SCOTTISH ISLANDS RENEWABLE PROJECT

GRID ACCESS STUDY

PREPARED FOR THE SCOTTISH GOVERNMENT AND THE DEPARTMENT OF ENERGY AND CLIMATE CHANGE

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ACRONYMS

Acronym	Full Term
AC	Alternating Current
ANM	Active Network Management
CfD	Contracts for Difference
CION	Connections and Infrastructure Options Note
CMP	CUSC Modification Proposal
CUSC	Connection and Use of System Code
DECC	Department of Energy and Climate Change
DNO	Distribution Network Operator
EMEC	European Marine Energy Centre
EMR	Electricity Market Reform
EU	European Union
FC	Forestry Commission
FID	Final Investment Decision
GB	Great Britain
HIE	Highlands and Islands Enterprise
HVDC	High Voltage Direct Current
IDNO	Independent DNO
IPR	Intellectual Property Rights
K	Thousand
km	Kilometre
kV	Kilovolt
kW	Kilowatt
LARF	Local Asset Reuse Factor
LPS	Lerwick Power Station
M	Million
MITS	Main Interconnected Transmission System
MVA	Megavolt-Ampere
MVAr	Megavolt-Ampere reactive
MW	Megawatt
NGET	National Grid Electricity Transmission
NPV	Net Present Value

Acronym	Full Term
Ofgem	Office of Gas and Electricity Markets
OFTO	Offshore Transmission Owner
PCI	Projects of Common Interest
RIIO	Revenue = Incentives + Innovation + Outputs
RO	Renewables Obligation
RPZ	Registered Power Zone
SHEPD	Scottish Hydro Electricity Power Distribution
SHE-T	Scottish Hydro Electric Transmission
SP	Scottish Power
SPT	Scottish Power Transmission
TEC	Transmission Entry Capacity
TIF	Tax Incremental Finance
TIRG	Transmission Investment for Renewable Generation
TIWG	Transmission Issues Working Group
TNUoS	Transmission Network Use of system Charges
TO	Transmission Owner
TPCR	Transmission Price Control Review
UK	United Kingdom
VES	Viking Energy Shetland
VSC	Voltage Source Converter
WAG	Welsh Assembly Government
XE	Xero Energy Limited

EXECUTIVE SUMMARY

Context

The Scottish Government and the Department of Energy and Climate Change (DECC) commissioned Xero Energy (XE) to investigate the main grid access barriers to connecting the Scottish Islands – the Western Isles, Orkney and Shetland Islands – and potential solutions to those barriers.

This study builds on earlier independent analysis by Baringa Partners and TNEI [1], co-funded by the Scottish Government and DECC, which recognised the significant contribution renewable generation on the Scottish islands could make. Based on the evidence form the report and other sources, DECC concluded that Scottish islands warrant distinct treatment and a different level of support from other onshore projects to address the funding gap, and this formed the basis of a Scottish island strike price of £115 per MWh for onshore wind projects as part of the first EMR delivery plan. Strike prices for all technologies are currently set only until 2018/19. In addition to the funding gap, the report also identified that there were issues around grid connection and charging. This report has been commissioned to investigate those further.

The three island groups share significant challenges in getting grid connections off the drawing board The lead times associated with large sub-sea transmission connections are typically, upwards of 4 years to achieve funding approval and build. Anticipated connection dates for the islands are all now beyond the end of March 2019 i.e. beyond the first EMR Delivery Plan. Without visibility of renewables support levels beyond March 2019, the firmness of commitment many developers can currently put behind grid connection needs cases is limited.

The three island groups also share the challenge of high and difficult to predict costs of connection.

There are also differences, especially in the predominant factors which affect progress on grid connections, and hence the most fruitful and immediate actions that could be taken to address these barriers. Key issues that affect the three island groups in the near term are summarised below, with further discussion of potential solutions presented later in the report at sections 8 and 9.

Orkney Islands

Orkney is a European hub for wave and tidal developers, attracted by the European Marine Energy Centre (EMEC), the designation of the Pentland Firth and Orkney Waters as a Marine Energy Park and by Crown Estate leasing rounds. There are currently ten developers testing wave and tidal energy converters at EMEC, where more marine energy devices have been grid-connected than at any other single site in the world. Activities at the facility support 240 jobs across the UK. [1]

The marine energy sector remains at an early stage of commercial deployment and both the Scottish and UK Governments have said they are “fully committed to the successful development of the marine sector” [1]. In this early development stage, marine energy players are focused on proving their technology, with project site development an outlet for demonstration, and their financial capacities are naturally focussed in that direction.

The existing grid reinforcement plans for an 180 MW AC cable to Orkney are underpinned by wave and tidal grid applicants, yet the related projects are not at a sufficiently advanced stage of technological development where they could be reasonably expected to sponsor the construction phase of a major grid upgrade.

Consequently there is a looming underwriting funding gap for the proposed Orkney connection. This funding gap will not be solved through only altering industry rules and regulations to rebalance grid risks, because until the technology is proven, a key risk is a generation technology one. EMEC exists to resolve these technology risks through testing and demonstration, but is limited in its ability to expand these activities by constraints on grid capacity.

Hence, it may be justified to secure some research and development grid capacity, in order to allow marine technologies and the sector to move towards commercial deployment at larger scale. Under EU State Aid rules, this may be best achieved through a neutral research body such as EMEC, rather than through support for individual companies (because of rules on distorting competition by favouring particular companies) . We believe that research and development funds are more suitable for supporting infrastructure for pre-commercial wave and tidal projects, rather than for example a guarantee scheme which is targeted at more commercial projects.

There are plans to bolster the Orkney reinforcement case with grid applications from onshore wind developments – both existing operational projects that currently have restricted access to the grid, and new projects under consideration. Whilst this will be helpful, we do not think it will be material in changing the prospects for an 180 MW reinforcement commissioning before 2020 due to the limited potential for unconsented onshore wind projects to contribute to a case in the near future.

A smaller scale reinforcement underpinned by a mixture of mature and less mature technologies may be a more promising option in the near-term before marine technologies are able to deploy in commercial scale arrays.

In conclusion, actions that are likely to benefit connecting Orkney in the near term are:

➔ Anticipate a continued funding gap for grid reinforcements on behalf of wave and tidal generators – and steps to fill this gap through European and national funds in support of scientific research, economic development and promotion of new industry.

➔ Rationalise reinforcement plans – considering alternative distribution reinforcements, (as set out in the recent Scottish Hydro Electric Power Distribution, SHEPD, consultation [2].

➔ Ascertain demand for export capacity from existing and new onshore wind, and appetite for aligning grid commitments for transmission or distribution reinforcements. Existing but restricted generators have the most potential to help the case for a pre-2020 cable, as these have their consents in place and a market outlet.

Western Isles

Plans for transmission reinforcement for the Western Isles are the most advanced of the three island groups. The first proposed cable (450MW HVDC) is over-subscribed and 342MW of contracted generation has planning consents. The field is dominated by onshore wind developments, more than half of which is being progressed by large utility players.

The main and immediate concern for generators has been difficulty in reaching a Final Investment Decision (FID) in an uncertain policy environment and unpredictable costs. These concerns are universal across all the islands but Western Isles projects are either taking or have tried to take FID decisions already. Generators' view on the importance of market and cost risk appears to have some relationship with where their funding is sourced, self-financed utility players having more flexibility than others.

In any event, Scottish Hydro Electric Transmission (SHE-T), the transmission owner, is required to make a needs case to Ofgem justifying funding for the full 450MW capacity of the investment, and this has been locked in a negative feedback loop fuelled by market and cost uncertainties. Investment cases have been made, and then withdrawn or sent back when circumstances have changed. Either certainty is required to allow the needs case to go forward, or the needs case should go forward despite the uncertainty. Unless one or other changes, this negative cycle will not be broken.

The most useful actions to secure progress on the Western Isles link will be to:

➔ Implement needs case improvements that allow stakeholders to influence its timing and reflect the full and varied dimensions of beneficial consumer impacts of the connection.

- ➔ Provide longer term visibility on the Scottish island strike price sufficient to back up the needs case.
- ➔ Stabilise grid costs targeted to individual generators (we suggest refinements to the TNUoS methodology).
- ➔ Progress the above actions in parallel to minimise further delays to connection dates.

Shetland Islands
For Shetland, the driving force behind a proposed 600MW HVDC reinforcement to the mainland is the 412MW Viking Energy onshore wind project, which is a 50/50 venture between a 90% community trust-owned company and SSE Renewables. The project will rely on bank and other outside finance when it moves into its construction phase. As far as finance is concerned, this construction phase begins with construction of the grid connection, as this is when project costs start to ramp up significantly.

Banks generally require some control of the assets they are funding. Under the current transmission regime, SHE-T is the developer and owner of the connection and this presents problems for developers in securing affordable finance for underwriting grid liabilities. Under the offshore transmission regime, the issue of developer control is tackled by giving generators the option of building their own connection, although this has tended to limit the playing field to larger utilities.

Even if greater control over the grid connection could be achieved, a project finance model would only stretch so far, and stakeholders believed there would still be a funding gap. Given that onshore wind is a commercial prospect, something like the UK Guarantees scheme would appear to be a suitable vehicle for support, although there are questions around whether the projects on Shetland would meet the precise terms of the scheme.

Furthermore, it almost goes without saying that any project-financed model that uses future revenue as security for the loan will need some surety on future revenues. This is a particular issue here because FID has to be reached in order to finance the grid liabilities – that is, around 4 years before connection.

Thus actions to facilitate outside finance for the project driving the Shetland connection are to:

- ➔ Consider as a matter of urgency with potential financiers whether measures such as using the Connection Infrastructure Options Note (CION) process will satisfy the desire for more control over grid risks. If not, then some form of regulatory change may be required to give generators more explicit control over grid assets, which will introduce significant delay.
- ➔ Consider (possibly with HM Treasury) whether some form of guarantees scheme could work in the Scottish island context – and in particular the issue of needing finance for relatively early, but significant, grid liabilities.
- ➔ Discuss with banks what kind of revenue security they would need in order to finance grid liabilities some four years before connection. Typically a project finance model is based around a secure Power Purchase Agreement (PPA). If this cannot be provided, or the requirement for it relaxed, it is doubtful whether community-backed projects will have alternative means of bringing in finance.

Other Conclusions
The actions described here for each island reflect the predominant types of development on each island. Of course, wave and tidal projects on the Western Isles and Shetland will need similar support to that described for Orkney, and commercial bank-financed projects on Orkney and the Western Isles will benefit from the actions described for Shetland.

Other conclusions reached by the study are around the operational phase risks faced by projects, and the way in which policies are progressed, namely:

Operation

Generation curtailment risk exists by virtue of single circuit island connections and likely use of Active Network Management (ANM) schemes when the single circuit connections are either offline or over-subscribed. Under the current regime curtailment is likely to be uncompensated and hence it is a generator's commercial risk. Insurance will probably be available to cover outage risks for some links e.g. an Orkney AC link, but the availability of affordable insurance for larger connections is not very well understood. Stakeholders are worried that they will not be able to cover outage risks and that self-insurance would push costs up. Curtailment levels under ANM schemes are uncertain and hence also represents a finance risk. There is a need to:

➔ Improve information on HVDC risks and the availability of insurance for HVDC connections. Work with manufacturers in disseminating information to insurers.

➔ Review compensation arrangements for curtailment risks where generators have no ability to control or mitigate the risk.

➔ Disseminate lessons from the commercial and contractual arrangements trialled on the Orkney ANM scheme.

Policies

Over the last ten years, the UK Government has proposed interventions on transmission charging, but has not implemented a scheme and is no longer minded to intervene directly in that regard.

Instead, the UK Government has now provided an enhanced island strike price within the first EMR Delivery Plan (to 2018/19). The purpose of this measure risks being undermined, however, if longer term visibility is not provided.

➔ To be effective, the Scottish islands strike price needs to factor in lengthy grid connection lead-times and provide longer-term visibility on levels of support.

Timescales

Timescales for the solutions described in this report are between 1 and 5 years. The emphasis is on keeping plans moving – in parallel where possible – and making sure that all stakeholders and policy makers understand what is most likely to be effective. Given the number of organisations and companies involved in facilitating these significant investments for the Scottish islands, a final conclusion is that it would be helpful if the Scottish Government and DECC maintained their collaborative work focussed on Scottish islands grid issues to support momentum and monitor developments.

1 Introduction

The Scottish Government and the Department of Energy and Climate Change (DECC) have commissioned Xero Energy (XE) to investigate "grid access" for renewable energy projects situated on and around three Scottish Island groups – the Western, Orkney and Shetland Isles. The study follows on from an earlier piece of work [3] by Baringa and TNEI. XE has sought to elucidate grid access problems, quantify grid costs, characterise the grid situation for each island group and draw conclusions on actions to facilitate timely connections to the mainland. XE's commission requires it to report in four specific areas, namely:

- Grid access barriers
- Options for aggregating developer demand for grid infrastructure
- Potential routes for third party underwriting of cable securities and liabilities
- Potential changes to the regulatory framework

Overseeing the study, the Scottish Islands Renewables Steering Group have provided valuable information and support. The group is chaired by DECC and additionally comprises the Scottish Government, Highlands and Islands Enterprise (HIE), the three Island councils, Scottish Hydro Electric Transmission (SHE-T), National Grid Electricity Transmission (NGET), and Ofgem as an observer. Island project developers have also supported the project with evidence on grid access barriers and their own perspectives on targeted actions to relieve them.

1.1 Report structure

This report begins with some scene-setting on the island connections and responsibilities for them (Sections 1.2 and 1.3 below), the grid connection process (Section 2) the policy and regulatory backdrop (Section 3), and grid operation (Section 4) followed by evidence gathered from stakeholders, arranged into island-specific sections (Sections 5 to 7) and additional evidence on potential island solutions (Section 8). Section 9 distils this material into key barriers and solutions. Appendix A provides a full referenced timeline of policies described in Section 3.

- Section 1 Introduction
- Section 2 The grid connection process
- Section 3 Policy and regulatory framework
- Section 4 Grid operation
- Section 4 Evidence base – Orkney
- Section 5 Evidence base – Western Isles
- Section 6 Evidence base – Shetland
- Section 7 Evidence base – potential solutions
- Section 8 Summary of options
- Section 9 References
- Appendix A Policies Timeline
- Appendix B Solutions

1.2 The connections

A map showing SHE-T's currently proposed connection routes for the Western Isles, Orkney and Shetland is show in Figure 1-1 below.

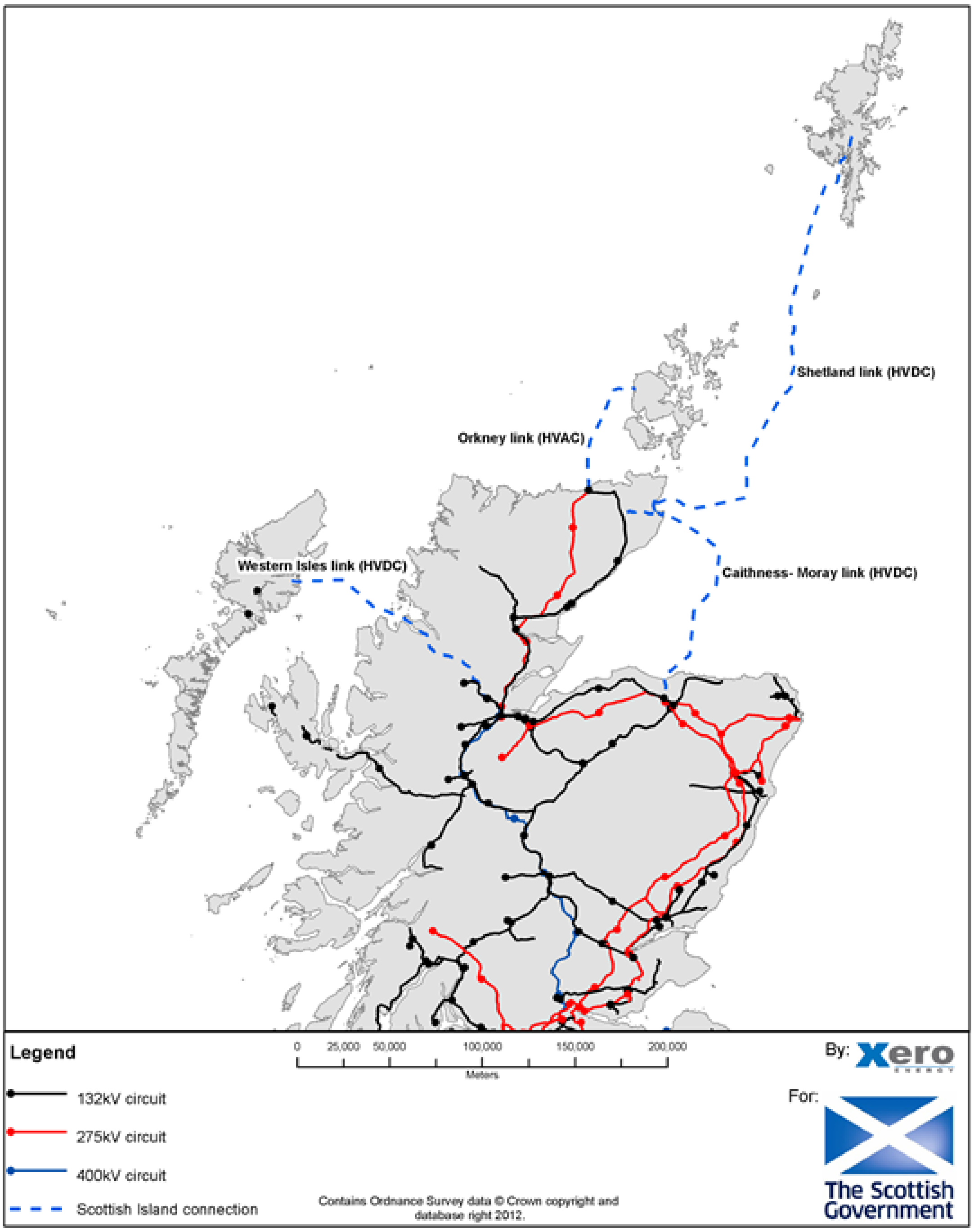

Figure 1-1: Map showing island links

Provided by SHE-T, Table 1-1 shows the latest (at time of publication) link costs, lengths and proposed design for the three Island connections. The costs in brackets are those previously published in the Baringa / TNEI report.

Link	Design	Estimated cost
Western Isles	±150kV 450MW 155km (76km subsea) VSC HVDC	£750M* (705) £1.7M/MW £10.7K/MW/km
Orkney	180MW 70 km (61km subsea) HVAC	£230M** (230) £1.3M/MW £18.8K/MW/km
Shetland	±320kV 600MW 297km (284km subsea) VSC HVDC	£620M (520) £1.0M/MW £3.5K/MW/km

Table 1-1: Link key data

*includes extra HVDC land cable but excludes 132kV infrastructure on Lewis
** includes new 132kV network on Orkney

By way of comparison, estimates for three major HVDC reinforcements are shown in Table 1-2. The Caithness-Moray works are being triggered by projects in Shetland, Orkney and on the Caithness mainland. A share of Caithness-Moray costs are being directly reflected back to projects on Orkney and Shetland through underwriting (and, potentially in future grid charges). The needs case for Caithness-Moray works is currently being considered by Ofgem. The East West interconnector between Ireland and Wales is operational. The Western HVDC bootstrap has been ordered and is moving into construction.

Link	Design	Estimated cost
Caithness-Moray	±320kV 800/1200 MW 165km VSC HVDC	~ £1,000M* £0.8-1.25M/MW £5-7.6K/MW/km
East West Interconnector [4], [5]	±200kV 500MW 264km (187km subsea) VSC HVDC	~ €600M €1.2M/MW €4.5K/MW/km
Western HVDC [6]	±600kV 2200MW 422km (385km subsea) CSC HVDC	£1050.7M £0.48M/MW £1.1K/MW/km

Table 1-2: Key data for selected HVDC reinforcements

* includes onshore works in Caithness

Some brief opening observations are:

Costs

Costs do show some economies of scale with higher capacity links having lower per MW costs, and longer links generally having lower per MW per km costs. According to SHE-T, market conditions, and specific circumstances for each link e.g. ground conditions, are also having a significant bearing on cost estimates. This report will explore how costs, and particularly cost uncertainties, are managed when developing the links.

One observation running through this report, and which is a major factor in underwriting difficulties for island projects, is the scale of grid costs compared to generation project costs. Recent estimates for onshore wind capital costs are in the region of £1.3-1.5M/MW [7], with the Baringa / TNEI study reporting costs of up to £1.8M/MW for some island projects [3]. This is the same order of magnitude as the cost of the grid connection to the mainland.

Timescales

The East-West interconnector took nearly four years to complete, from placing of contracts to commissioning [4], [5]. This more or less aligns with NGET's estimate of an average four year lead time for construction of transmission assets, (estimated during the development of the CMP 192 transmission underwriting methodology).

The supply chain for VSC HVDC technology is very limited and there is some concern that should order books fill up, lead times for the island links using VSC technology could be even longer. This is a difficult risk to assess as the market is world-wide. However, it is fair to say that timescales are particularly difficult to pin down before an order is placed.

1.3 Transmission responsibilities

All of the currently proposed Scottish Island links are at transmission voltages, and so transmission issues form the bulk of this report. There are however alternative distribution reinforcements discussed in this report and distribution responsibilities are covered briefly in the following section.

Transmitting electricity is a licensed activity. Ofgem awards transmission licenses and controls what conditions are placed in the licenses. Transmission is historically a monopoly activity and so there is only one Transmission Owner (TO) licensee for the north of Scotland, namely SHE-T (and one for the south of Scotland, Scottish Power Transmission, SPT, and one for England and Wales, NGET).

From 2005 the Scottish energy market merged with the market in England and Wales to create a single market in Great Britain (GB). As part of this, the two Scottish network companies relinquished their system operation (SO) roles to NGET. In practice this means that:

- NGET operates the transmission network GB-wide on a day-to-day basis (e.g. making sure that demand is met in real time and that potential network overloads are anticipated and avoided)
- As GB SO, NGET also has responsibility for co-ordinating and issuing connection offers to generators across GB, and administering industry codes that contain, amongst other things, the transmission system charging methodology.
- SHE-T and SPT plan, design and own the transmission network in each of their licence areas. NGET also undertakes these activities in England and Wales.

Adding to the mix, the Office of Gas and Electricity Markets (Ofgem), with DECC, has also started to introduce competitive tendering for a TO licence for certain defined assets. The legislation necessary to do this was developed by DECC and required a new definition of offshore transmission to be created. Hence at the moment competitive tendering is limited to offshore wind farm connections, but Ofgem has stated it will also consider developing arrangements for certain onshore assets, and this includes the island connections. As pre-construction work is already well underway for the island connections, any competition would be for a transfer of ownership from SHE-T at the construction or commissioning stage.

1.4 Distribution responsibilities

Like transmission, distributing electricity is a licensed activity with Ofgem issuing licenses. There are fourteen Distribution Network Operators (DNOs) in Great Britain. Scottish Hydro Electric Power Distribution (SHEPD) is the DNO for the north of Scotland and the Islands. Ofgem does also license Independent DNOs (IDNOs) which tend to be for circumstances where a private company wishes to supply electricity over a small private wire network to industrial or housing developments.

2 Grid connection process

Securing a grid connection agreement is the first step a generator needs to take when connecting to the electricity network, and the subsequent location and size of contracted generators is the basis of network planning by the transmission and distribution companies.

All of the proposed island connections are at transmission voltages hence the focus here is on development of the transmission grid connection process. This section briefly reviews the framework, and highlights issues that have arisen in the context of island connections.

2.1 Getting a connection offer

Figure 2-1 below shows the relationships between NGET, SHE-T and Ofgem throughout the grid offer and approval process. As noted in Section 1.3 and shown in Figure 2-1 below NGET is responsible for issuing connection offers, and NGET is the party with which generators contract. Behind each generator agreement with NGET is one between NGET and SHE-T. Most of the network planning to determine how and when a generator can connect is done by SHE-T, (although there is some collaborative working on for instance scheduling any system outages required for building the connection).

Generators can apply for a grid connection at any point they please – they do not for instance need to have planning permission before they apply. A developer's plans for its site can change over time, as does the network company's response to the changing pattern of generation and demand wishing to connect to the network. This means that once an agreement is signed, it needs to be maintained through two-way communication between the developer and the network company on each other's plans.

There is a process of quarterly reporting written into the grid connection agreements, but in practice this can be pretty variable in frequency and quality (both ways). For offshore generators building their own connections (see Section 4.2) there is a formal process called the Connections and Infrastructure Options Note (CION). The CION is a shared document which each party populates with their transmission reinforcement options and costs, and is used as a platform for discussing reinforcement options. Although the generator is not a party to the SO TO Code (STC), it participates in this process as a pseudo Offshore Transmission Owner (OFTO) before one is appointed through competitive tender. This contributes to an improved level of communication between generators and the TO. This could be implemented for other large connections such as the islands, with generators able to suggest their own fully costed reinforcement options, and comment on SHE-T's options.

- ➔ We consider later in this report whether the CION could form the basis of improving communications between island generators and SHE-T.

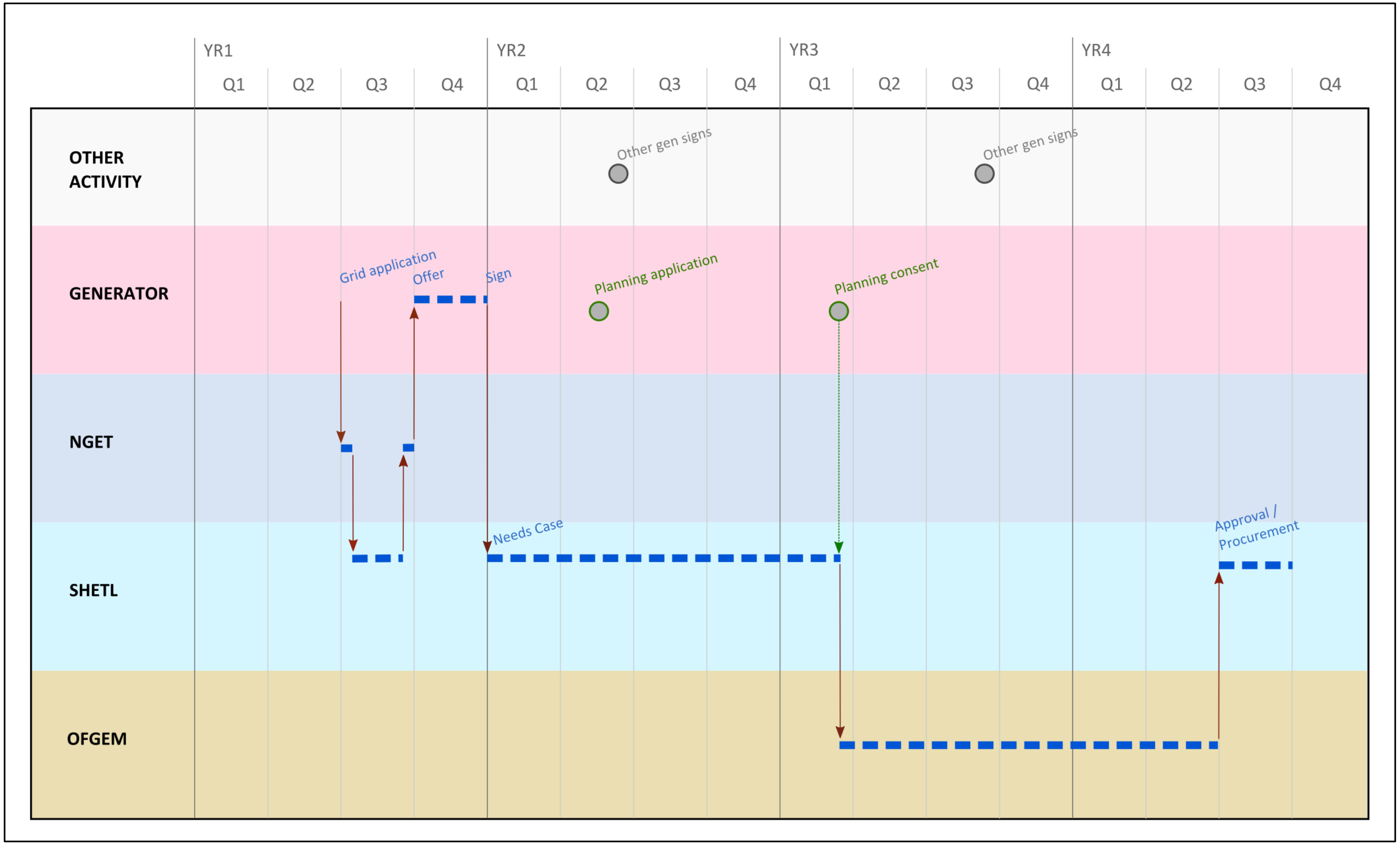

Figure 2-1: Relationships in offer process and needs case

2.2 Aggregating developer demand

SHE-T needs to take stock of contracted generation in its area, and develop and crystallise plans for reinforcements to accommodate that generation. This nearly always involves some aggregation of generator's requirements to trigger shared transmission reinforcements, leaving individual generators somewhat interdependent on other generators plans and progress.

This level of interdependence between different generators and shared reinforcements is at its most extreme in the island context where there are multiple generators triggering a single reinforcement. This is why one of the specific areas we have been asked to report on is whether generators agreements could in one way or another be aligned.

- ➔ We consider in Section 8.1 experiences with aggregating developer demand and whether further interventions in the islands would help connections.

2.3 Needs case

Under the current regulatory model, SHE-T is responsible for developing and financing construction of the island links. Before it does this, it needs to get approval from Ofgem for the costs involved in doing so. Ofgem will grant an "allowed revenue" to SHE-T which it can then be certain it will receive (with conditions) once it has commissioned each link. This process of SHE-T applying for funding from Ofgem is called the "needs case" process and involves SHE-T submitting a fully costed and justified proposal for the reinforcement. Figure 2-1 shows this interaction on the needs case between Ofgem and SHE-T.

To give some idea of the scale of the expenditure from SHE-T's perspective: the value of its total existing asset base in 2013/14 is around £1,214M [2]. That is, the three island links combined are worth more than SHE-T's current total asset base. It is easy to see that a cost overrun on any one of the links would have a significant impact on the whole transmission business (as would cost savings) and that therefore SHE-T is likely to be very sensitive to taking cost risks on these projects.

Furthermore, when approving construction spend on the island links, Ofgem needs to ensure that SHE-Ts activities are adequately financed, and that it is acting in the interests of consumers. It is unlikely to be in the interests of consumers for SHE-T to take risks that threaten the integrity of its business.

- ➔ SHE-T is responsible for developing and financing the island links, but is very sensitive to taking cost risks on the island connections. Generators, on the other hand, have no control over the link costs but under the current regime largely bear the cost risks. This separation of the party with the control from the party required to manage the risks is leading to major difficulties for island generators. This is a key point that runs through this report.

SHE-T also has sole control over when it submits a needs case, and – subject to Ofgem's guidance on the content of a needs case [8] – has control over what goes in it. However the timing of grid reinforcements is critical to generators in the context of subsidy regimes that are time-limited. Some stakeholders, particularly generators and those tasked with economic development in the Scottish islands, feel disenfranchised from the needs case process.

➔ We explore in this report whether SHE-T should have sole control over the timing of needs case decisions.

Developing a needs case can be complex and SHE-T may be building up a case for several years. Once a needs case has been submitted and accepted as competent, Ofgem estimates that it can take 12-15 months to fully approve a scheme [8].

➔ The timescales for building, submitting and approving a needs case can stretch to several years.

2.4 Summary

Grid connection agreements are often secured quite early in a developer's programme, (to secure grid capacity and give the generator valuable information on feasible grid connection dates and costs). Developer demand needs to be aggregated for SHE-T to plan shared reinforcements, and this can be a difficult process, especially for radial parts of the network such as the Scottish islands.

Information exchange between SHE-T and generators has room for improvement and we suggest the CION process used for offshore projects as a starting point for this.

SHE-T is responsible for planning, developing and financing the island connections and can exercise its sole discretion on when to submit a needs case to Ofgem. At the same time it is very sensitive to taking cost risks on the connections. We question whether generators should be able to influence the timing of needs case submissions, and whether it is appropriate for generators to bear the risks of forecasting errors in grid costs when they have very limited ability to manage these risks.

3 Operation of the grid

As well as specifying the technical and commercial terms on which a generator can connect to the network, a grid connection agreement (alongside general industry codes) also specifies the terms on which a generator can use the grid on a day-to-day basis.

3.1 Grid balancing

NGET as the SO needs to make sure that generation matches demand, that the grid is not overloaded and that power quality is maintained at acceptable levels. It achieves all this by requiring generation to provide certain mandatory grid services, and by contracting commercially with generators and demand for grid services. This is a very technical area and this report will not go too deep into technical grid services. However one area that will be covered is when NGET needs to curtail generators' output in order to balance the system locally or more widely. There are, very broadly, two main types of curtailment, as follows:

- Curtailment that is commercially compensated. In these circumstances NGET is usually trying to balance across the wider network to avoid 'congestion' (overload) on the network, and wants to secure the cheapest commercial offer for a reduction in output. A wind power generator for instance might offer to reduce its output in return for payment of its lost renewable energy subsidy revenue.
- Curtailment that is not commercially compensated. This is usually when a generator is cut off from the main grid by a fault and needs to stop generating for safety reasons, or when NGET is managing a local grid constraint and generators have been connected behind that constraint on the understanding that they will not be commercially compensated.

3.2 Single circuit connections

The island connections are all single circuit transmission connections. If there were to be a fault or an outage on the link, generation on the island would be isolated from the main transmission system and no compensation would be due (under the current Connection and Use of System Code (CUSC) rules). Even if the connection was a full redundancy double circuit connection, loss of both circuits would still only attract a very small amount of compensation.

Some stakeholders have suggested that island projects could opt to pay a higher level of Transmission Network Use of System (TNUoS) charge, as if there were full redundancy, and in so doing secure compensation for outages. This suggests that even though the TO has control over the design of island connections, that generators could exercise control over their operational risks by paying more. However, it is important to appreciate that if a single circuit connection to a Scottish island is not available, the island is completely cut off from the transmission system and in that circumstance NGET would not take bids and offers to manage congestion, as there is no congestion to manage. Hence there would be very little point in paying higher levels of TNUoS charges unless the current rules on CUSC compensation for outages were changed.

- ➔ For as long as island connections are single circuit, generators are taking commercial risk on any loss of availability of the connection.
- ➔ The only route by which generators can improve compensation available to them is through a CUSC modification. Paying higher TNUoS would only secure some small levels of compensation attached to grid outages.

The arrangements should there be management of congestion across island single circuit links are a little less clear. At the moment this is largely dealt with by simply avoiding congestion at transmission voltages by matching generator megawatts (MWs) to link MWs. If generators specifically request that extra MWs are connected, essentially over-subscribing the access rights on the link, then this will be considered, but the grid offer will almost definitely specify zero compensation for those extra MWs, should they be curtailed.

Some stakeholders have expressed concern about the lack of compensation where transmission infrastructure availability is not well understood and hence where insurance cover for outages is not readily available. This concern is being expressed by generators reliant on grid technology that does not yet have a proven track record.

- ➔ The lack of compensation for outages in the context of link technology with a limited track record means that generators are taking on grid technology risk. We explore this later in this report, in Section 7 on Shetland.

3.3 Constraint management schemes

If an island transmission link is outaged, it is very probable that the relevant DNOs will have to do some active constraint management across the distribution network. Active monitoring and constraint management is not something that DNOs would normally undertake, although intertrips are more common. The first scheme to do Active Network Management (ANM) in GB is the Orkney Registered Power Zone (RPZ) run by Scottish Hydro Electricity Power Distribution (SHEPD), which is in receipt of innovation funding allowed by Ofgem. The RPZ has been trialling curtailment practices, and in so doing has connected more generation to the Orkney distribution grid that it otherwise would. The RPZ is discussed further in Section 5.2.1.

- ➔ ANM schemes have to-date been in an experimental phase at Orkney. Lessons learned from Orkney will be important in the success of future schemes.

3.4 Summary

Because they are not designed for full redundancy (for economic reasons) island connections are not as secure as the Main Interconnected Transmission System (MITS). This also comes with very limited compensation for outages, meaning that generators are taking full commercial risk on network availability. Like cost risks on the island connections, generators are taking availability risks on the links without having any control or influence over this. Where insurance is not readily available, this is a major area of concern for generators.

Where there is more generation connected than the network is designed to accommodate, it is necessary to actively manage generator’s behaviour to avoid overload of the network. An experimental scheme is operational on Orkney, and similar schemes are expected to be required on other islands for when transmission links become unavailable.

4 Policies and regulations

Figure 4-1 overleaf details policy and regulatory developments aimed at island projects over a ten year period. This section provides a commentary on the development of these policies and highlights areas where improvements to facilitate island connections should be sought.

4.1 Funding the island connections

The orange and green lines in Figure 4-1 detail the policies and regulations developed around securing funds from Ofgem for the island connections. The orange line shows the main “price control” periods and the green line shows requests made for funding outside of the main price control settlement.

Price controls govern the spending of the three main TOs - SHE-T, SPT and NGET over a defined period of time. The current price controls for all three run from 2013/14 to 2020/2021. They each have a base level of spending which has been pre-agreed, which they will receive in return for pre-agreed outputs (e.g. an increase in system boundary capability) being delivered between April 2013 and March 2021.

Figure 4-1 shows that island funding requests have predominantly been outside of the main price control. Under these case-by-case arrangements, the TOs need to submit a needs case to Ofgem as and when they feel each individual investment is justified (this was touched on in Section 2.3). The TO will tend to time this needs case before it spends any unapproved funds (at its own risk) but generally not so early as it is too difficult to predict costs. This needs case will review the level of demand for the reinforcement, the risks associated with this (e.g. whether demand for the reinforcement is subject to uncertainty) and the costs submitted by the TO [8]. Ofgem will then make a decision on the following:

- **Whether the investment is needed**. The existence of connection agreements is strictly speaking the need, but the risk is that generators will change their agreements and that any credit cover placed by generators will not be sufficient to cover any stranded assets (in which case existing generators and suppliers – ultimately consumers – pick up the bill). Ofgem can (and has) queried the timing of the investment, the strength of the case and whether there are alternative design solutions.
- **Whether Ofgem agrees with SHE-T’s cost estimates** or whether it thinks they should be lower (or, more unusually, higher). Under the terms of the price control, Ofgem has already agreed a cost of capital with the TOs – i.e. the cost Ofgem will assume is its cost of capital when setting the allowed revenue. So the costs it is ascertaining here are the actual contract costs, project management etc., rather than financing.
- **Any special terms and conditions** associated with this, e.g. if some costs are unpredictable and it would be too harsh on SHE-T to set them in stone before construction begins. The existing price control already allows some flexibility on costs associated with subsea cable laying.
- **The treatment of other risks**. Note that the existing price control allows the TOs to keep 50% of any underspend compared to the allowed revenue, and they must use shareholders money to pay for 50% of any overspend. TOs therefore earn more money if they can undercut the allowed revenue amount. They might do this for instance by securing finance cheaper than their agreed regulatory cost of capital.

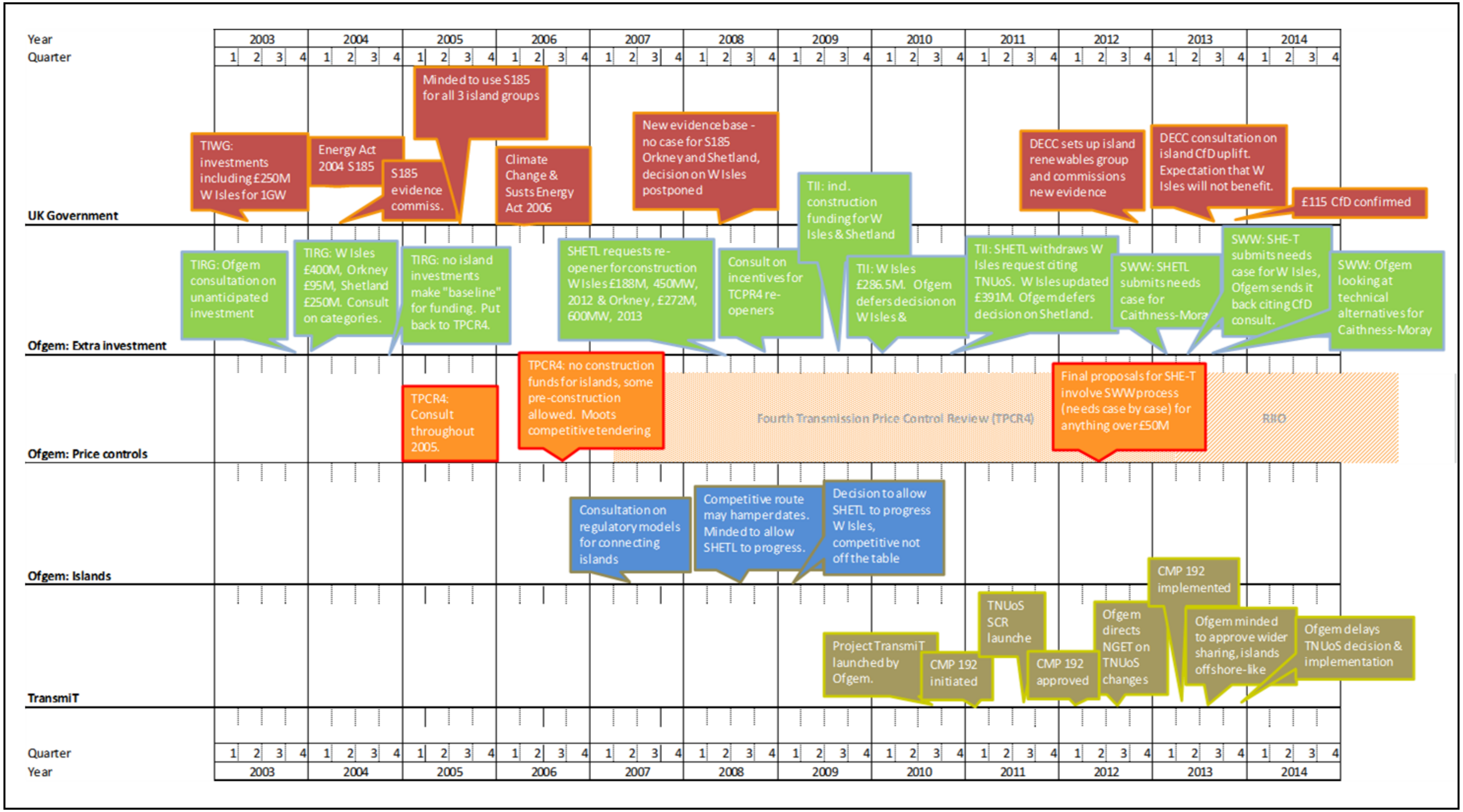

Figure 4-1: Timeline of island policies and regulations

In 2003 investigations began in to potential costs for connecting the three island groups, and in 2004 SHE-T's first proposal for funds was made under the Transmission Investment for Renewable Generation (TIRG) process. Ofgem at that time decided it was too early to consider construction funding, but later awarded pre-construction funds under the fourth transmission price control settlement.

Since then there have been several more requests for construction funding, shown in Figure 4-1, none of which have actually been considered by Ofgem. The requests have instead either been withdrawn by SHE-T, or consideration of the needs cases sent back by Ofgem for further information. Baseline construction funding for the islands under the RIIO (Revenue = Incentives + Innovation + Outputs) price control was not even considered – SHE-T's settlement under RIIO has case-by-case assessment for any expenditure over £50M. Details of each funding request, and references, are provided in Appendix A.

There is much debate about why the links have been delayed and where the responsibility lies for the ongoing failure to trigger construction funding. Some stakeholders feel that it is impossible to make a case for investment where there is uncertainty over generator's market prospects, and others feel it is essential to make the case while there is uncertainty, in order to ensure timely delivery of the connections. This is a fundamental disagreement between stakeholder groups.

Ultimately though, a key feature of the needs case process which is fuelling this debate is the lack of detailed scrutiny over decisions to delay a transmission reinforcement, as opposed to the full cost benefit analysis that would have taken place had an investment been sanctioned. This has resulted in there being statements of a decision to delay a needs case on the grounds of uncertainty, without any analysis of how the resulting risk and cost of stranded assets is balanced against the risks and costs associated with the link being delayed.

- ➔ There is an information asymmetry between full justification of approval of investments and scant justification for delaying an investment.
- ➔ We consider later in this report whether generators should be able to request greater scrutiny of delay decisions, or be able to put forward their own case for progression, where they are actively requesting that the link should move forward (with associated underwriting commitments).

4.2 Building and owning the island connections

The blue row in Figure 4-1 details the work that Ofgem has undertaken on who should build and own the Scottish Island links. Ofgem has consistently stated that it will consider alternative regulatory models for the island links – specifically competitive tendering of the transmission licenses (like the OFTO regime) or a merchant model (like the interconnector regime). [8], [9], [10].

If Ofgem competitively tendered a licence to own an island connection, aspects of the allowed revenue would be what bidders compete on e.g. the lowest cost of capital. In practice this doesn't actually avoid making decisions on other areas such as deciding on efficient costs, the treatment of uncertain costs, and where various other risks are placed. However, it is a tool that Ofgem has used in the offshore arena to bring some competition into the financing, design and management of transmission networks.

The "merchant" route has traditionally been used for interconnectors, whereby an interconnector company finances a link on the strength of future revenues it can earn from arbitrage trades between two different electricity markets. There is no regulated revenue for merchant links but they still need to be licensed, and are subject to regulations including the terms on which they offer access to traders and generators. A traditional merchant route is unlikely to be attractive for the islands given that the markets either side of the island links are one and the same. However, there is scope for a privately financed cable to be developed with its own, ring fenced, access and charging rules and commercial arrangements with island generators.

Ofgem consulted on these models in 2007 [11]. In 2008 Ofgem stated that it was minded to allow SHE-T to develop the Western Isles link (which was then subject to a needs case request rom SHE-T). In justifying this it said "adoption of a competitive approach may unduly delay renewable generation currently contracted to connect on the Western Isles by 2012/13, which may impact on the delivery of the government's 2020 targets" but that "We would also want to reappraise our view on the most appropriate way forward for this connection if there was a substantial change to the estimated costs or delivery timescale of the proposed link because this might imply greater potential benefits of a competitive approach." [12]

So, alternative regulatory models remain on the table for the island links. It is important to note that there is currently no explicit legislative provision nor regulatory framework to support neither competitive tendering nor merchant island connections for the islands. Ofgem is undertaking work on new regulatory models for interconnection between different countries, and onshore / offshore integrated networks [13] but this is at the policy development stage and has not yet considered island connections specifically.

A competitive regime would build on the existing offshore regime. Offshore, it is generators themselves that trigger a tender, and to-date all tenders have been initiated <u>after</u> the generator has financed and built its own connection (at its own risk). This is (relatively) easier to achieve offshore because the generators are generally large enough to have their own dedicated connection and they are able to manage construction of their own cables. The same cannot be said for most onshore and island connections, which not only involve multiple generators but which also serve electricity consumers.

Undoubtedly then, even if there were commitment from the industry and Ofgem to developing alternatives, it would likely be several years at minimum before they could become a reality. SHE-T has already progressed island links through pre construction stages and for two of the links undertaken tendering negotiations with cable manufacturers. At least some of this work would need to be repeated if a new party were to become responsible for building one of the links.

Thus the benefits of moving to an alternative would need to be significant to offset the cost of delay that would be introduced by developing and implementing new arrangements. Competitive tendering for offshore assets was initiated and driven forward by Ofgem and DECC, because of the consumer benefits they believed competitive tendering would bring. Ofgem could take a similar view on the islands, if it felt there were significant cost savings available. However, given that two out of the three Scottish island links (the Western Isles and Shetland) are reasonably progressed with preferred contractors already in place, we see little value in not progressing to consideration of SHE-T's needs case. This is in agreement with Ofgem's 2009 decision for the Western Isles.

- ➔ Consideration of cost savings from alternative regulatory models is likely best achieved during the needs case process for the Western Isles and Shetland. The savings would need to be very significant to justify a new regulatory model.

There is evidence that one or two larger island generators may need an OFTO-style route for the island connections because of the control over timescales and costs that this gives to their investors (hence leading to more affordable finance costs). This is considered in more detail in Section 7.3 on Shetland.

- ➔ Financiers of large island projects may require the control that an OFTO model gives.

The Orkney connection(s) are not as far forward as those for the Western Isles and Orkney. Furthermore there are alternative distribution reinforcement options available for Orkney e.g. a third 33kV connection to the mainland, which could use the existing IDNO regime as the basis for a private wire.

- ➔ The existing IDNO regime could form the basis of a private wire at distribution level on Orkney.

It is also worth noting that implementing a private wire route would be more straightforward for all of the islands if it was an offshore-like connection, i.e. a generator-only connection to the mainland with no link to demand on the islands. This may not be sensible given benefits to demand security of island reinforcements, but it is something that could be considered as part of any options analysis and / or something that would allow generators to fast-track a private wire route.

- ➔ A generation-only connection should be more straightforward to implement as a private wire option.

4.3 Generator charges for the island connections

As noted above, it is the TOs that make the initial outlay for grid infrastructure. TOs need to get approval from Ofgem for the outlay. Generators repay the capital costs back to NGET as the SO via TNUoS, and NGET re-distributes allowed revenue back to the TOs. NGET covers some of the stranded asset risk through underwriting arrangements with generators.

The grey line in Figure 4-1 details recent industry work on developing a new underwriting methodology and on developing the TNUoS methodology, both of which were prompted by Ofgem's wholesale review of transmission charges, "Project TransmiT".

The underwriting and TNUoS methodologies determine the level of exposure that generator's face to the actual costs of building and running the island connections over the development and operational lifetime of their project. Both methodologies are written in the CUSC and any changes to the methodologies need to go through a formal governance process which can take a year or more. Code changes are considered in more detail in Section 8.3.3.

4.3.1 Underwriting

To secure a transmission grid connection agreement with NGET, generators must agree to post a certain amount of financial security, and in signing the agreement they become liable for cancellation fees should they reduce their capacity requirements.

The current underwriting methodology is commonly referred to as "CMP 192" (CUSC Modification Proposal 192). Figure 4-1 shows how long it took to develop and implement CMP 192 via the CUSC governance process, namely a year to develop the methodology and get Ofgem approval, and another year to implement the new methodology into generator's grid connection agreements.

The underwriting methodology very basically divides up 'at risk' spending on the network (sums that are being spent for generators and demand that are not yet connected) between generators and demand customers, and then allocates the generator pot across individual generators, using factors such as their location, and the individual assets being built on their behalf. Changes to the underwriting methodology, whilst they can be complex, are essentially moving around ultimate responsibility for stranded asset risk, between different grid users and consumers.

So liability for the spend on works that form part of the MITS is split 50/50 between generators and consumers, and only those costs incurred in any one year are reflected in generators underwriting amounts. Liability for local or "attributable" works – typically radial connections off the MITS, including island connections – is reflected 100% onto generators (calculated according to their MW share of the link capability), and costs accrue cumulatively in underwriting amounts.

These differences in liability for different types of works are quite significant. They reflect the view that was taken, when developing the CMP 192 methodology, that where radial links are mostly driven by generation connections, that they should bear the bulk of the stranding risk.

Since CMP 192 has been implemented, there has still been a great deal of debate about the risk of stranded assets where the projects face market uncertainties. It is not at all clear how

SHE-T and Ofgem are / or intend to consider the absolute risk of asset stranding against the size of the liability that would fall to consumers to pick up – the latter determined by CMP 192. The underwriting methodology for island connections still does not provide full protection against consumers paying a portion of stranded asset risk, but it does provide much greater protection than for MITS assets.

- ➔ The relevance of underwriting amounts to the needs case has not been clear when debating island reinforcements. We would expect both the risk per se, and the size of the risk (here the liabilities falling to consumers) to be relevant. At the moment, most of the discussion is just about the risk, and not the scale of the risk. We consider this further in this report in the context of the Western Isles needs case.

When developing CMP 192, island constituents put forward an option that reduced local liabilities to 50%, in line with the MITS. Ofgem rejected this proposal but stated that it "did not consider there to be anything wrong with an appropriate portion of the liabilities for local works being shared with demand. However, we considered the proposal to be too broad and insufficiently developed." [14]

- ➔ There is potential for bringing forward a new CUSC Proposal which shares local liabilities with demand consumers.
- ➔ If this were simply based on the ratio of demand to generation, it is unlikely to be a game changing proposal. If it were based on broader benefits to demand of a link e.g. reduction in diesel subsidies in Shetland, it may be more significant.
- ➔ Changes to the underwriting methodology need to be considered in the context of the needs case process, and whether lower generator liabilities would simply make the needs case process even more protracted.

4.3.2 TNUoS

Once connected and operational, generators repay network investments via an annual charge - TNUoS. Again, how network costs are divided up and allocated to different grid users is determined by a methodology that is in the CUSC. TNUoS is a locational methodology, which very simply put, means that costs for generators are calculated per unit of distance from centres of demand.

Any changes to this methodology shifts costs from one party to another, which – depending on the materiality of the change – can often result in a north / south divide for and against the change. Some quite major changes and developments to the TNUoS methodology are contained in CMP 213, more commonly known as "Project TransmiT". Figure 4-1 shows some milestone dates for CMP 213.

CMP 213 included the development of a methodology for charging for island connections. The starting point for this was the methodology currently used to charge for offshore connections, which develops a unit cost for the link which is based on the actual delivered costs of the reinforcement. Ofgem has yet to make a decision on CMP 213 but its 'minded to approve' position is that, like offshore, the full delivered costs of island links should be reflected on to island generators.

This differs from the calculation of unit costs for traditional Alternating Current (AC) infrastructure on the mainland. So-called "expansion factors" for different classes of AC assets are set generically, in advance, and based on historical information on costs.

Furthermore AC expansion factors exclude costs such as river / road / rail crossings, surveying, interest accrued during construction and other cost categories [15]. They are therefore not as cost reflective as island and offshore charges.

➔ Island and offshore TNUoS charges are more cost reflective than mainland charges, because of differences in which cost categories are locationally charged.

It should be possible to challenge these differences through the CUSC modification process, although the outcome could go either way – namely island charges could become less cost reflective or mainland charges could become more cost reflective. Note that Island and offshore generators both pay "wider" mainland charges in addition to "local" TNUoS for their connection, so changes in wider charges affect island and offshore projects as well.

Figure 4-2 illustrates the impact on wider zonal charges of increasing the cost targeting of AC expansion factors – the blue line shows an estimate of tariffs under the current methodology for 2015/16, the red line shows the effect of increasing the unit cost multiplier for AC circuits (for readers familiar with TNUoS we have arbitrarily adjusted the expansion constant from 13 to 20 by way of an example). Because of the way that TNUoS works, an important point to note is that tariffs become higher in the north and more strongly negative in some southern zones.

Conversely, if island and offshore tariffs were to reflect the same cost categories as AC infrastructure, the costs taken out of the targeted portion of the tariff would be socialised and the effect would be that all of the wider tariffs would go up by an equal amount.

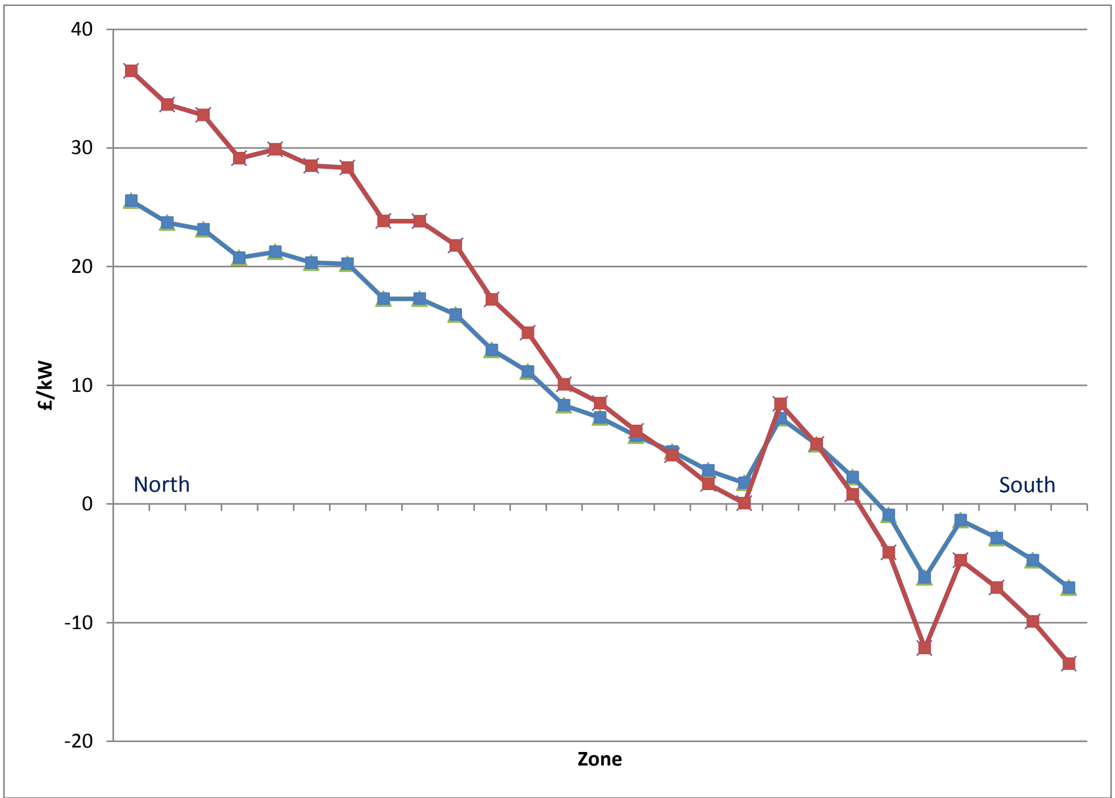

Figure 4-2: Impact on wider TNUoS tariffs of altering expansion constant

The implications of altering the cost reflectivity of tariffs are quite complex, but it's clear to see that such a proposal would be quite divisive between different groups of generators. As such it is likely to be difficult to progress.

- ➔ The disparity in cost reflectivity of tariffs could be challenged through the CUSC process, but it is likely to be a divisive and lengthy undertaking.
- ➔ Such a challenge would introduce further uncertainty on tariffs, on the heels of major proposed changes under Project TransmiT.
- ➔ All things considered we do not feel this would be a good option, (through the CUSC process).

The treatment of HVDC in the offshore and proposed island methodology attributes the cost of HVDC converters to the circuit cost, the effect of which is to locationally charge converter stations when most AC substations are not locationally charged. There was a lot of debate around this point during CMP 213, and several proposals were put forward for socialising some of the converter costs, on the basis of wider system benefits that converters provide.

Ofgem's view was that whilst there may be wider system benefits from the converters, as well as "technology learning" benefits, that it thought these were not significant [16]. However it asked for more views on this, with the HVDC VSC manufacturer ABB responding by reiterating system services (including independent control of reactive and active power, power oscillation dampening) provided by its technology.

- ➔ XE believes a more pragmatic approach to challenging existing expansion factors would be to present further evidence on the yet-to-be-decided treatment of HVDC converter costs, and in so doing attempt to influence Ofgem's decision on CMP 213.

4.4 Government policy

The preceding sections describe the main grid connection and charging framework, and the tools available to parties to influence developments – e.g. generators by making grid applications and participating in the CUSC governance process; SHE-T by making needs case submissions etc. This process, all overseen by Ofgem, is intended to run at arm's length to government.

However, government can and does intervene (within certain constraints – see below) if it thinks the process is not working well, or if it is simply not designed to deliver certain policy objectives. Government is also responsible for the renewable energy subsidy regime – currently the Renewables Obligation (RO) and soon-to-be Electricity Market Reform (EMR). As shown in Figure 4-1 on the red top line, the UK Government has employed both these levers on behalf of island projects – as described below.

There are constraints on what government can and can't do, and time implications for taking a particular path. Government cannot subsidise particular sectors or companies without gaining State Aid approval from the European Commission, and this can be time-consuming. State Aid is "using taxpayer-funded resources to provide assistance to one or more organisations in a way that gives an advantage over others" [17]. The Contracts for Difference (CfD) regime, for example, needs State Aid approval. The EU third package of electricity market reforms also requires that government does not interfere with regulatory authorities (Ofgem in GB) in its day to day activities.

4.4.1 Section 185

Section 185 of the Energy Act 2004 gives powers to the UK government to adjust transmission charges in defined geographical areas. The legislation was conceived to help projects in the Highlands and Islands of Scotland, although it could be used elsewhere if there were evidence that projects were being hampered by high transmission charges. The period for which the adjustment could work had to be extended in 2006 because of some problems with the way the legislation was drafted, and delays to the timescales of island projects.

A scheme on transmission charges could now run to October 2024, and would be for a fixed ten year period starting from when the first project commissioned. Because of further delays to island connections this timescale would need to be extended again if it were to be useful to island projects, and it is very unlikely that multiple projects could line up and commission on the same date to take advantage of a full ten years of transmission charge adjustment.

- ➔ A Section 185 intervention as currently set in legislation would not be an effective solution. Some major drafting changes are required.

In order to implement a transmission scheme, the UK Government must present evidence that it is justified (that projects economic viability is compromised by transmission charges). The UK Government has undertaken two evidence gathering exercises (shown in Figure 4-1), concluding in 2005 after the first that an intervention was merited [18] (it wasn't implemented) and after the second in 2008 that it may only be merited on the Western Isles [19] (it wasn't implemented on the Western Isles).

More recently, in 2013, when consulting on enhanced CfD support for island projects, DECC stated that “The regulation of transmission charging… is a matter for Ofgem under the EU Third Energy Package. The Government does not propose to deliver additional support for island renewables by intervening in the transmission charging regime, for example through an order under section 185 of the Energy Act 2004.” [20]

- ➔ Support via a Section 185 or other transmission charging intervention has been ruled out by the current UK government.

4.4.2 Island CfDs

Latterly, the Baringa / TNEI report undertook an evidence gathering exercise which led the UK Government to decide an intervention was merited for island projects. This intervention was in the form of an enhanced CfD strike price for island projects. The strike price is for the first EMR delivery period, which runs to March 2019. As island connection timescales are now all beyond this point, they will not be able to take advantage of this island strike price.

There have been calls for the island strike price to be extended to allow for the long lead times associated with island connections. CfDs are outwith the scope of this study. However, uncertainty over whether any island based projects will be supported through CfDs is having a significant bearing on SHE-T’s needs case deliberations. We comment later in this report on the interactions between government policy on renewable energy and the confidence with which major renewable energy-driven transmission upgrades can be progressed. We also comment on where the market risk is best managed.

- ➔ There is currently no visibility on the CfD regime for the timescales in which island projects can now be delivered – namely after the March 2019 cut-off for the first EMR delivery period.

Furthermore, the lack of a CfD market and specifically the inability of projects commissioning after March 2019 to apply for or bid for a CfD, is likely to impact directly on any of those projects hoping to secure project finance. This kind of finance uses the future revenue stream from the project as collateral for bank loans, and normally a Power Purchase Agreement (PPA) is used as proof of a future revenue stream. Some island projects are looking to bank finance to help with high underwriting amounts for the grid connection, and so are looking to reach a Final Investment Decision (FID) relatively early. Without a CfD this is going to be very difficult if not impossible, raising the question of how they will fund underwriting liabilities.

- ➔ Project finance for high underwriting liabilities in the absence of a CfD is likely to be difficult if not impossible.

4.5 Summary

A review of the last ten years of policy development around island connections shows a lot of activity across UK Government, Ofgem, NGET and industry. A user commitment methodology is now enshrined in the CUSC and there is more clarity on an island TNUoS methodology (although it is not yet approved). Whilst pre-construction funding for island connections has been granted, construction funding is proving much more difficult to secure.

UK government has held intentions to intervene on transmission charging, but has not implemented a scheme. Latterly UK government provided an enhanced island CfD, in effect saying that island projects are sufficiently different to onshore projects to justify a different pricing band. Whilst this is a helpful principle to set for island projects, implementation of the island CfD strike price times out before island projects can take advantage of it.

Overall there has been an intense but rather unstable policy environment around Scottish island projects, with the inevitable conclusion that some future stability would be a major improvement.

5 Evidence base – Orkney

5.1 Reinforcement plans

There are two transmission links connecting Orkney to the mainland on the drawing board. The first is an AC connection linking the Bay of Skaill on the west coast of the Orkney mainland, with Dounreay, on the north Caithness coast. This is shown in Figure 5-1 with available data on marine lease areas.

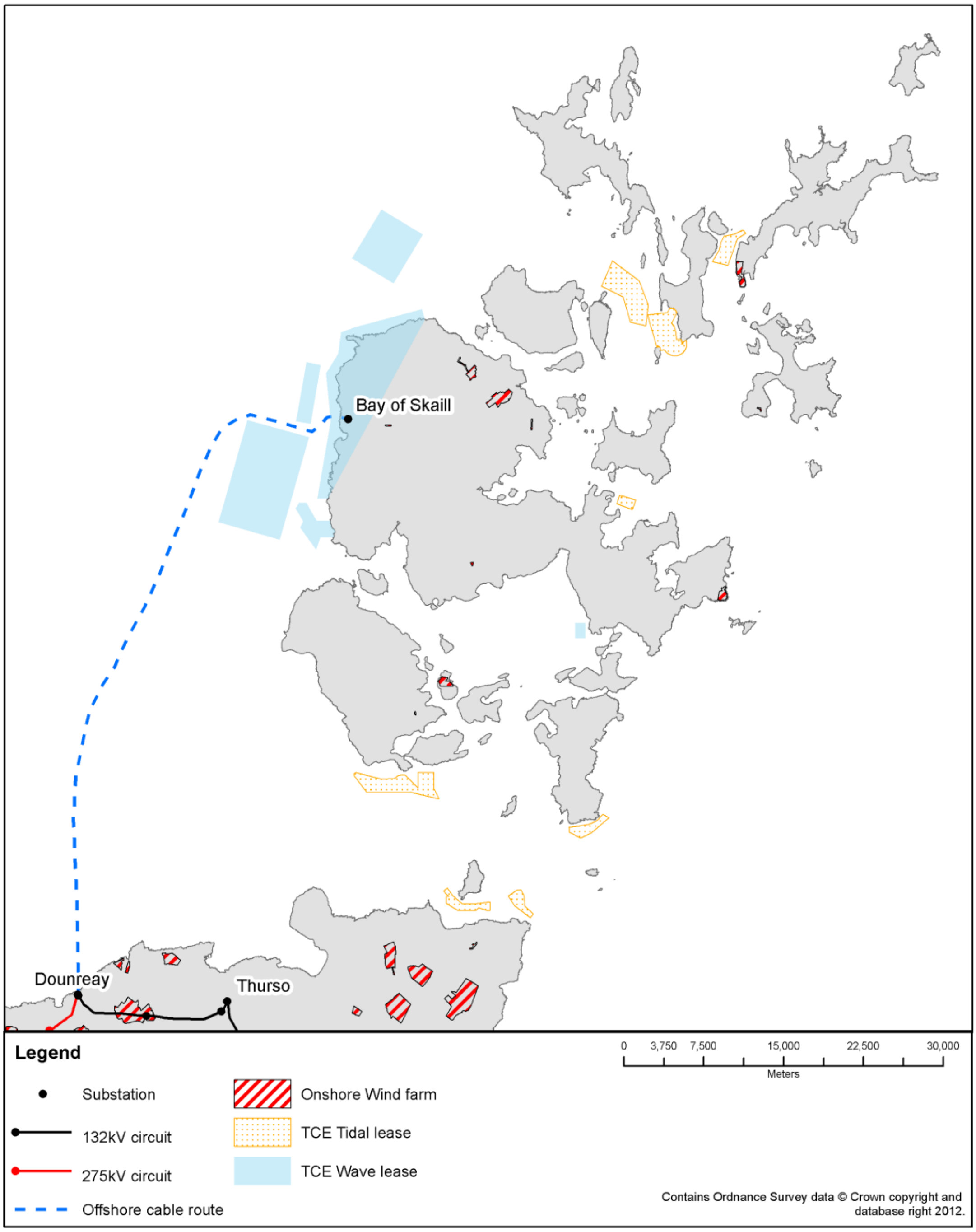

Figure 5-1: Proposed AC link from Orkney mainland to Dounreay

The second proposed link is at very early stages, and has been conceived to meet SHE-T's grid agreement contractual obligations (see Section 5.2.2). It is an HVDC link, also from Bay of Skaill, routeing across the Moray Firth and connecting to the mainland at Peterhead. A series of inter-island 132kV reinforcements is planned to bring power from the rest of Orkney to the Bay of Skaill.

However, the contractual position may change, and the final design for any further reinforcements from Orkney will very much depend on a settled and committed contractual background. SHE-T's current focus is on the first 220kV, 180 MW link. This focus was also mirrored in stakeholder submissions.

- ➔ SHE-T and generators' focus is on making a success of the first AC link to Dounreay.

5.2 Generation

5.2.1 Existing generation

Existing generation on Orkney is shown in Table 5-1 below. Local demand varies between 5.7 and 32.3MW. Total generation capacity on the island is more than double peak demand, (although the majority of the generation cannot currently be controlled to meet peak demand i.e. provide demand security). There are also two 33kV cables to the mainland, with a combined capacity of 38MW, which provide extra security of supply, but also, latterly, an export route for generation to the mainland.

	Firm (MW)	Non-firm (MW)	
		Intertripped	RPZ
Renewables	16	20.3	23.3
Microgeneration	5		
Flotta gas*	10		
Kirkwall diesel**	15.5		
TOTAL	**46.5**	**20.3**	**23.3**

Table 5-1: Orkney existing generation

* on-site supply, exports excess power to the grid

** used as standby generation

The non-firm renewable generation shown in Table 5-1 has been connected on the understanding that it will be curtailed when there is excess generation compared to the combination of on-island demand, on-island grid capability and Orkney export capability – all of which are variable. Intertripped generation is automatically disconnected when the system detects an imminent overload. Generation in the RPZ is subject to curtailment instructions from SHEPD.

There is understood to be some very limited, localised potential for extra generation to connect without impacting on existing generators. In most areas however there are no opportunities to connect without further on-island and Orkney export reinforcements, or an increase in local demand. New reinforcements would also likely alter the dynamic of the existing curtailment scheme creating winners and losers, unless they were completely separate to the existing distribution system.

Connection moratorium

A number of stakeholders referred to a moratorium on connecting new renewable generation to the Orkney distribution grid. This was announced by SHEPD in 2012. This includes "G59" connections of 50kW or less that normally have a different connection process to larger projects. Smaller G83 connections are still being accepted on Orkney (but not on Shetland).

The moratorium is in place because SHEPD cannot add more generation to the ANM scheme without impacting on the levels of curtailment in the RPZ. At the moment some generators are experiencing very high levels of curtailment – which is out of step with these generators' expectations. Curtailment for other generators are within expectations.

Stakeholders have attributed at least some of the problem (predominantly in outer island areas) to the connection of around 5MW in total of microgeneration. SHEPD would not normally control microgeneration connections in the same way it does for larger generators (e.g. undertake a full assessment of the impact on flows, and dictate connection dates), although as noted above it has latterly started to exercise greater control.

In retrospect SHEPD should have exercised greater control over microgeneration, and this lesson should be taken forward to future ANM schemes. The parties currently paying the price for this lesson are affected larger generators in outer islands.

SHEPD has recently issued a consultation on the options for moving forward in Orkney [21]. The intention is to gain consensus on three main options:

- The existing proposal for a transmission connection to Dounreay, with existing generators contributing to its needs case.
- Progression of an additional distribution circuit to the mainland.
- Make best use of the existing distribution grid on Orkney.

It is an unusual and serious step to implement a moratorium on connecting new generators, although in this case it appears to be a halt to opportunities to connect with Active Network Management (ANM) and without additional reinforcements. Generators can still request normal firm offers for connection.

RPZ lessons

The RPZ was justified on the grounds of technical innovation, but there are also some very valuable lessons to learn on the commercial and regulatory arrangements underpinning a constraint management scheme. For example, should there be limits to a DNO being able to claim a connection allowance if the connection is heavily constrained? Should generators take all the commercial risks on predicting curtailment when they have no control over it?

The RPZ is the first of its kind in the UK and any future active management schemes at distribution will look to the RPZ for evidence as to whether it can work well. We agree with the point that stakeholders have made that confidence in curtailment schemes will be important for the bankability of future schemes. To this end, project funders will look for objective evidence e.g. data on operational experience, experience with contract structures and lessons learned.

SHEPD has published some material on lessons learned under the RPZ but this does not reflect recent developments described here.

- ➔ There should be a more up to date review of lessons learned from the RPZ, which includes commercial and regulatory frameworks. This should support bankability of future ANM schemes and inform Ofgem's regulation of future innovation projects.

As a consequence of the RPZ – which was focusing on connecting more generation to the existing distribution system – existing embedded generators have no contractual relationship with NGET (either directly or through SHEPD) which would give them explicit rights to use the new transmission cable(s) when constructed.

This lack of a contractual relationship would not normally prevent electricity exported by embedded generators making its way onto the transmission system, rather it would just mean that an embedded generator would have no certainty over its access terms. However in the case of Orkney SHEPD does have the ability to manage embedded generation and could prevent export onto the transmission system. Whether it would use this ability to enforce strict contractual rights remains to be seen.

SHEPD is unlikely to ignore the existence of RPZ generators when planning the system but at the moment it is very unclear how their presence will contribute to the needs case for Orkney reinforcements. This is not optimal.

- ➔ The fact that existing, connected generation is not contributing towards the case for transmission reinforcements is a missed opportunity. They are connected generators with an existing need for extra capacity, where value is already being lost through curtailment. They should be taken into account when planning reinforcements.
- ➔ The reason that RPZ generators have not requested firm connections is, we surmise, that they cannot afford the underwriting obligations associated with transmission reinforcements and / or that they cannot afford the distribution system reinforcements required to reach the transmission system.
- ➔ Given that underwriting is a protection against a generator not connecting, and that these generators are already connected, we feel that there should be scope for waiving underwriting for RPZ generators. The risk of stranding is minimal (unless curtailment levels render some projects uneconomic in the meantime). Furthermore the RPZ generators have participated in an experimental ANM scheme the knowledge from which has benefited wider consumers, and therefore this could justify special treatment under the regulatory regime.
- ➔ Embedded generators are currently not liable for TNUoS but may be in the future, as a CUSC Modification to that effect is in preparation by NGET. This should be borne in mind by RPZ generators seeking transmission access.

5.2.2 Generation agreements

Contracted position

There is currently 769MW of generation (as of 6 February 2014 Transmission Entry Capacity, TEC, Register) contracted with NGET, with completion dates from 2018-2021. These are shown in Table 5-2 below with MWs allocated to the proposed AC and HVDC links. Costa Head, Brough Head and Marwick Head are wave power sites. Westray South is a tidal power site. Another 390MW of leased areas in Orkney waters are yet to make a grid application.

	AC link [MW]	HVDC link [MW]
SSER		
Costa Head, Westray South and Brough Head, Phase 1	130	
Costa Head, Westray South and Brough Head, Phase 1		320
Cantick Head Phase 1		30
Cantick Head Phase 2		65
Cantick Head Phase 3		65
SPR		
Marwick Head Phase 1	13.5	
Marwick Head Phase 2	26.5	
Marwick Head Phase 3	9	
SHEPD		
Non-firm embedded generation*	50	60
Demand	40	

Table 5-2: Orkney contracted generation and demand

*as yet unallocated to any generators

Submission of Ofgem needs case

On the face of it 769MW of contracted generation putting forward securities as required in their agreements looks good for a needs case. SHE-T is working on the pre-construction phase of the connection and a needs case at the moment. There is concern amongst stakeholders that the needs case is currently reliant on wave and tidal technology projects that are yet to be proven at the scale proposed – there is a belief that this would not be approved by Ofgem (although this has not been tested).

There is interest in onshore wind developments in Orkney, although no applications for capacity on the proposed export cable(s) from Orkney have yet been made. There are ongoing discussions between SHE-T and generators in Orkney around augmenting the Ofgem needs case, should onshore wind applications be forthcoming. This has been the focus of many stakeholders' verbal and written submissions to the study.

- ➔ XE agrees that the inclusion of onshore wind in the contracted background would improve the needs case. However, we are not confident that it would be sufficient, in of itself, given other market uncertainties.
- ➔ We also question whether the volume of onshore wind interest would be sufficient to justify a 180 MW cable, and whether a smaller, distribution reinforcement might be more appropriate.

- ➔ XE notes that it is not only new projects that could come forward and in so doing contribute to the needs case. As noted earlier existing non-firm generation could also apply for a firm or non-firm connection to the transmission system and contribute to the needs case.

GB transmission queue

Another issue raised in this context is how the new onshore wind generation would be treated in the GB transmission grid queue. Even if Scottish and Southern Energy Renewables (SSER) and Scottish Power Renewables (SPR) relinquished some capacity on the Orkney AC link, new transmission-connected onshore generators would be put to the back of the GB transmission queue. The queue is for space to be made available on a north to south transmission corridor through to customers in England.

This constant re-shuffling of the transmission queue does make it difficult to get applications aligned in time windows. In Section 8.1.4 XE reviews the system in Ireland which connects generators in tranches (“gates”), determined by generator’s progress and system reinforcement plans. Something similar is already operating in Orkney with the “gate” being approval of the needs case, but SHE-T and NGET must work within the existing rules for allocating access which are very much led by when generators submit their grid applications and provide underwriting.

It may help if SHE-T could achieve access allocation in a tranche by, for instance, contracting itself with NGET for a block of interchangeable capacity in Orkney, which it would then manage itself (SHEPD can do this at present, on behalf of embedded generators, but SHE-T cannot on behalf of transmission connected generators). This would however require some changes to the grid application and transmission access allocation rules which would likely be challenged by other queued mainland generators. SHE-T would also have to be required to do this and protected from taking risks on behalf of generators.

NGET is in the process of updating its queue management policy in order to cater for circumstances that are beginning to emerge. For example, a general principle of Connect and Manage is that when generators are ready to connect, they will be prioritised ahead of ‘paper’ generators. If generators could trust this general principle, they could have some faith that the queue would rationalise itself in favour of real projects over time.

- ➔ Any needs case that included onshore wind would likely need to factor in the issues around grid queuing, and the likelihood, over time, of the grid queue rationalising itself. If some generators are connecting later than others, this can be catered for in the needs case by looking at costs and benefits in Net Present Value (NPV) terms that take into account the value of costs and benefits in different years.
- ➔ NGET should help generators predict realistic connection dates with an updated and clear queue management policy.
- ➔ Anything more radical than this would require changes to transmission access allocation rules e.g. allow one party to purchase an option on transmission capacity which it could then re-allocate. This is not likely to offer a timely solution for Orkney.

Grid offer terms
Some generators queried the terms on which they would be offered connection to an already-committed cable. The two main options are that the existing contracted parties relinquish some capacity and / or new onshore generators accept non-firm offers based on them being “last on, first off” in any ANM scheme. If the latter case, there is a question over whether they should be required to pay the same level of underwriting and TNUoS as the firm connections. Under existing rules, their presence would reduce underwriting and TNUoS on a pro-rata basis rather than differentiate by access terms. It would seem reasonable to alter the rules to reflect different access terms.

- ➔ XE would recommend speaking to National Grid about a CUSC modification on underwriting and TNUoS for non-firm connection terms. Whilst this would likely take around two years to implement, we do not consider it to be a particularly controversial proposal.

Private wire
An alternative option raised by one stakeholder was building a private wire from Orkney to the mainland. This is a possibility, although it is not a route by which to avoid regulation or the GB grid queue. Furthermore, whilst a generator could finance and build a transmission line, it could not own and operate it, due to EU rules. It may be possible to own and operate a distribution line, although this may require some changes to the licensing regime.

- ➔ In summary, whilst we believe the private wire route to be possible, we believe that generators need to think carefully about what they want to achieve in doing this, and exactly what benefits it holds over the SHE-T / SHEPD route.

5.3 Underwriting

An approximate underwriting profile for the 220 kV subsea link, Orkney 132kV infrastructure (for 2019) and works at Dounreay, is shown in Figure 5-2 below. It shows costs for 180 MW of generation (the capacity of the subsea link to the mainland).

The red line shows the total cost of the local assets (it does not include Orkney projects’ share of the Caithness-Moray works), plus wider liabilities. The green line shows the same, but factoring in the Local Asset Re-use Factor (LARF). LARF is a part of the CMP 192 methodology and represents the proportion of local asset cost that NGET believes can be re-used (for readers that are familiar with CMP 192, the graph shows the LARF used for fixed underwriting profiles). The purple line takes off wider liability costs to give an idea of the proportion of local to wider underwriting costs i.e. wider liabilities are a small fraction of total liabilities (note that wider liabilities are estimated based on an inflation of NGET’s forecasts, but could be higher for the build scenarios implicit in island projects connecting). The graph also shows approximate spend to-date (“now”), from which current liabilities have been calculated.

We have received stakeholder submissions that whilst current, (relatively) low underwriting amounts have been manageable, the step-change in liabilities around year 3 of the profile is challenging. This is because the amounts involved are several times more than the spend on the actual generation project at that time, and represents a commitment that is out of step with the development and certainty of the generation project.

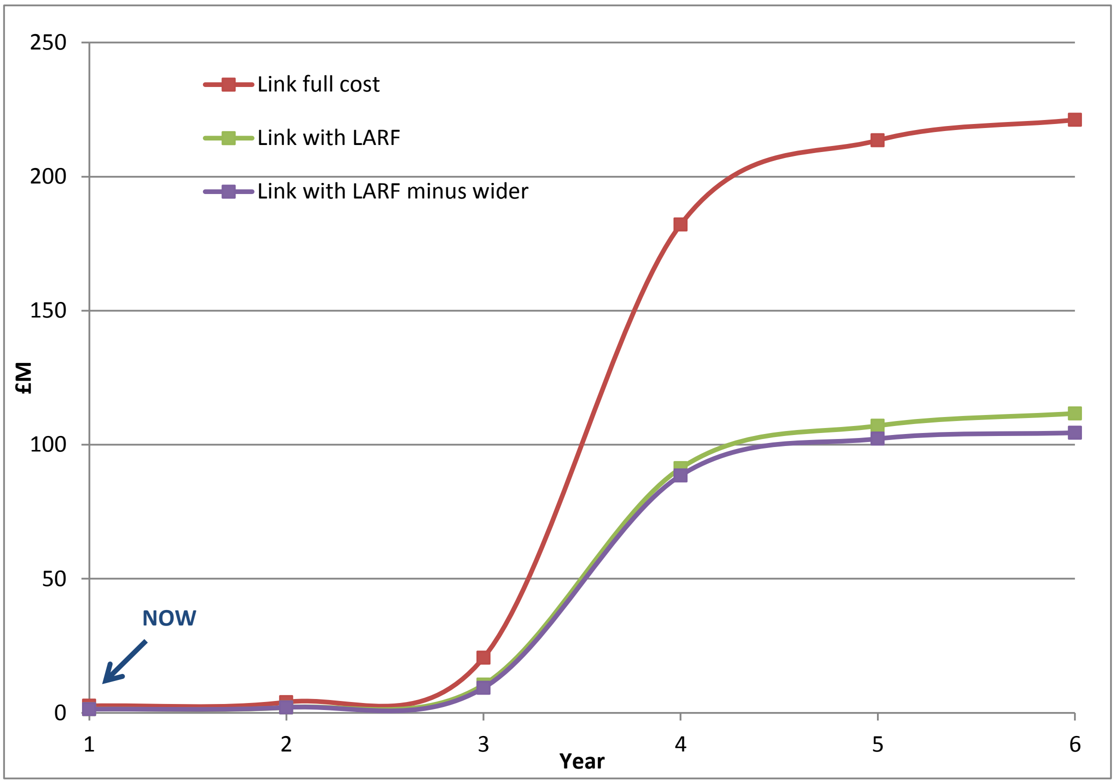

Figure 5-2: Illustrative Orkney underwriting profile

This misalignment of grid spend against generator financial strength is a common problem in grid securities, and is exacerbated on the islands by the high grid costs, relative to the generation projects. One stakeholder told us that they were facing an increase in grid securities to the tens of millions at a time when they would have committed around £1.5M on the project.

In the case of Orkney there is a window of say, between year 3 and year 5 (although the exact time period is uncertain as generator progress is uncertain) in which the generator will not have a project against which it can secure major project financing. At an aggregated level across all generators this represents an underwriting gap of around **£10M rising to £110M** over a two year period for these particular assets.

- ➔ There is an underwriting gap for the existing link on Orkney that wave and tidal projects cannot cover, in the order of £110M of guarantees for around 2-3 years.
- ➔ There is a risk that this period will be extended if the development of wave and tidal projects is slower than that of the grid, or vice versa.

Options to overcome this funding gap are:

- Find public or private sector investors with an appetite for the risks involved and the funds to cover the grid liabilities.
- Wait until the generation projects are financially strong enough to sponsor the link.
- Seek pre-commercial funding for the cable – for example grant support for research drawing on Marine Energy Park status (a UK designation that seeks to build academic and commercial links and create a scientific hub of activity [22]).

The first of these options is essentially the "third party" underwriting option that we have been asked to consider. We have received suggestions including an investment fund that would pool interested investors and share the risk, or a single investor that would take options on multiple projects in return for putting up the shared portion of grid liabilities.

All of these options are possible and are what we would characterise as 'behind the wire' solutions – namely they should be possible to arrange commercially between parties without any changes to the regulatory regime.

- ➔ There are no obvious grid-related barriers to implementing third party assistance with underwriting. There may be a need for some grid contract changes with NGET and discussions on the form in which underwriting can be provided.

We believe that the route to implementing third party underwriting is a secondary consideration to identifying the parties willing and able to provide the assistance. Stakeholders have told us that banks (in a project finance structure) will not provide funds where there is risk that the project will fail and not be able to provide a revenue stream (which is collateral for the investment). We do not know if government or equity investors are willing to take this kind of risk.

Marine stakeholders are not comfortable with the second option of waiting, as many of the test sites and first array sites being progressed to prove the technology are off the Scottish islands.

Marine stakeholders acknowledge the fact that they are not cost-competitive at the present time, and are at the stage of proving their technology. Companies behind the technologies do have commercial investors, but this is supplemented by public sector support. If the Orkney cable is integral to proving the generation technology, then it may equally be eligible for public sector support.

There are two routes by which public sector support could be provided. One is to fund the generator putting up the underwriting. The second is to directly contribute to SHE-T's investments, and reduce the requirement for underwriting (the funders and / or Ofgem may still require some commitment from generators).

- ➔ Pre-commercial support could be provided to the generators or to SHE-T.
- ➔ If provided to SHE-T, Ofgem would need to consider how this would be treated under its existing regulatory settlement, and how this was reflected in underwriting requirements.

This kind of support is likely to constitute State Aid, and would need approval from the European Commission. One stakeholder suggested that EMEC could take on the role of some kind of 'umbrella' grid agreement holder for wave and tidal projects, and perhaps allocate access by a competitive route as and when projects reached readiness. This kind of model would certainly ease EU concerns around favouring particular companies.

- ➔ We agree that public support for generators would be better channelled through a neutral organisation such as EMEC.

As noted earlier, many stakeholders believe that the likelihood of an Orkney link progressing on behalf of wave and tidal projects alone is low, on commercial terms at least. Banks and other investors are however more familiar with onshore wind, and there may be a better appetite for third party support on behalf of consented onshore wind projects. Hence the commercial route to realising a connection may rest on onshore wind prospects on Orkney. Marine projects may – in due course – be able to negotiate non-firm access on a cable that has been sponsored by onshore wind.

- ➔ Commercial third party support for an Orkney transmission link is likely to rest on onshore wind interest with consented projects. This is unlikely to offer a near-term solution (i.e. keep the existing plans on track for 2019) given the requirement for onshore wind projects to negotiate the planning system and secure grid agreements with acceptable connection dates. It does however at least offer a route towards overcoming the current impasse where wave and tidal technology cannot sponsor a transmission link.

5.4 TNUoS

Orkney-based project concerns tend to be dominated by underwriting. There is of course an appreciation that Orkney TNUoS tariffs will be much higher than on the mainland. To an extent wave and tidal developers (and embedded generators facing a potential liability for TNUoS) are looking to learn from other developers further down the development path, who are facing more immediate TNUoS challenges. The solutions that work for developers on other island groups e.g. stabilising TNUoS tariffs to support FID – see Section 6.4 are equally relevant to Orkney developers as and when they are closer to FID.

5.5 Access rights

By access rights, we mean the extent to which generators can rely on access to the new reinforcements in order to export their full output. As noted earlier existing Orkney generators are very focused on the operation of the RPZ. However, there was very little comment on access related to the reliability of export cables e.g. cable outages or cable faults.

This in part seems to reflect the fact that the first cable is an AC connection, and Orkney's existing experience with subsea AC cables (for which insurance against outages has been available to generators).

- ➔ AC cable outages and availability of insurance were not raised as a concern by Orkney stakeholders.

5.6 Cost Benefit Analysis

Proposals for new transmission link(s) from Orkney to mainland Scotland (and further reinforcements throughout the transmission system) are being driven by renewable energy projects that require a route to the GB electricity market. The direct benefit to commercial investors in these projects is the returns available from selling power into this market.

Where consumers, government or other third parties are being asked to help fund and / or underwrite these transmission links, the regulator needs to consider the cost / benefit balance to GB consumers, as well as the risk versus net benefit balance. This is in part what the Ofgem needs case consideration seeks to draw out.

5.6.1 Potential benefits

We have received submissions from Orkney stakeholders on what they would like to see considered in the needs case in terms of the benefit part of this equation, and this has been augmented by XE's additional considerations. Table 5-3 summarises these. This is not intended to be exhaustive, but hopefully offers useful guidance to SHE-T and Ofgem. Some commentary on each of the items in Table 5-3 is provided below.

Costs	Benefits
• Link capital costs • Substitution of wave & tidal for lower cost renewables	• Avoided stranded infrastructure • Substitution of island wind for higher cost renewables • Improved security and quality of supply, • Reduction in diesel costs • Reduced curtailment of existing generation • Local economic activity

Table 5-3: Orkney costs and benefits

Avoided stranded infrastructure

Orkney Islands Council provided evidence on public sector capital investments in Orkney in support of growth of the renewable energy supply chain. £32.4M of public sector money has been invested in the European Marine Energy Centre (EMEC) – mainly in physical infrastructure but also in standards development and capacity building. EMEC earns revenue from developers but this is now limited by grid capacity on Orkney. A further £25.4M has been invested in ports and harbours infrastructure [23]. More marine energy devices have been grid-connected at EMEC than at any other single site in the world [24]. Activities at EMEC support around 240 jobs across the UK [1]. There are currently ten developers testing wave and tidal energy converters at EMEC [25].

Substituting for offshore wind

If we assume the renewable energy support regime is aiming for fixed volumes of renewable energy, then lower cost technologies will give lower overall consumer costs of meeting the targets. A cost benefit analysis for the reinforcement should look at credible substitution scenarios to establish costs and benefits for consumers. For example if island-based onshore wind MWh replace offshore wind MWh in meeting targets, then this should result in lower overall consumer costs. Conversely island-based marine technologies are more expensive than other eligible technologies and will increase consumer costs.

Improved security of supply
Any additional connections to Orkney that serve demand as well as generation should improve energy security for demand customers and may improve the quality of supply. Ofgem has used a value of £16,000/MWh [9] for Energy Not Supplied, which could be used as the basis for quantifying the benefits of improved security.

Reduction in diesel costs
Diesel generation is used as back-up in Orkney, typically when there is a subsea cable outage. Improved Orkney connections to the mainland should reduce the need for expensive diesel fuel.

Reduced curtailment of existing generation
There is a lost opportunity cost of curtailing existing generation on the islands. It is standard practice when planning grid system upgrades to factor in the reduction in curtailment against the capital cost of the reinforcement.

Local economic activity
The Baringa / TNEI report detailed the local, regional and national economic benefits associated with realising the renewable energy potential of the Scottish Islands. This is clearly a substantial benefit to the local and wider economies, and is the driving force behind the island council's and Highlands and Islands Enterprise activities in renewable energy.

Whilst development of renewable energy on Orkney and the other Scottish Islands without question provides much-needed local and regional benefits, it is not so easy to determine whether there are additional national benefits available from developments on Scottish Islands. For example, are marine and tidal supply chain jobs in Orkney substitutable for marine and tidal supply jobs in Cornwall? We cannot answer that question in this report, but note that the Baringa / TNEI report did stress the additionality of wave and tidal jobs given UK Intellectual Property Rights (IPR) and content in the sector. To the extent that the potential resource in Orkney and other island waters is substantial, there is clearly scope for arguing UK-wide additional benefits.

Ofgem may also consider local economic benefits as counting as being in favour of the development, but it will probably not have the same risk versus reward focus as local economic agencies. That is, the fact that renewable energy is offering one of the very few sources of economic development potential for the islands means that island stakeholders are extremely focused on getting the infrastructure in place that would allow value to be extracted – the reward is high, and there are few if any alternative rewards available to them. This is inevitably impacting on their risk perspective. Thus Ofgem is unlikely to have the same perspective as many island stakeholders, and this can be a source of disappointment to island stakeholders.

- ➔ The GB-wide consumer focus of energy sector regulation, and the local economic focus of government agencies and councils, is the source of a mismatch between different stakeholder priorities.
- ➔ Economic benefit can be considered in a needs case, but different stakeholders will give it different weightings.
- ➔ In any event there is potential for UK-wide economic additionality to be considered for Orkney, because of the new jobs and prosperity that could be created by a wave and tidal sector.

5.6.2 Orkney factors

The benefit categories listed and discussed above are similar for each of the Scottish Island groups, so the commentary will not be repeated for the following sections on the Western Isles and Shetland. However there are some differences between the islands in the materiality of each benefit which we will seek to bring out.

For Orkney, the prevalence of wave and tidal stands out, and with it the focus on UK wave and tidal IPR and supply chain. The marine energy sector remains at an early stage of commercial deployment and both the Scottish and UK Governments have said they are "fully committed to the successful development of the marine sector" [1]. Locally investment has been channelled into EMEC and ports and harbour facilities to service the wave and tidal sector. When and how this value should be captured is discussed in Section 5.6.3 below.

The existence of existing, consented generation that is already being curtailed also represents easily quantifiable lost opportunity costs.

5.6.3 Timing of cost benefit analysis

When gathering evidence on the needs case process, it became evident that there are divergent views on who should be assessing benefits – in particular socio-economic ones – and when. We do not know exactly what goes into a needs case as the original submissions are not published. However, from what assessments are published, we do not believe socio-economic assessments feature very strongly, if at all. When undertaking its own assessment and consultation on the needs case, Ofgem may consider more wider economic factors.

Ofgem's guidance to TOs on a needs case submission states that "Lifetime cost benefit analysis (CBA) of reinforcement options… should include amongst other things, environmental benefits, monetised costs and benefits to consumers and impacts on security of supply". And that there should be "CBA results on the expected net economic benefits of the reinforcement options…" This guidance leaves some room for interpretation, but the guidance does also ask for TOs to state what stakeholder consultation they have undertaken and "an explanation of where stakeholder's views have informed the proposal, and where the proposal differs from the views of stakeholders and the TO's justification for this." [8]

Hence it is fair to say that stakeholders on the Scottish Islands strongly believe that socio-economic costs and benefits should be taken into account, and that this view should be reflected in the needs case. Of course, there is an issue on timing here. If socio-economic considerations are substantial but they are not considered by SHE-T, then the needs case cannot reach Ofgem's desk on the strength of these considerations, to then be given greater weight by Ofgem. Essentially, whilst Ofgem's guidance does ask SHE-T to consider economic costs and benefits, and stakeholder views, it gives no guidance on the weighting these should be given or how that should influence SHE-T's timing decisions.

SHE-T is not an economic development agency and we would question whether it has the expertise to assess these kinds of issues. However, we do feel that those who do understand these issues should be able to influence the content of the needs case and submission timing, through SHE-T's stakeholder engagement. They should also have the option of taking evidence to Ofgem.

- ➔ Expertise in socio-economic development should have the opportunity to influence the content and timing of a needs case.

5.7 Summary

Under current circumstances, Orkney's 180 MW, 220KV reinforcement plan will **not proceed**. This is because:

- Based on cost projections, the underwriting obligations for the wave and tidal generators underpinning the reinforcement are likely to be unaffordable to them if the reinforcements move into a construction phase.

- Wave and tidal technology is immature and uncertainties around the technology raise the prospect of stranded asset risk, which negatively impacts the needs case.

- There is no visibility on the market prospects for renewable energy after March 2019, and any Orkney reinforcements will be delivered after March 2019. Again, this raises the prospect of stranded asset risk.

This report explores a number of measures aimed at reversing this position. These are:

➔ Co-ordination of onshore wind applications – from existing RPZ generators as well as from new projects under development – to shore up the case for the reinforcement with more mature technologies.

➔ Making sure that socio-economic benefits of an Orkney connection are properly taken account of in the needs case process, balancing concerns around the risk of stranded network assets against stakeholder concerns of lost opportunities.

➔ Third party underwriting of the cable to keep it on its current timeline – this involves finding an organisation or organisations able and willing to bear a liability rising to approximately £110M (and higher if Caithness-Moray works are included), for the three years or more that generators cannot bear these liabilities.

Of all these options, the last is the most important for keeping current reinforcement plans moving. Otherwise, **reinforcement plans will almost definitely need to be scaled down and / or delayed**. Furthermore, wave and tidal technologies are at a pre-commercial stage and in the course of this study we found no-one expecting commercial support for underwriting to be forthcoming.

Therefore **support from organisations and public institutions with wider research, development and socio-economic remits appears to offer the best hope for keeping current Orkney reinforcement plans moving**. There are State Aid implications of providing this kind of support, and it would require very careful design.

We also received considerable representations from stakeholders on the Orkney RPZ. There are clearly lessons to learn on the commercial set up around an experimental scheme, and lessons to take forward on future ANM schemes. The creation of winners and losers in changing the dynamic of an ANM scheme is also complicating any plans for reinforcing the distribution system and lifting a connection moratorium for smaller generators. We have suggested **relief for underwriting obligations for existing RPZ generators**, where stranding risk is deemed to be minimal. However RPZ generators will still need to consider affordability of TNUoS.

6 Evidence base – Western Isles

6.1 Reinforcement plans

Planned reinforcements for the Western Isles are shown in Figure 6-1. These are a 450MW single circuit HVDC subsea cable to the Scottish mainland, a 900MW double circuit underground to Beauly, and various 132kV reinforcements on Lewis.

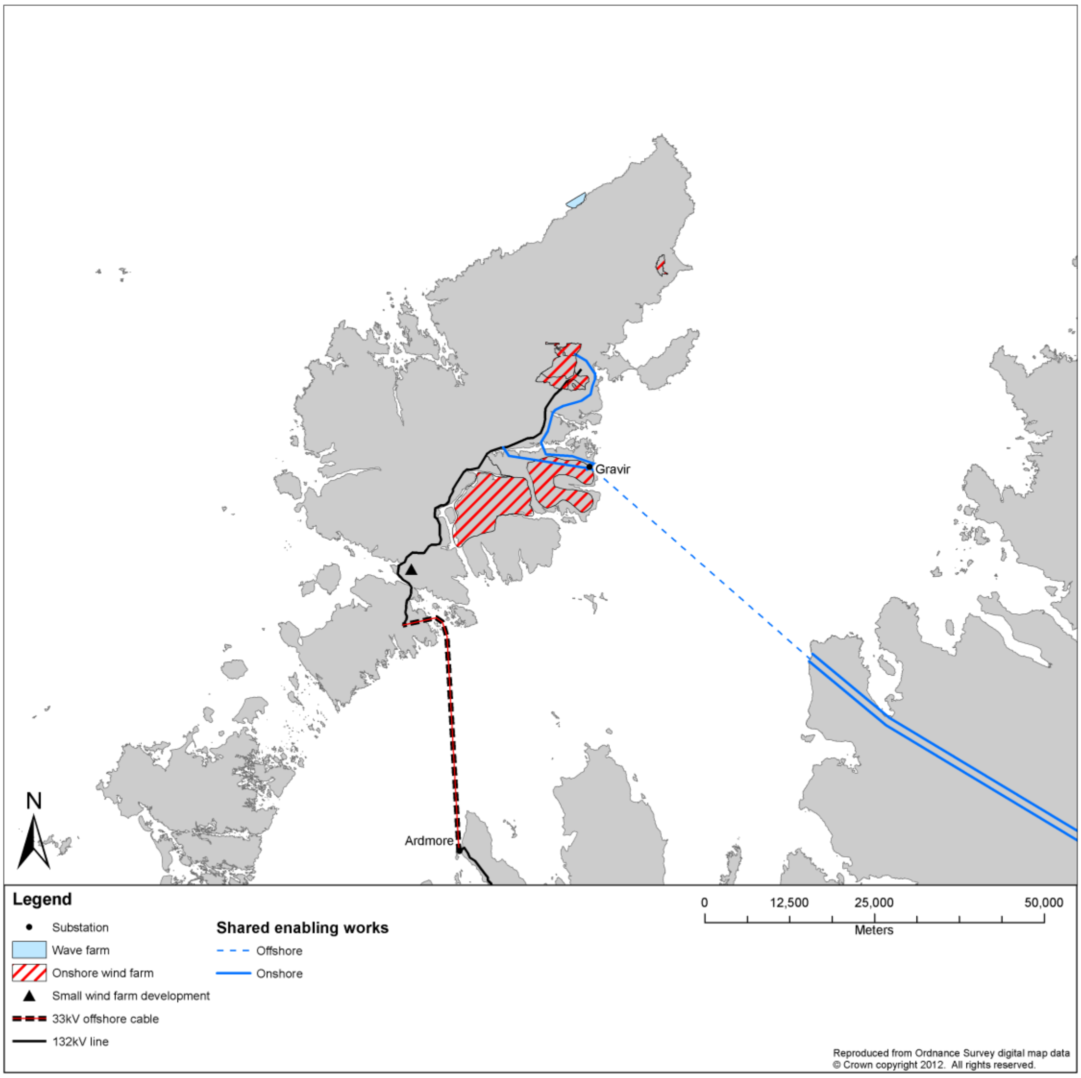

Figure 6-1: Proposed Western Isles HVDC connection and on-island reinforcements

The doubling up of capacity for the mainland portion of the HVDC section is for future-proofing the route – as the environmental authorities are understood to have major concerns around repeat visits to underground cables. A number of stakeholders in the Western Isles queried the cost of the second mainland circuit, and whether it is being properly accounted for as future-proofing in underwriting and TNUoS amounts. This is considered further in Section 6.3 and Section 6.4.

6.2 Generation

6.2.1 Existing generation

There is 28MW of renewable generation installed in the Western Isles, although 4MW of this is constrained until a new transmission link is installed. There are two diesel power stations at Arnish and Battery Point which serve as back up, with the 20MW cable connection through Skye to Harris and Lewis providing the main source of demand security.

Local demand varies from 5.7 to 27.6MW.

6.2.2 Generation agreements

Contracted position

Projects listed in the TEC register as of 17 February are shown in Table 6-1 below, alongside their consent status.

Project	MW	Consent status
Beinn Mhor Power, wind, GDF	133	Approved
Eishken Estate, wind, Uisenis Power	150	Not consented
Stornoway wind farm, AMEC and EDF	130	Approved
Druim Leathann, wind, 2020 Renewables	39	Approved
Lag Na Greine, wave, Aquamarine	40	Approved
TOTAL	492	

Table 6-1: Western Isles contracted generation

A total of 342 MW is now consented with grid connection agreements in place. Around 20MW of small embedded generators are also allocated to the planned transmission reinforcements. In total there is over 500MW waiting for transmission capacity. As this total exceeds the capability of the 450MW cable reinforcement planned, a second subsea cable, along the same route, is also now on the drawing board.

Submission of Ofgem needs case

This position of mostly-consented projects and more than 500MW of signed connection agreements has been steadily building up over the years. The last grid connection agreement was signed in the last quarter of 2013.

In view of the level of interest in the Western Isles and the gradual build-up of consents, SHE-T has made a request for construction funding for the Western Isles connection in each of the current and previous two price control periods. It has requested funding as “baseline” and also as a price control re-opener. Ofgem has either deferred consideration of the requests, or asked for more information, or SHE-T has subsequently withdrawn the request. Ofgem has queried or SHE-T has cited, amongst other things, the (previous) lack of planning permissions for projects and uncertainty over economic viability of projects. For example SHE-T withdrew a needs case submission in 2010 because developers said that their projects were not economic at the (then) estimated level of TNUoS and anticipated underwriting.

The latest submission, in 2013, was sent back by Ofgem in the same month it was submitted. Ofgem queried why SHE-T was submitting the needs case at a time when generators were seeking, but had not received, enhanced CfD support. Ofgem asked for “the justification for initiating the assessment of the WI proposal at this time under the SWW arrangements as opposed to deferring the assessment until further information is available. This should include SHE Transmission’s assessment of the benefits to consumers of doing so.” And also for SHE-T’s “assessment of the optimal timing, taking into account the need to balance potential supply chain issues and any potential risk for consumers associated with delivering the proposed WI link too early or too late.”

Ofgem did not attach a timescale for SHE-T to respond to this feedback. SHE-T has not responded publicly and has opted for waiting for a decision on CfDs and then wrote to developers asking for information on their projects. This was, in effect, a decision that it was better for consumers to risk the cable being “too late” than to risk making a decision with imperfect information (or to waste time having to update the information as it was being assessed). It may in fact be the case that even if the needs case was submitted in June with all the information Ofgem requested, we would not be any further forward as the information would keep changing and Ofgem would spend longer on the needs case until the information improved, and so the timing of the cable has not been affected.

Nonetheless, the point is that to delay consideration of a needs case <u>is</u> a decision on the needs case, it is just being made in a way that is not entirely transparent or subject to any detailed assessment or analysis.

- ➔ It is important to bear in mind that delaying a needs case submission and its consideration is an active decision on what is better or worse for consumers in terms of timing.

We have considered how a decision to delay submission of a needs case might be more transparent and objectively justified. SHE-T could for example be asked to provide periodic and quantified justification for delay, but this may simply cause further delay by creating extra obligations. Generators could have the option of making a quantified case for earlier submission, which they would make to SHE-T or Ofgem. In order to do this they would need some level of information on the costs and timescales for the link from SHE-T.

- ➔ There should be more accountability for delay in needs cases, <u>if</u> generators are actively requesting that a needs case is submitted, and an ability for generators to influence SHE-T’s decision making.

It has similarly been difficult for us to unravel different stakeholders perspectives on the needs case process. Some developers have expressed frustration that the Western Isles needs case has not been approved earlier, stating that they believed they were doing what was required of them – namely placing securities. SHE-T stated that it had to make a justifiable case for investment to Ofgem, and that securities was only part of this. It is also true that developers have variously stated in the past that TNUoS levels are too high or that revenues are too low.

Island project economics are unlikely to have stabilised in the context of rising cable costs and latterly a new renewable energy support regime. The estimated cost of the Western Isles link more than doubled between 2010 and 2012, which has been a significant contributing factor. Adding to this is the fact that the new EMR regime is working on a five year-ahead time horizon (i.e. CfD contract prices only run until 2018/19), which is about as long as it will take to get a needs case approved and build the Western Isles reinforcements.

This has left developers in the position that as soon as they have a stable economic environment which would help the needs case, cable delivery dates are just too late to qualify for support under the current EMR Delivery Plan. Developers felt that if a needs case requires certainty to go forward, then they would always be left just too late to qualify for EMR support.

The question then is where the responsibility should lie for breaking this cycle. UK Government has attempted to intervene either via Section 185 or latterly enhanced CfDs, so there has clearly been a desire to assist, but other factors – timescales and costs associated with the grid connection – have meant that these interventions have timed out before they could be useful.

There are a range of options for breaking the cycle, which differ by who bears the risk that projects will not reach fruition. At one extreme, developers could pay SHE-T's costs for the link up-front, keeping SHE-T cash positive in the same way that distribution connections are funded (and which as a result are not subject to a needs case). In so doing they would each be absorbing the risk that the other contributing developers may fail, the risk that the link costs may increase further, and the risk that there may not be a market for their power. At the other extreme, Ofgem could approve anticipatory investment in the link in the context of market and cost uncertainty, and in so doing placing stranded asset and cost risks with existing grid users and ultimately consumers.

Somewhere in between these two extremes is a balanced approach to risk allocation, and some risk mitigation where possible e.g. allowance for island grid delivery timescales in the EMR framework. Achieving a balance of risks is necessary for most transmission projects to go forward, so the islands are not unusual in this respect. The underwriting methodology seeks to achieve a GB-wide balance, but it seems clear that there are different views as to whether this is a correct balance for all circumstances.

- ➔ Breaking the needs case cycle is likely to lie in a balanced approach to risk allocation, supplemented by risk mitigation. Aside from points on transparency of the needs case process, this is really a question of who takes the risk for stranded investments, and / or a question of government providing more market certainty.
- ➔ The CfD market is outside the terms of this study, suffice to say that market uncertainty is impacting on the ability to progress the island link(s).
- ➔ Clearly as market certainty is a material concern in the Western Isles needs case, SHE-T believes that in this context of market uncertainty generators are not taking enough of the stranded asset risk to justify moving forward. One option to move this forward could be for SHE-T or Ofgem to issue a consultation on the generator / consumer risk balance on the cable – with options to maintain or modify this balance.

Private wires

The prospect of a privately-funded connection for all of the Scottish Islands has been repeatedly raised by Ofgem and debated by stakeholders, with the issues being more 'live' for the Western Isles as the most progressed of the three links. Generally generators have favoured the SHE-T route, on the assumption it would provide a more timely connection (it would avoid the regulatory developments needed to make a private enterprise possible), and, probably, that there would be some cost sharing with consumers.

Given that timescales have been protracted for the Western Isles, and that generators have had little ability to control or anticipate rising costs, there may be some renewed appetite for a private route – either from generators or Ofgem. However no-one has expressed any strong interest in the context of this study.

- ➔ The option of a privately-funded and developed merchant or OFTO-type link is on the table from Ofgem, but there has been no strong interest expressed as part of this study, from Western Isles developers.
- ➔ Under the current regulatory model, whilst SHE-T does communicate with developers e.g. by explaining the reasons for cost increases, we believe that there is room for improvement e.g. by giving generators the information they would need to anticipate potential cost increases.

6.3 Underwriting

An approximate underwriting profile for the Western Isles cable is shown in Figure 6-2 below. It shows the link full costs plus wider liabilities, an approximate liability profile (with LARF and costs fixed to the latest available costs) and the underwriting profile just associated with the local works. The green line is the best approximation of aggregated liabilities for the link, if it were fully subscribed.

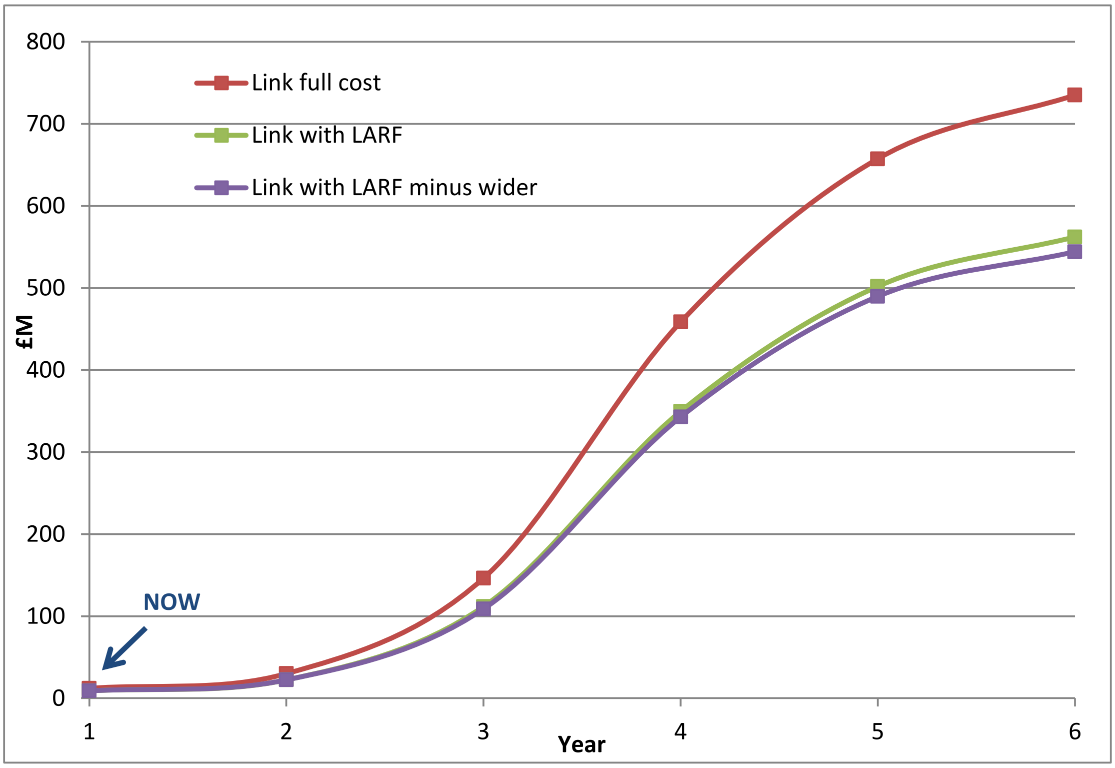

Figure 6-2: Illustrative Western Isles underwriting profile

The underwriting amounts for the Western Isles peak at around £1.2M per MW of generation capacity. These amounts are in a similar order of magnitude of cost as the generation project itself. This ratio of project cost to grid liabilities at roughly 50/50 is, as far as we know, unprecedented for large onshore wind projects in GB.

We have been told that banks will not provide finance for projects holding this level of liability, on the strength of the wind farm as collateral alone. This would appear to limit the market to those players not reliant on project finance during the construction phase of the cable, (which is reflected in this study by which generators have emphasised underwriting liabilities as a barrier).

One generator alluded to the need for government support – tied in with government shares in the project – to assist with the underwriting amounts, as they did not anticipate support from debt providers, i.e. government is providing equity.

- ➔ Some developers have highlighted that the amount of underwriting required is challenging, and have linked this directly to the fact that the generation project does not provide enough collateral for a project-financed undertaking.
- ➔ The consequence of this is to limit competition in the market, at least during the construction phase.

As part of this study there has been some discussion about mitigating this issue with a different regulatory model. Specifically, the offshore model where generators themselves finance and build the asset, and then hand over to an OFTO for operation. There has not been enough time to fully test the appetite for this. Generally though, generators agreed that the island projects are more similar to offshore than onshore projects in terms of the scale and nature of grid costs.

- ➔ There is general agreement that large, island onshore wind projects are similar to offshore projects in terms of their relationship with the transmission assets connecting them to the mainland.

6.4 TNUoS

Local TNUoS tariffs for the island connections are directly linked to the delivered cost of the link. The tariffs take on any cost fluctuations in the link costs, up to and including cost variations during the construction phase. Once operational though, the tariff should only really vary with inflation. In this sense, island projects are treated exactly the same as offshore projects, (the island TNUoS methodology copies the offshore TNUoS methodology).

This disbenefit of this methodology is the cost variations that occur when projects are attempting to establish economic viability and reach financial close. This disbenefit is exacerbated for the islands by the lack of any generator involvement in the design, procurement and management of the link, meaning they struggle to understand and manage the costs risks they are taking. The benefit of this methodology is the relative TNUoS stability once the project is operational.

The Western Isles has experienced the disbenefit side of the TNUoS methodology through some significant increases in the estimated cost of the link. So around the end of 2010 the cost of the link was estimated at approximately £391M. Towards the end of 2011 we understand one generator was ready to take a Final Investment Decision (FID) on its project (i.e. under the RO system as it was then with no enhancements for island projects), although there were still concerns about the stability of costs and hence TNUoS.

Over the period November 2011 – December 2013 there was a tender revalidation and further route surveys and the costs rose to around £750M. The cost increases are attributed in the main to changes in soil resistivity for the onshore portion of the cable. We cannot really comment on this, but we would expect any needs case assessment by Ofgem to probe this level of cost increase in considerable detail. However, the pertinent point from the generators perspective is that they could not anticipate this cost increase, and they are captive to it.

➔ Generators on the Western Isles have partly struggled to reach FID because of instabilities in cost estimates for the HVDC cable, which, under the TNUoS methodology are passed through to the generator.

Mainland reinforcements use index-linked generic costs for asset classes, for the very reason that this brings some stability to locational tariffs. The option of doing something similar for the islands has been discussed, most recently during Project TransmiT. However the conclusion was that the three island links are too different, and HVDC too new, to derive generic costs. Another option is simply to decide a point in time at which to fix the costs, and socialise the subsequent cost variations (upwards or downwards). The underwriting methodology already does something similar, and the effect on other grid users would be similar to the effect of using generic expansion factors i.e. cost variations would be socialised across all grid users.

➔ There is an option to stabilise targeted costs through the TNUoS methodology, and socialise cost variations. This would need to go through the CUSC Modification Proposal process and ultimately be approved by Ofgem.

Stakeholders have queried the treatment of the second mainland cable, described in Section 6.1. They are worried that even though it is future-proofing, that they are unfairly being asked to cover its costs through underwriting and TNUoS. However, as both underwriting and TNUoS are based on per MW costs of the link, we do not think the methodologies should, or would, target extra costs onto generators of over-sizing of assets. If anything, asset over-sizing should introduce economies of scale and reduce per MW costs.

6.5 Cost Benefit Analysis

Exactly the same cost and benefit categories as those cited for Orkney are relevant for the Western Isles – see Section 5.6.

6.5.1 Western Isles factors

Baringa / TNEI noted that the Western Isles economy is extremely fragile and that unlike Shetland and Orkney where populations are increasing, its population is in decline. The report goes on to say that "the Western Isles has a significantly lower gross weekly pay of £438.30 compared with the average for Scotland (£498.30) and Great Britain (£508.00)" and "the highest fuel poverty level in the UK, with 58% of households in fuel poverty compared with the national average of 28%." These statistics are what are driving local economic agencies and council's interest and focus on renewable energy.

6.6 Summary

The planned transmission reinforcements for the Western Isles are the most progressed of all the three Scottish Island groups. Earlier-stage issues such as uncertainty over consents and timescales for generator programmes are less important simply because enough time has passed for generators to be later on in their development. Western Isles generators made detailed comments on the TNUoS methodology, reflecting the attention that has been focused on stabilising costs to facilitate a FID.

Some consented wind farms have been timed out on benefiting from an island CfDs, because cable delivery times are now beyond the current EMR Delivery period. In turn this delay is attributed to uncertainties on TNUoS, underwriting and CfD market, with SHE-T feeling it cannot make a justified case for investment whilst these uncertainties prevail. **Unlocking this unhelpful circular situation where uncertainty introduces delay which introduces more uncertainty is absolutely key for the Western Isles reinforcement to progress**. Hence options are focused on:

- ➔ Stabilising TNUoS costs through socialising cost movements beyond a certain point, or; giving generators greater information and control over link costs, in order that they can anticipate and manage cost risks.
- ➔ Giving generators more influence and control over the content and timing of the needs case.

Underwriting amounts are significant in the Western Isles, with **grid costs at a similar scale to the costs of the generation projects**. This is **directly impacting the competitive environment for generation, limiting the market to players not reliant on bank finance**.

- ➔ The scale of underwriting is impacting on the players that are able to progress generation projects in the Western Isles, and largely limiting it to utility-scale onshore wind.
- ➔ Project diversity in the Western Isles is likely to suffer unless some projects reliant on bank finance can also receive help with an underwriting funding gap.

7 Evidence base – Shetland

7.1 Reinforcement plans

Figure 7-1 shows the planned reinforcements for Shetland, namely a 600MW HVDC single circuit link from Kergord on the Shetland mainland, landing at Caithness at Sinclair's Bay, and an onshore portion to an HVDC switching station near Keiss. There is then a second HVDC link from Keiss to Blackhillock on the Moray mainland, which will also take power from the Caithness mainland and Orkney. SHE-T says that Shetland generators need an intact system all the way from Kergord to Blackhillock in order to export any power. This means they are reliant on some 460km+ of HVDC single circuit links and an HVDC switching station.

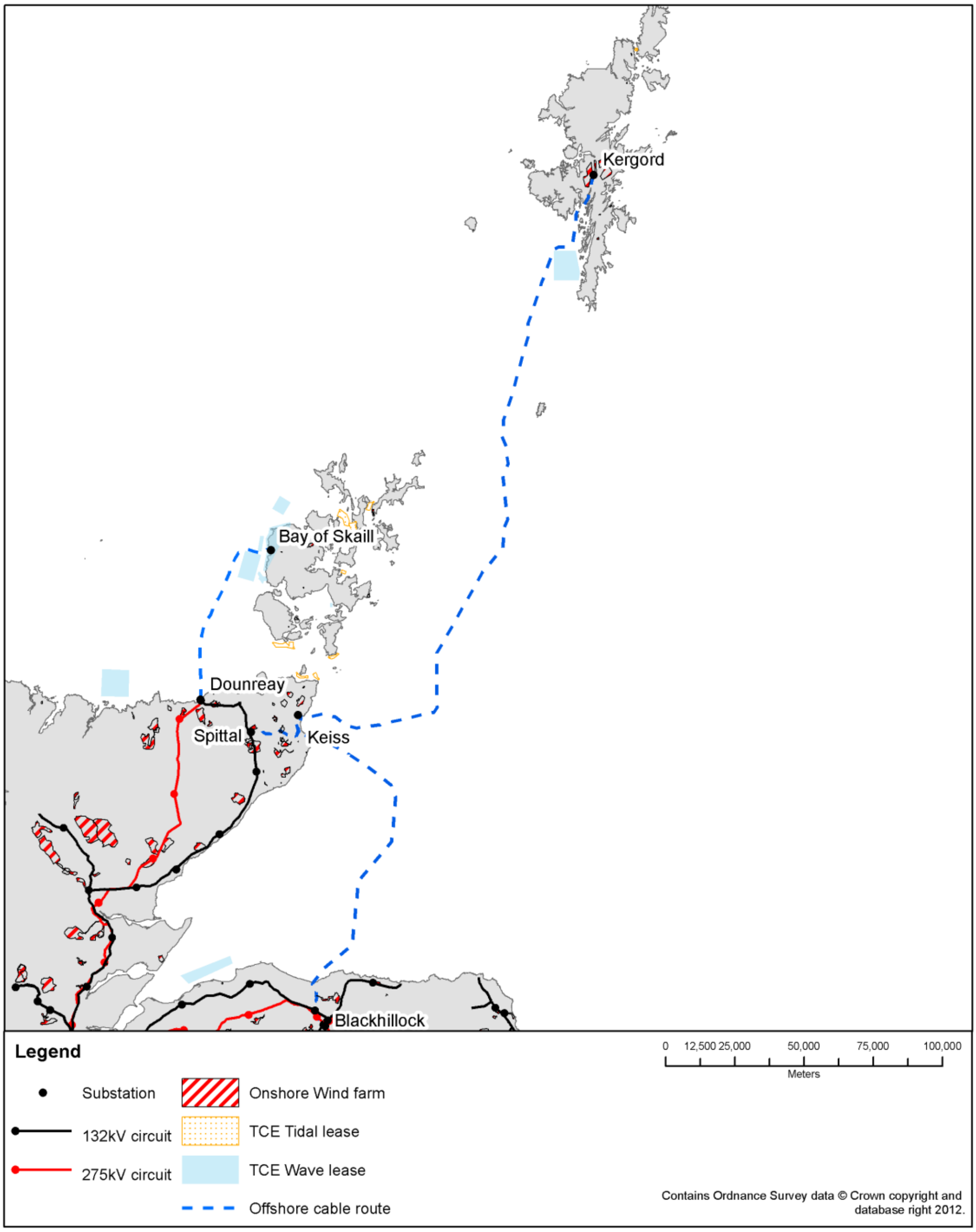

Figure 7-1: Reinforcement plans for Shetland

7.2 Generation

7.2.1 Existing generation

Shetland is not connected to the mainland, and thus is entirely reliant on generation on the island for demand security. Installed generation is shown in Table 7-1 below, taken from [26]. There are also a number of smaller community and domestic-scale generators. Demand varies from 12 to 45MW.

Generator	MW
Lerwick Power Station, diesel	67
Sullom Voe Power Station, gas*	100
Burradale wind farm	3.6
TOTAL	170.6

Table 7-1: Installed generation in Shetland

* exports excess requirements to the grid (max. 20MW)

Diesel subsidy

Because Shetland is isolated from the GB electricity market, and it relies heavily on relatively expensive diesel-fired generation, its cost of supply is higher than the market average. SHEPD operates the Lerwick Power Station (LPS) and receives a cross-subsidy from all SHEPD customers to cover the difference in market costs. In 2010/11 this amounted to a £19M subsidy. [26] Plans are advanced to replace LPS due to EU emissions legislation and to ensure future on-island security of supply. An application is currently being considered by Ofgem, for sanction of the required capital and operational spend

A number of stakeholders have suggested that a connection to the mainland would reduce, or perhaps eliminate the diesel subsidy (Shetland would have access to the GB market and would only need diesel for back-up if the cable suffered an outage – much like the existing arrangement for the other two Scottish islands). The reduction of this subsidy could therefore be considered as an economic benefit.

If the subsidy were to be reduced, then consumer bills should also reduce as SHEPD customers (ultimately electricity consumers) would no longer be covering the difference in market costs between diesel and the GB market average. LPS's output would largely be replaced by subsidised wind energy in Shetland, but it is arguable that as GB is working towards a renewable energy target, this would be a cost incurred regardless of whether Shetland was connected to the mainland or not. Hence there could be an overall saving on subsidising energy that needs to be set against the cost and justification for the Shetland Islands connection.

It is important to note that this is a saving specifically for electricity consumers. Hence we would expect any needs case for the Shetland Islands connection to factor in this consumer saving.

- ➔ Any needs case for a Shetland Island connection to the mainland should factor in consumer savings on diesel subsidies.

Connection moratorium

Like Orkney, there is a moratorium in Shetland for allowing even very small generators to connect to the distribution system without changes to the system. Domestic and business renewable energy schemes are restricted to 3.68kW of capacity per phase, with production over this level required to be dump loaded into heat under a SHEPD scheme called connect and notify.

- ➔ Like Orkney, Shetland cannot fully benefit from incentives in the rest of the UK that seek to promote domestic and business-scale renewables.

There is also a queuing system for commercial-scale generation with opportunities to connect with curtailment, although stakeholders told us the level of curtailment is such that schemes are not financeable.

7.2.2 Generation agreements

Contracted position

The Viking Energy wind farm, at 412MW, is the only transmission-contracted generator on Shetland. Around another 150MW+ of onshore wind is under development, as well as a 10MW wave farm.

Interestingly, the Viking Energy connection agreement was formerly two separate agreements being progressed by two separate organisations – SSER and the Viking Energy community trust. When the two (adjacent) wind farms became a single joint venture, NGET agreed to draw up a single connection agreement.

This is an example of developer-led aggregation of grid connection agreements, albeit by two proximate wind farms. However we believe there is potential in agreeing a common point of connection and joining agreements for more distributed projects, especially on the Scottish Islands which share common points of connection to the transmission system.

- ➔ XE notes the example of developer-led agreement aggregation on Shetland, and notes that this should be possible elsewhere if mutually agreeable between developers.
- ➔ Developers are only likely to pursue this themselves if it is mutually beneficial, so is unlikely to be a game-changer in triggering reinforcements for multiple projects with different timescales.

Submission of Ofgem needs case

Whilst there is understood to have been one previous SHE-T submission to Ofgem for construction funding for Shetland, very few details have been published on this. For example for the Western isles needs cases, although Ofgem has never produced a minded to position, it has previously published consultant's assessment of the design and cost of the link. Nothing equivalent has been published for Shetland, and we do not know why this is the case.

We can speculate that the needs case for Shetland is directly linked to the prospects of the Viking Energy wind farm, and that SHE-T (and Ofgem) have been deliberating over uncertainties similar to those on the Western Isles.

Stakeholders on Shetland appear comfortable, so far, with the timing decisions taken on the needs case. They also note that there is some regular communication between themselves and SHE-T on the progress of each other's projects, and a willingness from SHE-T to take on board suggestions. They would additionally benefit from visibility of the needs case as it is developed, and an ability to contribute to it. This is because they wish to ensure that costs and benefits are rounded enough to include their own generation lifetime costs and benefits, as well as benefits to Shetland and elsewhere described in Section 7.6.

➔ Generators would like visibility of the Ofgem needs case as it is being developed, and opportunities to contribute towards it.

Offer terms

In the terms of their offers, Shetland generators currently have dependency on works all the way to Blackhillock. The agreements ask generators to take the full risk of any outages in the HVDC works, which means that there will be no compensation for lost output should any part of the system not be available. Shetland generators need to cease generation if any part of that system is unavailable.

➔ Generators on Shetland are being asked to take operational and technology risk for the HVDC system to Blackhillock. Difficulties in managing these risks are cited as a grid access barrier by stakeholders.

Private wires

The possibility of an OFTO-style arrangement in Shetland has been discussed with stakeholders as part of this study. The main stakeholder motivation for this kind of model is to gain much greater control over, and information on, the connection, in order to better manage grid risks. This is in turn being driven by discussions with potential bank funders, who would look to manage and mitigate risks in order to make finance more affordable.

We have spent some time with Shetland stakeholders considering whether full ownership of the transmission assets during their construction phase is necessary to achieve better information, control and value from the transmission assets. There is interest in seeing how far the current regime can stretch towards improved information from SHE-T and their asset vendors, more collaboration on optimal solutions, and possibly an option to switch to fully refundable liabilities.

In the context of a connection that has already been tendered in some way, there may be issues in so far as any material change in the scope of the existing cable supply arrangements could compromise timescales. Nonetheless we feel there should be scope to explore greater information sharing and collaborative working between SHE-T, affected generators and the equipment suppliers, given that it is likely to be in all parties' interests in the long term i.e. it would facilitate the wind farm, a cable order and an enhancement of SHE-T's asset base.

➔ Shetland offers a good set of circumstances to explore more collaborative working arrangements between SHE-T and the generator. We believe this has merit.

➔ There is a model for collaborative working in the offshore regime, the CION. This could be used as vehicle for sharing information with island generators without any material regulatory change.

Moving to a full OFTO-style generator build regime is also possible, although it would require changes to the regulatory regime, which will take time to develop. Largely the regime is set up for SHE-T being the licence holder, although there will still be some work required to confirm the geographical extent of the license [10]. A generator-build regime would likely be easier to set up if there were no physical connection between the wind farm transmission infrastructure and the existing distribution system which serves local demand. However given the benefits to Shetland customers of connecting into the GB market, we don't think this is likely to be a sensible trade off, simply to avoid legal and regulatory complications.

➔ A generator build regime is feasible for Shetland, but would require regulatory regime change.

Stakeholders stress that it is information and control over construction programme, out-turn cost (as this defines TNUoS), technical viability and operational down-time which they lack, but which they bear the commercial risks of, under the current regime. The appetite is for resolving this lack of control and influence – either by being insulated from these risks or securing more control – rather than any strong appetite for the legislative and procedural changes that would be required to implement a private wire regime.

7.3 Underwriting

An illustrative underwriting profile is shown in Figure 7-2 below, for 600 MW aggregated generation on Shetland.

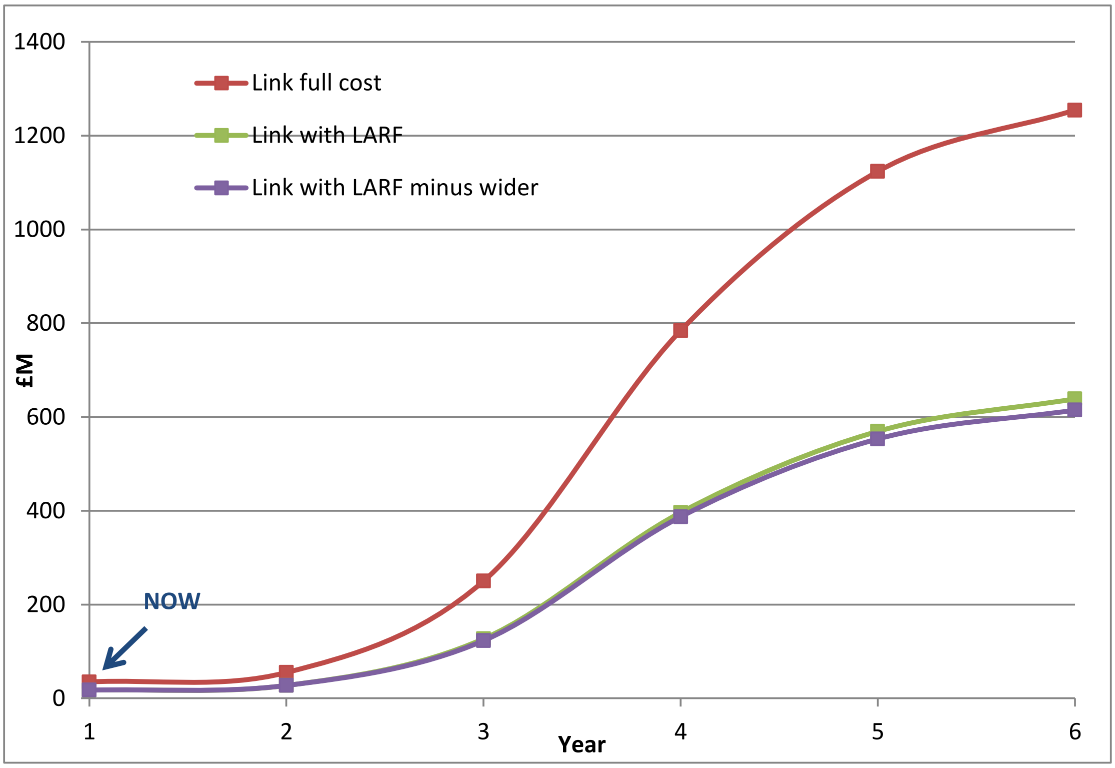

Figure 7-2: Illustrative underwriting profile for Shetland

Underwriting these significant sums has issues similar to those described for the other island groups. In particular stakeholders have emphasised difficulties in securing project or debt finance for grid underwriting amounts where: the generation project's revenue stream is providing the collateral; and, generators (and more specifically their funders) have no call on the assets and have no ability to manage risks on grid timescales, costs and other delivery risks.

We have spent some time trying to understand this issue in the Shetland context, because of the concerns expressed by one of the main investors on Shetland (a charitable trust), and the level and detail of the evidence that was made available to us by their financial advisors. This has been very helpful in understanding the financier's perspective, and the following points are of note:

- Typically the cost of grid connection is no more than 10-15% of the cost of the renewables project connecting to it. This relative scale of underwriting by the generator could be manageable using bank finance. On rare occasions, the costs of connection and requirement to underwrite could rise to around 20-25% and, if additional requirements in terms of monitoring milestones, /sharing information, etc. were met, it is conceivable that bank financing could be obtained, albeit at a higher cost.
- In the case of the Shetland interconnector, the scale of peak underwriting required for the interconnector is around 50-60% of the cost of the generation project, a relative amount which pushes beyond the limits of project-backed bank finance. In all cases, the bank looks to the revenue stream due to the generator (as this is the only means of collateral or security) on the money lent and this can only stretch so far.
- Broadly speaking, for a 200MW project, a range of 10-15% of the value of the generation project would translate into £30 - £50M.
- If banks can see that grid risks are being mitigated (principally timing, costs and recovery of value in stranded assets), then this might increase to a range of 20-25% of the value of the generation project, or roughly £60-90M.
- This still leaves an underwriting gap of around £100M, which would need to come from a combination of public or private equity, or from government guarantees that released more affordable debt finance, or a combination.
- The advice was that private equity is unlikely to fill all of this gap, and that some form of government support was by implication definitely required.

➔ Debt finance, in a project financed model, will at the very best cover around a half of a Shetland generator's grid liabilities. This leaves a gap where the other half would need to draw in public and / or private equity and / or government guarantees.

There is a question around whether the nature of grid liabilities, in limiting the market to players with deep pockets and an appetite for risk, is impacting on competition and the ability for community-lead projects. The former is a consideration for Ofgem, the latter for government. The market is similarly limited in large offshore projects.

➔ Ofgem and government could consider whether they wish to de-risk certain projects, in order to promote competition and community-lead projects respectively for large, capital intensive projects.

7.4 TNUoS

In common with other island and offshore generators, Shetland generators bear the risk of forecasting transmission costs, which is passed through to generators by the TNUoS methodology. Therefore all of the same concerns apply, and hence the potential solution of fixing the costs in order to allow generators to reach a Final Investment Decision, and socialising any subsequent upward or downward movements.

The unusual reinforcement solution on the Caithness mainland, specifically the HVDC switching station, also presents some uncertainty as to where the Shetland connection reaches the MITS. Specifically, whilst the switching station does perform a function that is the same as MITS substations, it would not be classified as MITS under the current methodology. There are two reasons for this, namely that: there are no HVDC circuit breakers planned at the substation (because they do not exist yet); and because the switching station may not have the requisite number of transmission circuits to qualify as MITS (in part because a single HVDC transmission circuit can carry more power than a single AC transmission circuit).

There are some quite in-depth technical arguments around whether the existing rules should change to reflect HVDC technology, but in the meantime we note some uncertainty in predicting TNUoS tariffs for Shetland generators. If the switching station at Caithness were considered to be MITS, Shetland TNUoS tariffs would be lower than if it weren't.

- ➔ The existing TNUoS methodology does not fully provide for the novel (for GB) HVDC switching station on Caithness. This presents some uncertainty in predicting TNUoS tariffs for Shetland generators. It is worth noting that TNUoS tariffs previously calculated by NGET and presented by Baringa / TNEI, assumed that the MITS began on the Caithness mainland.
- ➔ Whilst as the rules stand the switching station would not qualify as MITS, we believe NGET should review this definition specifically in the context of Caithness-Moray.

7.5 Access rights

Shetland stakeholders have highlighted issues with finance in the context of potential failures in the grid system between Shetland and Blackhillock. This is perhaps more prevalent in Shetland's concerns because of the amount of infrastructure involved between Shetland and Blackhillock: namely, the Shetland-Caithness link, an HVDC switching station and the Caithness-Moray link, all of which need to be intact for Shetland exports.

The Shetland and Caithness Moray works employ HVDC Voltage Source Converter (VSC) technology. HVDC VSC needs to be used in preference to Current Source Converter (CSC) technology where there is not a strong existing local AC system. It provides system services that help the local network.

There is a limited track record associated with VSC HVDC technology at higher voltages (in excess of ±200kV). VSC HVDC projects at ±320kV have recently been installed (2010) or are scheduled to soon be installed (2014). It may be several years until the technology at these voltages is considered to be operationally "proven", which in turn may have an impact on the cost of finance for any project exposed to the risks of outages. Furthermore the Caithness-Moray system is planned to be a multi-terminal design. At time of writing XE is aware of one recently completed project employing a multi-terminal system based on VSC HVDC technology [27].

Under the current access regime, there would be no compensation due to Shetland generators for any planned or unplanned outages in this system. Shetland generators are, therefore, taking operational and HVDC technology risk, again, without any say in, or control over, that technology or operational regime. There is interest, then, in increasing generators involvement, via more collaborative working with SHE-T and NGET, and / or in revisiting the compensation regime under the CUSC.

- ➔ SHE-T, NGET and generators should work together to look at how collaborative working could help generators minimise operational risks; and, or
- ➔ There should be changes in the CUSC compensation regime to reduce generators' exposure to operational risks which they cannot control.

The insurance market also has a role to play here, in offering products that could mitigate risk. Anecdotally the market for insurance for these kinds of products for links such as those proposed for Shetland is not fully developed. There is a need to disseminate data and information on the HVDC technology proposed to allow appropriate products to be developed. Manufacturers are keen to work with insurers to help this process along. They point out for example that the more established CSC technology shares a lot of the same component parts with VSC technology, and so a good proportion of the converter technology is proven at higher voltages.

- ➔ Industry needs to work with manufacturers in dissemination of information to insurance providers.

Furthermore, SHE-T has very limited incentives on it – beyond reputational – to maximise availability of the link. This contrasts with the offshore market where new OFTOs have specially designed availability incentives which are designed to minimise down time not only of the cable, but to reduce the amount of down time when the generator is at its highest output levels. We believe that an availability incentive for island infrastructure is something that Ofgem could address through license conditions attached to approval of the island link funds.

- ➔ Ofgem should consider availability incentives for the island links when approving spending on the links.

7.6 Cost benefit analysis

Exactly the same cost and benefit categories as those cited for Orkney are relevant for the Shetland – see Section 5.6.

7.6.1 Shetland factors

Diesel subsidy

Shetland is not connected to the mainland and as a result it is very reliant on subsidised diesel-powered generation. The subsidy is understood to be worth around £19M a year. Even if Shetland were connected to the mainland it would still need back-up diesel generation, but the amount of diesel fuel required would reduce, the amount depending on the operational regime of other generators on Shetland.

Stakeholders have provided us with scenarios which envisage subsidy savings of up to £15M per year once Shetland is connected to the mainland. Over the 25 year lifetime of a wind farm this could be worth nearly £200M in NPV terms. The savings are variable depending on the assumptions. To-date SHEPD has not published any of its own analysis on this. There is a need for more transparency on this and we believe SHEPD should publish analysis on the subsidy savings available from a Shetland connection to allow a proper debate. The potential for £200M of savings is very significant.

Charitable trust
Half of the Viking Energy project is owned by Viking Energy Shetland (VES), and 90% of VES is owned by the Shetland Charitable Trust, set up to benefit the Shetland community. A community development of this scale is pretty unique and is a defining feature of the Viking Energy project.

7.7 Summary

The driving force behind Shetland's proposed mainland reinforcement is the 412MW Viking Energy project. Stakeholders have drawn parallels with the offshore regime, where one large wind farm is associated with a single mainland connection, and where the regime allows the generator to have much greater control over the connection – with generators overwhelmingly opting to build the connection themselves.

Like the other island groups, the cost of the Shetland connection is around the same, per MW, as the cost of the projects underwriting it. Potential funders have told us that **liabilities associated with the connection are too large to be left completely outside of the generator's control**. Funders will struggle to accept the risk without a means of mitigating the risk.

And even if control were achieved, this would serve to reduce, but not eliminate, an underwriting funding gap. It seems **unlikely that Shetland projects could be solely project-financed**, and that **private and more probably public equity would be required to bridge an underwriting funding gap**.

Because of the legal and policy developments that would be required to implement a competitive regime in Shetland, stakeholders do not favour it. Instead, they would prefer to work within the existing regime but improve the level of collaboration between themselves and SHE-T in developing the connection. We have suggested the CION process used offshore as a basis for this. We do not know if this will be a sufficient level of change to allay financiers concerns, and we would urge that establishing this be a first priority. Otherwise, regime change (and delay) seems inevitable to make projects bankable.

Although the Viking Energy project has dominated discussions around the Shetland link, it is important to note that there are other projects under development, and some **not insignificant consumer benefits associated with Shetland no longer being an islanded network**. Primary amongst these is the reduction in a diesel fuel subsidy. **Stakeholders clearly believe that the reduction in diesel subsidy justifies higher a consumer stake in the cable** but this debate is being hampered by a lack of transparency on how the numbers add up. **We recommend therefore that SHE-T or SHEPD publish their own analysis on this**.

8 Evidence base – potential solutions

Difficulties in progressing electricity links for export of renewable energy from the Scottish Islands are not new. Interest in these projects and connections spans well over a decade, and, as detailed in Section 4, efforts to alleviate problems with connecting the islands began around a decade ago.

Before drawing conclusions on options for removing barriers to grid access for island projects, we have reviewed the evidence base on potential measures that could be taken. This includes measures that have been debated and / or implemented for the Islands and elsewhere. It also includes additional measures that are being mooted for the Scottish island projects by stakeholders, and consideration of the potential they have to help.

8.1 Grid connection co-ordination

Co-ordinating / aligning grid connection agreements between multiple developers (or aggregating developer demand) is something that has been debated and variously tried as a means of triggering major reinforcements that are being driven by multiple generators. Some examples, and lessons learned, are detailed here.

8.1.1 Mid Wales

In 2005, the Welsh Assembly Government (WAG) announced its aim to build an additional 800MW of onshore wind and 200MW of other renewable energy by 2010, but by 2010 Wales had only around 150 MW of wind power.

There are a number of reasons why growth has been slower than hoped, including planning constraints and competitive tendering for leases on Forestry Commission (FC) land which forms the bulk of areas identified by WAG as suitable for onshore wind. However amongst the issues has been a lack of grid capacity serving certain areas of resource. One of these areas is Mid Wales.

It was always understood that the lack of grid capacity could hold back development, but it immediately became apparent that triggering a lumpy grid upgrade would not be easy. Developers, the grid companies and Ofgem were all wary of approving “at risk” spend on grid infrastructure before generators had lease agreements with the FC, or planning permission.

More or less in parallel with lease negotiations, from June 2006 to June 2007, National Grid and SP Manweb undertook grid analyses with respect to three build scenarios: 150MW, 250MW, and 600MW, and understood that in addition to various 132kV network reinforcements, a new 132kV overhead line would be needed for smaller build scenarios while a 400kV or 275kV solution would be needed for the larger build scenarios [28]

An agreement was reached for developers to submit grid applications for their requirements in a small window of time in 2007-08. In order to achieve this Ofgem needed to approve some relief from statutory timescales for processing grid applications. This was not difficult.

The grid companies agreed to consider and design the grid for these collective requirements, which they duly did. In order to hasten the timetable a group of developers commissioned a route corridor study in which National Grid collaborated. The findings were useful and preparatory work for 60km of 400kV transmission network in mid Wales got underway with initial connection dates of 2013-15.

However these connection dates have subsequently slipped. As of 2013 there was 646 MW of embedded generation contracted with SP Manweb, which in turn has an agreement with National Grid. Because of the co-ordinated grid connection process, all of these embedded generators are understood to share one construction agreement.

As underwriting amounts have increased, and as underwriting arrangements have changed, developers have sought to become less interconnected with each other – essentially moving away from being jointly and severally liable for the transmission costs. One large generator has cancelled its agreement. So whilst generators benefited from collaboration and mutually agreed timescales to kick off the works, different development timescales and risk profiles have caused issues later on. It remains to be seen whether this model will successfully deliver the transmission works.

- ➔ Grid co-ordination was successful in so far as it triggered work on a major transmission upgrade to Mid Wales. However, as underwriting costs have risen, the reality of different generator timescales has meant that generators could not all progress as one unified block.

8.1.2 Pentland Firth / Orkney waters

A competition for Estate leases in Pentland Firth and Orkney waters was launched in 2008 with most licenses awarded in 2010. Like Mid Wales it was always apparent that such a distributed group of generation, in combination with onshore generation dispersed over the Orkney Island group, would present challenges in triggering major grid upgrades to the mainland.

In 2009 Highlands and Islands Enterprise published a report into options for connecting tidal generation in the Pentland Firth [29]. This made a number of recommendations including the need for incentives to "overbuild" grid capacity ahead of certainty on projects, if grid and project development paths were to align. Following on from this there were informal discussions between Crown Estate, government, SHE-T, NGET and other stakeholders about how to align generator and grid timescales. These included Scottish Government consideration of an "umbrella" grid application that included third party underwriting.

Concerns expressed over this model were largely around: the amount of funds that would be required (then estimated at up to £1 Billion of liabilities on the Scottish Government purse); the potential conflict with Scottish Government's planning consent responsibilities; and the need to refer any public support for State Aid approval (because the aid would give an advantage to specific companies) [30]. The umbrella model did not progress.

However, SHE-T did attempt some grid co-ordination, actively seeking to collect as many applications as possible before starting work on the most appropriate grid reinforcements. SHE-T only secured one applicant. Today, just two generation applicants underpin the proposed reinforcement from Bay of Skaill to Dounreay

- ➔ Although stakeholders fully understand the benefits of grid co-ordination, projects are unlikely to come forward if they simply cannot afford the costs and liabilities of securing a grid connection because of their early stage of readiness.

8.1.3 Viking Energy

As discussed in Section 7.2.2, the existing connection agreement for the Viking wind farm was formerly two separate agreements being progressed by two separate organisations – SSER and the Viking Energy community trust. The formation of a joint venture between the two adjacent wind farms meant that a single grid connection agreement made commercial sense. Hence co-ordination was achieved by the developers themselves.

- ➔ Although the two agreements in this case were merged because of a joint venture, the ability for developers to elect to share an agreement at a common point of connection may extend to other (limited) circumstances.

8.1.4 Ireland

Eirgrid in Ireland has faced very similar issues to TOs in Great Britain in that there is a large volume of renewable energy development with significant implications for grid reinforcements. It operates a “gate” system for progressing reinforcements. Generators are not eligible to apply for a grid connection until they have secured their planning permissions. Once they have applied, Eirgrid groups generators into different reinforcement schemes and connects generators in tranches (gates). Essentially the system is not entirely driven by what generators ask for, but also by what Eirgrid considers can be done, and by when, and only for those generators that have their permissions.

It is debateable what real differences there are between Ireland and the GB system – the differences are probably largely administrative. The GB system benefits from greater visibility of generators requirements early on, but this does mean a higher level of transmission queue shuffling and paper work as projects move from concept to reality.

It is arguable though that a gated system is really what is happening in the Scottish Islands, just less explicitly through various attempts to corral applications and / or delays to needs cases until more projects are at a better state of readiness.

- ➔ Island connections are tending to resemble a gated system, like that operated by Eirgrid. However this is not explicit leading to different expectations from different stakeholders. There is a high administrative burden of early-stage applications but a lack of strategy to make the most of early-stage information.

8.2 Third party underwriting

Generators will normally underwrite grid infrastructure with guarantees either from their parent company, or from a bank. This is a commercial arrangement with their funders. Third party underwriting refers to occasions where the generator cannot reach a commercial arrangement on underwriting and needs some other assistance. Typically what this refers to is government or another public institution helping with the grid guarantees.

8.2.1 UK Government loan guarantees

The UK Treasury has made available £40 Billion worth of government guarantees to energy, road and rail infrastructure projects. The scheme closes in December 2016. Forty projects have pre-qualified, although only half of those agreed to be named. Of those that are known, two – Drax biomass conversion and an energy efficiency fund – have already been awarded £75M and £8.8M respectively [31]. Hinkley C nuclear power plant has pre-qualified for support although the amount of the loan is not known.

In order to fully qualify for a guarantee, projects must have relevant consents (or be about to receive them), be 12 months from construction, "financially credible" but unable to proceed without the government guarantee. The guarantees are subject to fees and project due diligences [32], where the government may wish to adjust project structures to protect taxpayers interests. There appears to be flexibility around the form of the guarantee, and the types of projects that can qualify (they need to fall within sectors identified within the National Infrastructure Plan).

The government effects the guarantee by issuing government bonds which are then purchased at market rates, with the intention that the cost of doing so is equivalent to the market rate for debt. In the context of the Scottish Islands, it is worth noting that UK Treasury expects projects to be suitable for debt lending e.g. in risk profile. Furthermore projects need to be close enough to financial close (e.g. other equity and debt providers in place) for a decision on the guarantee to be made by the end of 2016.

Furthermore, it is likely that UK Treasury would have similar issues to banks on the provision of guarantees against infrastructure assets that are not owned by the generation project. An alternative might be for SHE-T to apply for the guarantee, if it thought this would reduce its own financing costs. Although with Ofgem approval for construction funds, SHE-T may not struggle to raise finance and thus not qualify for the guarantee. Note that under its price control settlement, any cost reductions that SHE-T manage to secure on its financing costs are shared 50/50 with consumers.

- ➔ On first examination the UK loan guarantee scheme only appears to offer support for well progressed projects where there is a definable finance gap.

UK Treasury appears to have designed the scheme so that it meets State Aid requirements e.g. on lending at terms that are equivalent to private lenders. Friends of the Earth have asked the European Commission to investigate the Drax biomass loan, although at this stage the Commission is reportedly making early enquiries with Treasury defending its position that the scheme is compliant with State Aid rules [33].

8.2.2 Scottish Government guarantees

Loan guarantee schemes are understood to have been agreed and operated in the past, although in different sectors and circumstances, and on a smaller scale. The Scottish Government has recently been given the ability to issue its own bonds. Amongst other things this is a potential vehicle for a guarantee scheme similar to the UK's. Furthermore, in principle there seems to be nothing to prevent the UK and Scottish Governments working together to provide joint loan guarantees with risks shared proportionately, provided both governments agreed.

8.2.3 Europe

The European Commission provides substantial assistance to interconnection projects, primarily to those identified as European Projects of Common Interest (PCI). The UK government supports PCIs that will benefit the UK [34]. For example the East West interconnector between Ireland and Wales received a European Investment Bank loan of up to €300M, and an EU grant of €110M (out of a total requirement of circa €600M) [4].

The European Commission states that PCIs must "have significant benefits for at least two Member States; contribute to market integration and further competition; enhance security of supply, and reduce CO_2 emissions." [35] The UK's nominations have tended to be interconnectors between different member states, although some internal reinforcements (gas) have been included where they enhance flows to / from other member states. Therefore in order to qualify for PCI status, the Scottish Islands would need to establish if there were benefits to other member states, and secure their support.

Research funds are also available to demonstrate new technology and practices. As there are a number of innovative / novel practices involved in the island connections, this may represent a more suitable route for support. For example the RPZ on Orkney secured additional funds from Ofgem (consumers) because of the innovation involved. SHE-T had secured European funds towards a proposed HVDC offshore hub in the Moray Firth, although there were time limits to this which have since passed.

- ➔ SHE-T should make further efforts to secure research funds towards some of the more innovative aspects of the Scottish Island connections. Any funds secured should in turn reduce SHE-Ts costs and risks which in turn should be reflected in lower underwriting requirements and link costs.

8.2.4 Tax Incremental Financing

One stakeholder suggested the use of Tax Incremental Finance (TIF) schemes to help fund island infrastructure. TIFs are proposed and used by local authorities, and, according to the Scottish Government are "a means of funding public sector investment infrastructure judged to be necessary to unlock regeneration in an area, and which may otherwise be unaffordable to local authorities". A scheme "uses future additional revenue gains from taxes to finance the borrowing required to fund public infrastructure improvements that will in turn create those gains." [36]

In the case of renewable energy, those additional tax gains would be business rates from renewable energy projects. We don't think local authorities will be able to finance a complete reinforcement using a TIF scheme, but it would form part of a package of measures with other investors.

- ➔ Local authorities could investigate the use of TIF schemes to contribute to financing of grid infrastructure.

8.2.5 Other institutions

There are clearly various other public institutions with the ability to provide loans, grants or guarantees towards grid infrastructure. For example the Crown Estate has stated that it is considering investing in “first array” wave and tidal projects. In 2013 it asked for expressions of interest from project developers for investment of £10M per project in two projects i.e. maximum £20M. Its objectives in investing are to make an acceptable return, and to “catalyse investment in first array projects by others, by virtue of sharing risk exposure and reducing the amount of capital others have to invest.” [37]

- ➔ Investors with specific objectives to further renewable energy projects and share risk offer potential for assistance.

8.3 Changes to the regulatory framework

Changing the regulatory framework covers a very broad range of actions from requesting a letter of comfort from Ofgem to smooth over minor changes in practice e.g. an extension to the three month grid offer period; to industry code modification processes to changes in primary legislation setting up the industry framework. The main categories of regulatory change that feature in this report and its conclusions are covered here.

By way of introduction, the regulatory framework is broadly made up of legislation e.g. the Electricity Act which establishes the licensed activities of generation, transmission, distribution and supply; the licenses, which are the main vehicle by which Ofgem effects change in the industry e.g. by recently inserting a Transmission Constraint License Condition in generation licenses, which requires generators to make cost reflective bids in the Balancing Mechanism; and a set of technical /administrative / economic codes govern industry practices.

8.3.1 Legislation

Making changes to legislation is a political process, convincing politicians that the changes need to be made and then finding time in the legislative programme. Changes to legislation impact the whole framework for the industry and so tend to be quite fundamental, and / or, a means by which government can influence the market when it feels it is not working. The implementation of Connect and Manage for example involved using government powers which needed to be set out in legislation. It is not generally a quick fix option, and often only used when other options have been exhausted. Examples of regulatory change that might support island projects are:

Extension to Section 185

There is not really any stakeholder appetite for using Section 185, although this may be due to being somewhat jaded rather than it wouldn’t be effective. The Baringa / TNEI evidence could form the basis for an intervention, but as noted in Section 4.4.1 there would need to be an extension of the length for which a cap would last, and some changes to the way it is implemented.

- ➔ Stakeholders have said they favour an island CfD over a Section 185 intervention.

More significantly though, as noted in Section 4.4.1, DECC has stated that it does not intend to intervene on transmission charging, and that instead grid charging is a matter for Ofgem.

- ➔ DECC has ruled out a transmission charging intervention.

Government intervention in the energy market

An example of this is the formal implementation of Connect and Manage with socialised constraint costs, but this was only after several years of industry code change process. Government would need to first take powers to intervene, and then subsequently intervene. This would take years rather than months to effect.

DECC has ruled out intervening in transmission charging in the context of Section 185 and Project TransmiT. It is probably fair to say that given this, and EU rules which govern Ofgem's independence from government, that any such intervention in the codes would need to be carefully designed and deliver significant benefits, for it to be worthwhile and effective.

- ➔ A government intervention in energy sector codes would need to be very carefully set out, and government would need to be absolutely convinced of its effectiveness in delivering its objectives.

8.3.2 License changes

Ofgem has the power to alter the existing, and insert new, conditions in the licenses of generators, TOs, the SO and DNOs. In implementing license changes, Ofgem will be mindful of its own duties and obligations – this is discussed further in Section 8.3.3. Conditions that might be of interest in the context of the Scottish Islands are, for example:

Conditions in the SO license describing how NGET has to maintain and develop the charging methodology – for example these could theoretically be amended to widen out the objectives of the charging methodology to include affordability as opposed to cost reflectivity.

- ➔ Ofgem unquestionably favours cost reflectivity and we consider the likelihood of Ofgem approving such a change very low.

Any special conditions in a TO licence associated with approval of a major transmission upgrade – for example, Ofgem could develop an availability incentive associated with an island upgrade in order to provide island project investors some protection against lengthy outages.

- ➔ We consider link-specific license conditions associated with the island links to be a pragmatic solution to concerns over availability of the links. They are unlikely to address all of investors' concerns but could form a package of measures alongside better information sharing and affordable insurance products.
- ➔ Ofgem needs to develop and justify any licence changes, and consult on them. The licensee can refer any decision to the Competition Commission if it does not agree the changes. The latter is rare, but can add substantially to timescales. Without a referral the process could take under a year.

8.3.3 Industry code changes

Industry codes govern all aspects of the industry from how the transmission system is designed to technical conditions for connection to the allocation of grid costs between grid users. The main code that we are concerned with in this report is the CUSC which contains the TNUoS methodology, the underwriting methodology and the arrangements for compensation when the grid is unavailable.

Any generator with an agreement with NGET can propose a change to the CUSC. Additionally, if Ofgem agrees, other materially affected parties can propose changes to (just) the charging methodology. A panel of elected industry representatives, and a consumer representative, then direct whether the proposal should be developed by a working group. Normally this is the case. A working group is formed from industry nominations.

Depending on the complexity of a CUSC Modification Proposal (CMP), a Working Group can take anything from a couple of months to a year and a half, including time for a consultation on its proposals. A final proposal is then sent to the CUSC Panel for a recommendation and then on to Ofgem for a decision. There is no time limit on Ofgem for making a decision. For major changes Ofgem will undertake an impact assessment and consult on this. All in all the process from proposal to decision can take a year to three years. Implementation of the proposal could then take up to another year or so, depending on what is involved in terms of IT systems, agreements etc.

If a change is particularly contentious, and if Ofgem's decision differs from the recommendations of the CUSC Panel, then there is the potential for a legal challenge to Ofgem's decision. This can add another year or more to timescales.

- ➔ CUSC Modifications are a lengthy process, especially if complex and / or there are major differences in approach between sections of the industry or between industry and Ofgem and / or NGET.

Ofgem is the ultimate decision maker on CUSC Modifications. When putting forward a CUSC Modification, it is therefore important to bear in mind what Ofgem is or isn't likely to approve. Ofgem can look at the market rules and see if they are fair and if everyone is being treated equally. For example, if there is evidence that the methodology for local TNUoS for offshore and island connections puts them at a competitive disadvantage compared to onshore generators, then Ofgem would need to consider this – but only if the way costs were being signalled were different in a way that is unjustified (for example in the differences in which expansion factors are calculated). Ofgem would not generally consider a higher charge per se to be anti-competitive, if it reflected costs. In fact, reflecting costs is what the charging methodology actively sets out to achieve.

- ➔ CUSC Modifications tend to be quite technical and focused on cost reflectivity and the promotion of competition. Ofgem has a sustainable duty and socio-economic guidance from government, but this does not generally extend as far as promoting renewable energy regionally.

8.4 Summary

This section looks at the evidence in support of using various tools as solutions to the issues in the Scottish Islands. These are:

- Grid application co-ordination – where this has occurred it has not been very successful at keeping generators together in the same timescales. Alternatives to trying to align generators is for generators to align themselves – although this is only likely to occur in limited circumstances – or for grid companies to connect generators in tranches (gates).
- Third party underwriting – we look at options for public or private investors with an environmental / social remit to provide support for underwriting liabilities. This support could be provided to generators or to SHE-T – the latter obviously needing to result in a reduction in generator underwriting liabilities. State Aid rules would come into play here, as they have for the existing UK loan guarantee scheme. We also mention in passing the potential for local authorities to raise infrastructure funds on the strength of future business rate revenues, which could be helpful but is not a solution on its own.
- Changes to the regulatory framework – the normal industry process for changing industry codes is available to any code signatory i.e. any generator with a grid connection agreement. The sort of changes that could be progressed are adjustments to underwriting and charging methodologies which have the effect of ‘socialising’ some of the targeted costs currently borne by island generators. Whilst we saw in Section 4.3 that an argument could be made on the grounds of equivalence with mainland charges, the code change process can be lengthy and difficult. Government could intervene to make the changes, but this would also take time to design an intervention in a way that was lawful in European terms.

9 Summary of options

9.1 Evidence base – the barriers

Table 9-2 summarises the main barriers (or hurdles) described in each island section, under the same subject headings used. The colour coding reflects XE's judgement of the criticality of each issue, informed by what stakeholders have told us.

Grade	Equivalent weight of issues
High	Major hurdle to progressing link, critical issue to resolve
Medium	Important hurdle, resolution would be major boost to progressing link
Low	An important issue, but not critical to maintaining timescales for link

Table 9-1: Categorisation of issues

Item	Orkney	Western Isles	Shetland
Generation agreements			
Not enough contracted generation from mature technology	High	Low	Low
Lack of needs case visibility & generator ability to influence it	High	High	High
GB queue rules limiting access re-allocation	Medium	Low	Low
Grid charging terms do not reflect different access terms	Medium	Low	Low
Lack of private wire regime limiting progress	Low	Low	Medium
Underwriting			
Funding gap	High	Medium	High
Generators have no influence on grid risks or call on assets	High	High	High
TNUoS			
Inability of generators to manage cost forecast risk	High	High	High
Need to review MITS point	Low	Low	Medium
Access rights			
Generators cannot manage operational risk of downtime	Low	Medium	High
Cost Benefit Analysis			
Lack of stakeholder input into benefits case	High	High	High

Table 9-2: Summary of findings on barriers

We can see that the most fundamental issues to tackle for grid access are:

- Needs case process improvements, (and, in the case of Orkney augmenting existing need)
- Underwriting funding gap
- Risks that are borne by, but cannot be managed by, generators – specifically grid cost forecast risk, reflected in TNUoS tariffs, underwriting liabilities that cannot be directly managed or mitigated, and operational downtime.

With the exception of marine technology risk, what these barriers essentially strip down to are that the grid risks being placed on generators are variously more than they say they can bear alone, namely the risk that:

- other generators underpinning investments fail
- other generators underpinning investments don't turn up
- grid costs increase
- the grid is not delivered on time
- the grid is unavailable

These are risks that under the current regime the generator has no ability to manage, and so it is worth asking whether they should wholly be placed with generators.

Then there is the question of benefits, and whether these are being properly accounted for in the needs case process. The focus of network companies is on the risk that assets will be stranded, whereas the focus of generators is the risk that benefits flowing from the link being in place will not be realised. In simple terms this is the probability of failure / success on one side against the impact of failure / success on the other. Because generators have no influence over the needs case before Ofgem consults on it, their perspective on impacts comes too late to influence timing decisions.

It is important to note that resolution of these barriers would facilitate island links, but not guarantee them. Clearly, the economics need to work as well, as discussed in the Baringa / TNEI report.

9.2 Evidence base – the solutions

Table 9-3 shows the same set of hurdles, and against each a set of potential solutions. Appendix B lists out each solution, briefly what is involved, who is responsible for taking the lead, how long it should take, and a grading of how easy or difficult it will be to achieve.

Item	Measures
Generation agreements	
Not enough contracted generation from mature technology	Application alignment
Lack of needs case visibility & generator ability to influence it	Needs case improvements
GB queue rules limiting access re-allocation	Develop written GB queue policy Move towards gate system of allocating access
Grid charging terms do not reflect different access terms	Underwriting and TNUoS commensurate with access terms
Lack of private wire regime limiting progress	Develop OFTO or merchant regime
Underwriting	
Funding gap	UK / Scottish Government loan guarantees Develop island "fund" (pooled investors, pooled generators) – government bridges gap Grant support – research / economic development funds bridge gap Methodological changes to reduce generators underwriting – consumers bridge gap
Generators have no influence on grid risks or call on assets	Generators and SHE-T to improve collaboration Implement CION process for islands
TNUoS	
Inability of generators to manage cost forecast risk	Stabilise targeted costs through CUSC Mod Improved collaboration between generators and SHE-T Develop OFTO or merchant regime
Need to review MITS point	Update MITS definition for HVDC through CUSC Mod
Access rights	
Generators cannot manage operational risk on downtime	Improve collaboration between NGET, SHE-T and generators Availability incentives on SHE-T Improve availability of insurance products Review of contractual and commercial RPZ lessons Compensation for lost access
Cost Benefit Analysis	
Lack of stakeholder input into benefits case	Needs case improvements

Table 9-3: Potential mitigation measures for barriers

Table 9-2 presents a menu of options to solve each barrier. It is not immediately obvious looking at this, which will be most fruitful and productive in securing connections for each island. In order to narrow down on solutions most likely to be helpful, it is necessary to consider the conditions for investment for each island group, informed by what stakeholders have told us. The following sections seek to do this.

9.2.1 Orkney

Orkney is characterised by being the only island group where there is not enough contracted generation from mature technologies. This is the most immediate and pressing problem to solve. The solution listed in Table 9-3 is to secure applications from more mature technologies (onshore wind) and to align those in the same timescales. We saw in Section 8.1 that previous attempts to align applications have not been very successful where generators are not bound commercially, and voluntarily. We understand that efforts are underway to achieve just this, and this should help Orkney's case.

However, we do not believe that this effort will secure sufficient capacity early enough to make a material difference to the prospects for the existing 180 MW reinforcement being delivered in 2019. Given their stage of development, the existing 180 MW contracted position for wave and tidal projects is ambitious, and we believe that this will undergo some rationalisation.

Even then, wave and tidal projects do not appear have the financial strength to sponsor major grid upgrades in tandem with developing the technology. This funding gap will not be solved through altering industry rules and regulations to rebalance grid risks, because until the technology is proven, the key risk is a generation technology one. EMEC exists to resolve these technology risks through testing and demonstration, but is limited in what it can do because of a lack of grid capacity. Hence, there is logic to securing some research and development grid capacity, in order to allow the technology and industry to grow. Under State Aid rules, this is probably best achieved through a neutral research body such as EMEC, rather than through support for individual companies.

In conclusion, we feel that the most fruitful path for Orkney will be to:

- ➔ Ascertain demand from onshore wind, ascertain appetite for aligning grid commitments for transmission or distribution reinforcements.
- ➔ Ascertain existing need and appetite for reinforcement from existing RPZ generators – (if transmission reinforcement still proposed, relieving them of underwriting commitments but in mind of future TNUoS tariffs).
- ➔ Rationalise reinforcement plans – considering alternative distribution reinforcements, as set out in the recent SSE consultation.
- ➔ Anticipate continued funding gap for grid reinforcements on behalf of wave and tidal generators – take steps to fill this through European and national funds in support of scientific research, economic development and promotion of new industry.

Other regime changes which re-balance grid risks are also of course important for Orkney, especially in the context of later-stage transmission reinforcements.

9.2.2 Western Isles

The Western Isles is dominated by onshore wind developments, more than half of which is being progressed by large utility players. The main concern for this utility-backed contingent was the difficulty in reaching FID in an instable policy and cost environment. If a support regime could be confirmed, reinforcement costs stabilised and the needs case progressed, the sense was that these utility-backed projects would proceed.

If these projects proceed, stakeholders wish was that they would drive the needs case for the reinforcement and other less financially strong players would be able to progress in their wake. We do not think this is necessarily credible, as the rules are that each and every generator must pay their own share of costs. If smaller or less financially strong players drop out (most likely the marine projects) SHE-T may seek to re-design the optimal reinforcement. However, more probably, smaller onshore wind players may need to bring in larger players, and there will be a concentration of ownership to a particular type of company.

The most useful actions to secure the Western Isles link will be to:

- ➔ Implement needs case improvements described in this report that allow stakeholders to influence its timing and reflect the size of beneficial consumer impacts of the connection.
- ➔ A visible CfD regime to back up the needs case.
- ➔ Stabilise grid costs targeted to individual generators through refinements to the TNUoS methodology.
- ➔ Progress the above actions in parallel to minimise further delays to connection dates.

To secure a more diverse investment environment for onshore wind, the Western Isles may also need help with an underwriting funding gap – via a loan guarantee scheme and / or more fundamental regime change. To secure marine projects, there will be a need similar to that in Orkney of financial support.

9.2.3 Shetland

The driving force behind Shetland's proposed mainland reinforcement is the 412MW Viking Energy onshore wind project, which is a 50/50 venture between a 90% community trust-owned company, and SSER. Whilst the Viking energy partners have committed funds to develop the project and secure current levels of underwriting, it will be reliant in part on bank and other outside finance sources when both the project and the link move into their construction phases.

Potential funders have told us that liabilities associated with the connection are too large to be left completely outside of the generator's control. Even if they were to secure greater control of the assets, this would reduce, but not eliminate, the gap in funding available from commercial providers.

This underwriting funding gap is being driven by the timing of construction of the grid connection, not the wind farm. As the Viking Energy project needs finance for the grid underwriting liabilities, it needs to reach FID in order to secure the liabilities, i.e. around 4+ years before connection. To reach FID on a project-financed project, it needs to have a secure revenue stream against which the finance is secured. This is impossible under current market conditions where there is no CfD visibility beyond 2019.

Thus actions to facilitate outside finance for projects on Shetland are:

- ➔ Consider as a matter of urgency with potential financiers whether measures such as using the CION process will satisfy the desire for more control over grid risks. If not, then some form of regime change will be required to give generators more explicit control over grid assets, which will introduce significant delay.
- ➔ Consider with UK Treasury whether the terms of the UK loan guarantee scheme could work in the Shetland context – and in particular the mismatch in the timing requirement for funds between the grid and the project. Again, if not, there will be some delay in establishing a new State Aid compliant government loan scheme, or sourcing alternative funds.
- ➔ A visible CfD regime to allow finance to be secured on the strength of revenues.

In addition to actions that bring in outside finance, Shetland generators also need to build an investment case within a relatively stable environment, and will benefit from all of the proposed measures for the Western Isles. Specifically on Shetland, consumer benefits that should be reflected in the needs case include savings on a diesel fuel subsidy. To this end:

- ➔ There needs to be improved information and transparency on the consumer benefits available from a reduction in diesel fuel use on Shetland.

Finally, in the context of being reliant on higher voltage HVDC VSC links with a multi-terminal switching station on Caithness, Shetland generators are particularly concerned about operational risks and downtime. Manufacturers would like to work with stakeholders to allay these concerns. Actions that will be helpful are:

- ➔ Improving availability of grid insurance, implementing incentives on SHE-T to minimise outages and reviewing compensation for outages under the CUSC.

9.3 Summary

Timescales for the solutions described in this report (and itemised in Appendix B) are between 1 and 5 years. There are no quick fixes. Even if there is the political will to support island projects, securing funds to fill underwriting funding gaps will take time – in the case of European and national funds to identify and secure, and in the case of UK loan guarantees, to structure the loan and ensure compliance with EU law.

The emphasis then is on keeping plans moving – in parallel where possible – and making sure that all stakeholders and policy makers understand what is most likely to be effective.

There is a raft of measures described here that need to come together for Scottish Islands to have a good chance of securing connections. Given the number of organisations and companies involved in facilitating these significant investments for the Islands, a final conclusion is that it would be helpful if DECC maintained its workstream on the Scottish Islands to monitor implementation.

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11 Appendix A - Policies timeline

Year	Events
2001	Brian Wilson, UK DTI, commissions West Coast Interconnector study looking at feasibility and cost of a subsea interconnector from the Western Isles (and taking in offshore west coast resources) to Hunterston and further afield.
2002	PB Power "Western offshore transmission grid" study published. [38] It looks at cost and feasibility of point to point and meshed / collector arrangements to harness renewable energy on the Western Isles and the Scottish west coast. Meshed systems more expensive and technically challenging. Indicative costs provided, including a 200km, 500MW subsea cable based on VSC technology estimated at £204M.
2003	June – UK Government publishes Transmission Issues Working Group (TIWG) report highlighting network investments to accommodate renewable energy. Much of this is in Scotland. Included an estimate of £250M to provide 1GW of access in the Western Isles. October – Ofgem consults on Transmission Investment for Renewable Generation (TIRG), with a view to allowing funds for the network companies additional to those allowed in the then price control [39].
2004	Energy Act 2004 – Section 185 provisions. April – consultants commissioned to examine evidence base for using Section 185. August – Ofgem consults on its consultant's analysis of TO reinforcement plans [40]. The consultants estimate connection costs for the Western Isles (£400M), Orkney (£95M) and Shetland (£250M) for connection at Beauly [41]. The work categorises TIRG investments into: baseline (where forecast constraint costs exceed reinforcement investment costs); incremental (where constraint costs could be substantial but are uncertain); or additional (where forecast constraint costs are less than 50% of investment costs). December – Ofgem provides full construction funding to Baseline projects – including Beauly Denny and Scotland-England circuit upgrades. Further consideration of funding for Incremental projects – reinforcements in the North East of England – and Additional projects – including all of the island connections – were put back to the next (2007-2012) price control [42]. In the meantime, Ofgem suggested that, in essence, island developers could directly fund the work themselves – albeit this would need some changes to the regulatory framework (as it was then).
2005	Ofgem consultations on Fourth Transmission Price Control Review (TPCR4)

	July – BERR (now DECC) consultation on adjusting transmission charges under Section 185. Minded to implement a scheme for all three island groups. Consulting on whether to include the north of Scotland. [18]
2006	Climate Change and Sustainability Act 2006 – extends application of Section 185 to October 2024. June – construction funding for island connections is not included in TPCR4 baseline allowances, although there is potential for a price control re-opener. Ofgem cites uncertainty over the links' technology and design. Ofgem moots opening up the links to competition, saying that such large scale investments "represent a large shift in the nature of SHETL's regulated business." Ofgem does allow some pre-construction funding leading up to planning applications [43], [44].
2007	June – Ofgem consultation on regulatory models for connecting the Scottish Islands. "There are few precedents for constructing connections of this nature in the United Kingdom and [they]…raise a number of challenges." Three models proposed (1) existing, i.e. SHET builds the link, (2) Merchant, private financing and running of the link (3) competitive tender for a regulated revenue i.e. the offshore connection model. [11]
2008	March – SHETL requests a price control re-opener for construction funding for the Western Isles and Shetland. Request based on 450MW Western Isles, £188M, complete 2012, and 600MW Shetland, £272M, complete 2013, as per contracted connection dates. June – Section 185 evidence base repeated. Found no case for intervention in Orkney and Shetland, marginal in Western Isles. Government decided to postpone decision on a scheme for the Western Isles. [45], [19]. September – Ofgem publishes its views on whether to allow this request or go down the competitive route. There are concerns about extending SHETL's licence outside of territorial seas to Shetland, but on the Western Isles it says that "adoption of a competitive approach may unduly delay renewable generation currently contracted to connect on the Western Isles by 2012/13, which may impact on the delivery of the government's 2020 targets" but that "We would also want to reappraise our view on the most appropriate way forward for this connection if there was a substantial change to the estimated costs or delivery timescale of the proposed link because this might imply greater potential benefits of a competitive approach." [12] December – Ofgem consults on how to incentivise investments additional to those allowed in TCPR4. [46]
2009	March – Ofgem publishes its decision on the Western Isles, which is to consider SHETL's needs case, but to keep open the prospect of competitive tendering. Anticipated a consultation later in 2009 on the

	incentives on SHETL to deliver the Western Isles connection. September – further consultation on the investments additional to baseline in TCPR4. Ofgem calls this process Transmission Investment Incentives (TII). Proposals include construction funding for the Western Isles and Shetland. Ofgem appoints KEMA and PB Power to review submissions, including the Western Isles. [47]
2010	January – Ofgem publishes a final decision on TII requests. Consider that Western Isles and Shetland submissions still have too many unknowns and so decision deferred for further developments. [48] January – publish Ofgem's consultants assessment of Western Isles submission In 2009 SHETL's submission estimated the cost of the link as £286.5M. "Summer" – SHETL updates its funding request for the Western Isles. September – Project TransmiT initiated, wholesale review of transmission connection and charging. November – in a half-year report to investors, SSE states that "In October 2010, SHETL concluded that the lack of financial underwriting from electricity generators (attributed to the level of transmission charges) relating to the link from the Western Isles to the mainland meant it would not be able to conclude a contract for the supply of the necessary electricity cable. As a result, it withdrew its request to Ofgem for authorisation to make the investment. It will, however, prepare a new request for authorisation to invest in the link as soon as these issues are resolved. In practice, this is likely to take at least one year." [49] December – Ofgem publishes its consultants, TNEI, assessment of SHETL's detailed funding case for the Western Isles. They basically agree with SHETL's proposal for a single subsea 450MW link and two onshore 450 MW cables, in terms of striking balance between current and future demand for capacity. The updated cost is £391M (about £30M of this increase due to the second land cable). TNEI considered that SHETL's pricing of risk was very conservative and took the worst case. December – Ofgem publishes details of funding requests in TPCR4 period, as well as proposals for extending TPCR4 for a year to 2012/13. No decision is made as on the Western Isles as SHETL has withdrawn the request. [50] Henceforth there are no island projects put forward as part of TII.
2011	February – CMP 192 on user commitment initiated. July – Project TransmiT Significant Code Review of transmission charging launched. [51] Technical Working Group established. December – Ofgem consults on "options for change" of the charging

	methodology for TNUoS. These are all focused on changing the allocation of costs across the "wider" network. Broadly speaking this does not include the island connections. Ofgem is minded to rule out fully socialised wider charges at this stage. Decisions were also required on how to treat the island connections, e.g. the existing methodology was (then) silent on how to treat HVDC technology. [52]
2012	March – Ofgem approves CMP 192 [14]. May – Ofgem directs National Grid to raise a CUSC Modification on Improved ICRP (usage-based charging that retains locational element); HVDC bootstraps; and an island methodology. On the island methodology, Ofgem generally favours a fully cost reflective charge, but asks National Grid to look at the treatment of HVDC converter costs. [53] October – DECC sets up Scottish Island Renewables steering group and commissioned independent study on the commercial viability of island projects, economics and supply chain.
2013	March – SHE-T submits a needs case for the "Caithness-Moray" reinforcements. These are part and parcel of the main works required for the Shetland connection. April – RIIO T1 price control begins. Islands now fall into "Strategic Wider Works" which are subject to case by case needs assessment. May – DECC-commissioned Baringa / TNEI report, Scottish Island Renewables Project is published. States amongst other things that island projects will need a CfD uplift. [3] June – SHE-T sends a needs case for the Western Isles link to Ofgem. June – Ofgem sends back the Western Isles needs case to SHE-T asking for further information, saying "notably, the implications of uncertainty, such as the risk of asset stranding or unrealised economic benefits, have not been examined adequately." Ofgem specifically asks SHE-T to justify submitting the needs case prior to DECC's conclusions on a CfD uplift. [54] August – Project TransmiT: Ofgem recommends changing the charging the charging methodology to Improved ICRP. Island connections fully cost reflective for each individual link, including 100% of converter costs, using actual link delivered costs, (meaning costs uncertain pre-connection, but reasonably certain post connection). [55] August – Ofgem provides an update on its review of the needs case assessment for Caithness-Moray. It generally agrees with the case for reinforcement but wants to examine alternative technical solutions and probes costs and risk sharing arrangements. [56] September – DECC publishes consultation on CfD uplift for island

	renewable projects. [20] December – Ofgem announces delay in making a decision on Project TransmiT charging methodology. Earliest date for a decision March 2014. If approved, implementation delayed for at least a year to April 2015 (although it's the delay in a decision rather than implementation that has the most impact on islands). [57] December – DECC confirms CfD uplift of £115/MWh for Scottish Islands, and states its intention to commission further work on grid access. [1]

Table 11-1: Policies timeline

12 Appendix B - Solutions

Measure	Implementation	Timescale	Relative ease
Generation agreements			
Application alignment	Generators – evidence suggests more successful when initiated and designed by generators, with help from SHE-T and NGET	1 year	Good (if interest)
Needs case improvements	SHE-T – to provide more visibility and accountability on decisions, including decisions to delay. Ofgem – consider provisions for generators leverage with SHE-T's case. Consider CION process for islands. Generators – to pro-actively justify earlier submissions.	1 year	Good
Review of contractual and commercial lessons learned from RPZ	SHEPD – if part of its existing reporting requirements. Ofgem – if this requires new work to be commissioned.	1 year	Medium
Compensation for lost access	NGET – review compensation regime for island connections Generators – bring forward desired CUSC Modifications on compensation regime	1-2 years	Hard
Underwriting and TNUoS commensurate with access terms	NGET – review underwriting and TNUoS for generators accepting temporary or permanent non-firm access Generators – bring forward CUSC Modifications on charges for non-firm access	1-2 years	Moderate
Develop written GB grid queue policy	NGET – this is understood to be under development already.	months	Good
Move towards a gate system of allocating access	NGET – to consider reducing GB queue administration by moving to a gate process such as that in Ireland. This would require a complete overhaul of the grid agreement contractual arrangements	2-4 years	Very hard
Develop OFTO or merchant regime for the islands	Ofgem – test developer's appetite for a private wire regime and develop if there is strong appetite	2-5 years	Hard

Measure	Implementation	Timescale	Relative ease
Underwriting			
Generators and SHE-T to improve collaboration	SHE-T – consider, with its vendors, how far information sharing can be improved.	1 year	Medium
Implement CION process for the Scottish Islands	NGET – consider with SHE-T how this can be achieved and seek Ofgem approval.	1 year	Good
UK and Scottish Government loan guarantees	UK Government – consider loan guarantees for bridging funding gap Scottish Government – consider loan guarantees for bridging funding gap Generators – apply for UK loan guarantee if can make a case	1 year	Medium to hard
Island funds	Generators, financiers, government – consider island funds that pool investment and spread risks	2-3 years	Medium to hard
Grant support	SHE-T and generators – seek grant support as direct contribution to capital costs or underwriting. Ofgem – consider treatment of grant support to SHE-T in regulatory settlement. NGET – consider how grant support to SHE-T would be reflected in underwriting.	2-3 years	Medium to hard
Reduce generator underwriting through methodological change	Generators – bring forward CUSC Mods that justify further socialisation of grid costs e.g. further evidence from manufacturers on HVDC converter system benefits	1-2 years	Medium
Offer FSL as a means of banks having fully refundable liabilities	Generators and financiers – to consider if refundable liabilities would mitigate risk for banks of having no direct call on grid assets		
TNUoS			
Stabilise targeted costs	NGET and generators – consider bringing forward CUSC Mod which uses island specific expansion factors that can be fixed pre-connection to support FIDs	1-2 years	Hard
Update methodology for HVDC	NGET – review methodology against design of Caithness-Moray system	1-2 years	Good

Measure	Implementation	Timescale	Relative ease
Access rights			
Compensation for lost access	As above under offer terms	1-2 years	Hard
Generators and SHE-T to improve collaboration	As above under timing and control – better information on system design should help understand grid availability issues	1 year	Medium
Generators to receive better information on operational regime	Generators and NGET – consider how better information on system outages and operational regime can help generators understand and predict grid availability	1 year	Medium
Availability incentives on SHE-T	Ofgem – to implement incentives on SHE-T to maximise availability as part of license conditions associated with funding approval	1 year	Good
Improve availability of insurance products	Manufacturers – keep insurance industry updated on HVDC technology	1 year	Good
Cost Benefit Analysis			
Needs case improvements	SHE-T – to provide more visibility and accountability on decisions, including decisions to delay. Ofgem – consider provisions for generators leverage with SHE-T's case. Consider CION process for islands. Generators – to pro-actively justify earlier submissions.	1 year	Good

Table 12-1: Solutions