to be taken of a number of SACs on the mainland coast, for example the Lismore Lochs SAC.

On exiting the Sound of Mull to the NW, the cable route passes to the north of the Island of Coll across a rugged seabed with water depths ranging between 25 and 100 metres. Due to this rugged seabed, burial is likely to be problematical in this section. The route then passes to the north of Hawes bank and the SW of Oigh Sgeir to avoid Mill Rocks and associated heavy seas during gales. Routing becomes slightly easier with a less rugged seabed as the cable heads north into the Little Minch and the landfall in Loch Geocrab, South Harris.

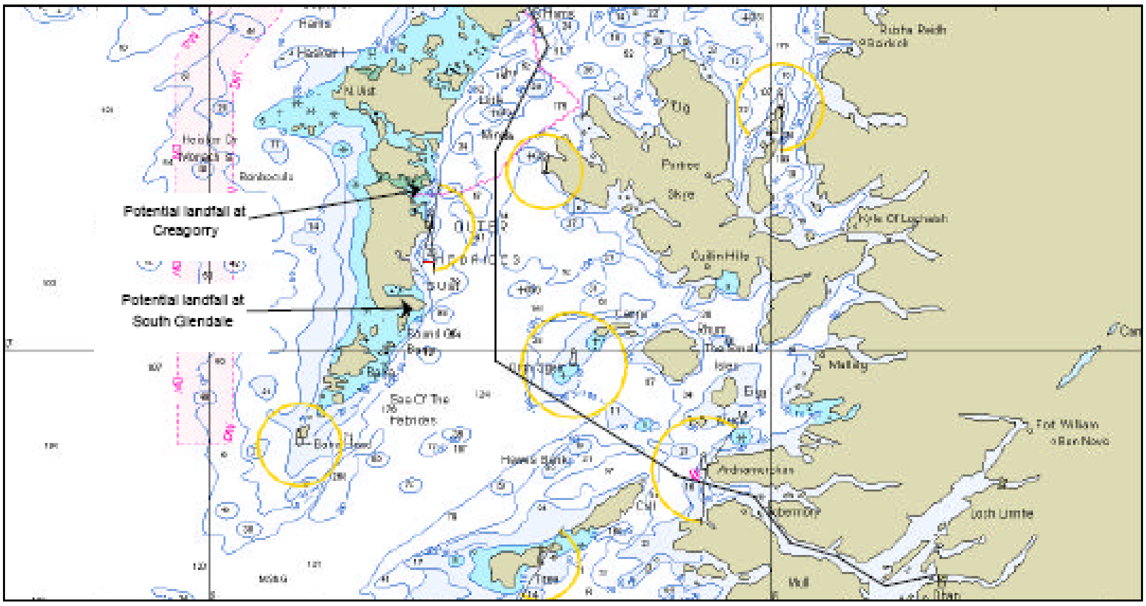

Figure 3.5 Route Overview Western Isles to Oban

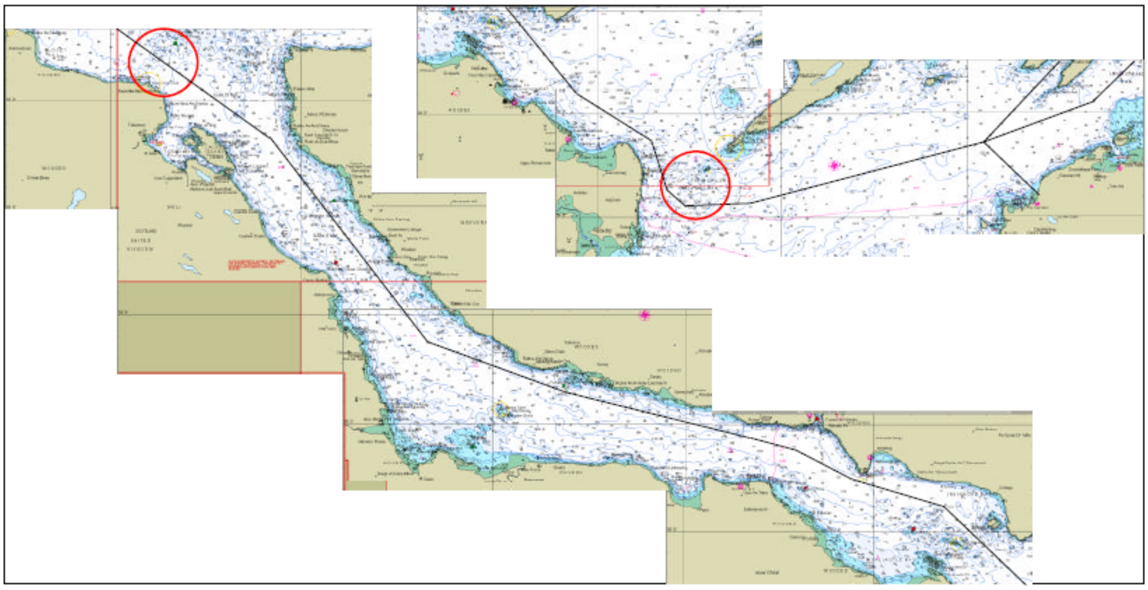

Figure 3.6 Potential Cable Routing Through the Sound of Mull

Potential Landfalls

Three Potential Landfalls have been identified based on physical suitability, one on the island side and two on the mainland side.

Loch Geocrab (South Harris) is the preferred location on the island as it there is already a telecommunications cable landed there. The presence of fixed floating fish farms together with the proximity of this telecommunications cable would need to be considered carefully. In addition, the location of offshore Annex 1 reefs around South Harris and the Uists will need consideration as will the sensitive on-shore environmental and landscape issues relating to the interconnection of the wind farms to the South Harris landfall exit.

Ganavan Bay is the preferred location on the mainland. Although there are other potential landfalls at Ardmucknish Bay and Camas Nathais Bay, these have significant tourist and environmental pressures associated with them due to caravan sites, yacht anchorages and shellfish growing sites.

Ganavan Bay is situated a mile north of Oban and offers good physical attributes for a potential cable landing. The admiralty chart indicates that two disused cables and one in-service cable to Mull make landfalls in this location.

Onshore Routes

The route from Ganavan Bay to Dalmally can mostly follow the existing A road – the A85 - by burying the HVDC cable in the road verges. This will avoid the need for overhead lines and new rights of way across relatively remote terrain.

There are a number of designations that will have to be taken into account when choosing the final route for this option including: The NSA to the north near Acnacroish; an AGLV at Benderloch area to the north; the Loch Etive Woods SAC; SSSIs along the south coast of Loch Etive near Taynuilt and possible sensitive bird areas near Firth of Lorn.

Onshore Reinforcements

Once this connection has been established to the Dalmally substation, the generation will only have firm access to the network once the reinforcement of the existing Dalmally line has been completed. The existing double circuit line currently has a summer circuit rating of 620 MW and a combined existing generation capacity of 500 MW. This generation consists of the Pumped Storage Power station at Cruachan and the existing wind and hydro generation in the area.

There are also up to 280 MW of additional wind generation schemes requesting connections in this area.

The conductor on these lines can be replaced with the “Rubus” type, increasing the summer circuit rating to 1200 MW. This would allow an additional 420 MW of firm generation to connect, and up to 1200 MW of additional non-firm generation. This would require alterations to the tower foundations and so may require planning permission.

If this connection route were chosen, then the first block of TEC would be available once the Dalmally reinforcement was complete. The second block of TEC may be offered as partially firm connection, with 170 MW firm and the remainder reliant on outages on this reinforced Dalmally line.

Any additional non-GB queue generation on Lewis may be offered a non-firm connection, reliant on the outages on the line. However, this would also be dependent on any required deeper reinforcements within the Scottish and England networks. They would need to enter into talks with the GBSO to determine if short-term TEC products would be available prior to all the required onshore reinforcements being completed.

3.5.3 Lewis to Hunterston

Technology Choices

A VSC based HVDC scheme is the most suitable for a 1000MW connection from Lewis to the mainland network. This is because the connection distance of 420km not practicable for subsea AC transmission, and the island network is very weak relative to the connection capacity. The VSC HVDC connection scenario considered is:

1) 2 x 500MW, ±300 kV DC

This multiple cable option would provide some security of supply, and would also allow for a staged installation based on when capacity was required.

Offshore Routing and Potential Landfalls

An approach through the Firth of Clyde would be likely to be the most direct routing for this option. However, there are numerous issues to evaluate and areas to avoid including designated shipping lanes, designated anchorages, existing submarine cable routes, military practise areas, disused explosives dumping grounds and ferry routes.

The departure of the cable from Lewis or South Harris will need to consider all the same issues raised in 3.5.1 and 3.5.2 (above). In particular, if the cable is routed close to the Shiant Isles, then consideration should be given to impacts on the imminent creation of a marine SPA.

An alternative route would be to cross Kintyre but this should be the subject of further consideration, as it would involve 2 additional landfalls, challenging routing and the crossing would be subject to SAC designations.

There are two Advanced Gas Cooled Reactors at Hunterson ‘B’ complex and a neighbouring wind farm, which is located 2 miles (3 km) northwest of West Kilbride on the North Ayrshire coast facing the island of Little Cumbrae. Connection into the existing grid would be relatively straightforward at this point. The recent announcement of the early closure of one of the reactors at Hunterston is beneficial for the connection, therefore landfalls in this vicinity would be advantageous.

The landfall selection should avoid the proposed developments at the Hunterston container terminal immediately to the North of the power station site in Fairlie Roads. These developments extend to the disused marine construction yard and the coal jetty. Similarly a landfall further South at Farland Head, Portencross may impact with two existing telecommunications cable landfalls.

One potential landfall site would to the South of Hunterston and is marked on the admiralty chart extract (Figure 3.7). Dredging and trenching associated with a cable landfall is likely to give rise to environmental concerns in any location in this area.

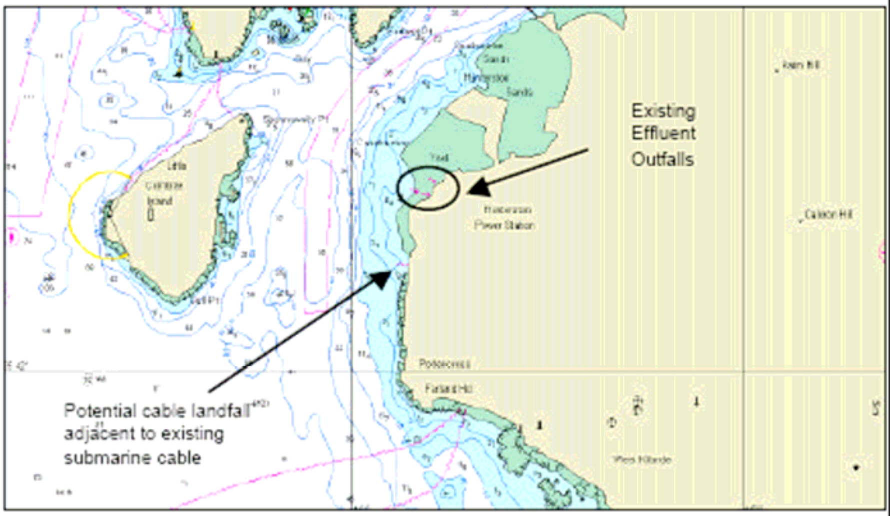

Figure 3.7 Marine Approaches to Hunterston Power Station

Onshore Reinforcements

Once this connection has been established to the Hunterston substation, the generators would have firm access to the network, subject to a few reconfigurations of the system. There are no significant reinforcements of the network within Scotland anticipated. Any projects not already in the GB queue are likely to still be subject to the capacity constraints on the Scotland/England inter-connectors. They would still need to enter into talks with the GBSO to determine if short-term TEC products could be made available for their connection prior to all the required onshore reinforcements being completed.

3.5.4 Lewis to Deeside

Technology Choices

A VSC based HVDC scheme is the most suitable for a 1000MW connection from Lewis to the mainland network. This is because the connection distance of 600km not practicable for subsea AC transmission, and the island network is very weak relative to the connection capacity. The VSC HVDC connection scenario considered is:

1) 2 x 500MW, ±300 kV DC

The multiple cable option would provide some security of supply, and would also allow for a staged installation based on when capacity was required.

Offshore Routing

A preliminary route running to the South of the Isle of Man is shown in Figure 3.8. The route exits the inter-tidal section of the River Dee and leaves the Hamilton and Douglas oil and gas fields in Morecambe Bay to the South. Water depth in this section is generally less than 50 metres with a predominantly sandy seabed. The route then turns northwest clear to the SW of the Calf of Man, an area of locally high tidal streams, before entering the North Channel.

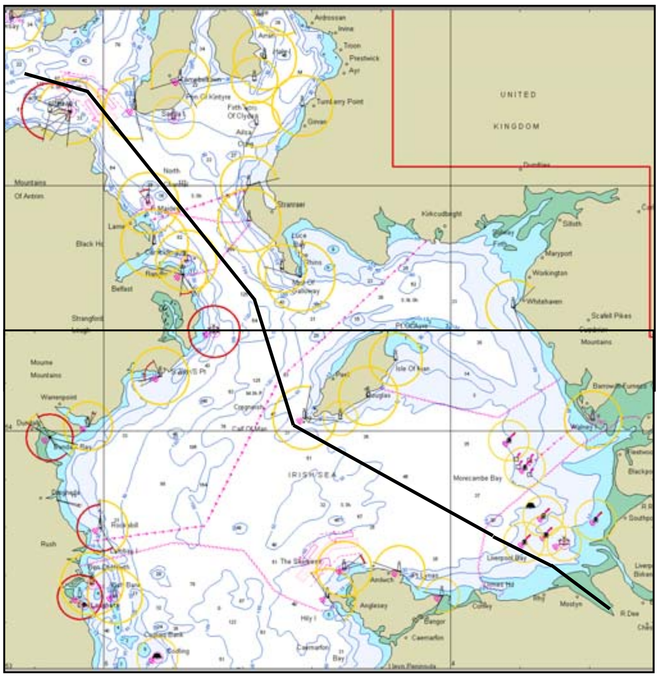

Figure 3.8 Preliminary Routing, Western Isles to Deeside

The Southern section of the North Channel and its approaches predominantly comprises a soft fine sandy seabed. Water depth is this section increases to a maximum of 125 metres, the route avoiding localised depressions. This location is a designated submarine exercise area. The route passes clear to the west of the Beaufort's Dyke, which has been previously discussed in the evaluation of the Western Isles to Ullapool route in section 3.5.1. It is recommended that the route is run in the centre of the shipping lane traffic separation zones through the North Channel narrows.

Much of the River Dee consists of tidal sandbanks and mudflats and the final 22 km of the route into the power station site dries. The shifting nature of the sandbanks in the estuary and strong tidal streams are a feature of the estuary with implications during cable installation and burial.

As a result, a shallow water lay vessel would be required to lay and bury this section. The offshore end of the cable would then be collected from the offshore vessel, and a connection made prior to laying away into Morecambe Bay.

Potential Landfalls

At Deeside, a short section (approximately 1.2 km) of salt marsh would need to be crossed at the landfall in order to reach a termination point in front of the power station. There appears to be sufficient room to lay the cable immediately to the NW of the north training wall at the entrance to the Dee River canalised section. This would minimise impact with local marine traffic.

Onshore Reinforcements

Once this connection has been established at the Deeside substation, the GBSO Seven Year Statement indicates that there may be capacity available for the generators to gain access to the network. As the capacity of the North to Midlands Boundary only just exceeds the planned and probabilistic transfers, this capacity is by no means certain.

If there is no firm capacity available, then the generators will have to wait for deeper reinforcements to be undertaken on the Legacy to Ironbridge and Macclesfield to Cellarhead lines. Generators would have to enter into talks with the GBSO to determine if short-term TEC products could be made available prior to all the required onshore reinforcements being completed.

This option is worth considering further as the capacity availability in this area of the network is still considerably higher then anywhere in Scotland.

3.6 Beatrice Offshore Windfarm Connections

The scenario being considered for the Beatrice offshore windfarm is for the connection of 1000MW of generation. Although this project has capacity booked in the GB queue, as of yet, there is no anticipated date for the capacity to be available. This is due to the uncertainty surrounding the levels of generation and network configuration at the point in time when Beatrice will be seeking connection. Although this project is not (commercially) dependent on the Scotland/England inter-connector, it is possible that further delays may be encountered if additional network reinforcement is required in the SHETL area.

The scheme developed to minimise this delay risk involves a connection from the offshore windfarm to Keith with landfall at Cullen. Then a ‘Bulk Transfer’ link from Peterhead would be established allowing all generation from Northern Scotland direct access to a point south of the anticipated network constraints. The ‘Bulk Transfer’ links are discussed in further detail in Section 3.7.

3.6.1 Beatrice to Keith

Technology Choices

The connection of a 1000MW offshore windfarm 25km from shore can be reasonably achieved with 6 × 180MW 132kV AC cables.

The 180MW 132kV cable is the most practicable high power AC subsea cable available and so a connection with fewer than six cables would not be possible at present. The multiple cable option would provide reasonable security of supply and would also allow for the staged installation of capacity.

Offshore Routing

The offshore routing will depend on the location of the offshore wind-farm substation platform(s), but should take into consideration the locations of the pipelines and telecommunication cables as described in Section 6.3.1.

Potential Landfalls

The landfalls at Cullen and Spey Bay discussed in Section 3.4.1 would also be suitable for this connection.

Onshore Routes

The route from Cullen or Spey Bay to Keith would need careful consideration. It could be achieved with a new 132/275 kV substation at the landfall site and a double circuit 275 kV overhead tower line into Keith. The alternative is to continue the under-grounding of the six cables from the landfall site into the Keith substation. The under-grounding option would require a very wide corridor to enable the required spacing between the circuits, and would cost significantly more than an overhead line. An economic and environmental analysis of the benefits and impacts would need to be undertaken to determine the most satisfactory option.

All cable routing areas would need to consider a number of European Protected Species such as dolphins, porpoises and whales, especially the Moray Firth Dolphins SAC. The cumulative impacts on these SACs as a consequence of other proposals e.g. Shetland connections and oil/gas installations will also have to be considered.

Also, the Moray Firth contains military firing practice areas, which could pose potential problems when laying the cable, especially if there are any unexploded munitions.

Onshore Reinforcements

Once this connection has been established at the Keith substation, firm access to the network will be dependent on completion of the reinforcement works. At present, these works would include the following reinforcements; the Beauly-Denny line upgrade, the Beauly-Blackhillock re-conductoring, construction of the new Beauly-Keith line, and the completion of the 400 kV SHETL ring.

If no firm capacity is available then the project would have to wait for the necessary deeper reinforcements to be undertaken and completed. It would also have to enter into talks with the GBSO to determine if short-term TEC products were available prior to all the required onshore reinforcements being completed.

3.7 A Third Scotland / England Inter-connector

Although this is not strictly a part of the connection of the Scottish Islands to the mainland grids, the issues surrounding capacity on the Scotland/England interconnection is a key issue for renewable generation in Scotland. Some of the Island projects are subject to potential delays from major deep network reinforcements. This will particularly be the case if the capacity of the 400kV SHETL ring or the reinforced Scotland / England interconnector is exceeded.

Developing long dedicated subsea connections from the Islands to the south of the GB network to bypass such constraints does not make good economic sense due to their low utilisation. A more appropriate use of such an asset would be for the strategic benefit of the whole GB system in the form of a third Scotland/England inter-connector. By interconnecting the North of Scotland with England with a direct subsea HVDC link of sufficient capacity, it may be possible to relieve some of the onshore transmission constraints, thereby allowing increased levels of generation to connect in Scotland and Northern England.

Such an approach may avoid the need to install a new overhead 400kV twin circuit tower line from Southern Scotland down through Northern England. The subsea cable could be installed down either the West or East coast, connecting into a point in the GB network where there is sufficient network capacity available.

It must be stressed though that under the present connection agreements for the island generation projects, none of the generation is subject to Scotland-England inter-connector constraints. Any projects not currently in the GB queue, such as 'The Lewis Wind-farm', or projects such as the Beatrice Offshore Wind-farm, which have unknown reinforcement requirements may benefit from the early development of such a third inter-connector.

At this stage, there is only a minimal commercial benefit to be gained for the majority of the Island generation projects through a bypass of the Scotland-England inter-connector constraint.

Therefore, such a bypass inter-connector should be viewed as a strategic backbone reinforcement to the GB network. It should be evaluated against the onshore alternatives once the cost of generation constraints across the boundary creates a sufficient business case for investment in the new link. A key issue is whether anticipated future costs of the constraints will be allowed by Ofgem to justify the acceleration development of such an inter-connector.

3.7.1 Peterhead to Cockenzie / Hawthorn Pit / Walpole

Technology Choices

A CSC based HVDC scheme is the most suitable for a 2000MW connection from North Scotland to the South of the GB system. This is because the connection distance is not practicable for subsea AC transmission, and both ends of the link are sufficiently strong. The CSC HVDC connection scenario considered is:

1) 2 x 1000MW, ±500 kV DC

Although onshore AC transmission at 400kV is likely to be lower cost and allow for co-ordinated network development, it is likely to be significantly more affected by wayleaving and consenting delays. As the development of a comparable subsea inter-connector is potentially faster and easier, there is a tangible practical and economic benefit to such a scheme.

Offshore Routing

A number of Gas pipelines enter the St Fergus terminal immediately to the North of Peterhead. Two additional oil pipelines enter the Cruden Bay refinery some 10 miles to the South of St Fergus. As a result, potential landfall sites in the Peterhead area will have to cross pipelines entering Cruden Bay to the South.

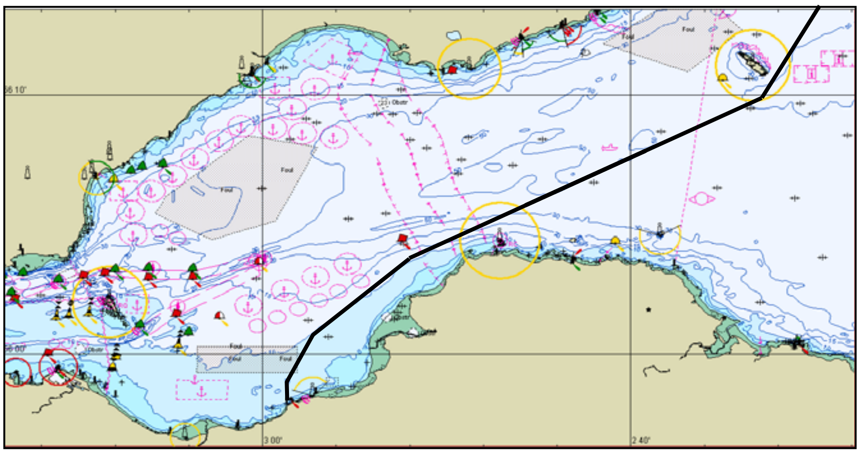

Figure 3.9 Route through Firth of Forth

Routing from Peterhead to Cockenzie would follow the route option shown in Figure 3.10 with an approach through the Firth of Forth as indicated in Figure 3.9 above.

The cable would pass south of the Isle of May and avoid crossing the existing submarine cables running between the Island and the Fife mainland near Crail, but would avoid two disused explosive dumping grounds immediately to the east. Three existing submarine cables would require crossing prior to following the 10 metre contour to avoid designated anchoring zones to the north prior to turning to the south to Cockenzie.

A potential route between Peterhead (Sandford Bay) and the Northumberland Coast was shown in Figure 3.10. The cable would cross the existing oil trunklines entering Cruden Bay. The seabed is expected to consist of a variety of surficial sediments mainly coarse in nature. Detailed routing to avoid wrecks would be carried out in a more detailed desk study prior to survey.

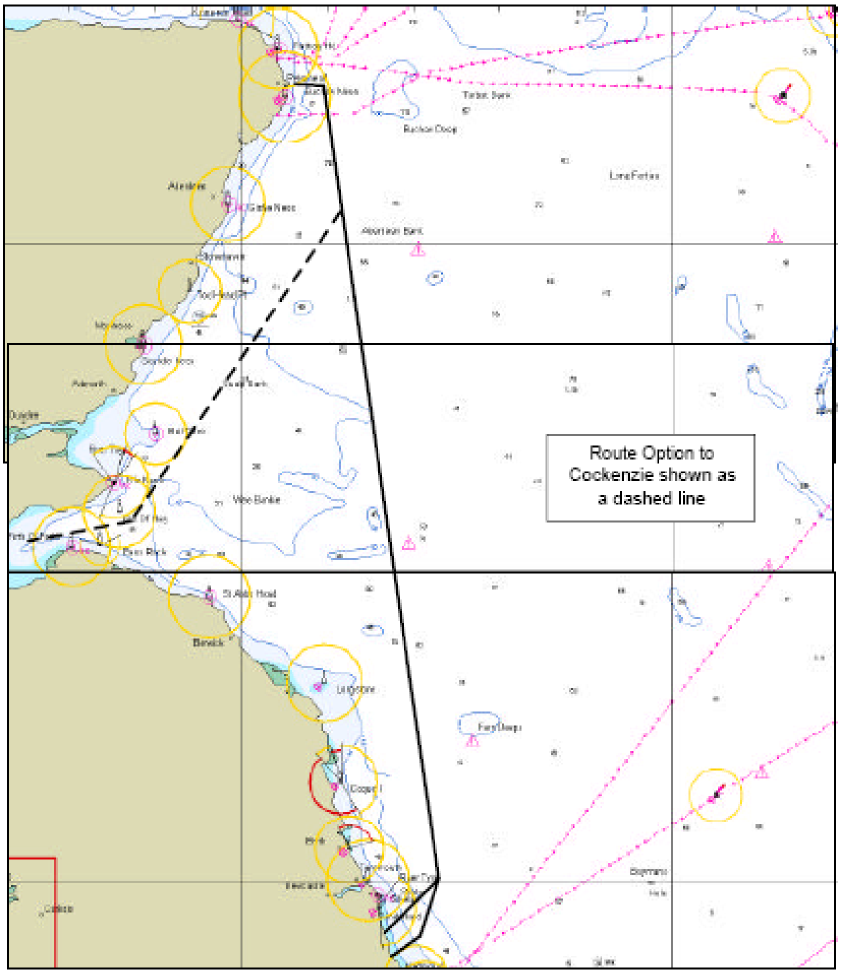

Figure 3.10 Route from Peterhead to Cockenzie or Hawthorne Pit

The subsea cable will also need to consider impacts on Environmentally Protected Species of cetaceans, potential marine designations of the Buchan Ness to Collieston Coast SPA, as well as cumulative impacts with other marine proposals.

Routing from Peterhead to Walpole in Lincolnshire would require the crossing of a considerable number of oil and gas trunklines. These enter terminals at Cruden Bay, Teeside, Easington and Theddlethorpe.

An approach to Walpole through the Wash will be a challenge both from an environmental standpoint and a routing standpoint with respect to the offshore wind farm development. The Greater Wash has been targeted as a major area for wind farm development and as a result, any power cable landfall within the wash area will have to route around these developments in addition to other third party constraints.

In addition, environmental issues will be potentially difficult within the greater wash area with numerous Special Protection Areas (SPAs), Sites of Special Scientific Interest (SSSIs), and Special Areas of Conservation (SACs) in abundance.

Two shipping channels run through the Wash NNR site. These are the channels of the rivers Nene and Ouse and are used daily by cargo and fishing vessels visiting the ports of Sutton Bridge and Wisbech, and King's Lynn respectively.

The Wash area is an area of high currents and extremely mobile sands and deep cable trenching would be required to provide reliable and permanent burial.

Potential Landfalls

The most suitable landfall site near Peterhead would be at Sandford Bay. Sandford Bay lies immediately to the South of Peterhead and would appear to offer a good landfall location within the sandy bay. The hydrographic chart of the area does however indicate a spoil dumping ground immediately offshore with 2 outfall pipelines feeding this area from the North side of the bay.

At Cockenzie, it would appear that there is sufficient space between existing cooling water outfalls and the jetty structure. The proposed landfall is in a gently sloping beach area, with the seabed expected to consist of sands with sufficient depth to enable the cable to be laid into a pre-dredged trench out to the 5 metre contour. Any isolated rock outcrops would need to be avoided in any detailed route study.

In the North-East of England, a great deal of planning work on an HVDC link between Norway and England has already been completed by Statnett SF and NGET. The 1200 MW system was originally planned to be operational in January 2007 but is presently on hold. The proposed route is between potential landing points in Norway (Hylen) and Ryhope near Seaham in England, with a UK converter station at Hawthorn Pit.

The landfall scheme considered was to be directionally drilled under the seacliffs and out under the beach, emerging a few hundred metres offshore. The cliffs in this area are mainly flat topped and fronted by narrow beaches with little surfical cover. A number of conservation issues, both archaeological and environmental, will feature in any development plan. Ryhope beach (shown in Figure 3.11) is also a RIGS site, designated for its wave cut platform, erosion features and Upper Permian Magnesium Limestone stratigraphy.

Figure 3.11 Ryhope Dean Beach Area

Should environmental issues become too sensitive, an alternative site approximately 0.75 miles (1.2 kms) to the north of the dene may also be suitable. This site is due east of Ryhope village.

Another potential landfall lies between Dogger Rocks and Black Hall rocks, which are 1.5 miles South-east of Peterlee and immediately North of Blackhall Colliery. There appears to be a breach in the low cliffs at this location providing better access than some other locations along this stretch of coastline, although it would require a railway crossing.

Onshore Reinforcements

Once the connection has established the substation at Cockenzie, Hawthorn Pit or Walpole, the expectation is that there will be more available network capacity than there is in the Peterhead area.

The GBSO Seven Year Study indicates that although connection into Cockenzie would avoid some of the upgrades outlined by SHETL, there would still be very limited capacity for connection. This is because it would still be constrained by the capacity of the Scotland/England inter-connectors. The same constraints would apply to all other possible connection locations in Scotland.

At Hawthorn Pit there would be more available network capacity, but reinforcements to the network would still be required to accommodate this connection. NGET has already considered the best approach to these reinforcements. They include the reinforcement of the two existing lines from the North-East into Yorkshire, which would require positive outcomes from public inquiries. There are no other locations north of Humberside that might present a more suitable connection point. This is because all other locations would also be constrained by the capacity on these two lines. Connections at Humberside were considered but there is very little capacity here due to the large amount of conventional generation in the area.

A connection into Walpole would have the fewest constraints, although there is a large amount of offshore wind connections planned for this area. This could quite easily introduce new local constraints demanding deeper reinforcements with their associated delays. Connections to the South of Walpole were considered but the additional route length could not be justified by the minor increase in capacity availability.

3.7.2 Hunterston to Deeside

Technology Choices

A CSC based HVDC scheme is the most suitable for a 2000MW connection from North Scotland to the South of the GB system. This is because the connection distance is not practicable for subsea AC transmission, and both ends of the link are sufficiently strong. The CSC HVDC connection scenario considered is:

1) 2 x 1000MW, ±500 kV DC

Although onshore AC transmission at 400kV is likely to be lower cost and allow for co-ordinated network development, it is likely to be significantly more affected by wayleaving and consenting delays. As the development of a comparable subsea inter-connector is potentially faster and easier, there is a tangible practical and economic benefit to such a scheme.

Offshore Routing and Potential Landfalls

The routing and landfalls would be as discussed in Sections 3.5.3 and 3.5.4.

Onshore Reinforcements

Once this connection has been established at the Deeside substation, there may be sufficient capacity available in the network. This is by no means certain, however, as the forecasted capacity of the North to Midlands Boundary at present only just exceeds the planned and probabilistic transfers.

4 Connection Costs and Timescales

As discussed in Section 3, there are a number of factors that will affect the Transmission Use of System Charges (TNUoS) paid by a generator connecting to the GB transmission system. The two most critical factors are the onshore TNUoS charges once reinforcements have been completed, and the capital cost of the subsea connection itself.

This section provides a comparison of the costs and timescales for the options discussed in Section 3. They are based on budget quotes and lead-times from manufacturers, and costs for previous projects. The costs will obviously vary depending on the availability of the prime equipment, cost of metals, and the day rates of installation vessels. The costs do not include on-shore reinforcements, additional works, land and wayleaving costs, or consenting. Although these costs are essential for a full project costing, they do not have a major impact on the comparative assessment on the different subsea connection options.

Security Factors

The security factors calculated in this report are based on the following simple methodology:

$$\text{Security Factor} = 1.0 + \frac{\text{Link Capacity during Outage}}{\text{Generation Capacity Required}}$$

This approach allows representation of the degree of security provided by multiple partially rated circuits. In this report the security factor is used to reflect only the connection between the respective Island and the mainland grid[1].

The existing approach used by the GBSO to describe security factors is slightly different to this methodology. The GBSO methodology includes the security of the full network, but focuses on the capacity of the connection and not its security. Therefore a 1 x 1000MW link is treated the same as 2 x 500MW links. Therefore an additional method will be required to reflect the benefit of multiple partially rated links.

TNUoS Charges

The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. The first part is a locationally varying element to reflect the costs of capital investment and the maintenance and operation the transmission system. The second element is a non-locationally varying element related to the provision of residual revenue recovery. The combination of these elements forms the TNUoS tariff.

In the timeframe of this study, it was not possible to replicate the NGT TNUoS tariff model in order to calculate the expected new TNUoS tariffs. In addition,

[1] Discussed and agreed as reasonable with NGT and SHETL

as the existing model does not have a suitable representation of sub-sea connections or HVdc links and so approximations would still be necessary. Instead, the method used for this report is taken from the NGT publication "Illustrative Zonal Security Factors for Scottish Islands"[1]. This method annualises the unit investment cost by using a straight-line depreciation model over 40 years with a 6.25% regulated rate of return and a 1.8% annual Opex charge. This provides the incremental cost of the new link and it is added to the existing onshore TNUoS tariff at the point of connection.

The GBSO proposes to introduce a discount in the TNUoS charges for connections that have a reduced security factor, either due to a single circuit link or multiple circuits with only partial capacity. The methodology for treatment of security factors and multiple cable links has not yet been developed. In the interim, the method described above was deemed as representative for the purposes of this study. This method uses the actual project cost estimates and the existing onshore TNUoS charge to calculate the expected TNUoS charges for each scheme.

This methodology automatically provides a reduction based on the actual security that is provided because it utilises the costs for the actual design being considered, and not those for a fully redundant system.

Final Sums Liability (FSL)

As discussed in Section 2.4 and Appendix D, there are two options for Final Sums Liability[2]:

- either the existing scheme, in which the developer provides security for all the reinforcements triggered by their connection or,

- a new voluntary scheme in which the developer provides security in a staged manner. The proposal is £1/kW per year up to planning consent for the reinforcements being gained, and then multiples of the expected TNUoS staged over 4 years until connection.

It is expected that this will be the full TNUoS charge, as otherwise there is a risk of insufficiently secured assets being built and then becoming stranded.

Timescales

The timescales involved in these connection options are presented in Appendix C. They show the expected timescales for the generation developments, the offshore connections and the onshore reinforcements. It is thereby possible to identify the critical path associated with each connection, and to determine if there is an alternative connection that would take less time to implement. It also allows for an analysis of the risk of delay to any key element and the impact of this on the critical path.

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[1] Received from NGT (GBSO)

[2] http://www.nationalgrid.com/uk/electricity/

Timescales for the building of the wind-farm developments are based on a maximum build rate of 200 MW per year[1]. This build-rate relates to approximately four 3MW turbines per week over a six-month annual erection window. This is a reasonably aggressive installation programme, which needs to be interpreted with care against the usually more conservative grid reinforcement programmes. This build rate has been confirmed in discussions with two of the major developers involved with the Island schemes.

The analysis also assumes that the wind-farms are constructed in order of TEC availability, or optimal sharing of TEC between the developers on the same Island. Any TEC sharing is likely to require a formal joint-venue or similar legal entity, as well as agreement with the GBSO[2].

Bulk Transfer Links

Bulk transfer links have been proposed as a more efficient and effective use of long subsea links, instead of the dedicated connection of an individual Island group to a part of the GB network bypassing onshore constraints.

A Bulk Transfer link is where a large capacity HVDC link is installed and made available to the GBSO as a route for moving power from the North to the South of the GB system. They can be fully utilised and can provide stability support services to the system operator such as providing controllable power flow and improving the dynamic stability of a network.

In this section there are number of schemes that may benefit from the installation of such a link, and so the appropriate cost for the provision of this link has been calculated.

The capital costs of the scenarios developed are shown in Appendix C, and they are based on a single 2000MW CSC HVDC Bipolar Link. The associated TNUoS charges have been calculated based on full utilisation of the link and the differential between the TNUoS zones that it interconnects. These charges show that to use the links would cost an additional £5 and £8 / kW / year.

The full utilisation factor on the HVDC link is justifiable, as the HVDC link would be used to relieve the two existing onshore AC inter-connectors. This would then allow additional generation to connect in Northern England, as the power flow from Northern Scotland would bypass that part of the onshore AC network.

The impact of the Scotland-England inter-connector constraint on the energy market is significant, and Ofgem has enabled some investment in TIRG to partially relieve it. This has not yet gone as far as releasing funds to progress a third inter-connector. This is because a new inter-connector is not considered justified at this time due to uncertainty concerning the rate of new generation growth and the rate of closure of existing stations[3].

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[1] Consultation with developers of major projects on Shetland and Lewis

[2] Consultation with NGT (GBSO)

[3] Consultation with Ofgem

If Longannet, Cockenzie and Hunterston were to be closed and not replaced by other thermal generation, then the balance of power flow could well reverse, making investment in new transmission capacity unnecessary. SPTL has indicated, though, that if these generators were to close and not be replaced, then the stability of the network in Central Scotland would be seriously compromised[1].

In line with the requirement for least cost development of the transmission system, the TO's are required to investigate an overland 400kV twin circuit tower line before consideration of the potentially more expensive offshore HVDC link. Although the overland option may take significantly longer to obtain planning consent, assuming that a possible route can be found, any avoided cost benefits of a faster connection cannot be included in the cost-benefit calculation[2].

If the generation constraint payments in Scotland reach a sufficient level, then it should be possible to write an investment case to justify an offshore HVDC link in order to remove these distortions from the energy market.

Ofgem proposals for licensing of off-shore transmission

Ofgem is currently consulting[3] on proposals for the licensing of offshore transmission, including the possibility of transmission license holders competing for the rights to develop specific offshore transmission assets. The objective is to ensure these required assets are delivered in a timely and cost-effective manner.

There is an obvious benefit if there are licensees who are highly experienced in the delivery of offshore transmission projects. In this case it is entirely possible that they may be able to deliver a more efficient and faster project. A negative aspect however is that there are definite issues associated with the potential loss of co-ordination in the development of the transmission network. A similar approach allowing competition in onshore distribution network provision has been active for some years with mixed results.

For the three existing TO licensees in the UK, none could be said to be highly experienced[4] in such activities and so the contract for major subsea cable connections is likely to be on a turnkey basis to minimise risk. This is particularly the case as subsea and HVDC technology are highly specialised activities. Therefore the scope for significant cost or time savings may be limited to their ability to negotiate commercial terms with suppliers, or their ability to achieve planning consent rapidly and manage projects efficiently.

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[1] Consultation with SPTL

[2] Consultation with Ofgem

[3] http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/17689_199_06.pdf

[4] Although NGT have recently been involved with the development of the Basslink HVDC scheme in Australia through NGT Int Ltd, this is their only recent significant offshore project.

4.1 Orkney Isles Connections

Connection Costs and Charges

Table 4.1 shows the estimated connection costs and associated charges for the proposed options. Further details on these costs are in Appendix C.

Option	Technology	Capital Cost of Connection	Onshore TNUoS Charges	New Zone TNUoS Charge		Approx Security Factor
					With s185	
		£million	£/kW/year	£/kW/year	£/kW/year	
Thurso / Dounreay	132 kV AC XLPE Cables: 2 x 180MW	47	20.52	40.59	30.56	1.9
	132 kV AC XLPE Cables: 2 x 100MW	46	20.52	39.87	30.20	1.5
Shetland to Orkney and then Keith	300kV HVDC Light: 2 x 500MW units with one via Orkney	205	20.52	42.16	31.34	1.6

Table 4.1 Connection Charges for Orkney [1]

Table 4.1 shows that the AC cable connection from Orkney to Dounreay is the most cost effective and provides a good security of supply. This connection could either be with 2 x 180MW cables or 2 x 100 MW. Although the option with 2 x 180MW links is marginally more expensive, it only has a £0.36/kW/year impact on the TNUoS charges. The outage costs associated with the difference in the level of security are expected to be significantly higher than this.

Final Sums Liability

For the 126 MW of GB queue capacity on Orkney, £126,000 of security needs to be provided at this point in time. This will then increase to a maximum of £53.1 million depending upon the FSL option selected and final TNUoS charging methodology.

Timescales

The timescales for these connection options show that the earliest predicted completion of the 126 MW of generation would be by 2010, with possible delays pushing this out to 2012[2].

For both the connection options considered, the onshore network capacity reinforcements are expected to be available by 2011, with possible delays taking this to 2014[3].

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[1] Costs based on existing TNUoS charges, internal database and Manufacturer estimates

[2] Consultation with SHETL

[3] Consultation with SHETL

The main factor between the two options considered is the availability of the subsea connection. The AC cable connection to Thurso is anticipated to be ready by 2010. The HVDC connection from Shetland to Keith via Orkney however is not anticipated to be ready until 2014 due to its more complex design, long cable runs, and increased consenting issues.

The earliest that an offshore connection and TEC is anticipated to be available for Orkney GB Queue capacity is by 2011, with possible delays taking this to 2014. This is for the Orkney to Thurso/Dounreay option. All the other options would take longer due to the longer subsea connections taking more time to design, manufacture and install.

As soon as the subsea cable installation is complete, short-term TEC products may be available to allow generation in advance of the onshore network reinforcements being completed. Therefore with the Orkney to Dounreay option, export may be achievable by 2010. Export would not be achievable until at least 2014 with the Shetland to Keith via Orkney option.

4.2 Shetland Isles Connections

Connection Costs and Charges

Table 4.2 shows the estimated connection costs and associated charges for the proposed options. Further details for these costs are in Appendix C.

Option	**Technology**	**Capital Cost of Connection**	**Onshore TNUoS Charge**	**New Zone TNUoS Charge**		**Approx Security Factor**
					With s185	
		£million	£/kW/year	£/kW/year	£/kW/year	
Cullen / Keith	300kV HVDC Light: 2 x 300MW units	300	20.52	62.65	41.59	1.5
	300kV HVDC Light: 2 x 500MW units	409	20.52	77.98	49.25	1.8
Keith and Norway	300kV HVDC Light: 1 x 1000MW unit to Keith and 1 x 400MW unit to Norway	620	20.52	78.16	49.34	1.7
Orkney / Keith	300kV HVDC Light: 2 x 500MW units with one via Orkney	250	30.59	82.86	51.69	1.6

Table 4.2 Connection Charges for Shetland[1]

For a connection from Shetland to Keith there are two possible options, both of which provide some reduced export in the event of a fault or maintenance on one of the cables or converters. For the 2 x 300MW HVDC link case, a reduced capacity of 300MW would be available. For 2 x 500 MW HVDC link case, a reduced capacity of 500MW would be available.

[1] Costs based on existing TNUoS charges, internal database and Manufacturer estimates

The installed costs for both of these options are similar, but the smaller cable size for the 2 x 300MW option results in £7.66/kW/year reduction TNUoS charge. As this is significantly higher than the expected outage costs that would be associated with this loss of security, the 2 x 300MW option is likely to be the preferred option.

For the Scotland/Norway Interconnector via Shetland, only 600MW of the capacity on the link to Scotland has been included in the TNUoS charges. This is because it is likely that the 400MW of connection capacity to Norway would be financed by other means and recouped via trading over the interconnector. As this interconnector also provides additional security to the Shetland generation then a charge for providing this security, based on the outage losses expected for this type of link, have also been included.

Final Sums Liability

For the first block of TEC, £300,000 of security must be provided at this point in time. This will then increase to a maximum of £248.6 million depending upon the FSL option selected and the final TNUoS charging methodology.

For the second block of TEC, £250,000 of security must be provided at this point in time. This will then increase to a maximum of £207.2 million depending upon the FSL option selected and the final TNUoS charging methodology.

Timescales

The timescales for these connection options show that the earliest predicted completion of the first 250MW of generation on Shetland would be 2011. Possible consenting delays may push this out to 2013. The next 350 MW of generation would follow with the earliest completion date in 2013, and possible delays pushing this out to 2015[1].

All of the options considered for this connection anticipate the onshore network capacity being available for the first block of TEC by 2011, with possible delays taking this to 2014.

The main factor between the three options considered is the availability of the subsea connection. The first cable of the relatively straightforward HVDC Light connection to Keith should be established by 2011. The more complex connections to Norway or via Orkney would be delayed by a more complex design, increased consenting issues, and a thorough commercial assessment of the economic value of an inter-connector.

The earliest that an offshore connection and onshore network capacity is anticipated to be available for the first 250 MW is 2011, with possible delays taking this to 2014. This is for the Shetland to Keith option. All the other options would take longer due to the longer subsea connections taking more time to design, manufacture and install.

[1] Consultation with SHETL

As soon as the subsea cable installation is complete, short-term TEC products may be available to allow generation in advance of the network reinforcement completion. Therefore, with the Shetland to Keith option, export may be achievable by 2011. For the other connection options, export would not be achievable until at least 2014.

The connection agreement associated with the second block of TEC is dependent on significant onshore reinforcements. The onshore network capacity reinforcements for this 350 MW of generation will not be available until 2015, with possible delays taking this to 2020.

The timescales for the subsea connections are not as critical as some of the capacity could be available by 2012 for the Shetland to Keith option, and 2014 for the other 2 options. Full capacity and security could be available by 2015 for the Shetland to Keith option, with possible delays taking this to 2018.

The earliest that a secure offshore connection and unconstrained onshore network capacity is anticipated to be available for the second block of TEC is by 2015, with possible delays taking this to 2020. This is for the Shetland to Keith option. All the other options would take longer due to the longer subsea connections taking more time to design, manufacture and install.

As soon as the subsea cable installation is complete, short-term TEC products may be available to allow generation in advance of the network reinforcement completion.

The most practical solution to avoid the onshore reinforcements is to install a HVDC Link to further south in the network. A link from Peterhead to Hawthorn Pit could relieve some of the constraints on the Scottish system making more capacity available for connection earlier. Optimistically, this could be installed by 2014, but it may face long delays associated with design, consent, installation and network capacity availability at Hawthorn Pit. This link could reduce the delay anticipated for the second block of TEC to get firm access to the system. However, a reassessment of the GB Queue and the provision of short-term access options could possibly make similar timescale reductions at lower cost and risk.

4.3 Western Isles Connections

Connection Costs and Charges

Table 4.3 shows the estimated connection costs and associated charges for the proposed options. Further details on these costs are in Appendix C.

Option	Technology	Capital Cost of Connection	Onshore TNUoS Charge	New Zone TNUoS Charge		Approx Security Factor
					With s185	
		£million	£/kW/year	£/kW/year	£/kW/year	
Ullapool / Beauly	150kV HVDC Light: 3 x 350MW units	287	20.52	44.71	32.62	1.7
	150kV HVDC Light: 2 x 500MW units	286	20.52	44.63	32.57	1.5
Oban / Dalmally	150kV HVDC Light: 2 x 500MW units	422	13.52	49.10	38.31	1.5
Hunterston	300kV HVDC Light: 2 x 500MW units	474	12.14	52.10	40.50	1.5
Deeside	300kV HVDC Light: 2 x 500MW units	621	3.84	56.19	46.69	1.5

Table 4.3 Connection Charges for Western Isles[1]

This shows that for a connection to the Western Isles then a HVDC Light connection from Lewis to Beauly with a landfall at Ullapool would be the most cost effective and provides the most security of supply. This connection could either be with 3 x 350MW links or 2 x 500 MW links. The table shows that although the option with 3 x 350MW links is slightly more expensive, it would only have a £0.05/kW/year impact on the TNUoS charges. The expected outage costs associated with this loss of security are expected to be significantly higher than this.

Final Sums Liability

For the first block of TEC, £300,000 of security must be provided at this point in time. This will then increase to a maximum of £168.6 million depending upon the FSL option and the final TNUoS charging methodology.

For the second block of TEC, £250,000 of security must be provided at this point in time. This will then increase to a maximum of £140.5 million depending upon the FSL option and the final TNUoS charging methodology.

For the third block of TEC, £450,000 of security must be provided at this point in time. This will then increase to a maximum of £252.9 million depending upon the FSL option and the final TNUoS charging methodology. There are likely to be other associated deeper reinforcements required for this block of TEC as it is not in the GB queue. However, these costs may not have a major impact on the TNUoS charge of the Lewis zone.

Timescales

The timescales for these connection options show that the earliest predicted completion of the first 250 MW of generation would be 2011, with possible delays pushing this out to 2013. The next 300 MW of generation would follow

[1] Costs based on existing TNUoS charges, internal database and Manufacturer estimates

with the earliest completion date in 2013[1]. The final 650 MW of generation is anticipated to follow that with an earliest completion date of 2016. The order of project development could be modified by TEC sharing between the different developers. The GBSO has indicated that provided this was done as a joint venture then this would an acceptable method for TEC sharing on Lewis[2].

The earliest that an offshore connection and onshore network capacity is anticipated to be available for the first block of TEC is 2011, with possible delays taking this to 2014. This is for the Lewis to Ullapool/Beauly option. All the other options would take longer due to the longer subsea connections taking more time to design, manufacture and install.

There is no practical way to avoid these reinforcements, as a longer HVDC Link to a point further South in the GB network would have considerably longer delays associated with it and significantly higher costs.

As soon as the subsea cable installation is complete, short-term TEC products may be available to allow generation until the network reinforcements are complete.

With the Western Isles to Beauly option export may be achievable by 2011 whereas with the other options, export would not be achievable until at least 2013.

The earliest that an offshore connection and onshore network capacity is anticipated to be available for the second block of TEC is 2013, with possible delays taking this to either 2015 or 2016. Both the option from Lewis to Ullapool and on to Beauly, and the option from Lewis to Oban and on to Dalmally, would achieve this date. This is so long as the first 2 cables from Lewis to Ullapool are installed at the same time. However, delays are more likely with the Ullapool/Beauly option due to its dependence on the Beauly-Denny line upgrade.

The Ullapool/Beauly options should still be considered though as once the subsea connection is complete in 2011 some short-term access to the network may be possible. TEC sharing options between the wind farm developments on Lewis should be investigated.

The earliest that an offshore connection and onshore network capacity is anticipated to be available, for the 650 MW of generation that is currently not in the GB queue, is 2015, with possible delays taking this to 2021. This is the Lewis to Beauly via Ullapool option, with an additional HVDC link from Peterhead to Hawthorn Pit. If the Scotland/England inter-connector is not a limiting constraint then this additional link may not be required.

This option and the Deeside option are the only ones that bypass the Scotland/England inter-connector constraints, but even with these options, there may not be available capacity in the network at Hawthorn Pit or Deeside

[1] Consultation with SHETL

[2] Consultation with NGT (GBSO)

that has not been committed for other parties with connection agreements already in the GB Queue.

These timescales indicate that these wind-farm developments could be delayed significantly due to the uncertainties surrounding the required onshore reinforcements. Once the planned reinforcements have been completed, together with the proposed reassessment of the GB Queue, TEC sharing and short term connection products, such developments may be able to connect prior to the envisaged inter-connector constraints being completely resolved.

4.4 Beatrice Offshore Wind-farm Connections

Connection Costs and Charges

Table 4.4 shows the estimated connection costs and associated charges for the proposed option. Further details for these costs are in Appendix C.

Option	Technology	Capital Cost of Connection	Onshore TNUoS Charge	New Zone TNUoS Charge	Approx Security Factor
		£million	£/kW/year	£/kW/year	
Keith	132 kV AC XLPE Cables: 6 x 180MW	59	20.52	25.55	1.9

Table 4.4 Connection Charges for Beatrice [1]

This was the only short-listed option considered for this connection.

Final Sums Liability

For the Beatrice Offshore Windfarm, £1,000,000 of security must be provided at this point in time. This will increase to a maximum of £255.5 million depending upon the FSL option and the final TNUoS charging methodology.

In this case it may be more suitable for the developer to provide security under the previous scheme, although the amount that would need to be provided for security of the proposed onshore reinforcements is unknown.

Timescales

The timescales for this connection option shows that onshore network capacity is anticipated to be available by 2015, with possible delays taking this to 2020. This is likely to be acceptable to this development, as completion of the construction and sub-sea connection is not anticipated until at least 2017[2].

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[1] Costs based on existing TNUoS charges, internal database and Manufacturer estimates

[2] Consultation with SHETL

5 Conclusions and Recommendations

The options considered in this study all have different costs, timescales, environmental constraints and network constraints associated with them. The following is a review of the most suitable options based on the data presented in Sections 2, 3 and 4.

Section 1.1 has a list of the parties consulted in the process of preparing this report. A number of the conclusions have been based on information obtained during this process.

5.1 Overall

Due to the increasing utilisation factors on the existing transmission network, there are now very few locations where significant levels of generation can connect without triggering reinforcement.

For low capacity factor generation such as wind it is difficult to justify long connections due to the low connection asset utilisation. A better utilisation of the assets can be made if the dedicated connections are kept short and then further onshore or offshore reinforcements to the grid are put in place.

The majority of the island generation under consideration is "commercially firm" with respect to the most serious onshore transmission constraint, the Scotland-England inter-connector. Therefore, a long bypass link into England or Wales becomes much more difficult to justify commercially.

The existing constraints on the Irish network plus the existing capacity in the Moyle inter-connector and the potential Dublin/Wales inter-connector mean there is little interest in establishing a link with Ireland.

An inter-connector to Norway is possible but there is currently no targeted incentive to generate from renewable sources in Norway. Also, an inter-connector linked primarily to wind power would not resolve their current demand/supply balance problems. In addition, a fundamental issue is that an inter-connector to Norway could at times represent an additional burden on the Scottish network.

There is a great deal of uncertainty surrounding the calculation and level of the TNUoS charges when applied to the Islands. The values given in the tables in Section 4 are produced using a methodology agreed with the GBSO. However as they are not produced using the actual TNUoS model, there may be variations from these values. The way in which HVDC cables and converters are treated in the GBSO model has not been clearly defined and the methodology for the implementation of security factors is still under development.

The reductions in TNUoS charges, enabled by section 185 of the Energy Act 2004, could help facilitate island developments. However as the benefits afforded to the projects face 5 year reviews, further uncertainty rather than security is offered to the potential developers.

5.2 Orkney Connections

For a 200MW connection from Orkney into the GB network, the fastest and least cost option is a 132kV AC subsea cable connection. This would run from Skail Bay on Orkney Mainland to Murckle Bay to the East of Thurso. The onshore connections to the generation sites on Orkney and to Dounreay substation on the Scottish mainland would be run as either overhead lines or underground cables. This option would have the shortest timeframe associated with it, allowing firm access to the network from 2011 and possible short term access from 2010.

If the planned generation on Orkney reduces but is still more than the 15MW of new capacity available under the active management regime, then a new sub-sea cable connection will be triggered. The degree of reinforcement of the existing links to the mainland will obviously depend on the amount of additional capacity that is required.

At this stage, if the additional generation schemes total less than 40MW, then it is likely that only an additional 33kV cable could be justified in terms of cost. Additional capacity requirements greater than this would require at least two 33kV cables, and so a 132kV cable is likely to be more cost effective. The installation of a 132kV cable would also provide significantly more additional capacity (90-180MW) than the corresponding two 33kV cables (40-60MW).

The 2 x 180MW 132kV AC option costs an additional £0.36/kW/yr based on 200MW of generation compared to the 2 x 100MW 132kV AC option. This would provide a higher level of security and would allow more generation to connect in the future using a managed approach. This is considered to be the best option for Orkney.

5.3 Shetland Connections

For a 600MW connection from Shetland into the GB network, the fastest and least cost option would be a +/-300kV VSC HVDC subsea cable connection from Shetland to Keith. This would run from West Voe of Skellister on Shetland to Cullen Bay on Mainland Scotland. The on-shore sections would be under-grounded to the most suitable site for a converter station; this is anticipated to be at the Keith substation on the mainland. This option would have the shortest timeframe associated with it, allowing the first 250 MW of generation to gain access to the network from 2012.

The 2 x 500MW VSC HVDC option costs an additional £2.81/kW/yr based on 600MW of generation capacity. This would provide a higher level of security and would allow more generation to connect in the future using a managed approach. However, the 2 x 300MW option is considered to be the more cost effective option at this stage.

An alternative viable option is a larger (1000MW) link following the same route as above, but with an additional link to Norway. This would create an inter-connector between Norway and GB for trading and provide Shetland with access to the Norwegian market. This option will take longer to implement and may attract higher annual TNUoS charges. Further studies would be required to determine if this is the most appropriate location for such an inter-connector between the two countries.

5.4 Western Isles Connections

For a 1000MW connection from the Western Isles into the GB network, the fastest and least cost option would be a +/-150kV VSC HVDC subsea cable connection from Lewis to Beauly. The cable would run from Chubag Bay on Lewis to Ardmair Bay near Ullapool and then continue with VSC HVDC underground cable to the Beauly substation. The cable on Lewis would also be run underground from the landfall to an appropriate site for the converter station. This option would have the shortest timeframe associated with it, allowing the first 250 MW of generation to access the network from 2011.

The 3 x 330MW VSC HVDC option has a comparable cost to the 2 x 500MW VSC HVDC option based on the requirement for 1000MW of capacity. As the 3 x 330MW option would provide more security and would allow a more staged approach to the connection, this is considered to be the best option.

Any developers that are not already in the GB Queue may struggle to obtain an offer that allows them to gain firm access to the system before 2020. They will need to consider TEC sharing with other developers in Lewis and start discussing the options for short-term access products with the GBSO. This may enable them to gain access earlier.

The other options open to developers in such a position are:

1. A connection into Deeside. This may bypass Scottish network constraints but will cost £14.12/kW/yr more than the least cost option, and will only enable connection in approximately 2018.

Or

2. A connection into Beauly as discussed above and then, once some of the Scottish reinforcements have been completed, a bulk-transfer connection from Peterhead into Hawthorn Pit or Walpole. This will cost approximately £5.20/kW/yr more than the least cost option, based on full utilisation of the link and capacity being available from Beauly to Peterhead. This approach may enable access to the system as early as 2015. This option will only be viable if Ofgem accepts that the third inter-connector is justified and that an onshore route would not be achievable. Ofgem would then have to allow this connection into the regulated revenue base of a transmission licencee.

5.5 Beatrice Offshore Wind-farm Connections

The fastest and least cost option considered for the 1,000MW connection from the Beatrice offshore wind-farm into the GB network is a multiple 132kV subsea cable connection. This would land at Cullen bay and continue from there with an overhead line connection to the Keith Substation.

6 x 180 MW 132kV AC cables would provide the capacity required with a reasonable security of supply. It is anticipated that this connection could be available by 2017 and access to the system may be available from 2015. As there is no anticipated date for the installation of the wind-farm, this connection may be delayed to ensure that TNUoS charges are not levied before generation is ready to connect.

5.6 Recommendations

The Island groups should be treated as entities rather than as the individual schemes that already have significant capacity in the GB queue. A single large connection would provide a stronger signal and lobbying position to the process than several smaller and potentially competing schemes. The stakeholders in the report are well placed to facilitate this merging of applications. The GBSO has indicated that it would look favourably on such a sharing of transmission access.

It is clear that the greater the extent to which uncertainty can be reduced and information shared, the easier progress will become for all parties. In particular, TEC sharing could represent a significant opportunity for bringing 'The Lewis Wind Farm' on line ahead of time without undue discrimination against other parties. There would seem to be a role for an organisation to facilitate this process and deal with the complex, potentially contractual issues of bringing parties together.

There is a high degree of Regulatory uncertainty surrounding the connection and charging arrangements that will be applied to the Scottish Islands. Decisions need to be made quickly as to how security factors will be calculated for subsea links, what the applicable TNUoS charge methodology will be, how S185 will be implemented and whether TEC trading can actually be utilised in Scotland by renewable generators due to differing grid code conditions.

The current proposals for competition in offshore transmission have an obvious benefit if there are licensees who are highly experienced in the delivery of offshore transmission projects. As this is not the case for the three UK TOs, the scope for significant cost or time savings may be limited to their ability to negotiate commercial terms with suppliers, or their ability to achieve planning consent rapidly and manage projects efficiently. These proposals are not viewed as providing any significant acceleration in the connection of the Scottish Island projects.

Proposals to thin-out the GB queue such as CAP 131 are likely to help improve clarity on viable projects. However, they are unlikely to resolve the key timescale issues where major reinforcements are required. Until the upfront development works begin on these schemes, there is still significant uncertainty surrounding them. We would recommend concentration of lobbying for increased allowances for initial pre-consent works for the transmission schemes where there is higher uncertainty of their requirement. This will serve to lessen the development time scales should the transmission scheme be deemed to be required.

Increasing User Commitment can be considered as a positive move to reduce uncertainty from the transmission owner's perspective, however it is unlikely to resolve the timing uncertainty for the generation developments. This is because it does not address the potential delay issues associated with the consenting, sanctioning and construction of transmission infrastructure.

Ideally, a developer would proceed with both the project consenting and the connection application in parallel. In a climate where there is significant uncertainty this approach involves an overly onerous financial risk. There would be significant strategic benefits to be had from a third party underwriting of the financial risks associated with gaining planning consent for connections.

Table 5.1 highlights the key barriers facing a number of the key Island projects. It shows that there is a strong strategic argument for categorising other onshore reinforcement work as 'Baseline' under the TIRG classification categories. It is not being suggested that infrastructure should be physically constructed ahead of definite demand. However, the key delays for the majority of transmission investments are associated with the consenting and wayleaving process.

A mechanism to secure the wayleave and consent ahead of time, perhaps at an increased level of financial risk, would dramatically reduce the time to develop infrastructure and significantly reduce the uncertainty facing generation developers.

In general, long subsea inter-connectors to connect the Island groups to locations other than the near coast lines are difficult to justify both in terms of the underlying economics and connection time-scales. In all cases considered, in addition to higher costs, the longer bypass links would be unlikely to deliver earlier connections due to the lengthy manufacturing and installation times. As timing is a critical factor, there is a clear requirement for the critical paths for Island developments to be established and examined, and then a strategic programme developed.

	TIRG Category	Affected Island Wind Generation (MW)	Eishken (Lewis)	South Lochs (Lewis)	'The Lewis Windfarm'	North Nesting (Shetland)	Viking (Shetland)	Fairwind (Orkney)	Beatrice Offshore Windfarm
Beauly-Denny upgrade	Baseline	2876	✔	✔	✔	✔	✔	✔	✔
Beauly-Dounreay second circuit	Additional	126				✔		✔	
Beauly-Blackhillock reconductoring	---	2500	✔		✔	✔	✔		✔
Beauly-Keith new build	Additional	1950			✔		✔		✔
Keith-Kintore-Tealing 400kV ring	---	1950			✔		✔		✔
Scotland/England interconnector (3rd)	---	1650			✔				
Lewis-Beauly subsea link	Additional	1200	✔	✔	✔				
Shetland-Keith subsea link	Additional	550				✔	✔		
Orkney-Dounreay subsea link	Additional	126						✔	
Beatrice-Keith subsea link	---	1000							✔

Table 5.1 Critical Transmission Reinforcement Dependencies for Key Island Developments

A Appendix – Map of Connection Options

To Norway
Shetland to Orkney
Shetland to Keith
Orkney to Thurso
Lewis to Ullapool / Beauly
Beauly - Dounreay
Beauly - Keith
Beauly - Blackhillock
Oil Pipelines
Lewis to Olban / Dalmally
400 kV Ring
Beauly - Denny
SCOTLAND
GRAMPIAN MOUNTAINS
Peterhead to Cockenzie
Peterhead to Hawthorne Pit
Dalmally Upgrade
Lewis to Hunterston
Eccles to Stella West
Glasgow to Gretna
Hunterston to Deeside
Lewis to Deeside
Peterhead to Walpole
SHETLAND ISLANDS
ORKNEY ISLANDS
OUTER HEBRIDES
INNER HEBRIDES
THE MINCH
SEA OF THE HEBRIDES

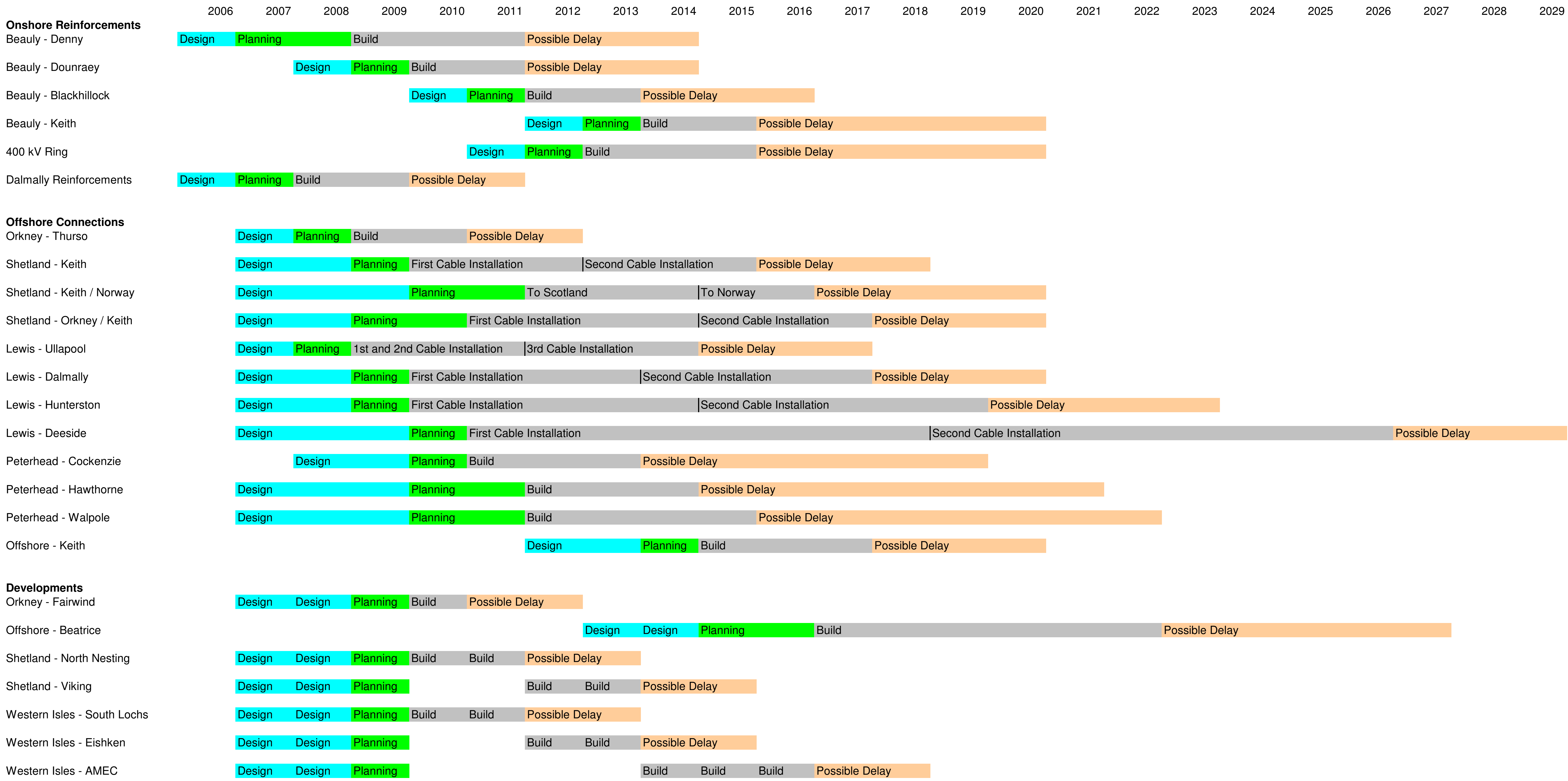
B Appendix – Timelines

These timescales are based on the following criteria:

The timeframes for the building of the windfarm developments are based on a maximum build of 200 MW per year, and the development with the earliest space in the queue building first. This build-rate relates to approximately four 2MW-4MW turbines per week over a six-month annual erection window.

The timeframes for the building of the sub-sea links are based on data from the manufacturers for lead-times of equipment, cable laying vessel availabilities, cable installation rates and expected seasonal windows for installation. Our internal planning and sub-sea experts have verified these timescales.

The timeframes for the completion of the onshore reinforcements are based on advice from the GBSO and relevant TOs. As there are very few similar projects that have been undertaken in the U.K. in recent years, estimates on the possible delays have been based on the experience of the North Yorkshire line.


2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029
Onshore Reinforcements
Beauly - Denny: Design Planning Build Possible Delay
Beauly - Dounraey: Design Planning Build Possible Delay
Beauly - Blackhillock: Design Planning Build Possible Delay
Beauly - Keith: Design Planning Build Possible Delay
400 kV Ring: Design Planning Build Possible Delay
Dalmally Reinforcements: Design Planning Build Possible Delay
Offshore Connections
Orkney - Thurso: Design Planning Build Possible Delay
Shetland - Keith: Design Planning First Cable Installation Second Cable Installation Possible Delay
Shetland - Keith / Norway: Design Planning To Scotland To Norway Possible Delay
Shetland - Orkney / Keith: Design Planning First Cable Installation Second Cable Installation Possible Delay
Lewis - Ullapool: Design Planning 1st and 2nd Cable Installation 3rd Cable Installation Possible Delay
Lewis - Dalmally: Design Planning First Cable Installation Second Cable Installation Possible Delay
Lewis - Hunterston: Design Planning First Cable Installation Second Cable Installation Possible Delay
Lewis - Deeside: Design Planning First Cable Installation Second Cable Installation Possible Delay
Peterhead - Cockenzie: Design Planning Build Possible Delay
Peterhead - Hawthorne: Design Planning Build Possible Delay
Peterhead - Walpole: Design Planning Build Possible Delay
Offshore - Keith: Design Planning Build Possible Delay
Developments
Orkney - Fairwind: Design Design Planning Build Possible Delay
Offshore - Beatrice: Design Design Planning Build Possible Delay
Shetland - North Nesting: Design Design Planning Build Build Possible Delay
Shetland - Viking: Design Design Planning Build Build Possible Delay
Western Isles - South Lochs: Design Design Planning Build Build Possible Delay
Western Isles - Eishken: Design Design Planning Build Build Possible Delay
Western Isles - AMEC: Design Design Planning Build Build Build Possible Delay

Development By Development

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Orkney - Fairwind		Design	Design	Planning	Build	Possible Delay																		
Option 1 - Thurso												Cost =	£30.56	per kW/yr										
Onshore Reinforcements Required																								
Beauly - Denny	Design	Planning		Build			Possible Delay																	
Beauly - Dounraey			Design	Planning	Build		Possible Delay																	
Offshore Connections Required																								
Orkney - Thurso		Design	Planning	Build		Possible Delay																		
Option 2 - Keith												Cost =	£31.34	per kW/yr										
Onshore Reinforcements Required																								
Beauly - Denny	Design	Planning		Build			Possible Delay																	
Offshore Connections Required																								
Shetland - Orkney / Keith		Design		Planning		First Cable Installation				Second Cable Installation			Possible Delay											

Development By Development

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Shetland - North Nesting		Design	Design	Planning	Build	Build	Possible Delay																	
Option 1 - Keith												Cost =	£41.59	per kW/yr										
Onshore Reinforcements Required																								
Beauly - Denny	Design	Planning		Build			Possible Delay																	
Offshore Connections Required																								
Shetland - Keith first half		Design		Planning	First Cable Installation			Possible Delay																
Option 2 - Norway												Cost =	£49.34	per kW/yr										
Onshore Reinforcements Required																								
Beauly - Denny	Design	Planning		Build			Possible Delay																	
Offshore Connections Required																								
Shetland - Keith / Norway		Design			Planning		To Scotland			To Norway		Possible Delay												
Option 3 - Keith via Orkney												Cost =	£51.69	per kW/yr										
Onshore Reinforcements Required																								
Beauly - Denny	Design	Planning		Build			Possible Delay																	
Offshore Connections Required																								
Shetland - Orkney / Keith		Design		Planning		First Cable Installation				Second Cable Installation			Possible Delay											

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Shetland - Viking		Design	Design	Planning			Build	Build	Possible Delay															
Option 1 - Keith												Cost =	£41.59	per kW/yr										
Onshore Reinforcements Required																								
Beauly - Denny	Design	Planning		Build			Possible Delay																	
Beauly - Blackhillock					Design	Planning	Build		Possible Delay															
Beauly - Keith							Design	Planning	Build		Possible Delay													
400 kV Ring						Design	Planning	Build			Possible Delay													
Offshore Connections Required																								
Shetland - Keith second half		Design		Planning	First Cable Installation			Second Cable Installation			Possible Delay													
Option 1B - Keith with Peterhead Link												Cost =	£46.79	per kW/yr										
Onshore Reinforcements Required																								
Peterhead - Hawthorne		Design			Planning		Build			Possible Delay														
Offshore Connections Required																								
Shetland - Keith second half		Design		Planning	First Cable Installation			Second Cable Installation			Possible Delay													
Option 2 - Norway												Cost =	£49.34	per kW/yr										
Onshore Reinforcements Required																								
Beauly - Denny	Design	Planning		Build			Possible Delay																	
Beauly - Blackhillock					Design	Planning	Build		Possible Delay															
Beauly - Keith							Design	Planning	Build		Possible Delay													
400 kV Ring						Design	Planning	Build			Possible Delay													
Offshore Connections Required																								
Shetland - Keith / Norway		Design			Planning		To Scotland			To Norway		Possible Delay												
Option 3 - Keith via Orkney												Cost =	£51.69	per kW/yr										
Onshore Reinforcements Required																								
Beauly - Denny	Design	Planning		Build			Possible Delay																	
Beauly - Blackhillock					Design	Planning	Build		Possible Delay															
Beauly - Keith							Design	Planning	Build		Possible Delay													
400 kV Ring						Design	Planning	Build			Possible Delay													
Offshore Connections Required																								
Shetland - Orkney / Keith		Design		Planning		First Cable Installation				Second Cable Installation			Possible Delay											

Development By Development

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Western Isles - South Lochs		Design	Design	Planning	Build	Build	Possible Delay																	
Option 1 - Ullapool												Cost =	£32.62 per kW/yr											
Onshore Reinforcements Required																								
Beauly - Denny	Design	Planning		Build			Possible Delay																	
Offshore Connections Required																								
Lewis - Ullapool/ Beauly first half		Design	Planning	1st and 2nd Cable Installation			Possible Delay																	
Option 2 - Dalmally												Cost =	£38.31 per kW/yr											
Onshore Reinforcements Required																								
Dalmally Reinforcements	Design		Planning	Build		Possible Delay																		
Offshore Connections Required																								
Lewis - Dalmally first half		Design		Planning	First Cable Installation				Possible Delay															
Option 3 - Hunterston												Cost =	£40.50 per kW/yr											
Onshore Reinforcements Required																								
None																								
Offshore Connections Required																								
Lewis - Hunterston first half		Design		Planning	First Cable Installation					Possible Delay														

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Western Isles - Eishken		Design	Design	Planning			Build	Build	Possible Delay															
Option 1 - Ullapool												Cost =	£32.62 per kW/yr											
Onshore Reinforcements Required																								
Beauly - Denny	Design	Planning		Build			Possible Delay																	
Beauly - Blackhillock					Design	Planning	Build		Possible Delay															
Offshore Connections Required																								
Lewis - Ullapool/ Beauly first half		Design	Planning	1st and 2nd Cable Installation			Possible Delay																	
Option 2 - Dalmally												Cost =	£38.31 per kW/yr											
Onshore Reinforcements Required																								
Dalmally Reinforcements	Design		Planning	Build		Possible Delay																		
Offshore Connections Required																								
Lewis - Dalmally first half		Design		Planning	First Cable Installation				Possible Delay															
Option 3 - Hunterston												Cost =	£40.50 per kW/yr											
Onshore Reinforcements Required																								
None																								
Offshore Connections Required																								
Lewis - Hunterston first half		Design		Planning	First Cable Installation					Possible Delay														

Development By Development

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Western Isles - The Lewis Windfarm		Design	Design	Planning					Build	Build	Build	Possible Delay												
Option 1 - Ullapool												Cost =	£32.62	per kW/yr										
Onshore Reinforcements Required																								
Beauly - Denny	Design	Planning	Build			Possible Delay																		
Beauly - Blackhillock					Design	Planning	Build		Possible Delay															
Beauly - Keith							Design	Planning	Build		Possible Delay													
400 kV Ring						Design	Planning	Build			Possible Delay													
Interconnector	Unknown Timescale																							
Offshore Connections Required																								
Lewis - Ullapool/ Beauly second half		Design	Planning	1st and 2nd Cable Installation			Third Cable Installation			Possible Delay														
Option 1B - Ullapool with Peterhead Link												Cost =	£37.82	per kW/yr										
Onshore Reinforcements Required																								
Beauly - Denny	Design	Planning	Build			Possible Delay																		
Beauly - Blackhillock					Design	Planning	Build		Possible Delay															
Beauly - Keith							Design	Planning	Build		Possible Delay													
400 kV Ring						Design	Planning	Build			Possible Delay													
Peterhead - Hawthorn Pit		Design			Planning		Build			Possible Delay														
Offshore Connections Required																								
Lewis - Ullapool/ Beauly second half		Design	Planning	1st and 2nd Cable Installation			Third Cable Installation			Possible Delay														
Option 2 - Dalmally												Cost =	£38.31	per kW/yr										
Onshore Reinforcements Required																								
Dalmally Reinforcements	Design		Planning	Build		Possible Delay																		
Interconnector	Unknown Timescale																							
Offshore Connections Required																								
Lewis - Dalmally second half		Design		Planning	First Cable Installation				Second Cable Installation				Possible Delay											
Option 3 - Hunterston												Cost =	£40.50	per kW/yr										
Onshore Reinforcements Required																								
Interconnector	Unknown Timescale																							
Offshore Connections Required																								
Lewis - Hunterston second half		Design		Planning	First Cable Installation					Second Cable Installation					Possible Delay									
Option 4 - Deeside												Cost =	£46.69	per kW/yr										
Onshore Reinforcements Required																								
None																								
Offshore Connections Required																								
Lewis - Deeside second half		Design			Planning	First and Second Cable Installation								Possible Delay										

Development By Development

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Offshore - Beatrice								Design	Design	Planning		Build						Possible Delay						
Option 1 - Keith												Cost =	£25.55 per kW/yr											
Onshore Reinforcements Required																								
Beauly - Denny	Design	Planning		Build			Possible Delay																	
Beauly - Blackhillock					Design	Planning	Build		Possible Delay															
Beauly - Keith							Design	Planning	Build		Possible Delay													
400 kV Ring						Design	Planning	Build			Possible Delay													
Offshore Connections Required																								
Offshore - Keith							Design		Planning	Build			Possible Delay											

C Appendix – Detailed Costing Analysis

C.1 Overview

These cost breakdowns are based on budget quotations from manufacturers and costs from previous projects. These will obviously vary depending on the availability of the components, cost of metals, and the day rates of installation vessels. The costs do not include on-shore reinforcements, additional works, land or wayleaving costs, or permitting, as the aim is to provide a comparative assessment of the options provided. These additional costs will result in an increase the effective TNUoS charges. As these costs are typically a percentage multiple of the installation costs, then the TNUoS costs calculated here are suitable for the purposes of comparative analysis.

The Transmission Network Use of System (TNUoS) Tariff comprises of two separate elements. The first part is a locationally varying element to reflect the costs of capital investment and the maintenance and operation the transmission system. The second element is a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

As it would not be possible to replicate the NGT TNUoS tariff model to calculate the expected new TNUoS tariffs, the method used for this report is taken from the NGT publication "Illustrative Zonal Security Factors for Scottish Islands"[1]. This method annualises the unit investment cost by using a straight-line depreciation model over 40 years with a 6.25% regulated rate of return and a 1.8% annual Opex charge. This provides the incremental cost of the new link and it is added to the existing onshore TNUoS tariff at the point of connection.

The GBSO are proposing to introduce a discount in the TNUoS charges for connections that have a reduced security factor, either due to a single circuit link or multiple circuits with only partial capacity. The methodology for treatment of security factors and multiple cable links has not yet been developed. In the interim the method described above was deemed as representative for the purposes of this study. This method uses the actual project cost estimates and the existing onshore TNUoS charge to calculate the expected TNUoS charges for each scheme.

This methodology automatically provides a reduction based on the actual security that is provided because it uses the costs for the actual design being considered and not a fully redundant system.

[1] Received from NGT (GBSO)

C.2 Short-listed Options

C.2.1 Orkney

Subsea Cable		
132 kV AC	60 km	£18,200,000
Overhead Line (Wood Pole)		
132 kV OHL	35 km	£8,700,000
132 kV Switchgear		
Feeder Bays	4 units	£1,500,000
Transformer Bays	2 units	£700,000
33 kV Switchgear		
Transformer incomer panel	2 units	£200,000
Transformers		
132 /33 kV Transformer	2 units	£2,200,000
Cable Installation		£14,400,000
TOTAL INSTALLED EQUIPMENT COSTS		**£45,900,000**

Table C.1 - Option Two - 2 x 100MW option from Orkney to Thurso

Subsea Cable		
132 kV AC	60 km	£21,800,000
Overhead Line (Lattice Tower)		
132 kV OHL	35 km	£6,800,000
132 kV Switchgear		
Feeder Bays	4 units	£1,500,000
Transformer Bays	2 units	£700,000
33 kV Switchgear		
Transformer incomer panel	2 units	£200,000
Transformers		
132 /33 kV Transformer	2 units	£2,200,000
Cable Installation		£14,400,000
TOTAL INSTALLED EQUIPMENT COSTS		**£47,600,000**

Table C.2 – Option One - 2 x 180MW option from Orkney to Thurso

Option One - 2 x 180MW	
Site Capacity (MW)	200
Zone 1 (Northern Scotland) TNUoS Charges (£/kW/year)	£20.52
Additional Costs to provide connection (£/kW/year)	£20.07
Predicted TNUoS Charges for Zone 1A (Orkney)	**£40.59**
Option Two - 2 x 100MW	
Site Capacity (MW)	200
Zone 1 (Northern Scotland) TNUoS Charges (£/kW/year)	£20.52
Additional Costs to provide connection (£/kW/year)	£19.35
Predicted TNUoS Charges for Zone 1A (Orkney)	**£39.87**

Table C.3 - Comparative TNUoS charges for Orkney options

Option One - 2 x 180MW	
Site Capacity (MW)	200
Zone 1 (Northern Scotland) TNUoS Charges (£/kW/year)	£20.52
Additional Costs to provide connection (£/kW/year)	£10.04
Predicted TNUoS Charges for Zone 1A (Orkney)	**£30.56**
Option Two - 2 x 100MW	
Site Capacity (MW)	200
Zone 1 (Northern Scotland) TNUoS Charges (£/kW/year)	£20.52
Additional Costs to provide connection (£/kW/year)	£9.68
Predicted TNUoS Charges for Zone 1A (Orkney)	**£30.20**

Table C.4 - Comparative TNUoS charges for Orkney options (inc S185)

C.2.2 Shetland

	2 x 300 MW Links	2 x 500 MW Links
Converter Stations	£125,000,000	£125,000,000
Subsea Cable	350 km	350 km
300 kV VSC HVDC	£100,450,000	£200,900,000
Underground Cable	15 km	15 km
300 kV VSC HVDC	£8,610,000	£17,220,000
Cable Installation	£65,832,800	£65,832,800
TOTAL INSTALLED EQUIPMENT COSTS	**£299,892,800**	**£408,952,800**

Table C.5 - Option One - Shetland to Keith

	1 x 1000 MW Links	1 x 400 MW Links
Converter Stations	£131,700,000	£52,500,000
Subsea Cable	350 km	350 km
300 kV VSC HVDC	£203,000,000	£81,200,000
Underground Cable	15 km	20 km
300 kV VSC HVDC	£17,400,000	£9,280,000
Cable Installation	£88,730,000	£36,426,000
INDIVIDUAL LINK TOTAL COSTS	**£440,830,000**	**£179,406,000**
TOTAL INSTALLED EQUIPMENT COST		**£620,236,000**

Table C.5 - Option Two - Shetland to Keith and Norway

Option One - 2 x 300MW	
Site Capacity (MW)	600
Zone 1 (Northern Scotland) TNUoS Charges (£/kW/year)	£20.52
Additional Costs to provide connection (£/kW/year)	£42.13
Predicted TNUoS Charges for Zone 1B (Shetland)	**£62.65**
Option One - 2 x 500MW	
Site Capacity (MW)	600
Zone 1 (Northern Scotland) TNUoS Charges (£/kW/year)	£20.52
Additional Costs to provide connection (£/kW/year)	£57.46
Predicted TNUoS Charges for Zone 1B (Shetland)	**£77.98**
Option Two - Scottish Charges and Security	
Site Capacity (MW)	600
Zone 1 (Northern Scotland) TNUoS Charges (£/kW/year)	£20.52
Additional Costs to provide connection (£/kW/year)	£37.16
Additional Costs to provide security (£/kW/year)	£20.48
Predicted TNUoS Charges for Zone 1B (Shetland)	**£78.16**
Option Two - Costs Above Direct Interconnector	
Site Capacity (MW)	600
Zone 1 (Northern Scotland) TNUoS Charges (£/kW/year)	£20.52
Additional Costs to provide connection (£/kW/year)	£57.64
Predicted TNUoS Charges for Zone 1B (Shetland)	**£78.16**

Table C.6 - Comparative TNUoS charges for Shetland options

Option One - 2 x 300MW	
Site Capacity (MW)	600
Zone 1 (Northern Scotland) TNUoS Charges (£/kW/year)	£20.52
Additional Costs to provide connection (£/kW/year)	£21.07
Predicted TNUoS Charges for Zone 1B (Shetland)	**£41.59**
Option One - 2 x 500MW	
Site Capacity (MW)	600
Zone 1 (Northern Scotland) TNUoS Charges (£/kW/year)	£20.52
Additional Costs to provide connection (£/kW/year)	£28.73
Predicted TNUoS Charges for Zone 1B (Shetland)	**£49.25**
Option Two - Scottish Charges and Security	
Site Capacity (MW)	600
Zone 1 (Northern Scotland) TNUoS Charges (£/kW/year)	£20.52
Additional Costs to provide connection (£/kW/year)	£18.58
Additional Costs to provide security (£/kW/year)	**£10.24**
Predicted TNUoS Charges for Zone 1B (Shetland)	**£49.34**
Option Two - Costs Above Direct Interconnector	
Site Capacity (MW)	600
Zone 1 (Northern Scotland) TNUoS Charges (£/kW/year)	£20.52
Additional Costs to provide connection (£/kW/year)	£28.82
Predicted TNUoS Charges for Zone 1B (Shetland)	**£49.34**

Table C.7 - Comparative TNUoS charges for Shetland options (inc S185)

	Orkney to Keith	Shetland to Orkney	Shetland to Keith
Converter Stations	£62,500,000	£62,500,000	£62,500,000
Subsea Cable	125 km	250 km	350 km
300 kV VSC HVDC	£35,875,000	£71,750,000	£100,450,000
Underground Cable	15 km	20 km	15 km
300 kV VSC HVDC	£8,610,000	£11,480,000	£8,610,000
Cable Installation	£13,175,000	£24,650,000	£32,916,400
INDIVIDUAL LINK TOTAL COSTS	**£120,160,000**	**£170,380,000**	**£204,476,400**
TOTAL INSTALLED EQUIPMENT COSTS			**£495,016,400**

Table C.8 - Shetland to Keith via Orkney (500MW VSC HVDC links)

For Orkney Generators	
Site Capacity (MW)	200
Zone 1 (Northern Scotland) TNUoS Charges (£/kW/year)	£20.52
Additional Costs to provide connection (£/kW/year)	£21.64
Predicted TNUoS Charges for Zone 1A (Orkney)	**£42.16**
For Shetland Generators	
Site Capacity (MW)	600
Zone 1A (Orkney) TNUoS Charges (£/kW/year)	£42.16
Additional Costs to provide connection (£/kW/year)	£40.70
Predicted TNUoS Charges for Zone 1B (Shetland)	**£82.86**

Table C.9 - Comparative TNUoS charges for Shetland options via Orkney (500MW VSC HVDC links)

For Orkney Generators	
Site Capacity (MW)	200
Zone 1 (Northern Scotland) TNUoS Charges (£/kW/year)	£20.52
Additional Costs to provide connection (£/kW/year)	£10.82
Predicted TNUoS Charges for Zone 1A (Orkney)	**£31.34**
For Shetland Generators	
Site Capacity (MW)	600
Zone 1 (Northern Scotland) TNUoS Charges (£/kW/year)	£20.52
Additional Costs to provide connection (£/kW/year)	£31.17
Predicted TNUoS Charges for Zone 1B (Shetland)	**£51.69**

Table C.10 - Comparative TNUoS charges for Shetland options via Orkney (500MW VSC HVDC links) (inc S185)

C.2.3 Western Isles

	2 x 500MW	**3 x 350MW**
Converter Stations	£105,000,000	£125,000,000
Subsea Cable	90 km	90 km
150 kV VSC HVDC	£74,625,882	£64,492,941
Underground Cable	80 km	80 km
150 kV VSC HVDC	£66,334,118	£57,327,059
Cable Installation	£40,040,000	£40,180,000
TOTAL INSTALLED EQUIPMENT COSTS	**£286,000,000**	**£287,000,000**

Table C.11 Option One - Lewis to Beauly (VSC HVDC)

	Lewis to Dalmally	Lewis to Hunterston	Lewis to Deeside
Converter Stations	£105,000,000	£125,000,000	£125,000,000
Subsea Cable	180	420	600
150 kV VSC HVDC	£172,324,528	£240,751,304	£348,932,308
Underground Cable	85	40	50
150 kV VSC HVDC	£81,375,472	£22,928,696	£29,077,692
Cable Installation	£63,300,000	£85,320,000	£117,990,000
TOTAL INSTALLED EQUIPMENT COSTS	**£422,000,000**	**£474,000,000**	**£621,000,000**

Table C.12 Option Two, Three & Four - Lewis (VSC HVDC)

Option One	A	B
Site Capacity (MW)	1000	1000
Zone 2 (Northern Scotland) TNUoS Charges (£/kW/year)	£20.52	£20.52
Additional Costs to provide connection (£/kW/year)	£24.19	£24.11
Predicted TNUoS Charges for Zone 1C (Western Isles)	**£44.71**	**£44.63**
Option Two		
Site Capacity (MW)	1000	
Zone 6 (Cruachan) TNUoS Charges (£/kW/year)	£13.52	
Additional Costs to provide connection (£/kW/year)	£35.57	
Predicted TNUoS Charges for Zone 1C (Western Isles)	**£49.10**	
Option Three		
Site Capacity (MW)	1000	
Zone 9 (South Scotland) TNUoS Charges (£/kW/year)	£12.14	
Additional Costs to provide connection (£/kW/year)	£39.96	
Predicted TNUoS Charges for Zone 1C (Western Isles)	**£52.10**	
Option Four		
Site Capacity (MW)	1000	
Zone 14 (South Yorks and North Wales) TNUoS Charges (£/kW/year)	£3.84	
Additional Costs to provide connection (£/kW/year)	£52.35	
Predicted TNUoS Charges for Zone 1C (Western Isles)	**£56.19**	

Table C.13 - Comparative TNUoS charges for Lewis options

Option One	**A**	**B**
Site Capacity (MW)	1000	1000
Zone 2 (Northern Scotland) TNUoS Charges (£/kW/year)	£20.52	£20.52
Additional Costs to provide connection (£/kW/year)	£12.10	£12.05
Predicted TNUoS Charges for Zone 1C (Western Isles)	**£32.62**	**£32.57**
Option Two		
Site Capacity (MW)	1000	
Zone 6 (Cruachan) TNUoS Charges (£/kW/year)	£13.52	
Additional Costs to provide connection (£/kW/year)	£24.79	
Predicted TNUoS Charges for Zone 1C (Western Isles)	**£38.31**	
Option Three		
Site Capacity (MW)	1000	
Zone 9 (South Scotland) TNUoS Charges (£/kW/year)	£12.14	
Additional Costs to provide connection (£/kW/year)	£28.36	
Predicted TNUoS Charges for Zone 1C (Western Isles)	**£40.50**	
Option Four		
Site Capacity (MW)	1000	
Zone 14 (South Yorks and North Wales) TNUoS Charges (£/kW/year)	£3.84	
Additional Costs to provide connection (£/kW/year)	£42.86	
Predicted TNUoS Charges for Zone 1C (Western Isles)	**£46.69**	

Table C.14 - Comparative TNUoS charges for Lewis options (inc S185)

C.2.4 Beatrice Offshore Windfarm

Subsea Cable (6x180MW)	25 km
132 kV AC	£27,576,000
Transformer Bays	6 units
132/275 kV	£28,220,400
Overhead Line	15 km
275 kV OHL	£14,052,960
Cable Installation	£18,000,000
TOTAL CONNECTION COSTS	**£59,628,960**

Table C.15 Option One - Beatrice Offshore Windfarm to Keith

Option One	
Site Capacity (MW)	1000
Zone 1 (Northern Scotland) TNUoS Charges (£/kW/year)	£20.52
Additional Costs to provide connection (£/kW/year)	£5.03
Predicted TNUoS Charges for Zone 1D (Offshore)	**£25.55**

Table C.16 - Comparative TNUoS charges for Beatrice Offshore Windfarm options

C.2.5 Bulk Transfer HVDC links

	Peterhead to Cockenzie	**Peterhead to Hawthorn Pit**	**Peterhead to Walpole**	**Hunterston to Deeside**
Converter Stations	£106,800,000	£106,800,000	£106,800,000	£106,800,000
Subsea Cable	200km	300km	550km	350km
500 kV CSC HVDC	£125,490,000	£189,850,000	£347,775,000	£221,600,000
Cable Installation	£34,710,000	£52,350,000	£96,425,000	£61,600,000
TOTAL CONNECTION COSTS	**£267,000,000**	**£349,000,000**	**£551,000,000**	**£390,000,000**

Table C.17 - Bulk Transfer Link Costs

Peterhead to Cockenzie	
Zone 1 (Peterhead) TNUoS Charges (£/kW/year)	£18.39
Zone 9 (Southern Scotland) TNUoS Charges (£/kW/year)	£12.14
Costs to provide connection (£/kW/year)	£11.25
Charges to Use Connection (£/kW/yr)	**£5.00**
Peterhead to Hawthorn Pit	
Zone 1 (Peterhead) TNUoS Charges (£/kW/year)	£18.39
Zone 10 (North East England) TNUoS Charges (£/kW/year)	£8.89
Costs to provide connection (£/kW/year)	£14.71
Charges to Use Connection (£/kW/yr)	**£5.20**
Peterhead to Walpole	
Zone 1 (Peterhead) TNUoS Charges (£/kW/year)	£18.39
Zone 15 (Midlands and South East) TNUoS Charges (£/kW/year)	£1.22
Costs to provide connection (£/kW/year)	£23.22
Charges to Use Connection (£/kW/yr)	**£6.05**
Hunterston to Deeside	
Zone 9 (Southern Scotland) TNUoS Charges (£/kW/year)	£12.14
Zone 14 (South Yorks and North Wales) TNUoS Charges (£/kW/year)	£3.84
Costs to provide connection (£/kW/year)	£16.44
Charges to Use Connection (£/kW/yr)	**£8.13**

Table C.18 - Comparative usage charges for Bulk Transfer links

C.3 Discarded Options

The original methodology was to investigate links to the south of onshore constraints. The early investigations found that that the existing Scotland/England inter-connector constraints are not commercially binding for most developments.

The following options are some of those considered but were not economically favourable, or did not result in shorter connection timescales.

C.3.1 Island Grid Network

There has been some discussion on whether a Scottish Island Grid network would enable one single connection to the mainland and with co-ordination between the various developers, may enable a more efficient and timely connection option.

The technical characteristics of HVDC means that they are best suited to A-B links not networks. A significant part of the costs are the converter stations, which are required at each location that you need to connect and so multiple connections require multiple converters.

The connection of both Orkney and Shetland in one ring was discussed in Section 3. However onshore reinforcements such as adding second circuits to existing towers and re-conductoring existing routes are both cheaper and quicker than offshore subsea connections. Therefore, joining Orkney to Lewis and then into the mainland system would not provide any significant benefits. It would require an expensive and challenging link from Orkney to Lewis rather than a direct link to Thurso and would only avoid the Beauly-Dounraey upgrade work.

C.3.2 Connections to Peterhead from the North

These connections would require the cable to cross up to 22 pipelines. As this would cause significant design, installation and project management costs and would impact the timeline of the project significantly, without reducing the requirements for onshore reinforcements. Given the significantly more straight-forward connection available near Keith, then further consideration of this option was not undertaken.

C.3.3 Connections to Longannet

A connection into Longannet would follow the same route as a connection to Cockenzie but would need to negotiate the inner parts of the Firth of Forth with no timescale or capacity benefits so it was not considered further.

C.3.4 Connections to Heysham or Liverpool

Significant on-shore reinforcements are required on the 400kV network around Heysham. These works are already under investigation to facilitate planned onshore and offshore generation. However, the time-scales are not fully developed. In addition, any generation connection to this part of the network will be subject to the North-South flows on the Western Scotland/England interconnector. These flows are already causing constraints, so the addition of 600-1000MW would not be possible. Therefore this option was not considered further as the required network capacity was not likely to be available within any reasonable timeframe.

C.3.5 Connections to Hunterston and on to England/Wales

An alternative to major onshore reinforcements would be a connection into Hunterston and a 'Bulk Transfer' connection from Hunterston to England or Wales. This is likely to be a more cost efficient design than a dedicated subsea cable from the Western Isles direct to England or Wales. However, it would be more difficult to achieve than a 'Bulk Transfer' offshore link down the East coast due to the seabed conditions and the need to negotiate munitions dumps and gas pipelines.

A connection directly into Hunterston without the additional Bulk Transfer link to England or Wales has already been discussed in detail in the main report.

C.3.6 Connections to Anglesey, Deeside, and Pembroke

As well as a connection to Deeside, connections to Wylfa (Anglesey) and Pembroke were also considered, but the available capacities at these points in the network are very dependent on other generation connections. This means that the increased cost of connection was highly unlikely to be outweighed by the available network capacity.

Pembroke is unlikely to have capacity available in the near future due to planned additional new CCGT generation (2400MW) as well as the wind generation from the Tan-8 developments in Wales. Increasing this on-shore capacity would require significant re-conductoring work on the 400kV system, as well as upgrading the Severn crossing.

Network capacity at Wylfa is limited due to existing generation capacity. There are recent suggestions of a new 500MW link with EirGrid (Ireland), which may require additional reinforcement of the 400kV network. However, there is a known constraint across the transmission boundary in Cheshire due to the North-South interconnector flows. It is likely that additional reinforcement would be required to relieve this boundary constraint in order to accept an additional 600-1000MW from a North-Wales or Merseyside connection.

The initial cost and time analysis of the required lengths of HVdc links suggested that none of these would result in more timely or affordable connections than the more direct alternatives. A significant factor is that fact that such a connection would have a low utilisation due to the low capacity factor of wind generation.

C.3.7 Connections to South West

It was determined that there would be sufficient network capacity available for the connection of the proposed generation at Indian Queens in the South West of England. However, the significant increase in connection costs, timescales and the risk of faults on the subsea cables due to the very long distances mean that this option can provide no discernable benefit to the connecting parties. Therefore it was not considered further.

C.3.8 Connections to Northern Ireland or Republic of Ireland

Connections to either the Northern Ireland Electricity (NIE) network or the EirGrid network in the Republic of Ireland were considered but with the current high level of wind generation applications in Northern Ireland and the Republic of Ireland, an additional connection of this size was unlikely to be feasible or achieve any timescale improvements.

There have been recent suggestions of a new 500MW link from the Republic of Ireland to North Wales. However it is unlikely that this would provide any benefit to a connection from the Western Isles into the Northern Ireland or Republic of Ireland grids due to onshore network constraints.

C.3.9 Airtricity and SuperGrid

There has been much discussion recently about a proposal put forward by the wind farm developer Airtricity about a large scale network of offshore wind farms. The proposal is to form a "supergrid" of subsea HVDC connections linking different countries via offshore windfarms. This would allow both the supply of renewable generation to the countries from the wind farms as well as providing trading links between the different power systems. The Scotland to Norway interconnector via Shetland option is based on this same idea.

A request was made by HIE to discuss the SuperGrid project with Airtricity to determine if there were any possible synergies with the Scottish Island connections.

A useful discussion was held; however the initial phases of the SuperGrid are envisaged to be too far south i.e. the Wash and Southern North Sea, for there to be any practical or commercial benefit in linking these projects. It was agreed however, that both projects would benefit from the profile being raised of the ability of VSC HVDC to link "offshore" generation islands to the mainland grids.

C.3.10 North Sea Oil Platforms

Recently, HVDC links have been made from the onshore networks to Offshore oil platforms in the North Sea to provide them with the power they need to run their compressors and to enable the platforms to be operated 'unmanned'. The Talisman Beatrice Oil Platform is currently installing 2 offshore wind turbines to provide the energy required for that operation. There is a discussion as to whether the energy generated on the Scottish Islands, especially Shetland, may be able to provide power to the nearby Oil Platforms in the North Sea by way of an offshore grid. This was not considered further in this report as oil platform energy requirements are quite small compared with the proposed installations, and the distances involved are significant.

(http://www.abb.com/cawp/gad02181/c1256d71001e0037c1256c17002dabad.aspx)

D Appendix – Commercial and Regulatory Overview

This section provides an overview of the non-technical factors that may influence the connection of renewable generation on the Scottish Islands.

D.1 Roles and Responsibilities

It is important to understand the roles and responsibilities of the key industry participants, including the DTI, the regulator OFGEM, and the transmission and distribution companies. This is because their designated responsibilities and licence conditions have a significant impact on the way they treat all generation connections onto the Great Britain grid.

D.1.1 The DTI

The Department of Trade and Industry's (DTI) Energy Group deals with a wide range of energy related matters. Its responsibility is to ensure that there is an energy strategy that provides competitive energy markets while achieving safe, secure and sustainable energy supplies. Its role is to establish a fair and effective framework in which competition can flourish for the benefit of customers, the industry and suppliers, and which will contribute to the achievement of the UK's environmental and social objectives. These include, amongst other things, renewable energy targets.

The DTI Energy Group also administers legislation such as the Electricity Act 1989, The Utilities Act 2000, and the Energy Act 2004, and it determines the licence conditions for supply, distribution, transmission and generation activities.

D.1.2 OFGEM

The day-to-day regulation of the gas and electricity industries are carried out by the regulator for the gas and electricity markets (Ofgem). The Office for Gas and Electricity Markets (Ofgem) is responsible for the provision of safe, secure, diverse and sustainable supplies of energy at competitive prices. Its primary duty is to protect the interests of GB customers where possible through the promotion of effective competition. In particular, its role is to ensure the gas and electricity markets work effectively, regulating monopoly businesses, securing a diverse and long-term energy supply , and at the same time meeting its social and environmental responsibilities.

Ofgem sets the transmission and distributions price controls where the Transmission Owners (TOs) and Distribution Network Operators (DNOs) agree their investment and operating costs in the context of their allowed revenues over the next five years.

Ofgem also manages the Renewables Obligation but has stated clearly that it is outside of Ofgem's legal vire to provide a subsidy to renewable (or any other) generators.

D.1.3 The Great Britain System Operator (GBSO) Role

The GBSO is the system operator for England, Wales and Scotland (as of April 2005 with the introduction of BETTA). The National Grid Company (now part of National Grid Transco) undertakes this role and has responsibility for balancing overall generation and demand while operating the system in a secure, efficient, economic and coordinated manner. In general, the system is intended to balance itself with generators and suppliers contracting bilaterally for their outputs and demands. However, there is a need to manage this whilst ensuring that the entire system remains within safe operating limits, and that the pattern of generation and demand is consistent with any transmission system related constraints. This includes the purchase and sale of electricity to keep the transmission system in energy balance in real time.

The wholesale electricity market trades and settles (generators selling electricity and suppliers buying electricity) for each 48 half-hourly period during every day of the year. Those parties who depart from their contracted volumes face an imbalance cash-out charge in the central settlement system operated by Elexon. The balancing mechanism provides a tool whereby the SO can accept offers and bids for electricity at very short notice to 'fine tune' the balancing needs of the system for the trading half hour. In this role of balancing the system, costs are incurred for which the electricity consumer ultimately pays. The regulator, Ofgem, provides a financial incentive to encourage the GBSO to manage this balancing taking account of transmission constraints in a cost effective manner.

The GBSO also has responsibility for providing connection to, and use of, the GB transmission system to those who seek it. The transmission owners; National Grid Electricity Transmission Limited Company in England and Wales and Scottish Power Transmission Limited and Scottish Hydro-Electric Transmission Limited in Scotland provide the necessary transmission services to enable the GB system operator to offer connection and use of system terms. Connection and "use of system" procedures are documented in the Connection and Use of System Code (CUSC) and the interface between system operator and transmission owner is managed through a SO-TO code. The GBSO is also required to maintain the Grid Code.

D.1.4 The Transmission Owner (TO) Role

The TOs are responsible for building and maintaining the grid infrastructure. In Scotland, Scottish Power Transmission Limited (SPTL) in the Scottish Power region and Scottish Hydro-Electric Transmission Limited (SHETL) in the Scottish Hydro Electric region (now part of Scottish & Southern Energy plc.) undertake this role. In England and Wales, National Grid Electricity Transmission Limited (NGET) undertakes this role.

As licensed transmission owners they are subject to conditions in terms of how they treat connectees and users of their systems. They are also obliged to offer the lowest cost options in line with developing and maintaining an economic, efficient and co-ordinated transmission network, facilitating competition in the supply and generation of electricity. They are not allowed to show any bias in the provision of network access to Users.

D.2 Transmission Price Control

As monopoly businesses, the Transmission Owners are regulated by Ofgem, which sets a price control period in which revenues from connections and use of system charges are controlled along with expenditure on new capital infrastructure and operating costs. There is currently a price control review underway to provide direction for the 2007-2012 period. The last price control reviews were in 1999 for SPTL and SHETL and 2000 for NGET.

Generation and Demand customers drive the development of the GB Transmission System. In order to accommodate these users, the Transmission Owners will often need to reinforce the transmission network. If these transmission reinforcements are carried out efficiently then they will be allowed to form part of the Transmission Licensees' regulated asset base. The cost of the investments can then be recovered from all transmission Users via the Transmission Network Use of System (TNUoS) Charges and Connection Charges, which use a cost reflective methodology.

D.3 Connection and TNUoS Charges

To connect into the GB transmission network, it is necessary for a developer to pay the appropriate connection charges for the provision of their connection, and subsequently annual Transmission Network Use of System (TNUoS) charges.

D.3.1 Connection Charges

Network connections and infrastructure assets are designed by transmission owners; in accordance with their duties and security standards. These standards provide for transmission users to express choice concerning the design of the network where this choice would not adversely affect other users in terms of cost or reliability.

The connection charges are site-specific asset-based charges that fund the establishment and maintenance of transmission assets that form the immediate connection of a directly connected transmission customer which are not and would not normally be used by any other connected user. Previously, a generator connecting into the Transmission network would pay an asset based charge for the costs of the dedicated substation assets and a proportion of the costs of the assets required to connect this substation to the remainder of the transmission system.

As part of its consultation on GB charging arrangements, the GBSO brought forward proposals for a "Plugs" model for connection charging, where the Plug comprises the single user connection assets between the user and the substation. Substation assets would be no longer classed as connection assets but instead would be classed as infrastructure and so recovered via the TNUoS charge. Also, dedicated spurs to generators would also be classed as infrastructure.

These shallow connection charges significantly reduce the charges generators would have to pay up front to connect to the transmission network. Ofgem considers that shallow connection charging arrangements promote effective competition as they ensure parties are not disadvantaged on the basis of when and where they connect to the network.

D.3.2 Transmission Network Use of System Charges

The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

The calculation of the locationally varying element takes into account the cost of the circuit infrastructure to cope with both intact and secured outage conditions, with the latter achieved by applying the locational security factor.

TNUoS charges are applicable to both generation and demand and are levied on suppliers, generators and inter-connector asset owners. Generators connected to a distribution network, which in Scotland are network voltages of 33kV and below, are classified as Embedded. Embedded generators that are not capable of exporting 100MW or more to the total system, and do not intend to use the transmission system, are not liable for TNUoS charges.

Figure D.1 shows the current TNUoS charging zones for the GB system as taken from the latest Seven Year Statement.

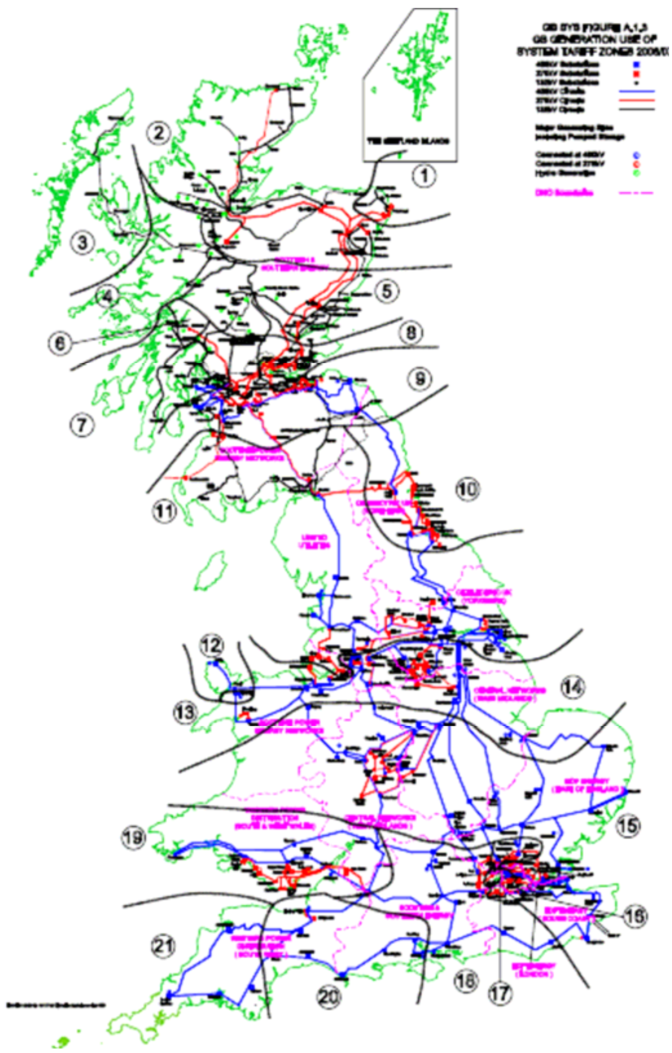


Figure D.1 Generation TNUoS Charging Zones

To determine the generation tariff that will be applied in any area, the locational element of the TNUoS tariff is derived as follows. A linearised loadflow Incremental Cost Related Pricing model is used to calculate the marginal costs of investment in the transmission system that would be required for an increase in generation at each connection point. Marginal costs are calculated initially in terms of increases or decreases in units of kilometres of the transmission system for a 1MW injection (£/MW-km).

Given the requirement for relatively stable cost messages, connection points are assigned to zones. The zonal marginal km are converted into costs and hence a tariff by multiplying by the annuitised value of the transmission infrastructure capital investment required to transport 1MW over 1km derived from the projected cost of 400kV overhead line and the locational security factor. Circuit expansion factors are used to model other circuit types (e.g. 275kV underground cable).

D.4 Section 185 of the Energy Act 2004

As the generation connections discussed in this report are all located in Northern Scotland, which is geographically removed from the main demand centre in the South East of England, the locational element of the TNUoS tariff for these connections is likely to be quite high.

The Government were enabled under Section 185 of the Energy Act 2004 to adjust transmission charges for renewable generators in a specified area of Great Britain if the charge would otherwise deter renewable development in that area. The Government announced in March 2005 that the power would be exercised to support renewable generation in the Scottish islands of Shetland, Orkney and the Western Isles.

As projects in the islands were not likely to be generating electricity until the beginning of the next decade, there is some uncertainty as to how effective this will be in encouraging generation connections. This is because the existing power in the Energy Act (s.185) would only allow a scheme to adjust transmission charges to be in place until 2014 with reviews at the end of every 5 year period. The Climate Change and Sustainable Energy Act recently passed in parliament extended this cut-off date to 2024 but with the reviews still required every 5 years, there is no guarantee that it will be extended until the cut-off date.

There are two options being discussed for the implementation of this reduction in transmission charges:

(a) 50% of the value above £25/kW

(b) 50% of value above the highest existing charging zone (£20.52 for Northern Scotland)

If the expected TNUoS charge for an Island Zone was £45/kW, then under option (a) the reduced charge would be £35/kW and under option (b) it would be £32.76/kW.

D.5 Security Factors

The GB Security and Quality of Supply Standard (SQSS) includes criteria for variations to connection designs based on customer's request as long as they do not:-

1. reduce the security of the main interconnected transmission system below the minimum planning criteria specified in the SQSS standard;

2. result in additional investment or operational costs to any particular customer or overall, or a reduction in the security and quality of supply of the affected customers' connections to below the planning criteria in the standard, unless specific agreements are reached with affected customers; or

3. compromise the Transmission Owners (TOs) ability to meet other statutory or licence obligations.

These criteria would allow a single circuit connection to a generator so long as the generator accepted that they would have uncompensated access restrictions in the event that the single circuit is unavailable as a result of a fault outage or maintenance outage.

Prior to the implementation of "Plugs" a customer choosing a lower standard of connection design had a proportion of the capital savings directly reflected in lower connection charges. It was then able to compare the savings with the loss of revenue caused by the associated access restrictions. They would then be able to choose the most efficient connection design. Now, since infrastructure assets are funded from use of system rather than connection charges, the savings are no longer passed directly through to the generator so alternative methods for encouraging an efficient connection design are required.

The GBSO consulted on four options for modifying the TNUoS charging arrangements to provide a mechanism by which the capital savings associated with SQSS connection design variations are passed through to customers. In its recent consultation is set out a preference for an approach based on the use of a circuit and substation discount factor. The circuit discount factor would be determined from a process consistent with that used to calculate locational security factor.

The substation discount factor would be calculated from the cost difference between standard substation designs required to accommodate single and double circuit connections. A single cable with a rating equal to the required capacity would have a security factor of 1.0, a double cable connection with each cable having a rating equal to the required capacity would have a security factor of 2.0 and a double cable connection with each cable having a rating of half of the required capacity would have a security factor of 1.0. In this case, a multiple cable expansion factor may be required to ensure cost reflectivity.

The resultant TNUoS tariffs would not proportionally reflect reduced security factors. For example, the TNUoS charge resulting from using a security factor of 1 would not be half of that resulting from a security factor of 2. This is because only the new connection assets would have this reduced security, the system beyond this has a much higher security so the user would have to meet the full TNUoS for the system beyond the restriction.

If the GBSO's preferred solution is implemented the generator would also have to accept the risk that the connection may be modified to a double circuit connection in the future. This may be for reasons completely beyond their control should for example another generator wish to connect. Whilst the generator would lose the single circuit (circuit and substation) discount factor, they would no longer need to accept any uncompensated access restrictions.

D.6 Renewables Obligation Certificates

The new Renewables Obligation and associated Renewables (Scotland) Obligation came into force in April 2002 as part of the Utilities Act (2000). It requires electricity suppliers to derive from renewables a specified proportion of the electricity they supply to their customers. This started at 3% in 2003, rising gradually to 15% by 2015. The obligation is guaranteed in law until 2027.

Eligible renewable generators receive Renewables Obligation Certificates (ROCs) for each MWh of electricity generated. These certificates can then be sold to suppliers, in order to fulfil their obligation. Suppliers can either present sufficient certificates to cover the required percentage of their output, or they can pay a 'buyout' price for any shortfall. The "buyout price" rises in line with inflation each year. It caps the costs of the obligation to suppliers and, in turn, consumers.

The obligation was due for a comprehensive review in 2005/2006 but was delayed and the review is currently underway. It was intended to review how the RO may be used to support renewables in the long term but this has caused some uncertainty amongst developers as they are unsure how it will affect onshore wind projects and the delays are adding to this anxiety.

The energy review in 2006 did indicate a desire to stimulate significant growth in renewable micro-generation technologies and emerging technologies.

To ensure that the RO remains supportive of renewables development the energy review identified the following steps:

1. extending Obligation levels to 20% (when justified by growth in renewable generation);

2. amending the RO to remove risk of unanticipated ROC oversupply; and

3. adapting the RO to provide greater support to emerging technologies and less support for established technologies. The Government's preferred option for achieving this is through a "banding" system, ensuring that current ROC rights for existing projects and for those built prior to implementation of changes are preserved. Any changes would be introduced in 2010.

The first two steps would have a stabilising effect on the ROC market but the third step – "banding" may reduce the number of ROCs available to onshore wind projects unless they are built, commissioned and are producing electricity prior to 2010.

The increases in Obligation levels above 15.4% will not occur at pre-determined stages, as with existing announcements, but will follow a "guaranteed headroom" model, where increases are contingent upon appropriate levels of growth in renewables generation up to a maximum of 20%.

To ensure the costs to consumers associated with the Obligation are acceptable, there is also an intention that the commitment to extend Obligation levels to 20% will be made cost neutral by freezing the ROC buyout price from 2015.

If the RO were to be banded, projects that become operational after this change comes into effect will receive the number of ROCs determined by their band. This value would not be reduced for the lifetime of the project, irrespective of subsequent changes. The position of projects and investors would therefore be protected, subject to further changes to the RO.

D.7 Transmission Entry Capacity (TEC) and TEC trading

Transmission Entry Capacity (TEC) is a term that defines a generator's rights to access the transmission system on a long-term basis.

If a generator is seeking additional TEC, or a new generator is seeking an initial allocation of TEC, this may be done by submitting an application to the GBSO. The GBSO has a licence obligation to offer terms to all parties seeking access to the GB transmission system. If the GBSO considers that TEC allocation would require network reinforcements then the connection offer for TEC that it would provide would be on an "invest-then-allocate" basis.

Under the CUSC amendment proposal CAP068, this TEC can be traded. If there is a willing seller of TEC, parties may wish to negotiate bilaterally for the purchase of that TEC.

The GBSO would calculate the appropriate Exchange Rate at the same connection point or between different connection points. This Exchange Rate would be used in the calculation of the TEC that would be made available to a specific party as a direct result of a specific reduction in the TEC by the other party whilst keeping the system compliant with the SQSS.

D.8 Firm / Non- Firm Connections

Generators that do not have any TEC do not have the right to export energy on to the transmission network. There are currently a number of short-term TEC products (Short term TEC and Limited Duration TEC) available that allow generators to connect and export prior to their enduring TEC becoming available. Generators with TECs are said to have 'commercially firm' access rights and these proposals would allow 'commercially non-firm' access rights.

These short-term access rights would allow a generator to connect to the network and export energy as long as capacity is available in operational timescales without exacerbating transmission constraints, i.e. when demand level, transmission and generation outages are considered. It should be noted that these products are 'firm' albeit for a defined time period. 'Non-firm' products (where access can be withdrawn without compensation) are not seen as useful to users at this stage.

D.9 Final Sums Liability and User Commitment

To ensure that transmission work is not undertaken that ends up being unnecessary, a financial commitment is required from the connecting party. This forms a bond against the required works such that if part way through a particular reinforcement the user that triggered it withdraws, then instead of the monies spent being borne by other users, it is actually borne by the withdrawing party.

Final Sums are the abortive costs incurred in reinforcing the transmission system that arise when works are no longer required when the user's agreement is terminated.

Currently, the users (or user) that triggered the reinforcement are liable for the full costs of the work. Especially if the reinforcement becomes unnecessary in the event of one of them pulling out. For some circumstances where the deeper reinforcements are going to cost multi-millions of pounds, then this becomes extremely difficult for developers to justify for particular projects.

Recently, a voluntary option for final sums (or user commitment) has been introduced. To provide the GBSO with reassurance that the connection is required, the developer will be required to put up £1/kW each year (up to a maximum of £3/kW) prior to the Transmission Owner gaining consents for the reinforcement work. Once consents have been obtained, the developer will need to provide 2.5 times the final TNUoS charges for the connection in the 1st year, 5 times this TNUoS charge in the 2nd year, 7.5 times in the 3rd year and 10 times in the 4th year.

There is currently a proposal (CAP-131) to formalise these user commitment signals in the industry codes using the voluntary scheme as a basis. As such the, this scheme is indicative of what the final arrangements, if approved, could look like. The main changes to the proposal are that once consents have been obtained, the developer will need to provide 1.5 times the final TNUoS charges for the connection in the 1st year, 3 times this TNUoS charge in the 2nd year, 4.5 times in the 3rd year and 6 times in the 4th year.

Under most circumstances, this will reduce the security provision required and remove the volatility of that security requirement, as it will not change if other developers withdraw. It will also advance the commitment required by most generators with the aim of deterring speculative connection applications.

Once the generator is connected, in the event a generator reduces TEC without providing the GBSO with 2 years notice, the generator would be liable to pay 2 times the generation TNUoS tariff multiplied by the reduction in capacity.

E Appendix – Technology Overview

This section introduces and discusses the technical issues associated with the connection of renewable generation on the Scottish Islands.

E.1 Transmission Technology Issues

A key aspect of developing an efficient and flexible transmission network is the ability to interconnect, transport and distribute in a cost effective manner. This is true of most transport networks such as electricity, gas, water, railways, roads and communications.

For electrical energy networks, Alternating Current (AC) technology has the inherent ability to easily expand and tap into as well as transform between different voltage levels and split power away. This is why it is used as the basis of the GB grid. Different voltage levels are used, as losses are proportional to the square of the current so with a higher voltage level, the same power can be transmitted with a lower current so significantly reducing the losses for the same amount of power transfer.

Direct Current (DC) transmission technology has inherent control advantages over AC transmission as it becomes possible to redirect power flows and provide controlled response to system disturbances. Unlike AC technology though, DC requires converters to transform between voltage levels, or to convert to AC.

The interconnection of a DC network also has significant issues when it comes to protection in the event of faults. This requires complex additional equipment and so there are very few interconnected DC network installations in the world.

Consequently, DC or HVDC (high Voltage Direct Current) is primarily used for point-to-point bulk energy transport transmission. It is not well suited for multiple interconnections due to the need for a converter station at each connection of the DC link as well as the security and cost implications of a DC line fault. Most HVDC schemes in the world have been implemented as either bulk power transmissions across long overland distances or subsea crossings, controllable interconnections between two AC systems, or the coupling of different frequency systems.

Therefore, the selection of the most appropriate technology requires a multi-faceted decision involving not just the case at hand and prime cost, but also consideration of future development needs and the need for flexibility.

E.2 High Voltage Direct Current (HVDC)

HVDC is now considered to be a mature transmission technology. A recent document suggested that in 2005 there was worldwide installed HVDC capacity of 55GW (GB peak demand is approximately 60GW as a reference).

The main advantages that are generally claimed for the use of HVDC are:

1. DC lines have lower losses than equivalent AC lines but higher terminal costs and losses

2. AC cables are impractical over long distances but this is not a problem for DC

3. DC connection can connect AC systems with different frequencies or control philosophies

4. Powerflow can be easily controlled at high speed in a DC scheme

There are three dominant suppliers of HVDC technology, ABB, Areva, and Siemens. Each offer both the "conventional" and "new" forms of the technology but they use different terms to describe them. At this stage, only ABB have reference projects using the "new" form of VSC HVDC.

	"Conventional"	**"New"**
Generic Description	Current Sourced (CSC) HVDC	Voltage Sourced (VSC) HVDC
Typical Size	500MW – 4000MW	50MW – 750MW
Voltage (dc)	250kV – 800kV	80kV - 300kV
Technology	Thyristor	IGBT
ABB terminology	HVDC Classic	HVDC Light
Areva terminology	HVDC	VSC HVDC
Siemens terminology	HVDC	HVDC Plus

Table E.1 Comparison of HVDC technologies

At present these two forms of HVDC are considered to be incompatible on the same DC system. This is primarily because the voltage-sourced technology maintains a constant voltage with the current directly being reversed to achieve power reversal. The current sourced technology however maintains a constant current with the voltage polarity being reversed to achieve a power reversal.

Although theoretically possible to have a hybrid system of some form, with VSC on the island end and CSC on the network end, it is unclear as to whether this actually provides a more cost effective solution, or even if it is would be able to achieve a sufficient technical capability. However, this is a blue-sky issue at the moment as it is not a commercially available or proposed configuration.

E.2.1 HVDC Terminology

Some of the terminology used to describe HVDC installations:

Monopole – A single HVDC unit with a positive circuit and either the return circuit being either earth/sea return (single conductor) or metallic return (two conductors)

Bipole – Two Monopoles with one positive circuit and one negative circuit. The current flows out on the positive circuit and back on the negative circuit so no third return circuit is necessary. This doubles the power of a single monopole while still only using two conductors

Back-to-Back – This is an HVDC link with no transmission line, both converters are in the same building. These schemes are used to link AC systems that either operate at different frequencies, or cannot be linked directly with AC transmission due to stability problems.

Group Connected – These are HVDC schemes where the sending end is directly connected to a group of generators to provide a dedicated export of the generated energy.

E.2.2 Current Sourced HVDC

The vast majority of HVDC schemes are implemented using current sourced technology. The converters are line-commutated converters typically using low loss electrically triggered or light triggered thyristors. These devices have a controlled turn-on, but require the AC system to turn them off by forcing the current to zero. Consequently, CSC HVDC schemes need strong AC networks for both converter stations to connect into, as this is needed for the operation of its conversion process. A typical minimum is a Short-Circuit Ratio (SCR) of at least 3.0, although with additional equipment it is possible to go as low as 2.0. A simple description of the short-circuit ratio is the ratio of the HVDC link rating to the amount of generation on the network.

In addition, the converter stations operate at a lagging power factor of about 0.85 and so need considerable reactive power compensation and harmonic filtering. This results in the need for a reasonably large footprint for the HVDC station in addition to the usual requirements of the AC substation.

Due to the nature of the converter technology, CSC HVDC can control the magnitude and direction of active power flow independently of the AC systems to which it is connected, unlike an AC transmission line. The magnitude of active power flow does not have many restrictions other than the DC current must remain continuous. This means that operation at levels of power less than 10% of rate power can be difficult and less than 5% is generally not considered to be possible.

This technology has been developed to a point where most of the improvements now are relatively minor and concentrating on incremental improvements in control, efficiency and cost. It is a well-proven technology with the economic models well understood.

Almost all schemes worldwide are implemented as point-to-point transmission of power, some over considerable distances (>2000MW, >1000km). The economics of this form of HVDC mean that most schemes are large capacity units and the standard products are not well suited to schemes of less than 500MW capacity.

The two UK examples of this technology include the 500MW twin Monopole link between Scotland and Northern Ireland and the 2000MW Bipole link between England and France.

CSC HVDC connections require two cables per circuit but can operate at half power in earth return or sea return mode for either short-term or continuous operation if designed in this way.

CSC HVDC losses are one of the main factors when performing comparisons against AC schemes. Although the HVDC line will have lower losses than the equivalent AC scheme, the thyristor based converter stations contribute to around 0.75% of additional losses per station.

The following table shows a number of reference examples of CSC HVDC for reference purposes.

	Voltage	**Capacity**	**Distance**
Moyle Link	275kV (ac) 250kV (dc)	2 x 250MW 1000A (dc)	64km
England – France (Cross Channel)	400kV (ac)	2000MW	70km
Tian – Guang	500kV (dc)	1800MW	960km
Quebec – New England	315kV (ac) 230kV (ac) 345kV (ac) 450kV (dc)	2000MW	1480km

Table E.2 - Examples of CSC HVDC schemes

E.2.3 Voltage Sourced HVDC

Voltage Sourced HVDC is similar but different to CSC HVDC. The key difference is that it uses forced commutation devices such as IGBTs. Forced commutation means that the devices can be turned on and off when required rather than having to wait for the AC network. To operate all they require is a sufficient voltage on the DC network. To minimise harmonic generation, the VSC HVDC converters typically use a higher frequency PWM (~1000Hz) to create a better approximation of the sinusoidal AC voltage. The other advantage of forced commutation is that the power factor of the converters is fully controllable allowing both leading and lagging operation independent of active power transfer.

Although there are a number of commercially viable VSC HVDC schemes now operational, some utilities will view this technology as not fully proved as the experience is limited to power levels of up to 350MW, and there has been insufficient operational time to adequately determine reliability. Due to either regulation or the requirements for maintaining network security, utilities are usually risk adverse and so extra care and consideration will be required if VSC HVDC is being put forward as the most appropriate technology.

VSC HVDC is currently offered in a number of smaller block sizes ranging from 300MW to 500MW and experience is limited to power levels of up to 350MW, although a 1000MW scheme is considered possible. For the transmission of larger power levels this requires a number of smaller blocks to be installed in parallel. While on the downside this increases cable installation costs, it does have the advantage of allowing a phased capacity increase as well as additional security in the event of a cable failure. I.e. For a scheme with three parallel units, the failure of one unit means that 67% of the capacity is still available.

In terms of losses, against the cable losses will be lower than an equivalent AC connection, but the VSC converter losses are in the order of 3% of the transferred power. This is higher than CSC HVDC and so additional justification is usually required to demonstrate that a VSC scheme is the most appropriate.

For remote island networks, a key justification is that VSC does not need to be energised from the network that it is connected to. This means that it could connect into a network where there is no generation, or in the case of Wind, it could supply the island during low wind speeds. There is also no minimum power transfer level required to maintain operation.

The following table shows a number of reference examples of VSC HVDC for reference purposes.

	Voltage	**Capacity**	**Distance**
Estlink	150kV (dc)	350MW	105km
Troll A platform to Norway	56kV (ac)	84MW	70km
Cross Sound Cable	150kV (dc)	330MW	40km

Table E.3 Examples of VSC HVDC schemes

E.2.4 Multi-terminal HVDC

There are only two CSC HVDC schemes in the world that operate as a multi-terminal configuration. Multi-terminal means that instead of just the HVDC link being just point-to-point with two terminals, it has three or more converter stations. This theoretically provides the ability to transfer power between any of these three terminals. There are a number of limitations however and the two operational links operate primarily with each terminal in a single mode, i.e. either importing or exporting power.

Due to the complexity and cost of DC circuit breakers, security of supply becomes an issue with multi-terminal configurations in the event of a link failure. This is because the network is now interconnected in more locations on a single point of failure.

Another limitation of multi-terminal HVDC is the requirement that the converter stations are all of a similar rating. It is not cost effective for example for one station to only be 10% of the total link rating. VSC HVDC does a lot to overcome some of the conventional issues with multi-terminal links, however it is still an untried application for VSC links.

E.3 High Voltage Alternating Current (HVAC) Cables

The critical length of AC cables is often defined as the length at which the charging current is so high that no useful power can be transmitted. The following table shows typical critical lengths for different voltage and ratings of HVAC cables.

Voltage	Rating	Critical Length
380kV	390MVA	40km
132kV	100MVA	80km
33kV	30MVA	250km

Table E.4 Comparison of AC subsea cable critical lengths

It is possible to increase the critical length of AC cables by inserting shunt reactors to compensate for the charging current, however this is impractical for subsea links.

AC cable repairs are typically more complex than an equivalent DC cable because they typically consist of three conductors instead of only one.

E.4 HVDC Versus HVAC for Subsea Connections

The comparison of HVDC and HVAC for application to the connection of the Scottish Island groups is not a simple comparison. This is because consideration needs to be given to variables such as energy losses, cable costs, transmission voltage, charging current, converter station costs, island integration costs and required security factors as well as the environmental issues.

Although both types of technologies are commercially viable for subsea inter-connections, there are a number of technical and commercial factors that will affect selection.

One of the key limiting factors for AC cable installations is the high level of charging current due to the distributed capacitance of the cable, which is caused by the “electrical closeness” of the conductor to the earth. This is worse for subsea cables due to the more compact design and higher amount of armouring required for mechanical strength.

The cable charging current is proportional to voltage, frequency and length of the cable. As the frequency for DC installations is zero, the charging current is not a limiting factor on the DC application. For AC systems, as the system voltage is increased to reduce line losses and voltage drop, the charging currents also increase thereby aggravating the situation. High voltage cable installations on land or sub-sea therefore require significant care in managing this charging current if any significant length of installation is to be achieved. For each project, there is a limiting length at which it becomes unfeasible to use HVAC cable because the capacitance or losses become too high.

At present, AC sub-sea cable technology also has a practical upper voltage limit in the order of 200kV due to the physical size of the cable, as it becomes too massive to carry a useful length onboard the laying vessels. Cable joints are possible but contribute to the unreliability of the cable. Therefore it is essential to minimise the number of cable joints in both AC and DC installations.

The reason for the difference in size of cable between AC and DC installations is because the AC cables generally include all three conductors (phases) for field balancing purposes, whereas the DC cables are single conductor cables.

Although it would be possible to also install single conductor AC cables, this increases the number of trenches thereby increasing the installation costs, time required, and environmental disturbance.

E.5 Technology Application Issues

E.5.1 On-shore

All of these subsea cabling options would need to be continued onshore to connect into the existing network. For AC cables it is possible to either continue them onshore using underground cables and connect them directly into the nearest suitable substation or convert these cables into Overhead Lines to cover the distance to the substation. For HVDC cables, a connection into the existing network would need converters and these can be located either just inland of the landing point with the connection to the nearest substation made by AC cable or overhead line as above or the HVDC circuits can be continued to the nearest suitable substation and locate the converter next to the substation.

VSC HVDC cabling technology is suitable for being undergrounded for long distances but if necessary, the cable can also be hung from wooden poles above ground. ABB have a technique for the burial of two cables in the same trench allowing for a fast and cost effective overlanding of their HVDC Light technology.

Figure E.1 - HVDC Light land cable burial

CSC HVDC cabling technology is not suitable for being undergrounded more than a few hundred metres and so generally would need to be installed as uninsulated conductor on overhead towers for overlanding.

E.5.2 Island Network Integration

CSC HVDC typically requires strong electrical networks for both converter stations to connect into, as this is needed for the operation of its conversion process. A typical minimum is a Short-Circuit Ratio (SCR) of at least 3.0. A simple description of the short-circuit ratio is the ratio of the HVDC link rating to the amount of generation on the network. For the island networks, the SCR is likely to be in the order of 1.0. This means that additional equipment would be required to allow for stable operation. The additional equipment would in the form of harmonic filters to provide the necessary reactive power and maintain power quality, synchronous condensers to provide the minimum network inertia and Static VAr Compensators to provide the dynamic reactive power support.

The other key limitation of CSC HVDC is that the DC current must be continuous. This means that it becomes difficult to operate below 10% of rating and almost impossible below 5% of rating. Therefore, export of generation at low wind speeds would be limited and power reversal to supply the island community in times of insufficient wind generation may not be possible.

The smaller standard block size of VSC HVDC provides certain project advantages over CSC HVDC as it lends itself better to a phased development of connection capacity. As VSC HVDC is energised from the DC link instead of from the AC network, it does not have a minimum SCR as is the case for CSC HVDC. VSC HVDC can also provide "Black-Start" capability for a network in a similar way to an AC connection. This means that in the event of a total loss of generation on the Island, it is possible to re-energise via the HVDC link and provide a supply from the mainland network.

Both HVDC subsea options require a larger footprint for the terminal substation than an AC option due to the converter stations and associated equipment. Of the two HVDC technologies, the CSC HVDC is likely to be significantly larger particular for the more complex Island end installations.

For AC options, provided that the cable lengths are sufficiently short, then the connection via HVAC cables poses no real problem. Due to the amount of capacitance likely to be involved, it may be necessary to have additional reactive compensation to manage the voltage at both ends of the link. Surge arrestors will also be necessary to manage transients on the island network and care will have to be taken to ensure that there are no harmonic resonance conditions.

E.5.3 Grid Code Compliance Issues

The "Grid Code" describes the requirements that generation must meet to connect to the GB transmission system to ensure that the whole system is developed in a stable and robust manner.

There is a strong case for the relaxation of some of the grid code compliance issues, such as reactive power, fault ride through, and voltage and frequency limits, for the case where the generation on the islands is decoupled from the GB transmission system via DC technology. This relaxation would allow a more efficient design of the island systems involving a co-ordinated design between the wind turbine generators and the HVDC interconnection.

There are some issues around ensuring that the demand customers on the islands do not suffer from a reduction in quality of supply. However, provided that a lateral approach is permitted, it may be possible to mitigate these issues via technologies such as mini low-voltage dc interconnections between the wind generation networks and the existing distribution networks.

E.5.4 Cable Installation Vessels

There are a number of companies that operate cable lay vessels with varying cable carrying capacities. Most of the cable lay vessels have a draft of around 6-8 metres, although there are vessels that have a smaller draft which are restricted to sheltered water operations. Early discussions with cable suppliers and vessel operators are required to ensure that delivery of cable and installation can be undertaken within the proposed project schedule. Some vessels can be committed up to 2 and 3 years in advance.

Depending on whether the cable will be surface-laid on the seabed or laid and buried simultaneously the vessel laying rates will vary. For surface lay of the cable on the seabed average rates of 20 to 30km per day may be achieved.

The closest a lay vessel can get to shore at a landfall is usually in the 500m to 1000m range. This distance however is subject to detailed design of the cable to ensure that it can be floated or pulled ashore without affecting the structural integrity. Scheduling the landfall works to coincide with a high tide may reduce the extent of handling the cable through the foreshore areas.

E.5.5 Cable Burial Techniques

The best method to protect the cable from fishing activity or vessel anchoring is to bury it. This can be simultaneous to the cable lay or post lay. Equipment used falls into three categories: cable ploughs, post-lay burial jet-tools and tractors fitted with either chain or wheel cutters. If burial is not possible, other protection measures such as mattressing or localized rock-dump may have to be considered.

F Appendix – Environmental, Physical and Social Constraints

For each of the connection options discussed in this report, there may be constraints and specific concerns in the local environment that will either increase the cost of the connection or will make it unfeasible, as the impact that it will have on the environment will be deemed too significant.

As part of the study TNEI has consulted our own planning specialists, the local island councils, subsea experts – JP Kenny and Scottish Natural Heritage. A subsea routing and landfall study of the identified connection options was commissioned with a group of leading subsea experts as part of this report.

The connection route selection process is guided by the following criteria:

Third Party Constraints

- Compliance with overall client requirements.
- Compliance with international borders.
- Minimisation of interference with other users of the sea.
- Minimisation of impact on the environment e.g. avoidance or minimisation of impact to Sites of Special Scientific Interest (SSSIs), Special Protection Areas (SPA), Special Areas of Conservation (SAC) and other important nature conservation areas.
- Avoidance of wrecks.
- Minimisation of the impact on the receiving landscape designations via consideration of the different cable routing options available e.g. minimisation of pylons in National Scenic Areas (NSAs) and Areas of Great Landscape Value (AGLV).

Physical Constraints

- Selection of appropriate landfall locations.
- Minimisation of length and number of turn points.
- Minimisation of water depth along proposed cable routes.
- Restriction of cable routes to areas of smooth seabed and benign gradient.
- Avoidance of geo-hazards and seabed features.
- Seabed sediments relating to trenchability.

Engineering Constraints

- Ability to utilise existing cable lay construction methods.
- Minimisation of seabed pre-lay intervention requirements.
- Minimisation of post-lay intervention requirements.
- Stability and Lay Radii
- Minimisation of pipeline and cable crossings.

F.1 Landfall

F.1.1 Landfall Location

The ideal location for a cable landfall would be a sheltered sandy bay with sufficient water depth close inshore to allow access for the cable laying vessel. Unfortunately these conditions are rarely found at the preferred landfall location.

The amount of land available for use during the cable installation would be subject to negotiations with the landowner(s). The location of the landfall may be influenced by onshore land issues; in particular if the land is of special scientific or environmental interest.

Burial of the cable through the foreshore and beyond will be required for both security and protection purposes. The ease by which this can be achieved is a key factor in the choice of landfall location. Rock excavation should be avoided where possible due to the costs and environmental issues associated with this operation.

Conventional means of burying the cables through the foreshore can be either excavation techniques or, where water depth permits, a sub-sea trenching technique can be employed.

F.1.2 Seabed and Foreshore

Once beyond the foreshore, subsea cables are normally buried in the seabed for protection. Other methods for protection include "rock blankets" that can be laid overtop of the cable in conditions where burial is deemed unsuitable or impractical.

The shore approach and beach areas can be made up of sand, clay, or rock, and in some locations, a combination of all of them. Each of the seabed sediment and hard geology categories would require a different approach to the cable landfall design.

A sandy seabed with sufficient depth to allow cable burial to acceptable depths offers a conventional installation solution. The cable can be placed in an excavated trench or jetted into the seabed by means of proprietary cable jetting and ploughing machines. Limits of trenches and jetting will be based on the operational parameters of both the trenching machines and support vessel.

If superficial sands overly clay, then the choice of burial technique will be influenced by the strength and type of clay encountered. Jetting machines and cable ploughs may not have the capability to trench through the clay. To achieve a satisfactory depth of burial conventional pre lay dredging techniques may have to be employed.

If superficial sand deposits overlay rock, then some form of pre treatment (i.e. drilling and blasting) may also have to be employed prior to dredging.

Dredging and backfill, will require further permissions and licences, especially if pre-treatment works are required. Depending on the sensitivity of the landfall location such licences may be difficult to obtain.

Optional construction techniques such as directional drilling could also be utilised whereby a guide tube could be installed prior to cable laying operations. To commence the cable lay offshore, the cable would initially be pulled through the guide tube up to a point onshore, for connection to the onshore cable.

F.2 Seabed Conditions

The vast majority of sub-sea cables are buried within the seabed for protection. Generally, cables are buried to approximately 1m depth where the seabed is stable. Where there are signs of high seabed mobility the burial depth would have to be assessed as part of the detailed design process. The degree of difficulty of burial is directly dependent on the nature of the seabed. A cable route would initially look for large areas of predominantly sandy seabed to allow for burial either by ploughing or jetting. Areas such as these allow for simultaneous lay and burial operations.

Areas that do not display these characteristics may require more expensive means of cable protection. These could range from:

1. Remotely operated subsea trenching systems
2. Conventional dredging
3. Gravel dumping
4. Subsea mattress placement

F.3 Vessel Activity

The choice of cable route and landfall should avoid areas of high vessel activity wherever possible. This includes the entrance to ports and harbours and identified major fishing locations. Numerous Royal Navy bases and offshore firing ranges are located around the coastline and any routes should be take account of restrictions imposed in these areas.

Crossing of major merchant shipping lanes will also be a major consideration, in particular in areas of close proximity to ports and harbours. Due regard shall be placed upon the requirements of any maintenance dredging that is ongoing within the proposed cable route areas.

F.4 Fishing Activity

Interaction with all the major types of fishing activity is likely to be a major constraint during the route selection process and installation.

Prior to route selection, a detailed fishing intensity study should be completed to identify the level and type of fishing activity pertinent for each location. An overview and general indication of where the main fisheries take place over the year is shown in Figure F.1.

Fishing for the main *demersal* species such as haddock, cod, whiting, anglerfish, saithe, plaice and a variety of flatfish, is carried out in most of the sea area around Scotland. However, the best catches are usually taken from the Northern North Sea and to the north and west of the Hebrides.

The Firth of Forth, Fladen Ground, Moray Firth, Minches and Firth of Clyde are the main *nephrops* fishing grounds around Scotland. Nephrops are fished throughout the year but the heaviest landings usually take place from March to October.

The *pelagic* fisheries are extremely important for the Scottish Fishing Industry. The main North Sea and West Coast herring fishery starts in June and is normally finished by the end of October while the main mackerel fishery starts in October and finishes in March. Small-scale seasonal herring fisheries also take place in the Minch from January to March and in the Clyde from July to October. Localised sprat fisheries also take place in these areas from November to February.

Shellfish such as scallops, queen scallops, lobsters and crabs also make a significant contribution to the earnings of the Scottish Fleet, particularly for the inshore sector. Lobsters and crabs are taken in varying quantities all around the coast with the largest landings by vessels fishing around the Western Isles and also Orkney. Dredging for scallops takes place from the Solway Firth to Shetland and in the North Sea.

Fish Farms may also be present in the vicinity of a number of potential landfall sites within the study area.

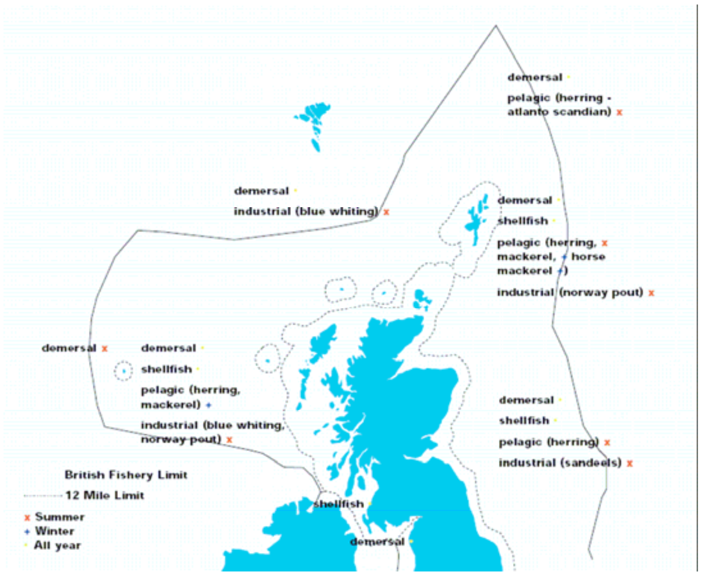


Figure F.1 - Types of Fishing Activity

Figure F.2 summarises the likely intensity of pelagic fishing activity for the area.

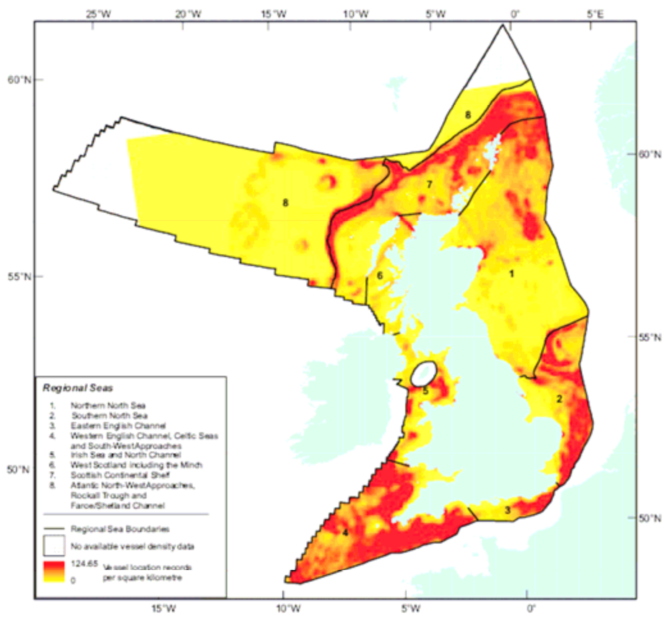


Figure F.2 - Observations of all European fishing vessels >24m in length in 2002

F.5 Conflict with Military and Government Cables

All reasonable efforts should be made to ensure that the planned cable route does not conflict with military, government or any other submarine facilities. Additionally, consultation with other International Cable Protection Committee (ICPC) members that have cables in the area of planned installation could assist in locating appropriate military and government contacts.

The limits of all practice and exercise areas are shown on Practice and Exercise Areas (PEXA) charts Q.6401, Q6402, Q.6403, Q.6404, Q.6405, and Q.6407. These charts are available through appointed Admiralty Distributors.

F.6 Existing Pipelines and Cables

The ICPC recommendations for crossing existing cables and pipelines highlight the areas that require detailed scrutiny. The issues are broadly included under the following headings;

1. Planning
2. Crossing Agreements
3. Cable Crossings and parallel cables
4. Cable Types
5. Burial Procedures
6. Pipeline routing and profiles
7. Exclusion zones

Figure F.3 shows the existing allocation of license blocks in the study area (green) together with existing oil and gas pipelines. Useful oil and gas database information can be extracted from the UK Deal website. Any routing through allocated blocks would require negotiation with the licence holder.

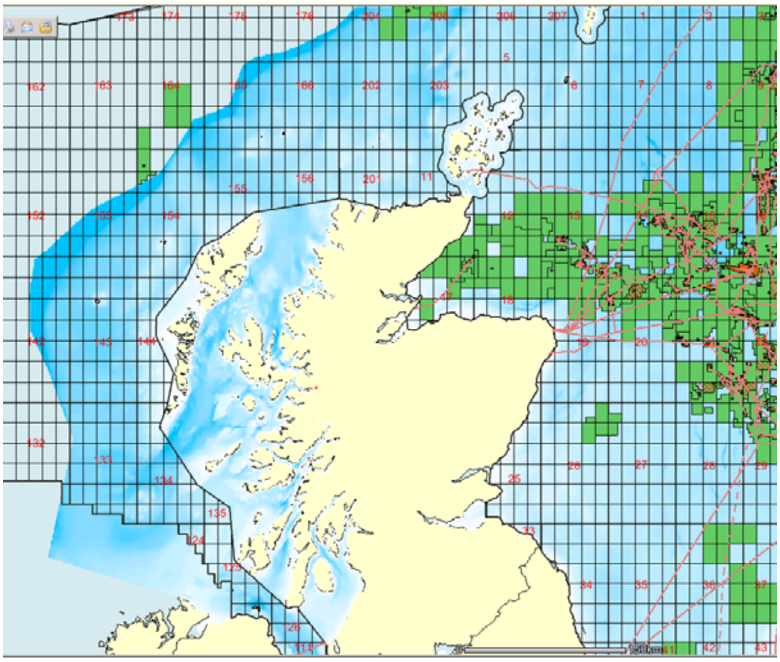


Figure F.3 UK Oil and Gas License Blocks and Existing Pipelines

Within the ICPC recommendations, subjects relating to preferred separation and crossing geometry, highlight issues that need consideration and agreement with third party owners.

The most important consideration is that as soon as it becomes apparent that a pipeline/cable crossing will occur an exchange of information must be initiated at the earliest possible moment.

A valuable set of planning charts with respect to existing submarine cables are the Kingfisher Awareness Charts.

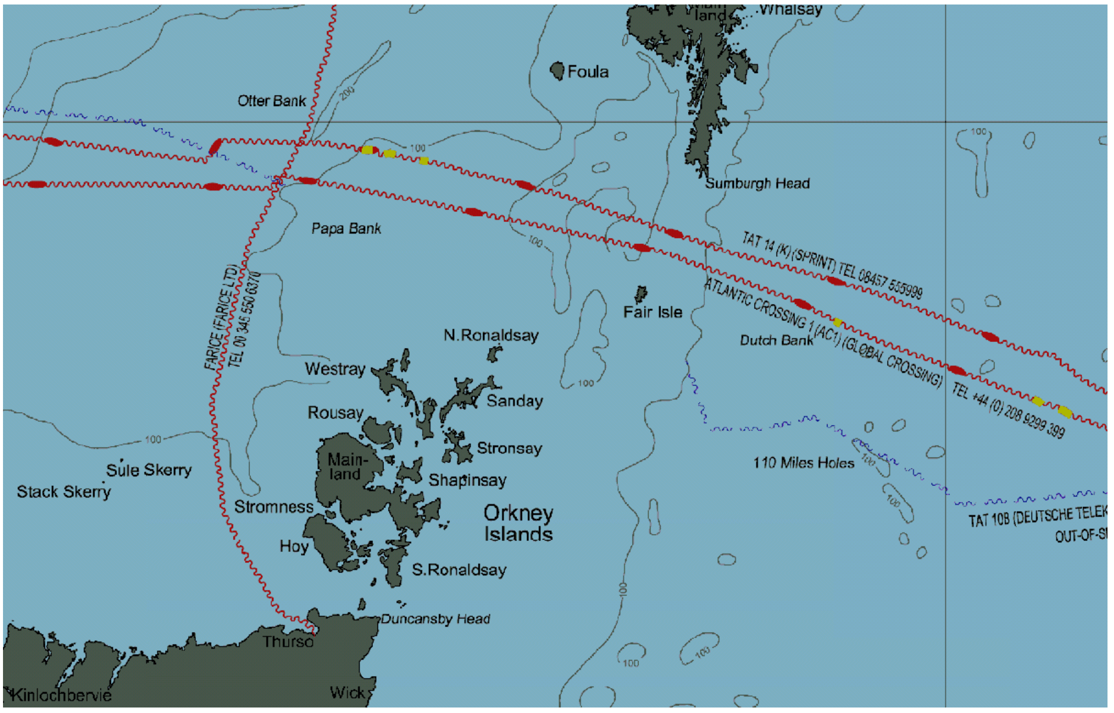


Figure F.4 Extract from Kingfisher Cable Awareness Chart North Sea - North and West

F.7 Routing Desk Study and Pre-Route Surveys

A Desktop Study (DTS) is an essential prerequisite to a detailed submarine cable route survey. A DTS will identify the safest and most technically viable route for use in the engineering, construction, installation and subsequent maintenance of a submarine cable system.

Following completion of the desk study, a cable route survey will be required to identify and verify the seabed topography and give an indication of the seabed soils. The survey will be based on bathymetric and shallow geophysical techniques and will typically employ Swathe Echo Sounding Systems (MBES), Side Scan Sonar (SSS) and shallow sub bottom profiling systems (SBP). Some ground truthing of the geophysical survey data will be provided by sampling of the seabed sediments using grabs or cores, and in situ testing using cone penetration tests, (CPTs). In some instances where burial is expected to be difficult due to seabed conditions, an instrumented cable plough may be run along the proposed route centerline to supplement burial assessment data.

F.8 Onshore Constraints

The following section contains a list of the various environmental designations that have/ or may be encountered during a specific cable route assessment. Each designation type is described, whilst measures to minimise potential impacts are described in Section 5.8.1.

SSSI (Site of Special Scientific Interest) - SSSIs are the country's very best wildlife and geological sites. SSSIs are important as they support plants and animals that find it more difficult to survive in the wider countryside. Over half of the UK SSSIs, by area, are internationally important for their wildlife, and are thus also designated as Special Areas of Conservation (SACs), Special Protection Areas (SPAs) or Ramsar sites (see below). Many SSSIs are also National Nature Reserves (NNRs) or Local Nature Reserves (LNRs).

SPA (Special Protection Area) – This designation is intended to protect populations (and individuals) of rare and/or nationally and internationally important bird species e.g. those listed in Annex I of the Birds Directive, or regularly occurring migratory species. SPAs are strictly protected sites classified in accordance with Article 4 of the EC Directive on the conservation of wild birds (79/409/EEC), also known as the Birds Directive, which came into force in April 1979.

SAC (Special Area of Conservation) - This designation is intended to protect rare and/or nationally and internationally important habitats and fauna i.e. those habitat types and species that are considered to be most in need of conservation at a European level (excluding birds). SACs are strictly protected sites designated in compliance with Article 3 of the EC Habitats Directive. This requires the establishment of a European network of important high-quality conservation sites that will make a significant contribution to conserving the 189 habitat types and 788 species identified in Annexes I and II of the Directive (as amended).

Marine SPA - A network of Special Protection Areas is also being established for important estuarine sites in the UK. To date, only one wholly marine SPA has been classified but work is underway to identify a suite of marine SPAs throughout the UK.

Ramsar - Ramsar sites are wetlands of international importance designated under the Ramsar Convention. The initial emphasis was on selecting sites of importance to waterbirds within the UK, and consequently many Ramsar sites are also Special Protection Areas (SPAs) classified under the Birds Directive. However, both within the UK and overseas, non-bird features are increasingly taken into account, both in the selection of new sites and when reviewing existing sites.

NP (National Parks) **-** National Parks are nationally designated areas of outstanding natural heritage of special importance to the nation, and where the integrated management of a number of complex land use issues requires resolution.

NSA (National Scenic Area) – NSA's are a Scottish designation and include the "best of Scotland's scenery". Like National Parks, NSAs should be considered as a natural heritage designation of the highest national standing, identifying the national interest in the scenic qualities of the area. However, the NSA designation has a focus on scenic value and does not have the breadth of purpose and comprehensive integrating role envisaged for National Parks. NSAs are unlikely to ever require such an approach due to their size, location, and having more limited management needs.

AONB (Areas of Oustanding Natural Beauty) – These are an English, Welsh and Northern Ireland designation, similar to NSAs in Scotland. AONBs are aprecious landscapes whose distinctive character and natural beauty are so outstanding that it is in the nation's interest to safeguard them.

AGLV (Area of Great Landscape Value) – AGLVs are a range of regional areas identified as being of scenic importance. They are designated by Local Authorities and protected in Structure and Local Plans. The role of an AGLV is quite limited in some cases, however some authorities do not differentiate between national and local designations in area or policy terms.

F.8.1 Impact Minimisation

Minimisation of any impact to environmental designations, will depend on the reason for the designation e.g. is the area designated to protect existing geological strata, the presence of birds, fauna, insects and/or habitats? The best available option for addressing each issue is addressed below:-

Bird Designations - Avoidance of important designations in particular, such as SPAs and Ramsar sites would ideally take the form of re-routing to avoid the area by an appropriate distance. Avoidance distances should be site specific and depend on the exact species being protected. If this is unavoidable, perhaps due to the weight of social and/or economic benefits, which outweigh the potential impacts from the development, then alternatives could be considered. There are specified legal and planning routes outlined in the Birds Directive (Council Directive 79/409/EEC) that must be met prior to the consent for a development within these designations. For other designations the degree of impact would need to be assessed and demonstrated to be acceptable via an Environmental Impact Assessment (EIA).

Minimisation of bird collision risk from the cable route in designated areas could be managed via the underground burial of an insulated cable subject to ground conditions. Alternatively, assuming appropriate approval from the UK utilities, an insulated cable could potentially be carried on overhead pylons, although this would necessitate a large number of pylons and associated visual impacts.. Insulated overhead cables are likely to be of suitable visibility to minimise bird collision risk and will also prevent bird electrocution.

Habitats and Species Designations (excluding birds)- Avoidance should take the form of re-routing to avoid the designated area, in order to avoid disturbance of the ground or on-site species. If this is impossible then as a 'worst-case' the insulated cable or conventional electricity lines, should be carried overhead on towers as this will then minimise the extent of any habitat and species disturbance. The acceptability of potential impacts to habitats is assessed via an EIA or in the case of SAC's in addition is assessed via legal and planning routes outlined in the Habitats Directive (Council Directive 92/43/EEC on the Conservation of natural habitats and of wild fauna and flora).

Geological Designations – Cable landing or directional drilling should be avoided.

Landscape and Scenic Designations – If avoidance is infeasible, then impact to scenic landscapes should ideally be minimised by avoidance of overhead pylons and cables. Instead, cables would be buried, subject to ground conditions.

In some situations, however, it may be impractical to take the best course of action, due to a range of conflicting interests. In those circumstances the least impact option would have to be considered, and appropriate costs apportioned to any associated environmental impact. For example, if a proposed grid route needed to pass through an area that is designated for its habitats interests as well as its ornithological interests (e.g. an SPA and SAC). To minimise impacts to the habitats the best option would be to route a possibly insulated overhead cable/conductor on pylons. Carriage of the electricity via conventional electricity lines would pose a collision risk to the designated bird species. The visual impacts from a large number of pylons or wood pole carrying insulated cable might also however be assessed to be too high.

Where national designations such as SPAs or SACs are involved it should be noted that there is a very rigorous and onerous legal and planning route, which must be taken in order to satisfy the legal requirements of the Birds and Habitats Directives (e.g. Council Directives 79/409/EEC and 92/43/EEC). This could potentially delay the delivery of the grid route under consideration, usually by a considerable time period.