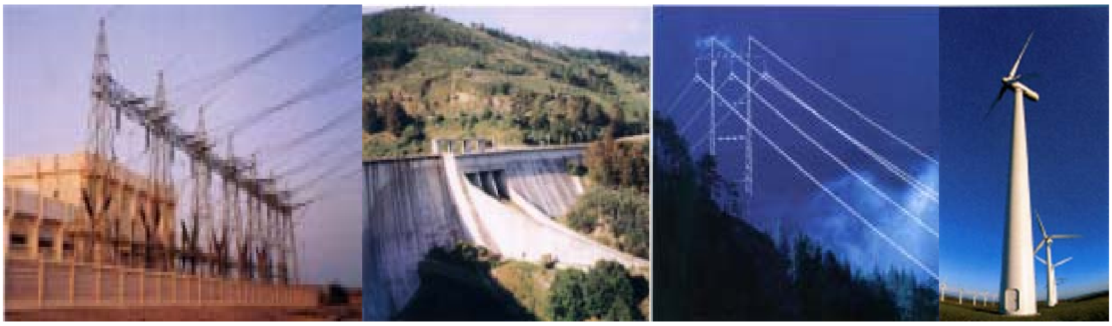
Final Report



The Relative Economics of Wind Farms Projects in the Scottish Islands

to

BERR

June 2008

IPA Energy + Water Economics **Sinclair Knight Mertz**

The Relative Economics of Wind Farms Projects in the Scottish Islands

to

BERR

IPA Energy + Water Economics
41 Manor Place
Edinburgh
EH3 7EB
Scotland

Tel: +44 (0) 131 240 0840
Fax: +44 (0) 131 220 6440
Email:
contact@ipaeconomics.com
web: www.ipaeconomics.com

TABLE OF CONTENTS

TABLE OF TABLES

TABLE OF FIGURES

1 EXECUTIVE SUMMARY

This report investigates the economics of wind farms in Shetland, Orkney and the Western Islands, and investigates the extent that differences in transmission charges on the Scottish islands relative to those charged on mainland Scotland could hinder the development of the renewable resources on those islands.

The report aims to inform the Government debate on the whether, in the absence of a S185 scheme (see below), transmission charges would be likely to deter, or otherwise hinder in a material respect, development of renewable generation on the Scottish islands.

1.1 The S185 Scheme

The Energy Act 2004, as amended by the Climate Change and Sustainable Energy Act 2006, gives the Secretary of State the power to limit transmission charges for renewable generators in a particular area of Great Britain if certain conditions are met. The purpose of the power given under Section 185 (s185) is to address concerns that the locational transmission charging scheme operated by the GB SO might hinder the development of renewable generation especially in the North of Scotland.

Before exercising this power the Government requires to be satisfied that a scheme provides a beneficial and cost-effective way of supporting additional renewable generation.

1.2 The Current Status of Island Wind Farm Generation

There are currently no transmission connected generation projects on the Scottish Islands of Shetland, Orkney and the Western Isles. However, there is interest in developing over 1.1GW of wind capacity, the connection of which will require the reinforcement of the transmission system, including the installation of subsea cables and infrastructure work on the islands and mainland.

The commissioning dates for these planned wind farms must reflect possible connection dates, which are dictated by the completion dates of the reinforcement works, and likely to be around 2013/14 at the earliest.

1.3 Transmission Reinforcement Costs and TNUoS Charges

SHETL are currently undertaking pre-construction development work for these required connections and have provided this study with cost data for both single and double circuit connection options.

This cost data has also been provided to NGET, who have provided a forecast of TNUoS charges, based on SHETL’s estimated capital costs. These are shown below.

Table 1: NGET Indicative Forecast TNUoS Charges

	Shetland (£/kW)	Western Isles (£/kW)	Orkney (£/kW)
1 x 100%	55.5	46.6	N/A
2 x 100%	84.2	66.4	61.3
Onshore base tariff	19.2	21.8	25.33

1.4 Comparator Projects

In order to inform the decision about the level of transmission discount that might be justified for Scottish Island wind farms under S185 it is necessary to examine in detail the relative economics of generic wind farm developments on the Scottish Islands of Shetland, Orkney and Western Isles relative to comparator projects on the mainland situated in relatively close proximity (Northern and Western Highlands). Generic comparator projects were developed, to analyse the impact of the differences between the locations under study on wind farm project economics.

The comparator projects were designed to be representative of the generic costs incurred at the different locations, without necessarily reflecting the specific costs of the individual projects that are under development.

Based on the capacity of representative developments on the Islands and the mainland, we have chosen a project size of 150MW with which to compare the economics. From examination of the various parameters that affect the economics of a wind farm we have concluded that there would be no material difference between mainland projects in the North and West Highlands and so have chosen a single mainland comparator project.

However, there exists significant levels of difference in the costs and capacity factors between the three Island areas under consideration to merit separate comparator projects for each. We have therefore chosen one project for each of the Island areas.

1.5 Consultation

To identify the differences in the project economics between developments on the mainland and on the Islands, a consultation with wind farm developers and operators within the industry was carried out. During this process, many developers indicated that a S185 scheme would be important and some identified it as the single most important factor. They were all of the opinion that a decision on the future structure and level of any scheme was critical and want a decision made quickly.

Relatively little explicit cost data for projects was provided through the consultation process, although some indication was provided of expected uplifts for specific cost elements between the mainland and the island areas under consideration.

1.6 Capacity Factors

A major parameter in the economics of a potential wind farm is the expected Capacity Factor, or Load Factor of the project, which dictates the amount of electricity that can be produced.

We have taken data from a number of sources, including the consultation process, to build up a picture of expected load factors for the areas under consideration. These are shown in the table below.

Table 2: Expected Capacity Factors

Mainland	W. Isles	Shetland	Orkney
30%	35%	49%	49%

Clearly there are higher capacity factors expected on Shetland and Orkney than on the mainland and the Western Isles.

1.7 Wind Farm Economics

We have developed generic comparator projects, using data from the consortium's experience, supplemented by the consultation process. The costs and revenue streams investigated were as follows.

Table 3: Cost and Revenue Parameters

Costs	Revenues
Pre-construction costs	Electricity price
Transmission connection costs	ROC price
Capital costs	CCL.
Fixed operating costs	
Variable operating costs	

Where distinctions had been identified between costs on the mainland and on the Islands, the uplifts assumed for the parameters were applied.

1.8 Financial Models

Financial models of the comparator projects have been constructed and their economics assessed by calculating the equity IRRs under a range of power and ROC price scenarios. For this we have used GB power and ROC price forecasts from IPA's January 08 PowerView product. The results from the analysis, assuming base case cost and capacity factors are shown in the following table.

Table 4: Range of Potential Equity IRR

	Mainland	W. Isles	Shetland	Orkney
Single Circuit Connection	11% - 19%	9.6% - 17.9%	29% - 58.2%	
Double Circuit Connection	11% - 19%	6.2% - 13.4%	16.2% - 31.9%	29.8% - 58%

The analysis suggests potential returns to investors on Shetland and Orkney which indicates that a s185 scheme would probably not be required in these areas to bring forward wind farm development. However, the economics of projects situated on the Western Isles is much less favourable, particularly with a double circuit connection, and a s185 scheme might make the difference to project economics.

1.9 Sensitivity Analysis

Sensitivity analyses were carried out on key cost and capacity factor parameters, whilst holding the power and ROC prices constant at the base case levels, to determine the impact of potential variations between the areas under consideration.

This indicated that the parameter with the most impact on the project economics is the capacity factor.

Capacity factor uncertainty results in the greatest variability in the IRR of all the different parameters. Whilst this is most obvious in Orkney and Shetland where the capacity factor uncertainty is highest, it is also true in the mainland and Western Isles, where the range of capacity factors used is relatively tight. The range of equity IRRs for the identified range of capacity factors is shown in the following table.

Table 5: Range of Equity IRRs at Range of Capacity Factors

	Mainland	W. Isles	Shetland	Orkney
Capacity Factor Range, %	28% - 32%	33% - 37%	45% - 54%	42% - 50%
Equity IRR Range, %	12.6% - 16.6%	11.5% - 15.0%	32.2% - 51.5%	27.0% - 42.7%

The effect of a Zonal Losses scheme would detrimentally affect the project economics of projects situated on the Islands, most significantly on Shetland, where the cable losses are highest.

There is more uncertainty in the sensitivity results for projects in Shetland and Orkney, than in the Western Isles or the mainland. However the economics are fairly robust to variations in the major parameters that feed into the economic analyses, with results indicating that it could be marginal as to whether a s185 scheme would also be required for projects on Shetland under a scenario with a combination of low power and ROC prices, and low capacity factors. This is, however, a relatively low probability, pessimistic scenario.

1.10 TNUoS Variation

Sensitivity analyses were carried to investigate the impact of varying the TNUoS charges on the equity IRR of the projects.

We have varied the TNUoS charge ranging between £22.09/kW/annum (the average of the mainland charges for the landing points for all the subsea cables for the three Islands – provided by NGET) and the levels provided by NGET for the single and double circuit connections for all the Island projects.

Results, using the base case power and ROC price assumptions, are shown in the following figures.

Figure 1: Western Isles Range of Equity IRRs expected with varying TNUoS Charges

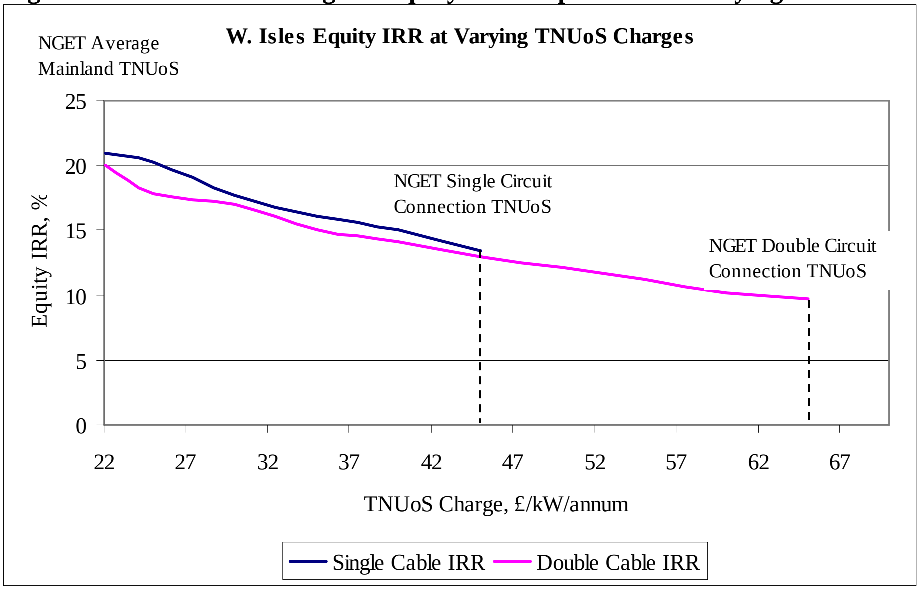


Figure 2: Shetland Range of Equity IRRs expected with varying TNUoS Charges

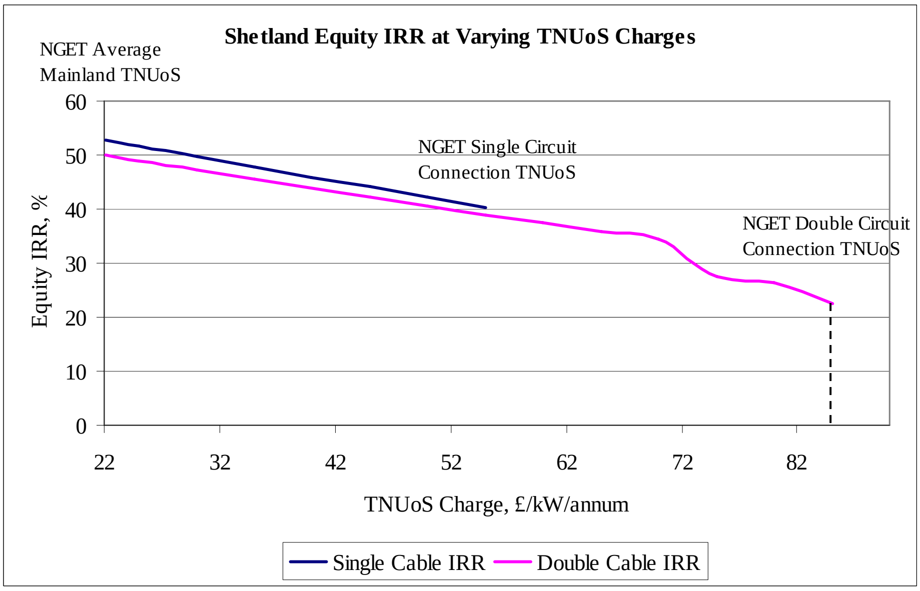
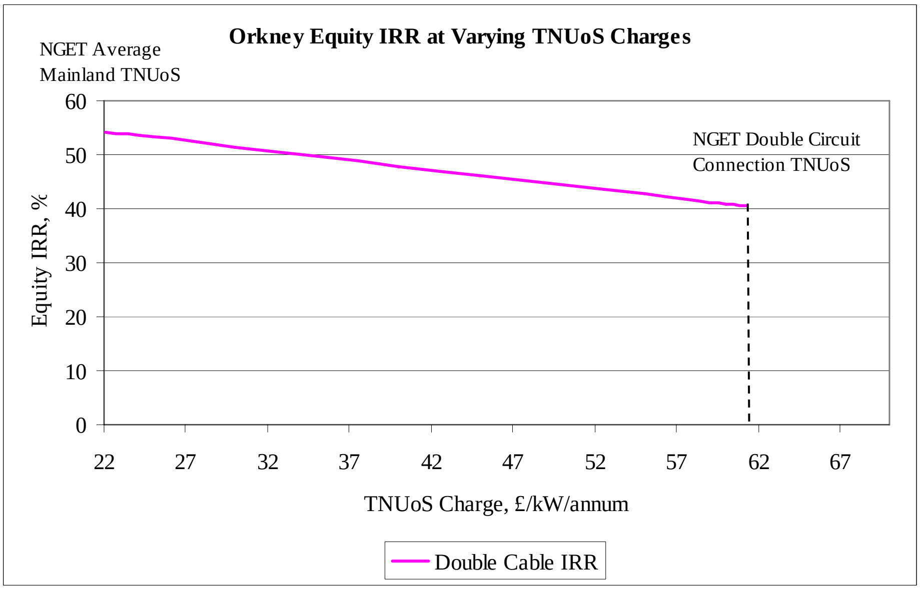


Figure 3: Orkney Range of Equity IRRs expected with varying TNUoS Charges



The results presented above are based on current assumptions regarding the costs and operating parameters of the links provided by SHETL and the transmission charges provided by NGET. It should be recognised that these have been developed for the current regulatory framework and charging methodology, both of which could be subject to change. In addition, they are based on wind farm cost and revenue estimates, based on current expectations, which could also change.

2 INTRODUCTION

This report investigates the economics of wind farms in Shetland, Orkney and the Western Islands, and investigates the extent that differences in transmission charges on the Scottish islands relative to those charged on mainland Scotland could hinder the development of wind projects on those islands.

The report aims to inform the Government debate on whether, in the absence of a S185 scheme, transmission charges would be likely to deter, or otherwise hinder in a material respect, development of renewable generation on the Scottish islands.

The detail of the Section 185 of the energy act is given in Section 2.1 below, and an analysis of the current status of renewable generation developments on the Scottish islands is given in Section 2.2.

2.1 The S185 Scheme

The Energy Act 2004, as amended by the Climate Change and Sustainable Energy Act 2006, gives the Secretary of State the power to limit transmission charges for renewable generators in a particular area of Great Britain if certain conditions are met. The purpose of the power given under Section 185 (s185) is to address concerns that the locational transmission charging scheme operated by the GB SO might hinder the development of renewable generation especially in the North of Scotland. The power can be exercised if it appears to the Secretary of State that:

a) a particular area in Great Britain is suitable as a location for the generation of electricity from renewable sources;

b) as a result, that area represents an area of high potential for the development of the generation of electricity from such sources; and

c) that development is likely to be deterred, or otherwise hindered in a material respect, by the level of transmission charges that would, apart from the s185 scheme, apply.

The Act provides that any shortfall in transmission charging revenue because of a s185 scheme must be recovered from electricity suppliers. It is envisaged that the increased charges will be passed on to electricity consumers, who will ultimately bear the costs of any scheme. Therefore, the Government will want to be satisfied that a scheme provides a beneficial and cost-effective way of supporting additional renewable generation.

The Energy Minister announced in 2005 the intention to exercise this power, which enables the Secretary of State to adjust charges for renewable generators for a maximum of 10 years, with the s185 scheme coming to an end in any event by 4 October 2024. However, this intention is clearly subject to the statutory tests set out at (a) – (c) above being met.

The Government issued a consultation on the application of S185 in July 2005[1] in which it was suggested that the Government would consider developing a scheme to adjust transmission charges for renewable generators on the Scottish islands of

[1] Adjusting transmission charges for renewable generation in the north of Scotland, DTI, July 2005

Shetland, Orkney and the Western Isles and would consult upon whether a scheme should also apply to the mainland of Northern Scotland. The Government has not published a response to this consultation.

This report is intended to inform further Government debate on implementation of a S185 scheme for implementation on the islands of Shetland, Orkney and the Western Isles.

2.2 Current Status of Island Wind Farm Generation

There is considerable interest in developing wind generation on the Scottish Islands (see Table 6). However, none of the Scottish Islands currently have transmission connection with the mainland, so wind generation projects that have been developed to date have been relatively small in scale (<10MW) and are connected to the distribution systems – and so are not subject to payment of Generation Transmission Charges.

There are a number of large wind generation projects planned for the Scottish Islands (see Table 7). These projects will require transmission connections, and all of the projects (except Lewis wind power) have contracted with the GBSO to provide connections.

Connecting these projects will require reinforcement of the transmission system, requiring the installation of subsea cables, as well as infrastructure work on the islands and mainland. SHETL are currently undertaking pre-construction development work on these various transmission reinforcement works.

The planned commissioning dates for many of these large island projects were initially around 2010. However, these large wind projects planned for the Scottish islands cannot be developed until subsea connection with the mainland (as well as other reinforcement works such as the Beauly-Denny transmission line which is currently subject to a public enquiry) have been completed. Thus, the commissioning dates for these wind farms must reflect possible connection dates, with the earliest connection dates likely to be around 2013/4.

It should be noted that any s185 scheme would expire by 2024 at the latest, and therefore could only provide support for wind farm economics over the first 10 years of a projects life.

These generation projects are at different stages in the development process, with three having applied for planning permission (S36 consent from the Scottish Executive) and four having contracted for grid capacity who are currently underwriting the pre-construction development costs currently being incurred by SHETL in developing the links.

Construction for all of these renewable generation projects will not occur for a number of years, and a final commitment to construct the projects will be dependent upon an assessment of project economics. This report investigates the impact that a S185 scheme could have on the economics of these proposed wind farms, and whether an appropriate S185 scheme would bring about development that would be likely to be deterred, or otherwise hindered in a material respect, by the level of transmission charges in the Scottish Islands.

Table 6: Operating & Proposed Wind Farms in Northern Highlands & Scottish Islands

Developer	Current Projects On The Islands	Proposed Developments On The Islands	Current Northern Highland Mainland Projects	Proposed Northern Highland Mainland Projects
Beinn Mhor Power Ltd		Eishken Estate, Lewis (159MW)		
E.ON UK				Camster (50MW) Ross-shire (25MW) Lairg (25MW)
Fairwind (Orkney) Ltd		Fairwind Ltd, Orkney (126MW)		
Falck Renewables				Loch Ness (10MW) Easter Ross (10MW) Loch Ness (40MW)
Farm Energy	Bu Farm, Orkney (2.7MW)	Arnish Mhor, Lewis (3.9MW) Bu Farm Extension, Orkney (5MW) Rothiesholm Project, Orkney (7MW) Pentland Road, Lewis (12MW)		
Infinergy				Lochluichart (51MW) Darngarroch (51MW) Doronell Wind Farm (180MW)
Lewis Wind Power		Barvas Moor (652MW)		
North British Windpower				Inverness (40MW) Caithness (4.6MW) Arkaig (118MW)
Npower renewables	WWW Burger Hill, Orkney (5MW)		Causeymire (48MW) Farr (92MW) Beinn Ghlas (8.4MW) Novar (17MW)	Auckengill (30MW) Ross-shire (24MW) Yarrows (20MW)
RDC		Ben Aketil, Skye (23MW)		Kilbraur (47.5MW) Millenium (40MW)
RES			Hill of Lybster (5.2MW)	Strath Fleet (49.5MW) Dunmaglass (108MW) Ferness (30MW)
Shetland Aerogenerators	Burradale, Shetland (1.98MW + 1.7MW)			
Scottish Power			Beinn Tharsuin (29.75MW)	
SSE	Spurness, Orkney (8.25MW)	Pairc, Lewis (250MW)		Lairg (35MW) Muir of Ord (35MW) Strathy North (80MW) Strathy South (177MW) Gordonbush (87.5MW) Melvich (30MW)
Viking Energy/SSE		Viking, Shetland (600MW)		
Your Energy	Spurness, Orkney (8.25MW)			

Table 7: Status of Large Planned Island Wind Generation Projects

Project	Island	Size (MW)	Planning	Connection Agreement and date[2]
Eishken Estate	Lewis	159	Applied	Yes, 2013/2014
Fairwind	Orkney	126	Not Applied	Yes, 2012/2013
Barvas Moor	Lewis	652	Applied[3]	No
Viking	Shetland	600	Not Applied	Yes, 2013/2014
Pairc	Lewis	250	Applied	Yes, 2012/2013

[2] Source: National Grid Seven Year Statement 2007
[3] At the time of writing the Scottish Executive had rejected this project, but had given the developer 21 days to appeal.

3 ISLAND CONNECTIONS & TNUoS

3.1 Island Connections

The Scottish islands do not currently have transmission connections with the mainland. However, the Western Isles and Orkney are connected to the mainland distribution systems via 33kV (20MW) and 2*33kV (20+30MW) connections respectively. There is no connection from Shetland to the mainland electricity systems. The ability of the islands to host new renewable generation developments is therefore currently extremely limited.

There are a number of large wind farm projects being developed on Shetland, Orkney and the Western Isles, as detailed in Table 7, which will require the islands to be connected to the mainland transmission system. All except one of the wind farm projects has a connection agreement with the TSO, requiring transmission connections to be developed to each of the three islands. SHETL are currently undertaking pre-construction development work including technical design and route survey work in respect of these transmission reinforcements. The costs incurred by SHETL are underwritten (through the TSO) by those contracted generation projects which have applied for connection to the GB system on the islands.

3.1.1 Regulatory Options

In June 2007 Ofgem published an open letter entitled Connecting the Islands of Scotland, that discussed potential regulatory options which could be applied to the Scottish Island connections. These included:

- The status quo (SHETL construct island connections);
- Merchant approaches – privately financing a connection to the main system; and
- Tendering the right to build a connection and obtain a regulated revenue.

Whilst there has been industry discussion about possible regulatory frameworks, there have been no firm developments in this area. Thus, since SHETL's existing licensed area includes the Scottish Islands, they have an obligation to offer terms for connection to NGET in response to a request for connection by any generator on the islands.

Whilst a change in the regulatory framework could potentially result in differences to the approaches and costs associated with connecting the Scottish Islands, SHETL's pre-construction development work currently represents the most reliable estimate for the capital costs associated with the required transmission reinforcements, and so will be used in this report.

3.1.2 Security Standards

Under the existing regulatory framework, the transmission reinforcements would normally connect the Scottish islands consistent with the GB Security and Quality of Supply Standards (SQSS).

However, there are a number of current consultations on security of supply standards for offshore connections and reviewing standards for onshore intermittent generation. In particular the Offshore SQSS subgroup has recommended that the offshore level of security should be set to zero redundancy connections. In addition, the network in Scotland (particularly in the SHETL area) has historically not used the same security standards as applied in England & Wales (reflecting the different characteristics of the networks) and there are a number of connections in the region that would not have met the GB SQSS as implemented with BETTA and therefore are deemed SQSS customer choice variations to connection designs.

Thus, there is the possibility of taking different approaches to developing the transmission reinforcements to connect the Scottish Islands. Whilst the connection of the Scottish Islands may be fully compliant with the GB SQSS, it is also possible that customer choice design variation schemes could also be proposed.

3.1.3 SHETL Transmission Reinforcement Schemes

SHETL are currently undertaking technical design and route survey work in respect of three island transmission reinforcement schemes, and developing and costing candidate schemes. These include both schemes that will be compliant with the SQSS and schemes which would require customer choice variations to connection designs, where these could provide the most economic option.

SHETL provided a detailed submission to this work which is included in Appendix B. The capital costs associated with the most cost effective compliant and design variation schemes are summarised in Table 8- Table 10 below, along with indicative estimates of link availability and link transmission losses.

Table 8: Orkney Transmission Options

Description	Link Configuration	SQSS Design Variation	Indicative Capital Cost £m	Average Annual Hours of no link capacity	Indicative level of Losses (as % of energy put onto link)
Double AC Link	2*132kV 180MVA	No	86		2.5-3%

Table 9: Shetland Transmission Options

Description	Link Configuration	SQSS Design Variation	Indicative Capital Cost (HVDC Link Only) £m	Average Annual Hours of no link capacity	Indicative level of Losses (as % of energy put onto link)
Single HVDC Link	1*550MW	Yes	237	435	6.1%
Double HVDC Link	2*550MW	No	473	26	5.8%

Table 10: Western Isles Transmission Options

Description	Link Configuration	SQSS Design Variation	Capital Cost (HVDC Link Only) £m	Average Annual Hours of no link capacity	Indicative level of Losses (as % of energy put onto link)
Single HVDC Link	1*550MW	Yes	163	230	4.9%
Double HVDC Link	2*550MW	No	326	9	5.2%

3.1.4 Treatment of Customer Choice Design Variation Connections

The current regulatory framework is designed around the premise of the provision of firm connections that are compliant with the GB SQSS. The connections are known as firm because generators receive compensation in the event of interruption of transmission access. The compensation available is detailed in the CAP048(c) amendment to the CUSC which states: "for planned events this [Alternative] Amendment seeks to compensate an eligible generator for TNUoS charges while for unplanned events an eligible generator would be compensated using the Market Index Price (MIP) as published on the Balancing Mechanism Reporting Service (BMRS) for the first 24 hours of an event or fault. After 24 hours, compensation would be for TNUoS".

There are however a relatively large number of customer choice design variation connections, particularly in Northern Scotland which historically had different connection standards. The rights to compensation for these connections are within their Bilateral Connection Agreement (Clause 10 - Design variation), which usually states that they will not be eligible for any compensation in the event of curtailed transmission access due to outages on the identified non-compliant circuits.

The potential transmission reinforcements for connecting the Scottish islands have both schemes that are fully compliant with the GB SQSS and schemes that would be covered customer choice design variations criteria. Although it is recognised that compensation will be available in a variety of instances when the generator is constrained off, or down, in order to simplify the modelling we have assumed that, for all schemes, there is no compensation for any periods where the links are unavailable,. During periods where transmission capacity is unavailable the island wind farms are unable to generate and get no compensation. Thus there is an opportunity cost for the wind farm associated with any periods where transmission capacity is unavailable and this cost is inevitably significantly higher for the customer choice design variation connections.

3.2 TNUoS

NGET have provided a forecast of the indicative TNUoS charges that could be applied to the islands under the transmission reinforcement options identified in Section 3.1.3 above. Full details of the NGET submission to this work are provided in Appendix C.

There are a number of potential methodologies that could be applied to island transmission charges and the full development of generation local asset charging arrangements are still to be consulted upon and implemented. There are several alternative approaches to developing a methodology for the calculation of TNUoS tariffs for island connections:

- To replicate the onshore methodology exactly. Such an approach assumes the island connection is at the same connection security standard as the GB average, currently the Locational Security Factor of 1.8. Consequently a double circuit island connection (sized at 2 x the island wind generation capacity) would have 20% of the cost of one of its cables socialised across all other Users.
- National Grid is currently developing TNUoS arrangement for generation local assets so as to improve the cost reflectivity of charging for spur connections. Industry consultation has yet to be performed on possible approaches although it is anticipated that such a methodology would lead to the full cost of both cables being factored into the TNUoS tariff.
- The onshore methodology is exactly replicated for island connection with the exception of if the link security standard is greater than the Locational Security Factor. In such cases the cost of the additional transmission assets would be charged as a one off capital contribution. This ensures the full cost of the island connection is reflected upon the User and not socialised.

The last of the approaches discussed above has been used for the indicative tariffs, as this methodology ensures the full cost of the island connection is reflected upon the island connection. This approach would provide the highest cost for island wind generation and so is the approach under which the highest level of discount under an S185 scheme could be justified.
The forecast of indicative TNUoS is reflective of the magnitude of TNUoS charges that are likely to apply over the period 2013-2024 with the development particularly of the Scottish transmission networks and renewable generation. However, only a forecast for a single year, 2008/09, has been provided reflecting the fact that despite the significant uncertainties associated with transmission and generation developments, the TNUoS uplift associated with the Scottish Islands should be relatively stable through time. System reinforcements such as Beauly –

Denny are likely to significantly impact absolute tariff levels for island connections without altering the island to mainland differentials.

NGET have calculated an indicative transmission charge for the onshore network using the existing charging rules and the associated DCLF transport model. They have then calculated the island TNUoS as an uplift from the tariff applied to the relevant onshore node.

The methodology NGET used for calculating the uplift associated with the transmission reinforcements connecting the Scottish Islands is that broadly proposed for transmission charges for offshore networks. NGET recently published a document on Transmission Charges for Offshore networks[4], suggesting that expansion factors would be developed to ensure that network charges recovered the actual costs associated with offshore transmission networks. The document notes that NGET believes that, at a high level, the treatment of offshore transmission charging could be applicable to the Scottish Islands.

It is also interesting to note that the offshore SQSS subgroup have recommended that the offshore level of security should be set to zero redundancy connections. National Grid has also consulted on a charging amendment to deal with onshore SQSS Design Variation single circuit connections, with the proposed amendment providing a financial signal to reflect the lower security of the connection and the reduced asset investment.

The NGET methodology used for calculating the TNUoS uplift associated with the transmission reinforcements connecting the Scottish Islands is summarised below:

- Circuit Specific Expansion factors derived such that the actual annuitised capital cost is precisely recovered from the TNUoS tariffs;
- Where there is redundancy, and the spare capacity exceeds that of the average for onshore connections (namely 80%), the TNUoS tariff is calculated using the onshore Locational Security Factor of 1.8. For this example this only includes the double circuit offshore connections; and
- Generators pay for transmission capacity used (charges are per MW TEC) rather than transmission capacity installed.

The methodology ensures that the actual annuitised capital cost is precisely recovered from the TNUoS tariffs, and so provides a financial signal to the generator where the connection provides a lower connection security standard with reduced asset investment requirements.

The NGET indicative forecast of TNUoS charges is shown in Table 11 below. In the cases where there is redundancy and the capacity exceeds the average redundancy for the onshore transmission system of 80%, the indicative charge is derived using the existing onshore Locational Security Factor of 1.8. This applies to the double circuit transmission development solutions and requires developers to pay a capital contribution equivalent to 10% of the transmission asset costs.

National Grid is currently developing and consulting upon several alternative approaches for the charging of local assets for generators connected by spurs which

[4] Modification proposal to the transmission network use of system charging methodology to introduce charging arrangements associated with offshore transmission networks, NGET, December 2007.

may impact the indicative charges produced for island connections. The intention of such proposals is to increase the charge cost reflectivity for local assets.

Table 11: NGET Indicative Forecast TNUoS Charges

	Shetland (£/kW)	Western Isles (£/kW)	Orkney (£/kW)
1 x 100%	55.5	46.6	N/A
2 x 100%	84.2	66.4	61.3
Onshore base tariff	19.2	21.8	25.33

Table 12: NGET One-off capital costs for full redundancy connections

	Shetland (£m)	Western Isles (£m)	Orkney (£m)
2 x 100%	47.3	32.6	8.6

3.2.1 Small Generator Discount

Small generators (those with a generating capacity less than 100MW) connected to the transmission network in Scotland at 132kV currently receive a discount of 25% on the total residual TNUoS tariff.

Whilst this discount will continue in the short term, Ofgem have acknowledged that it is an interim solution. NGET have confirmed their intention to work toward developing and implementing an enduring solution, given that the discount currently ceases to have effect in May 2009.

This discount could potentially interact with the setting of any S185 scheme if the two separate schemes were both in place at the same time.

Whilst there clearly could be an interaction between the two schemes, there is clearly significant regulatory/policy uncertainty about both schemes, and the small generator discount was not put in place with a view to it being an enduring scheme, and so is likely to have been phased out before island transmission connections have been developed. In addition the wind farms that we consider in this report are larger than 100MW and so would not be eligible for the small generator discount. As a result we do not consider the small generator discount further in this report.

3.3 Additional Issues

There are clearly a wide range of regulatory issues that will need to be resolved in terms of the arrangements surrounding the transmission reinforcements connecting the Scottish Islands. These cover the connection design, transmission access, transmission charging and allocation of constraint costs. All of these issues are currently under discussion through a number of industry work groups such as the SQSS and TAR groups as well as through the discussion of a number of change proposals on industry codes.

A major issue associated with the transmission reinforcements connecting the Scottish Islands is that the reinforcements will provide transmission connection to both generation and on-island demand. This gives rise to a number of issues:

- Where transmission reinforcement is required for generation and demand, should connecting generation be given a choice of the security standards associated with the connection?
- If the transmission reinforcements are developed as SQSS customer choice design variation connections, how is on-island demand secured? If this requires maintenance of on-island back-up generation are these costs included within the economics of the different transmission options?
- The TNUoS charges presented here are based upon the proposed offshore charging model, where the costs of transmission connections are targeted on connecting generators since the transmission asset provided is a generation only spur. Where transmission is also used to supply demand should the full cost of transmission assets be targeted at generation? Historically NGET have shared the cost of transmission spurs where they are used by both generation and demand.
- The implementation of S185 could serve to dampen the financial incentives put in place to ensure that, where the generator can influence the choice of transmission investment, the most economic reinforcement scheme is selected.

This report does not discuss these wider regulatory issues further since they are already subject to industry debate. However, the resolution of these issues could have a significant impact upon the transmission reinforcements that take place, and the transmission charges that are levied at island generators, and so could have a significant impact upon the decisions on any s185 scheme.

4 COMPARATOR PROJECTS

In order to inform the decision about the level of transmission discount that might be justified for Scottish Island wind farms under S185 of the Energy Act (2004) it is necessary to examine in detail the relative economics of generic wind farm developments on the Scottish Islands of Shetland, Orkney and Western Isles relative to comparator projects on the mainland situated in relatively close proximity to the islands(Northern and Western Highlands). This work develops generic comparator projects, to analyse the impact of the differences between the locations under study on wind farm project economics.

The comparator projects are designed to be representative of the generic costs incurred at the different locations, without necessarily reflecting the specific costs of the individual projects that are currently under development.

The S185 scheme provides for a reduction on generation TNUoS for transmission connected renewable generation. Thus, it is necessarily restricted in applicability to relatively large scale wind farms, connecting at 132kV or above.

Whist there are a number of operational wind farms on the Scottish Islands, all of these developments are relatively small in scale, with the largest project having a capacity of 8.25MW. There have been larger developments on the mainland in the Northern and Western Highlands, with the Npower Farr project having a capacity of 92MW, although the other developments are significantly smaller in scale.

Since there is a lack of developed projects that could be used to inform the comparator projects, a consultation has been run to gather data from as many companies as possible who are involved with the operation or development of wind farms in the areas of interest. Details of the consultation and the consultation responses are provided in Section 5. This has allowed collection of a wide range of data, including experience from operational wind farms as well as views of project developers.

4.1 Project Scale

It can be seen that most of the proposed wind farm developments on the Scottish Islands are large in scale, ranging from 126MW (Fairwind – Orkney) to 652MW (Barvas Moor – Lewis). The mainland developments tend to be slightly smaller in scale although there are also some large developments on the mainland, with projects up to 180MW capacity.

In developing comparator projects it is interesting to consider whether the development of larger projects on the Scottish Islands is inherent due to their location, and thus that there should be economies of scale associated with developing island projects. Developments on the Scottish Islands have either been very small or very large in scale. This probably reflects the fact that to be developed without a dependence on the transmission connection of the islands to the mainland, projects had to be small enough to be contained within the existing island distribution grids. However, if a wind farm was to be developed that would require transmission connection of the island to the mainland, it would have to be large enough to justify the economics of laying subsea transmission connections with the mainland. This has naturally meant that transmission connected island wind farm projects have focused on relatively large capacity developments.

Whilst the need to justify the economics of subsea transmission developments have focused island developers on large projects, there are also large projects being developed upon the mainland, with 3 projects over 100MW capacity. A large number of projects being developed upon the mainland are around the 20-50MW size, and arguably this size of wind farm would not be developed (individually) upon the islands due to the requirement to economically justify transmission connections. However, it does not appear to be the case that it is inherent in the locations that island wind farms are necessarily larger in scale than those developed upon the mainland. Thus, in developing comparator projects it seems appropriate to assume the same size of development on both the islands and the mainland.

Since all of the island projects under study are >100MW capacity it is appropriate to consider large scale wind farm comparator projects. We have therefore developed an analysis of the economics of comparator projects based upon an assumption of 150MW wind farm capacity.

4.2 Comparator Locations

This work develops detailed economic analysis for wind farm developments on the Scottish mainland and the Orkney, Shetland and Western Isles, further details are provided in Section 6.

Analysis shows that there are relatively significant differences associated with the economics of wind farms on the different Scottish Islands (other than TNUoS charges), and so the analysis investigates a comparator project for each of Shetland, Orkney and Western Isles.

Analysis of mainland wind farms did not show any significant cost differences between developments in the Northern or Western Highlands (other than TNUoS charging differences). Although there may be site specific differences in costs between individual projects, there did not appear to be any significant differences in development costs inherent in the different mainland locations. Thus, we have developed a single mainland comparator project in this analysis.

5 CONSULTATION RESPONSE SUMMARY

This section provides a high level summary to the responses made to the consultation investigation. For completeness, a list of the consultation questions is included in Appendix A.

5.1 Respondents

IPA conducted telephone and email interviews with 12 companies who had an interest in the s185 scheme. Respondents to the survey were:

- E.ON UK
- Fairwind Ltd
- Falck Renewables
- Farm Energy
- Lewis Wind Power/BE
- Npower Renewables
- Renewables Development Company/West Coast Energy
- RJ McLeod
- Scottish Power
- Scottish & Southern Energy
- Viking
- Scottish Renewables Forum

Views were sought on a number of areas that were significant to the study. Not all respondents answered all questions. Responses have been anonymised to protect any commercially confidential data.

5.2 Key Transmission Issues

Respondents were asked to comment on the key issues related to TNUoS charging on the Islands. The majority of respondents saw uncapped TNUoS charging as a significant potential barrier to development.

Question	Response Summary
Would a Transmission Charge Adjustment Scheme to 2024 be likely to have a significant impact on your decision of whether to invest in a development on the Islands?	Most respondents believe that this is likely to have a significant impact and is the single most important factor in the decision making process. A small number of respondents had no plans to develop on the islands and as such the scheme would not impact on their development strategies. One respondent felt that whilst a Transmission Charge Adjustment scheme would have an impact on project economics, it wasn't one of the most significant factors. Some individual respondents had specific comments on the application of a Transmission Charge Adjustment Scheme, such as: - Suggestion that the scheme should extend for 25 years from a project starting operation (i.e. 25 years from 2013 on islands). - Suggestion that the scheme should be extended to include the Highlands as well. - Concerns about the risk inherent in having a subsidy that may be removed in the future and not replaced. - Suggestion that the TNUoS methodology should be reviewed instead of applying a subsidy; for example, by setting generation TNUoS at zero.

Question	Response Summary
What level of Transmission charges do you think would make your wind development on the Orkney/Shetland/W.Isles economically infeasible?	The majority of respondents saw a linkage to mainland charges as appropriate. There was some range in the absolute levels required before projects become economically infeasible: Wind: £30 - 40/kWpa. Marine: £5 - 7/kWpa. Some respondents felt that it was preferable for costs not to be subsidised or capped as it is a risk if continuing subsidy is dependent on political decisions. Alternative suggestions included reform of the TNUoS methodology or making island projects eligible for banded offshore ROCs. One respondent preferred cost reflective banding.
How critical to your investment choices now will it be if a decision is not made in the near future? (in the context that transmission connections may not be available on the Islands until 2014+)	Critical. Most respondents agree that developers must know the decision before signing any contract to build. Otherwise investment decision could be delayed or even that developers would look elsewhere. One respondent estimated that every year of delay adds at least 1% to the required rate of return. Most respondents felt that a decision date of 2008 was required in order to meet project development timescales and utilise any existing connection agreements.
There are a number of potential regulatory options for connecting the islands. Do you have a preference for a particular option, and do you believe this could have an impact upon transmission charges or your decision to develop Island wind projects?	Whilst there was no real consensus on the best approach for connecting the islands, respondents preferred simplicity and a proven approach. It was agreed that it was vital that a decision was made without delay.

Question	Response Summary
To what extent are the levels of current credit cover / Final Sums Liabilities (FSL) a significant issue in terms of the development?	No real consensus as a number of respondents commented on their uncertainty until decisions on level of charging and infrastructure were made. Some respondents commented that recent changes to credit cover calculations were likely to improve the situation. Some individual comments include: - FSL a significant issue regardless of location. - Larger developers may be able to finance FSL more easily as island developments have higher FSL than mainland locations.

5.3 Key Development Issues

Respondents were asked to give high level comments on more general development issues, to highlight broader distinctions between wind project developments on the Islands compared to the nearby mainland of the Highlands.

Question	Response Summary
What do you consider the primary differences, both positive and negative, to be between developing projects on the Islands and in the Northern Highlands?	*Positives to Island Developments:* - Higher Load Factors. - Ease of obtaining planning consents with Shetland specifically identified as having a positive attitude to developments. - Socio-economic/employment benefits (can provide valuable support to vulnerable communities, for example by increasing local job opportunities and possibly helping to reduce migration away from islands). - Strategic benefit of linked investment in wave & tidal. - Very large resources - 1-2GW wind and 5-10GW marine. *Negatives to Island Developments:* - Long cable routes expensive (especially compared to overhead cabling). - Can be difficult achieving planning consent in the Western Isles (environmentally sensitive). - High level of competition for sites. - Lack of availability of labour. - Higher costs associated with supplies/materials. - Longer transmission timescales.
Do you believe there is a difference in the level of risk associated with developing wind projects in Orkney/Shetland/W. Isles/Northern Highlands?	Most respondents agreed that there are higher risks for island developments.

<table>
<tr><th>Question</th><th>Response Summary</th></tr>
<tr><td>What are the main causes of the differences in risk?</td><td>Answers given by respondents included:
- Costs associated with subsea cable (for example, advanced services could be over £1m in Orkney, but under £50k in the Northern Highlands).
- A single subsea cable is potentially less secure and more difficult to maintain (resulting in more downtime).
- Transmission charging.
- O&M costs for turbines & spare parts higher due to higher loads.
- Accessibility and costs associated with moving staff to sites.
- Political risks associated with the continuing length and level of any cap/subsidy.

One respondent noted that there may be positive sides to risk due to the increased community benefits (especially when compared to Southern England for example) which may reduce opposition and planning risks.</td></tr>
<tr><td>Would they impact upon the developer's required returns?</td><td>Split responses. Some respondents believed that higher risks mean that higher returns would be expected (as well as more contingency). However, other developers thought that the additional load factors achievable on the islands would offset the risk resulting in little, if any, difference between island and mainland developments.</td></tr>
<tr><td>Would they influence the final project financing structures in terms of project gearing?</td><td>Consensus was that there would be a marginal difference between the Islands and the Northern Highlands as by this stage in the process everything should be in place without uncertainty. Financing would be impossible if key parameters are not clearly defined.</td></tr>
</table>

Question	Response Summary
Do you see any factors that would influence the scale of wind farm developments on the Islands relative to Northern Highlands locations?	Most respondents expected island developments to be either very small (to meet on-island demand and to use existing infrastructure) or to be very large (to justify infrastructure investment). However, there were some comments that suggested risks associated with very large developments on the island such as difficulties in getting sufficient skilled labour. One respondent commented that at present it is a seller's market for turbines, and that they would expect to need 150+ turbines to secure a manufacturing contract. One respondent felt that the large scale of some proposed developments on the islands may not reflect the ultimate scale of projects, as this might be reduced at the planning stage. They also commented that the larger scale may give added political pressure.

5.4 Detailed Development Issues

Respondents were then asked to go into deeper detail about the extent to which certain development issues were significant factors in differentiating project developments. They were also asked to give detail on the resulting cost differences.

Question	Response Summary
Wind Resource	
Wind Speed/Load Factor	Shetland - prudent 45% - 50% LF (even for large developments). Orkney - 45% - 50% LF. Lewis – 35% - 37% LF (accounting for local losses). Northern Highlands - 35% LF (accounting for local losses). Island developments generally expected to have higher LF than mainland developments.

Question	Response Summary
Turbine Certification	For the Islands would expect either Offshore Grade or JEC Class 1. As a comparator, most of GB and all of Scotland is Class 1 and Europe is Class 2. The higher Load Factors may affect price and/or warranty.
Development Issues	
Planning Permissions	Variability between the islands, with Shetland developments being seen as easier to obtain planning permission than mainland developments whereas Lewis has difficulties due to environmental considerations. In any event, it is seen as easier to obtain planning permission in the Scottish Highlands and Islands than in Southern England. However, most respondents were unsure as to whether there would be a significant difference between the various sites as it can be quite site specific. The change in councils recently may impact on local decisions.
Land Access & Contracts	Varied response with some differences noted due to unique circumstances/sites. Some respondents commented that they believed that Lewis sites had additional complexities due to a high proportion of crofted land which increases the number of parties involved in the process.
Community Benefit	Most respondents consider the community benefit to be in the range £1k-£2k/MW/yr and unlikely to be different between Island and Mainland sites.
Transmission Availability/Timing/Cost	Islands are further behind in transmission queue than mainland. So it is unlikely for new developments to be proposed on the islands until queue sorted out. Some respondents noted that if projects cannot connect until 2016 then a 2024 deadline for the S185 scheme will not be long enough to give them sufficient security, especially as the RO stops in 2027.

Construction Costs	
Transportation Issues	There was some variability in responses: - Some respondents thought that transportation costs would be similar as supplies would be coming from overseas, so as long as there was sufficient port capacity it would be similar on the Islands to the mainland. - A second group of respondents thought that the Islands would be more expensive (possibly 10% more) due to the additional distance and freight time involved in getting supplies to the Islands. - A third group thought that the Islands might actually be cheaper in terms of reduced distances for transportation once supplies were on the islands (as compared to inaccessible mainland sites). Additionally, it was noted that the Western Isles have a sizeable fabricating facility for tower construction which is an advantage over the Northern Highlands.
Civil Engineering	All respondents agreed that aggregates would be locally sourced and quarried as much as possible meaning that costs would likely be similar for islands and mainland. It is expected that the cost of transporting concrete to site would be slightly higher in the Islands, with costs in the Western Isles up 10%-15% over the mainland. Cost premium not known for Shetland and Orkney, but expect Shetland costs to be higher than for Orkney.
Site Geography	Some respondents noted that they expect slightly more accessible sites on islands due to not being as remotely sited as some mainland developments. In general, it was considered that conditions on the islands are not dissimilar to conditions encountered on mainland sites although some respondents noted that Lewis is very boggy which increases construction and maintenance costs (e.g. of roads) which could add up to 30% to the costs of civils when compared to a 'good' mainland site.
Labour Issues	Respondents thought these might be similar although labour costs could be up to 10-20% higher on the islands due to small pool of resources. Some respondents thought labour availability in Orkney and Shetland would be good.

Cost of EPC Contract	Respondents believed that EPC costs would likely be slightly higher on the islands due to increased risk (with a range of 5%-20% higher quoted). The additional costs associated with islands could result in fewer tenderers which may increase costs. Actual costs very site specific however.
Timeline	Respondents felt that the biggest difference is that for islands 3 years could be required for the construction of a transmission cable, which is a significant difference to mainland sites which would only require overhead reinforcement (if anything). Construction could take longer on islands if shipping was delayed due to poor weather and adverse weather (which is expected to be more likely on the islands) could result in a marginally longer construction phase.
Local Grid Connection Issues	Comments from developers suggest that they are struggling with distribution connections. - Could be delays on islands if additional substations required. - Regional Power Zones (RPZ) may be easier on the Islands. - Beauly-Denny upgrade is expected to make a big difference to the mainland situation. - One respondent noted that Lewis would require a transmission connection or upgrade to the existing system to allow for additional capacity which would not be required on the mainland.

Operating Costs	
Maintenance	Respondents agreed that a dedicated team would be need on islands for larger schemes (>10 turbines was the 'rule of thumb'). On the mainland, it was expected that one team could be shared amongst several wind farms which would reduce costs. Additionally, with the higher wind speeds on the islands, the turbines are expected to require more regular maintenance which would also increase costs. Also, the higher load factor means more hours running and reduces the window for ongoing operational maintenance. Estimates of cost premium for the islands over mainland vary from 10%-25%, with mainland O&M around £17k/MW/yr.
Availability	Most respondents agreed that a subsea cable is less secure than an overhead cable which would increase down-time in the event of a fault as well as have higher repair costs.
Contractual Issues	It is believed that turbine manufacture is a seller's market and that turbine developers can pick and choose at the moment so they are likely to attach a premium to unpredictable/unique developments - such as high wind island developments, or extremely mountainous sites. Therefore, island developments may have higher contract costs for turbines over the mainland, except for the most unusual mainland sites.
Land Costs	Respondents didn't expect there to be much regional difference as fairly strong competition exists everywhere (although site specific costs could vary considerably). A range of different costs were quoted: £3-£4/MWh or £1000/turbine/yr
Other Factors	Capital expenditure is dependant on infrastructure and labour availability. Some responses indicated that there is no reason why this shouldn't be similar on the islands to the mainland. Other responses indicate that capex will be 10% to 20% higher due to remoteness.
Overall Difference	Most respondents thought the economics of island sites to be broadly equivalent to mainland sites as the benefits of higher load factor are offset by higher installation and manpower costs, and longer periods of grid unavailability (if island connections are developed on a non-firm basis).

5.5 Off-take Contracts

Question	Response Summary
What options would you expect for length of contract?	Respondents agreed that this would generally be 10-15 years (or project life). As noted above, it was commented that if islands are not connected before 2014, and S185 expires in 2024, then there might be a mismatch in when the contract expires and when the scheme expires which could therefore limit the contract length.
Would you expect these contracts be pegged to market values?	Generally yes.
Would you look for fixed price contracts of floor price levels?	Most respondents believed that contracts would have Floor price levels.
Is there any difference between Northern Highland and Island Projects?	Most respondents think these would be similar between Islands and Highlands. Comments from individual respondents include: - May have less leeway for negotiation on islands if transmission charges are high. - Risk of unavailability (of cable) might result in a form of spill contract. - There may need to be solutions if there are concerns related to maintenance as there is limited scope for this in standard contract. - Off-take contracts will be similar to mainland other than likely higher transmission losses. – The higher cost of the island schemes would require the contract to be structured to provide higher levels of certainty than might be required for a less risky project.

5.6 Other Comments

Some respondents made additional comments or statements that do not fit neatly into the above categories:

- The islands may also be a good location for marine renewables, and this should be taken into account.
- Shetland's demand is met by electricity sold at national tariffs. However, its cost of production is considerably more than what is charged to consumers as the bulk comes from an ageing diesel/heavy bunker fuelled generation plant. The difference between the cost of production and what is recouped from consumers is made up by the national consumer base. This subsidy is required by law and is rising in line with the price of the fuel burned to produce the electricity. If Shetland does not achieve a grid connection to the UK grid then the existing generation plant in Shetland will need to be replaced and as such a perpetual subsidy (in the order of £10-£20 million a year) will be required to keep ongoing island electricity tariffs down.

6 WIND FARM ECONOMICS

This section discusses the factors that affect the economics of a potential wind farm and identifies the components which are expected to vary between the project locations under consideration (Mainland, Orkney, Shetland and the Western Isles). All numbers quoted are for a 150MW farm.

6.1 Wind Resource

A major parameter in the economics of a potential wind farm is the expected Capacity Factor, or Load Factor of the project, which dictates the amount of electricity that can be produced.

The capacity factor of a wind farm is a function of the wind speed in the area of development and the power curve of the particular wind turbines employed. The wind resource varies throughout the UK, with evidence that the Islands of Shetland and Orkney have one of the highest wind resources in the UK. This would suggest that the capacity factors on the Islands of Shetland and Orkney would be higher than elsewhere in the UK. In addition, the potential capacity factors will also be affected by the availability of the turbines and array and site losses, which serve to reduce the actual amount of electricity for sale into the grid.

We have taken data from a number of sources to build up a picture of expected load factors for the areas under consideration. These are discussed below.

- **NOABL Database:** Data from the Numerical Objective Analysis of Boundary Layer (NOABL) database, combined with typical power curves for wind turbines was used to provide a wind power output profile for each area under consideration. This data indicated a range of expected load factors for the area under consideration.
- **ROC Register:** Over the last few years, experience of operating wind farms on the Islands and the mainland has been gained and, from examination of data from Ofgem's ROC Register, capacity factors for the areas under consideration can be estimated. This data indicates that there are differences between the wind resource on the Islands and the Northern Highlands.
- **REGO Database:** Implemented in 2003, the Renewable Energy Guarantee of Origin (REGO) electronic certificate system enables producers of renewable-sourced electricity that is eligible under the EU Renewables Directive to be issued with evidence (guarantees) that their electricity is indeed renewable. Examination of this data provides an estimation of achieved load factors for wind farms throughout the UK. Again, this data indicates that there are differences between the wind resource on the Islands and the Northern Highlands.
- **Consultation:** Consultation responses also which suggested that island projects are generally expected to have higher load factors than mainland projects.

The table below summarises the range of load factors extracted, or calculated from the various data sources.

Table 13: Representative Load Factors

	Mainland	Orkney	Shetland	W.Isles
NOABL	32.9%	41.8%	49.7%	40.1%
ROC Register	Data from 8 wind farms ranging in size from small to 92MW. Little difference between Northern and Western areas, excepting the Forss scheme which has an average capacity factor of 45%. Average of projects (excluding Forss) is 29.3%.	Very patchy data for 6 small wind farms - can achieve similar LFs to Shetland.	Data from Burradale 1 & 2 gives averages of 51% - 47%.	No Data
REGO Register	Forss scheme, 47.5% Average of projects (excluding Forss) is 30.4%	Patchy data but capacity factors of 43.8% and 48.5% achieved.	Data from Burradale 1 gives 53.7%.	No Data
Consultation	35%	45% - 50%	45% - 50%	35% - 37%
Other			Viking project website suggests 50%	Lewis Wind Farm web site suggests 35%
Used in Analysis	**We have used the average of data from the ROC and REGO databases (excluding the Forss project) - 30%**	**As there is evidence to suggest that Orkney can achieve similar load factors to Shetland we have used the same value - 49%**	**We have used the average of the data from the ROC Register - 49%**	**In the absence of actual data we have used the data from the Lewis Wind Farm website - 35%**

Note: Data from both the ROC Register and the REGO Register indicate that the Forss wind farm (also known as Hill of Lybster), on the mainland, has achieved load factors in excess of 40%. However, the other seven existing projects in the Northern and Western Highlands have outturn averages of around 30%. For our mainland comparator project we have taken the average of the majority of the projects and assumed a load factor of 30%.

6.2 Pre-Construction Costs

Pre-construction costs for a wind farm typically comprise a Feasibility Study, an Environmental Impact Assessment and a planning application.

These costs tend not to vary significantly between projects of different sizes, although there may be some economies of scale to be made, and are unlikely to vary between the areas under consideration. We have therefore taken typical development costs based on the consortium's experience in developing these types of projects and maintained these across all the projects under investigation[5]. These are assumed to total £5/kW.

6.3 Transmission Connection Costs

Transmission connection costs are charged to developers both as one-off costs and as annual charges. Each of these costs are discussed below, along with the levels of charges assumed in this study.

6.3.1 Final Sums Liability

A generator with a connection agreement has to provide security cover against the costs of deeper transmission reinforcement, undertaken by the Transmission Owner (TO). Historically the full costs of the capital expenditure have been underwritten through the Final Sums Liability (FSL) framework. However CAP131, due for implementation in April 08, allows for a User Commitment Model where the liability is related to the zonal TNUoS charges.

The contracted generation on the Islands has to provide credit cover to underwrite the capital costs (including subsea cables) as they are incurred by the TO; the costs of this credit cover will be significant.

We have assumed the costs of providing Final Sums Liability cover to be approximately equal to 5% of the infrastructure cost, which will be shared between the contracted generation on each island pro-rated to the generation capacity. The costs of FSL will be significantly lower in the event that a single circuit connection is developed, rather than a double circuit.

Using the costs provided by SHETL, detailed in Section 3.1.3, we have estimated the following Final Sums Liability costs.

[5] There is some evidence to suggest that planning costs would be lower on Orkney and Shetland, however the consultation was not conclusive.

Table 14: Final Sums Liability Costs

	Mainland	Orkney	Shetland	W. Isles
Single Circuit Cost, £/kW	4.7	N/A[6]	21.55	13.58
Double Circuit Cost, £/kW	4.7	34.13	43.00	27.17

6.3.2 Contribution to Transmission Connection CAPEX

In the cases where there is circuit redundancy and the capacity exceeds the average redundancy for the onshore transmission system of 80%, the indicative charge is derived using the existing onshore Locational Security Factor of 1.8. This applies to the double circuit transmission development solutions and requires developers to pay a capital contribution equivalent to 10% of the transmission asset costs. In the modelling we assume that this cost is allocated on a £/kW basis, as a one-off capital charge – the most pessimistic case and would justify the most S185 support.

Using capital costs supplied by SHETL, and the expected capacity to be constructed on each Island, we have calculated levels of contribution to the transmission connection CAPEX to be paid by each of the Island projects under consideration, in the event of connection with a double circuit.

Table 15: Contribution To Transmission Connection CAPEX

	Mainland	Orkney	Shetland	W. Isles
Double Circuit Cost, £/kW		68.25	86.0	59.27

6.3.3 Transmission Network Use of System

TNUoS Charges have been discussed earlier in Section 3.2. These are annual charges, based on the connected capacity.

For the mainland comparator project we have used a TNUoS charge equal to the average of the values provided by NGET for the three landing points of the subsea cables.

Table 16: Transmission Network Use of System Charges

	Mainland	Orkney	Shetland	W. Isles
Single Circuit Cost, £/kW/annum	22.09	N/A[7]	55.46	46.56
Double Circuit Cost, £/kW/annum	22.09	61.31	84.17	66.39

[6] Only the option of a double cable is being pursued for the Orkney connection.
[7] Only the option of a double cable is being pursued for the Orkney connection.

6.3.4 Transmission Connection Costs

There are currently significant costs associated with Island infrastructure development, including the costs of connections between clusters of wind turbines and the convertor stations on both the mainland and the Islands. It is currently unclear exactly how these costs will be treated, but we have assumed in this analysis that they have been categorised as Transmission Connection Costs and charged accordingly. These costs will vary between the Islands.

For Shetland and the Western Isles we have taken costs supplied by SHETL and annualised these using a 40 year term at a rate of 8%. We assume that the costs on Orkney are the same as those on the mainland, which are assumed to be lower than those on Shetland and the Western Isles.

Table 17: Transmission Connection Costs

	Mainland	Orkney	Shetland	W. Isles
Single and Double Circuit Cost, £/kW/annum	1.5	1.5	5.34	2.29

6.4 Capital Costs

This study is focused upon identifying cost differences between the Scottish Islands and mainland developments, and so detailed investigation has been undertaken into potential differences in cost drivers.

The main components of the Capex costs have been identified in the following list, with the main cost differentials being identified as the cost of concrete, the cost of labour and turbine transportation & erection.

- Concrete;
- Labour;
- Other Civils;
- Turbine Cost;
- Turbine Transportation & Erection; and
- Local Connection Cost;

Discussion on each of the components follows.

6.4.1 Concrete

Consultation responses indicated that the limited supplies of concrete on the Islands could mean uplifts of between 10% and 30% compared to those on the mainland (with the highest uplift being for Shetland).

The following table details the assumed cost differentials from the mainland.

Table 18: Concrete costs

	Mainland	Orkney	Shetland	W. Isles
Concrete Cost, £/kW	84	+15%	+20%	+15%

6.4.2 Labour

Responses to the consultation indicated that labour costs could be 10% - 20% higher on the Islands due to the small pool of local resources and the requirement to bring in construction workers and accommodate them over the construction period.

The following table details the assumed cost differentials from the mainland.

Table 19: Labour costs

	Mainland	Orkney	Shetland	W. Isles
Labour Cost, £/kW	20	+10%	+15%	+10%

6.4.3 Other Civils

Other civils, including the cost of constructing access roads, are likely to utilise locally quarried aggregates as much as possible and so are unlikely to vary between the areas under consideration. We have assumed that they remain constant between the comparator projects, at £81/kW.

6.4.4 Turbine Costs

The costs are assumed to remain constant irrespective of the location of the development, at £661/kW. Note that this is excluding the cost of transportation & erection.

6.4.5 Turbine Transportation & Erection

The majority of turbines are currently not supplied from the UK and are already shipped to the UK. The difference in costs of shipping to mainland Northern Scotland or the islands is unlikely to be significant. For example, turbines for projects in Northern Scotland have been and continue to be landed at Wick Harbour. The relative distance between Wick and Orkney/Shetland is unlikely to give rise to significant cost differences considering turbines are likely to be shipped from Europe; likewise for the Western Isles.

However, the cost to source transportation and cranes on the islands can be assumed to be higher as this will need to include transportation from the mainland. Typically, crane hire contracts may include a large initial payment with smaller subsequent daily hire payments. The initial payments include for sourcing the crane to site and this payment could be expected to be larger for an island site.

The following table details the assumed cost differentials from the mainland.

Table 20: Turbine Transportation & Erection costs

	Mainland	Orkney	Shetland	W. Isles
Turbine Transportation & Erection Cost, £/kW	58	+15%	+20%	+15%

6.4.6 Local Connection Costs

In addition to the Island transmission development costs discussed in Section 6.3.4 wind farm developers will have to pay for their own assets which are necessary to connect to the Transmission system. These are termed 'local connection costs' and have been assumed to remain constant between the areas under consideration at a cost of £152/kW.

6.4.7 Capital Costs Summary

Overall the capital costs are approximately 2.3% higher than the mainland for Orkney and the Western Isles, and approximately 3% higher for Shetland, as shown in the following table.

Table 21: Capital Costs

£/kW	Mainland	Orkney	Shetland	W. Isles
Concrete	84	97	101	97
Labour	20	22	23	22
Other Civils	81	81	81	81
Turbine	661	661	661	661
Transportation & Erection	58	66.7	69.6	66.7
Local Connection	152	152	152	152
Total	1,056	1,080	1,088	1,080

These mainland costs are broadly consistent with the DTI's earlier report 'Impact of banding the Renewables Obligation – Costs of electricity production', published in April 2007.

6.5 Fixed Operating Costs

Operating costs comprise a number of components, the majority of which the consultation responses indicated will remain constant between the areas under consideration. These are listed below.

- Insurance & Rates;
- Lease Payments;
- Community Benefit Payments; and
- Operation & Maintenance;

The only component where we have assumed there will be a significant variation is the Operation and Maintenance cost.

These costs will be independent of whether the Islands are connected to the mainland either by a single circuit or a double circuit.

6.5.1 Operation & Maintenance

The turbines will probably undergo the same (typically 6-monthly) maintenance regardless of location and the costs for this will be similar to or slightly higher than any mainland site. However, the higher wind speeds may result in increased unscheduled maintenance when compared to lower wind speed sites on the mainland.

Availability will mainly be influenced by spare part availability and suitable weather windows to undertake remedial work. Smaller spare parts can be expected to be stocked locally either on site or in a service depot and island/mainland availability is unlikely to be influenced by availability of small spare parts. As with most sites, larger spare parts are typically shipped direct from the manufacturers and long lead times result in reduced availability. Long lead times should give time for transport/cranes to be scheduled but it would be prudent to assume that, in addition to higher costs for transporting/erecting individual components to/on islands, higher wind speeds on the islands may result in delays when replacing components and that both availability and costs will be negatively impacted.

Therefore, to account for these delays we have reduced the availability of the turbines, from 97% on the mainland to 95% on the Islands.

In addition, to account for the higher wind speeds on the islands, we have assumed that the cost of Operation and Maintenance will be 25% higher on Orkney and Shetland, than on the mainland, and 10% higher on the Western Isles.

6.5.2 Overall Fixed Operating Costs (excluding Transmission Costs)

The table below shows the overall fixed operating costs for each of the projects under consideration.

Table 22: Annual Overall Fixed Operating Costs

	Mainland	Orkney	Shetland	W. Isles
Annual Fixed Operating Costs, £/kW	40	43	43	41

6.6 Variable Operating Costs

In addition to the Fixed Operating Costs, identified above, the operation of a wind farm will incur a number of other charges, which are dependent on the amount of electricity generated. These are

- Balancing Services Use of System Charges (BSUoS);
- Residual Cashflow Reallocation Cashflow (RCRC); and
- Central System Charges

BSUoS charges for the duration of the study period have been extracted from IPA's latest PowerView forecast – see Section 6.7.

The level of these charges will not vary between the projects under consideration and are shown in the following table.

Table 23: Variable Operating Costs

Component	Level, £/MWh
BSUoS	0.96
RCRC	0.037
Central System Charges	0.1
Total	1.097

6.7 Revenues

Revenues to wind farms are determined by several components: electricity price, ROC price and CCL income.

IPA produce, every three months, an update of forecast GB electricity and ROC prices for the next 25 years under Base, Low and High cases, which are encompassed in our PowerView product.

PowerView uses IPA's proprietary model, ECLIPSE (Emissions Constraints and Policy Interactions in Power System Economics) that has been specifically designed to capture the issues that will impact upon the power industry over the next 10-25 years.

ECLIPSE has been specifically designed to model the macroeconomics of the power industry and to capture the complex interactions between market developments, governmental policy and regulatory instruments, in shaping the industry.

ECLIPSE simulates power station despatch, capturing the interactions between the major market and policy developments.

We have used our latest forecasts (Jan 08) in determining project revenues.

The revenue streams are discussed in more detail below.

6.7.1 Electricity Price

Generators will sell the electricity produced to a supplier and will receive a price for this electricity. Our analysis includes revenues from the PowerView Base, Low and High power price cases.

6.7.2 ROC Price

Electricity generated from renewable sources is eligible to receive Renewable Obligation Certificates (ROCs). Currently, wind projects receive 1 ROC for each MWh of electricity generated and this is not planned to change under the Government's proposed banding system.

In PowerView the assumptions on the level and duration of the RO vary between the scenarios:

In the Base and High ROC Price Cases we assume that the RO, or other equivalent support mechanism, continues to 2032, with an increasing obligation, rising from a maximum of 20% in 2020 to a maximum of 30% at the end of the period. This is a difference from the current proposals for the Obligation, which have a maximum obligation level of 20% by 2020, remaining at that level until the end of the Obligation period in March 2027.

Under the Low ROC Price Case we assume that the Obligation follows the current proposals and ceases in March 2027 with the maximum level remaining at 20% of energy supplied from 2020 to the end of the Obligation period.

Our analysis includes revenues from the PowerView Base, Low and High ROC price cases.

6.7.3 CCL

Electricity from renewable sources also receives Levy Exemption Certificates which can be sold in the market. CCL is currently set at £4.41/MWh for 2007/08 and is due to increase with RPI.

We have also taken this revenue stream into account when determining the total revenues for each project.

6.7.4 Typical Contracts

Many projects will enter into long-term contracts for the offtake of the electricity, ROCs and CCL with a supplier. However, these contracts tend to be project specific, varying in level and length from project to project.

The consultation responses indicated that contracts were generally being offered for 10-15 years although it was noted that if islands are not connected before 2014, and S185 expires in 2024, then there might be a mismatch in when the contract expires and when the scheme expires which could therefore limit the contract length.

It should be noted that over the last few years the trend has been for shorter term contracts.

It was expected that these contracts will be pegged to market values with developers mostly looking for floor prices and most respondents thinking that there would not be much difference between contracts for Island projects and mainland projects.

In our modelling we assume that the projects receive the same prices for their output, independent of their location. Through discussions with suppliers we have assumed contract levels as detailed in the following table.

Table 24: Offtake Contract Data

Revenue Component	% of Full Market Value
Market Power Price	95%
CCL	97%
ROC Buyout	93%
ROC Recycle	100%

6.8 Development Risk

Respondents to the consultation implied that there could be higher risks on the Islands, the main ones being the costs of advance services (associated with pre-development costs of the cable connections to the islands), transmission charging and higher costs of O&M for the turbines and spares. All these costs have been modelled separately and discussed earlier in this section.

They perceived that, because of these higher risks, developers would expect higher returns, although no absolute levels were indicated. There was no evidence of variations between the returns required for the different Islands.

7 FINANCIAL ANALYSIS

This section provides a description of the financial anlaysis undertaken to determine the overall differences in project costs and benefits in the different locations.

IPA's generic renewable energy financial asset model REFER (Renewable Energy Financer) was used to support this task. Financial asset models were constructed for the projects to identify the impact upon the projects of differences in project costs, and project revenues.

7.1 Financial Assumptions

In addition to the cost and revenue assumptions, discussed in Section 6 above, we have applied various economic assumptions to the asset models. These are discussed briefly below.

7.1.1 External Parameters

In constructing the financial model we have used several parameters, reflecting external economic factors. These are detailed below.

Bank of England Interest Rate: The current cash interest rate, published by the Bank of England is 5.50% and this is the rate we assume in the models.

Inflation: Forecasts of inflation for 2008 to 2011 have been sourced from The Treasury[8] and applied in our models.

Wage Inflation: The Annual Earnings Index over the year to Nov 07 was 4.2%[9]. We have applied this annual increase over the period.

Tax Rate: The corporation tax rate from 2008 of 28% has been applied.

Capital Allowances: Capital allowances of 20% on a reducing balance basis.

Economic Lifetime: An economic lifetime of 20 years has been assumed.

7.1.2 Financing

For each of the projects under consideration we have calculated the level of debt that the project can sustain. This has been based on financing measures that debt providers apply.

There are many different financing deals in the market and, through discussions with debt providers, we have attempted to construct typical project financing structures.

[8] Forecasts for the UK Economy: A comparison of independent forecasts. Macroeconomic Prospect Team, HM Treasury, November 2007.
[9] National Statistics Online 16-01-08 – Average Earnings

Loan Repayment Period: Typically loans for wind farms last for 15 years and this is what we have assumed in our models.

Interest Rate on Debt: Following discussions with renewable energy financiers we assume that the interest rate on debt is at a premium of 1.2 percentage points above the cash interest rate.

Level of Debt: For each of the projects under consideration we have calculated the level of debt that the project can sustain. This has been calculated by adjusting the level of debt in order to maintain the average Debt Service Cover Ratio[10] of the project between 1.3 and 1.35 over the first five years of operation.

In calculating the level of debt that a project can support we have used the P50 capacity factor for the project and the Low Power and ROC Price scenarios.

7.2 Financial Model

For each of the projects under investigation we have constructed a financial model and measured the financial returns of the project in terms of the Equity Internal Rate of Return (IRR).

For each project, we have investigated the equity IRR and levelised costs under Base, High and Low power and ROC price assumptions. We have investigated this range under both connection options - single circuit and double circuit, excepting Orkney where the only option being progressed is for a double circuit.

The following assumptions are common to all the models of the projects under investigation.

- 150MW project;
- First electricity is generated in 2013; and
- The current transmission losses scheme, with losses allocated uniformly across all regions in GB, is in operation.

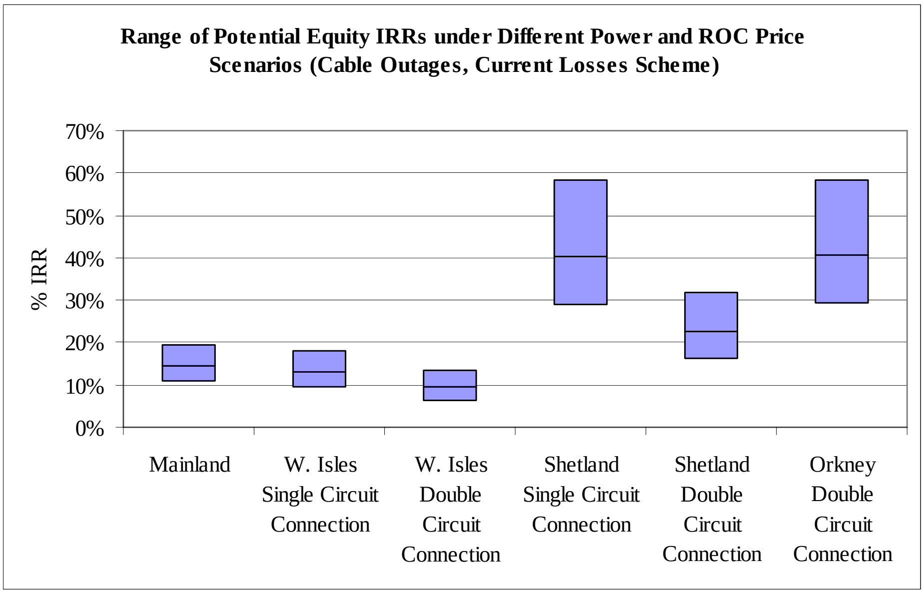
7.2.1 Equity IRR

The corresponding ranges of equity IRRs for each of the projects are shown in the following figure under the assumed range of power and ROC prices.

Note that the IRRs are presented in nominal terms, accounting for inflation effects.

[10] The amount of cash flow available to meet annual interest and principal payments on debt.

Figure 4: Range of Expected Equity IRRs



Mainland

The modelling suggests that mainland projects will earn returns of between 11% and 19% for investors, likely to be sufficient to attract developers.

Western Isles

With a single circuit connection, the Western Isles project has lower returns than the mainland project (between 9.6% and 17.9%), reflecting insufficient uplift on the wind resource to compensate for the higher transmission, capex and operational costs. This is likely to be towards the lower end of investors expectations.

The return on investment is significantly lower with a double circuit connection (6.2% - 13.4%), at best at the lower end of expected returns of an investor and may be too low to attract investment.

This suggests that the introduction of a s185 scheme for the Western Isles might be required to stimulate project development.

Shetland

The modelling suggests that the investor returns on Shetland will be significantly higher than a similar project on the mainland. This is due to the increased capacity factors which provide significant additional income to the projects, outweighing the increased capital and operational costs.

With the single circuit configuration the returns are within the range 29% - 58.2% and, even assuming a double circuit connection, returns of between 16.2% and 31.9% are indicated. These are likely to be sufficient to attract development without the requirement for a s185 scheme.

Orkney

Developers on Orkney would see the highest returns of all the projects (29.8% - 58%) due to the lower levels of costs than Shetland and the high capacity factors. It should be noted that there is some uncertainty over the capacity factors achieved on Orkney and the effect of varying this parameter is investigated further in Section 7.3.

The equity IRR for the projects under the Base Case Power and ROC Price scenarios is shown in the following table.

Table 25: Equity IRR Under Base Case Power and ROC Price Scenarios

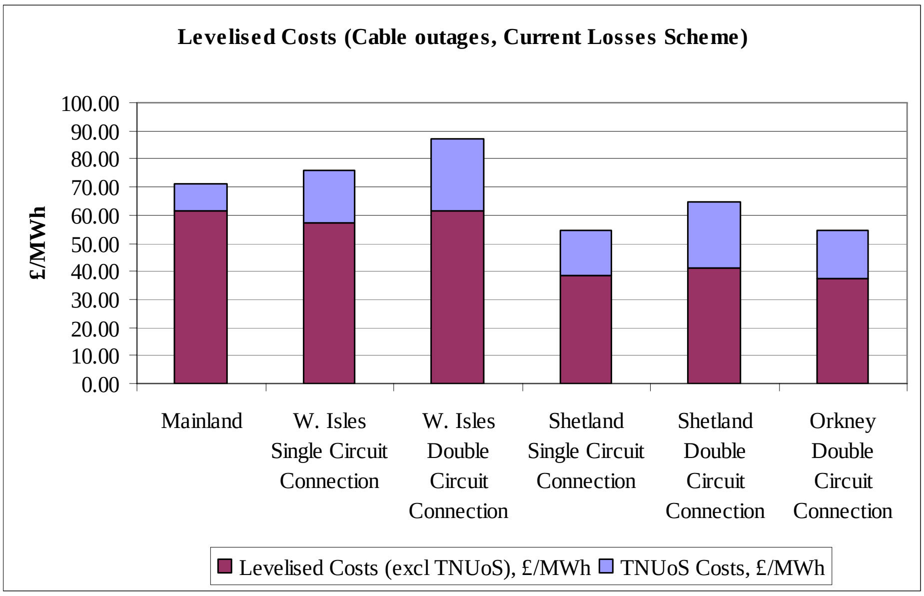
	Mainland	Orkney	Shetland	W. Isles
Single Circuit, %	14.6	N/A[11]	40.3	13.2
Double Circuit, %	14.6	40.5	22.7	9.5

7.2.2 Levelised Costs

In addition to the equity IRR of the projects we have calculated their levelised costs.

Information available in the public domain indicates that developers would expect returns of at least 16% for Shetland, although it is recognised that this level will be dependent on the type of developer (vertically integrated power companies might require lower returns than private investors). We have therefore used an equity return of 16% in calculating the levelised costs. These are shown in the following figure.

Figure 5: Levelised Costs



Mainland

Levelised costs for the mainland project outturns around £70/MWh.

[11] Only the option of a double cable is being pursued for the Orkney connection.

Western Isles

Under a single circuit connection, the levelised costs for a project on the Western Isles is around £75/MWh, increasing to £87/MWh with a double circuit connection.

Shetland

The levelised costs for Shetland are around £55/MWh under a single circuit connection, rising to £65/MWh under a double circuit connection.

Orkney

Levelised costs outturn around £55/MWh for projects on the Orkneys.

The levelised costs for the projects are shown in the following table.

Table 26: Levelised Costs Under Base Case Power and ROC Price Scenarios

	Mainland	Orkney	Shetland	W. Isles
Single Circuit, £/MWh	71.28	N/A[12]	54.69	75.73
Double Circuit, £/MWh	71.28	54.38	64.63	87.23

7.3 Sensitivity Analysis

This section considers the robustness of the results of the financial modeling to changes in key parameter values.

7.3.1 Assumptions

For the sensitivity analysis the following assumptions have been made:

- Base Case Power and ROC Price scenarios;
- The Western Isles connection is a single cable;
- The Shetland connection is a single cable;
- The Orkney connection is a double cable; and
- In all cases, only the variable in question is altered – all other parameters remain unchanged from the base case position.

7.3.2 Key Parameters

The sensitivity analysis focuses on parameters where there are potential cost differences between the regions and looks at the impact of uncertainty in the value of these parameters on the project economics. Some of these will reflect site specific issues. Therefore, variables such as power prices and inflation, which are constant across all comparator projects and are not differentiating factors, are not investigated in the sensitivity analysis.

[12] Only the option of a double cable is being pursued for the Orkney connection.

The sensitivity analysis was undertaken on the following parameters and ranges:

- **Pre-Construction Costs:** There could be considerable uncertainty in the development costs across all comparator projects with a range of +/- 20% being considered a credible range for the investigation.
- **Capital Costs**: There is some variability expected in the capital costs, some of which are region specific (such as transportation, access road construction and local connection costs). The turbines themselves have been excluded as it is assumed that the turbine cost is independent of the region and as such is not a differentiating factor. As the local connection costs are quite significant, the sensitivity analysis considers the impact of changing the capital costs both including and excluding altering the local connection costs. A range of +/- 20% has been used, which is expected to be a credible range of expected values.
- **Operating Costs**: The consultation suggested that there was some uncertainty around the operating costs and how these might vary between regions. As such a range of +/- 20% of the base assumed values is used and is considered a credible range of possible values.
- **Capacity Factor**: There is some uncertainty surrounding the likely capacity factor that could be achieved in each of the regions, as discussed in Section 6.1. The ranges used in the sensitivity analysis for the mainland and the Western Isles are quite small, reflecting the confidence in the expected capacity factors. The ranges for Orkney and Shetland are much wider, reflecting greater uncertainty in the achievable wind speeds in these regions.
- **Zonal Transmission Losses**: There have been a number of BSC modification proposals seeking to change the charging for transmission losses from the current postage stamp charge to a zonal charging methodology. The impact of this change is explored separately in Section 7.3.4.

The ranges used in the sensitivity analysis are summarised in Figure 6 below:

Figure 6: Parameter Ranges by Comparator Project

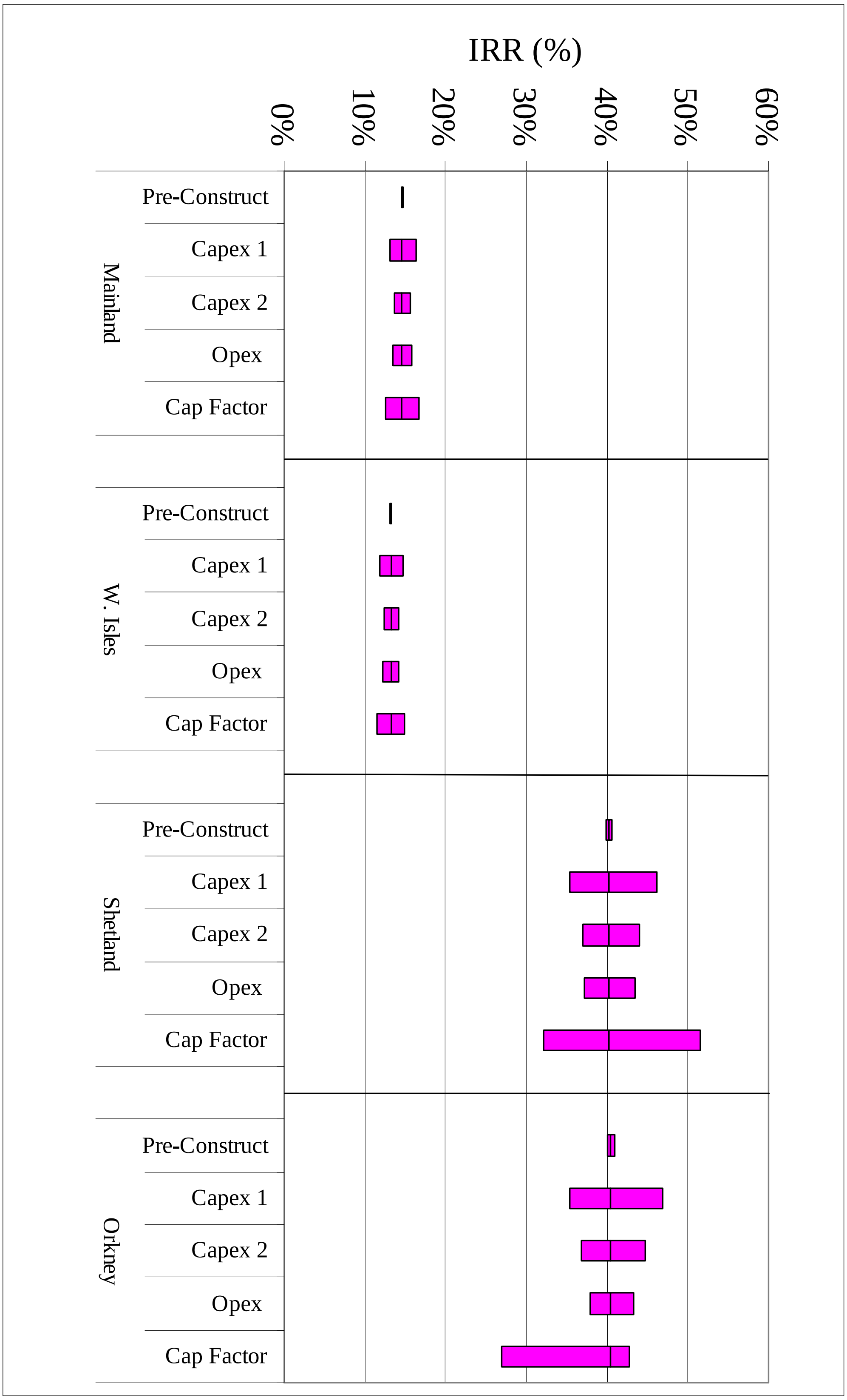
Category	Mainland	Western Isles	Shetland	Orkney
Pre-Construction Costs	+/- 20%	+/- 20%	+/- 20%	+/- 20%
Capital Costs (excl. Turbines)	+/- 20%	+/- 20%	+/- 20%	+/- 20%
Capital Costs (excl. Turbines & local Connection Costs	+/- 20%	+/- 20%	+/- 20%	+/- 20%
Operating Costs	+/- 20%	+/- 20%	+/- 20%	+/- 20%
Capacity Factor	28% - 32%	33% - 37%	45% - 54%	42% - 50%

7.3.3 Sensitivity Analysis Results

The results of the sensitivity analysis are shown in Figure 7 for each comparator project and for each parameter, with power and ROC prices held constant at the base case assumptions throughout the analyses. The main conclusions from this analysis are:

- The most significant factor impacting on the project economics is the Capacity Factor.
- Capacity factor uncertainty results in the greatest variability in the IRR of all the different parameters. Whilst this is most obvious in Orkney and Shetland where the capacity factor uncertainty is highest, it is also true in the mainland and Western Isles, where the range of capacity factors used is relatively tight.
- Across all comparator projects, the equity IRR is very robust to variability in the pre-construction costs. This is because the pre-construction costs only represent a very small proportion of the costs of a project over its lifetime.
- Changes to capital costs (excluding costs to turbines and local connection costs) result in similar magnitudes of variability in the IRR to changes to the operating costs.
- Across all parameters, Orkney and Shetland have much greater variability in resulting IRR than either the mainland or the Western Isles due to the much higher costs and wind speed uncertainty associated with these projects.

Figure 7: Equity IRR Sensitivity by Parameter[13]



[13] Note: Capex 1 refers to all Capital Costs excluding the turbines; Capex 2 refers to all Capital Costs excluding the turbines and the local connection costs.

7.3.4 Zonal Transmission Losses

There have been a number of BSC modification proposals (see Table 27) seeking to change the charging for transmission losses from the current postage stamp charge to a zonal charging methodology.

The BSC panel considered all of these modification proposals (and alternative proposals) and concluded that none of the modifications should be made. The proposals went to Ofgem who have published an impact assessment and consultation, and in June 2007 published a consultation on a ‘minded to’ decision to approve P203 with an implementation date of 1 October 2008, and reject the other proposals. However, on 14 September Ofgem published an open letter effectively delaying a decision on zonal losses. It states that it has considered responses to the consultation, some of which considered Ofgem had placed too much weight on the quantitative analysis of the schemes in coming to a minded to decision. Ofgem is planning to review the analysis of the schemes, with a view to making a decision by Spring 2008. Any scheme would therefore have a later implementation date than October 2008.

Teesside Power, Immingham CHP, Drax Power and British Energy have taken Ofgem to court over the proposed introduction of zonal transmission system losses. The judicial review is on a legal technicality – specifically whether the proposed rule change could be implemented other than in accordance with the proposed implementation date timetable set out in the Final Modification Report of the BSC panel. It is expected that a High Court Hearing will be set for the end of February 2008.

In the event that any of the proposals are approved by the Authority, it is possible that the decision could be appealed to the Competition Commission.

Table 27: Transmission Losses Modifications

Modification	Description
P198	Zonal Transmission Losses Scheme
P200	Zonal Transmission Losses Scheme with Transitional Scheme
P203	Seasonal Zonal Transmission Losses Scheme
P204	Scaled Zonal Transmission Losses

In this section, the impact of any zonal transmission losses scheme on the financial returns in the different regions has been assessed.

The zonal transmission losses assumed in the analysis are a combination of the following two factors:

- **Zonal Loss Factors:** These have been taken from the Impact Assessment[14] (although it should be noted that the TLMs published in the document appear to only be the locational losses – fixed losses have also been included within the analysis). All 3 island regions,

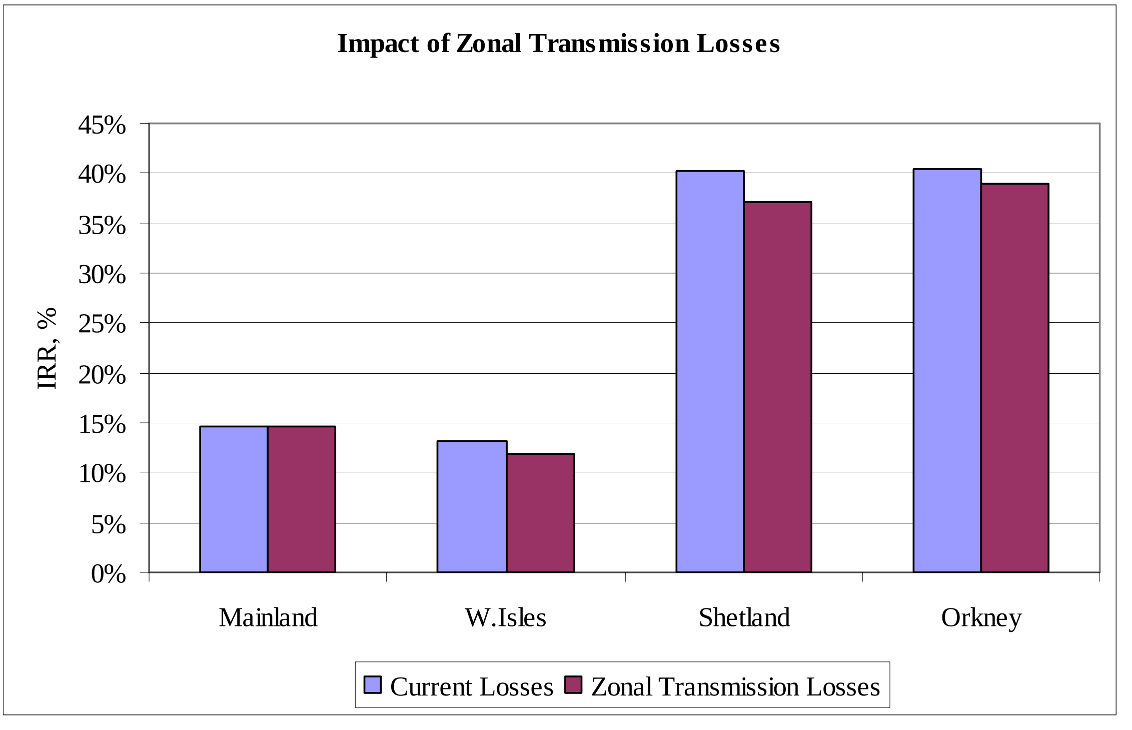
[14] Zonal transmission losses – assessment of proposals to modify the BSC, Ofgem 23/2/2007

and the northern highlands mainland fall in the same zone (North of Scotland) and have the same zonal loss factor of 0.977.

- **Cable Losses**: Cable(s) connecting the Scottish islands to the mainland would give rise to transmission losses, as described in Section 3.1.3. It is assumed in this study that all of these losses are allocated zonally. This is likely to be a worst case scenario as the methodology could mean not all cable losses allocated to zones, but may be partially absorbed into fixed losses.

The projected impact on equity IRR of introducing a zonal transmission losses scheme is shown in Figure 8. For each comparator project the IRR is lower when zonal losses are applied, with Shetland being impacted the most, with the equity IRR decreasing from 40.3% to 37.1% reflecting higher cable losses.

Figure 8: Zonal Transmission Losses



7.3.5 Sensitivity Analysis Conclusions

The following conclusions are made on the analysis of costs, capacity factors and transmission loss schemes:

- The most significant factor affecting the project economics is the capacity factor.
- There is a higher level of uncertainty surrounding the capacity factor on the islands of Shetland and Orkney than on the Western Isles of the mainland.
- For all parameters investigated, including transmission loss schemes, the variability in results for Orkney and Shetland is higher than for

the Western Isles and the mainland due to the higher costs, transmission losses and capacity factor uncertainty on these islands.

- Despite the higher level of variability in the results for Shetland and Orkney, the projects are still favourable when compared to the mainland - even when considering the most pessimistic estimates of capacity factor for these two islands. Therefore, for Orkney and Shetland, the analysis presents a robust picture in that a S185 scheme is unlikely to be required to support wind farm development in these regions.
- The Western Isles has much lower levels of variability in its results and typically results in equity IRRs which are towards the lower end of the equity IRR range for the mainland project across all parameters. As such, the analysis does suggest that the introduction of a S185 scheme might be required to stimulate project development in the Western Isles.

7.4 TNUoS Charge Variation

This section investigates the equity IRRs for wind farm projects on the Scottish Islands based upon the different level of TNUoS charges that could be levied. These graphs can be used to quantify the effect of different levels of TNUoS discount under a S185 scheme on developers' returns, and to inform the debate as to whether, in the absence of a S185 scheme, transmission charges would be likely to deter, or otherwise hinder in a material respect, development of wind farms generation on the Scottish Islands.

We have varied the TNUoS charge ranging between £22.09/kW/annum (the average of the mainland charges for the landing points for all the subsea cables for the three Islands – provided by NGET) and the levels provided by NGET for the single and double circuit connections for all the Island projects.

For each level of TNUoS we have calculated the level of debt that the project can support, using the same methodology as discussed in Section 7.1.2, and investigated the equity IRRs under the base case power and ROC price scenarios, that these parameters will give.

We have assumed that the level of TNUoS charge remains constant (apart from inflation effects) throughout the study period. However, it should be noted that the level does not change at the end of the proposed S185 scheme in 2024.

As well as the TNUoS charge variations, there are a number of other differences between the single and double circuit connection models. These are itemised below.

- Capital Costs;
- The Final Sums Liabilities; and
- Cable outages.

The corresponding IRRs are shown in the following figure.

Figure 9: Western Isles Range of Equity IRRs expected with varying TNUoS Charges

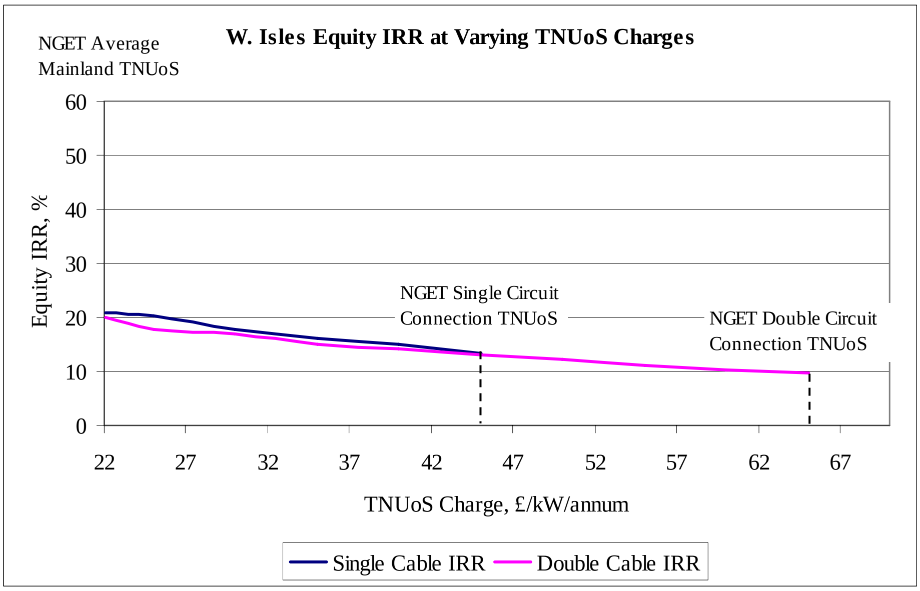


Figure 10: Shetland Range of Equity IRRs expected with varying TNUoS Charges

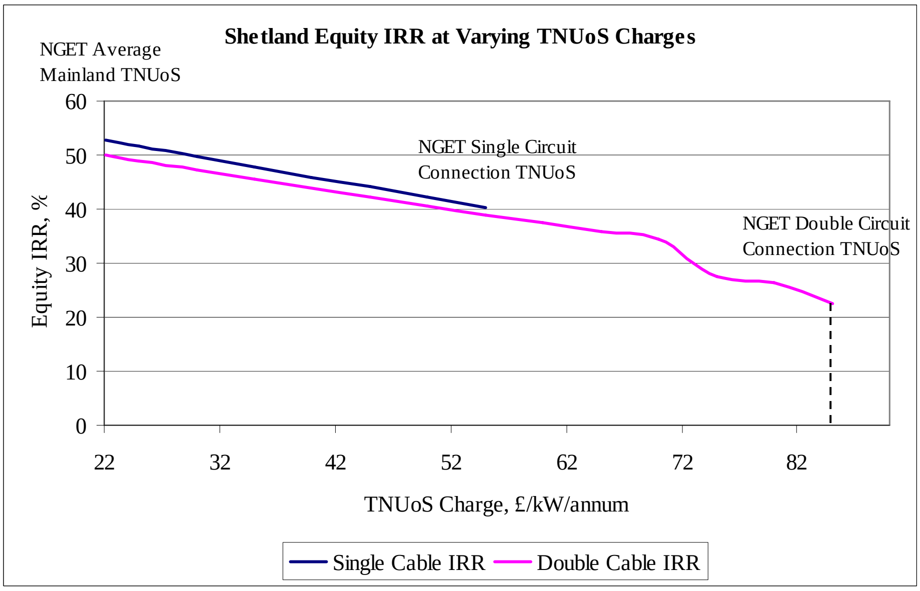
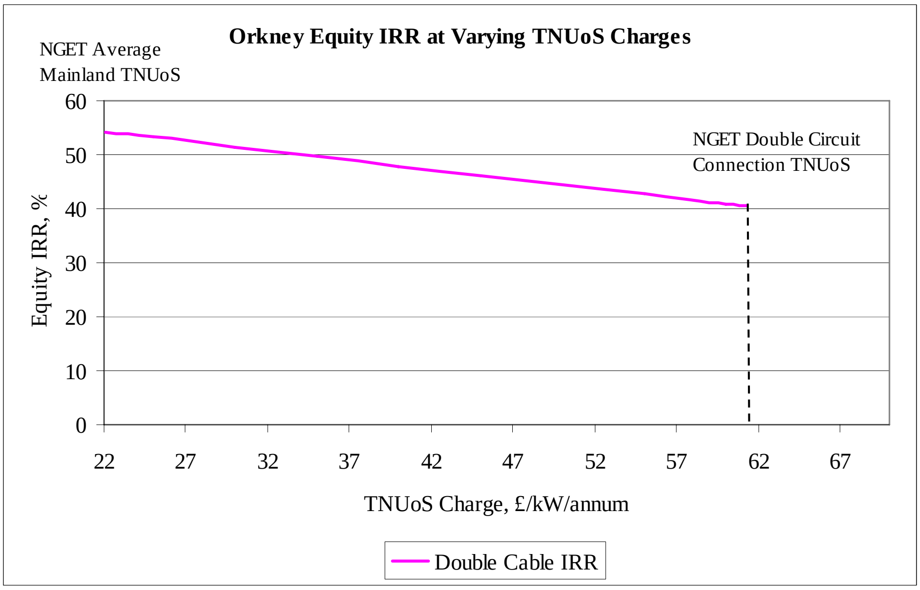


Figure 11: Orkney Range of Equity IRRs expected with varying TNUoS Charges



8 CONCLUSIONS

The economics of wind farms in the Northern Highlands of mainland Scotland and the Scottish islands of Shetland, Orkney and the Western Isles have been investigated in this report, with the aim of informing the Government debate as to whether, in the absence of a S185 scheme, transmission charges would be likely to deter, or otherwise hinder in a material respect, development of renewable generation on the Scottish islands.

8.1 The S185 Scheme

The Energy Act 2004, as amended by the Climate Change and Sustainable Energy Act 2006, gives the Secretary of State the power to limit transmission charges for renewable generators in a particular area of Great Britain if certain conditions are met. The purpose of the power given under Section 185 (s185) is to address concerns that the locational transmission charging scheme operated by the GB SO might hinder the development of renewable generation especially in the North of Scotland.

Before exercising this power the Government requires to be satisfied that a scheme provides a beneficial and cost-effective way of supporting additional renewable generation.

8.2 The Current Status of Island Wind Farm Generation

There are currently no transmission connected generation projects on the Scottish Islands of Shetland, Orkney and the Western Isles. However, there is interest in developing over 1.1GW of wind capacity, the connection of which will require the reinforcement of the transmission system, including the installation of subsea cables and infrastructure work on the islands and mainland.

The commissioning dates for these planned wind farms must reflect possible connection dates, which are dictated by the completion dates of the reinforcement works, and likely to be around 2013/14 at the earliest.

8.3 Transmission Reinforcement Costs and TNUoS Charges

SHETL are currently undertaking pre-construction development work for these required connections and have provided this study with cost data for both single and double circuit connection options.

This cost data has also been provided to NGET, who have provided a forecast of TNUoS charges, based on SHETL's estimated capital costs.

8.4 Comparator Projects

In order to inform the decision about the level of transmission discount that might be justified for Scottish Island wind farms under S185 it is necessary to examine in detail the relative economics of generic wind farm developments on the Scottish Islands of Shetland, Orkney and Western Isles relative to comparator projects on the mainland situated in relatively close proximity (Northern and Western Highlands). Generic comparator projects were developed, to analyse the impact of the differences between the locations under study on wind farm project economics.

The comparator projects were designed to be representative of the generic costs incurred at the different locations, without necessarily reflecting the specific costs of the individual projects that are under development.

Based on the capacity of representative developments on the Islands and the mainland, we have chosen a project size of 150MW with which to compare the economics. From examination of the various parameters that affect the economics of a wind farm we have concluded that there would be no material difference between mainland projects in the North and West Highlands and so have chosen a single mainland comparator project.

However, there exists significant levels of difference in the costs and capacity factors between the three Island areas under consideration to merit separate comparator projects for each. We have therefore chosen one project for each of the Island areas.

8.5 Consultation

To identify the differences in the project economics between developments on the mainland and on the Islands, a consultation with wind farm developers and operators within the industry was carried out. During this process, many developers indicated that a S185 scheme would be important and some identified it as the single most important factor. They were all of the opinion that a decision on the future structure and level of any scheme was critical and want a decision made quickly.

Relatively little explicit cost data for projects was provided through the consultation process, although some indication was provided of expected uplifts for specific cost elements between the mainland and the island areas under consideration.

8.6 Capacity Factors

A major parameter in the economics of a potential wind farm is the expected Capacity Factor, or Load Factor of the project, which dictates the amount of electricity that can be produced.

We have taken data from a number of sources, including the consultation process, to build up a picture of expected load factors for the areas under consideration. These are shown in the table below.

Table 28: Expected Capacity Factors

Mainland	W. Isles	Shetland	Orkney
30%	35%	49%	49%

Clearly there are higher capacity factors expected on Shetland and Orkney than on the mainland and the Western Isles.

8.7 Wind Farm Economics

We have developed generic comparator projects, using data from the consortium's experience, supplemented by the consultation process. The costs and revenue streams investigated were as follows.

Table 29: Cost and Revenue Parameters

Costs	Revenues
Pre-construction costs	Electricity price
Transmission connection costs	ROC price
Capital costs	CCL.
Fixed operating costs	
Variable operating costs	

Where distinctions had been identified between costs on the mainland and on the Islands, the uplifts assumed for the parameters were applied.

8.8 Financial Models

Financial models of the comparator projects have been constructed and their economics assessed by calculating the equity IRRs under a range of power and ROC price scenarios. For this we have used GB power and ROC price forecasts from IPA's January 08 PowerView product. The results from the analysis, assuming base case cost and capacity factors are shown in the following table.

Table 30: Range of Potential Equity IRR

	Mainland	W. Isles	Shetland	Orkney
Single Circuit Connection	11% - 19%	9.6% - 17.9%	29% - 58.2%	
Double Circuit Connection	11% - 19%	6.2% - 13.4%	16.2% - 31.9%	29.8% - 58%

The analysis suggests potential returns to investors on Shetland and Orkney which indicate that a s185 scheme would probably not be required in these areas to bring forward wind farm development. However, the economics of projects situated on the Western Isles is much less favourable, particularly with a double circuit connection, and a s185 scheme might make the difference to project economics.

8.9 Sensitivity Analysis

Sensitivity analyses were carried out on key cost and capacity factor parameters, whilst holding the power and ROC prices constant at the base case levels, to determine the impact of potential variations between the areas under consideration.

This indicated that the parameter with the most impact on the project economics is the capacity factor.

Capacity factor uncertainty results in the greatest variability in the IRR of all the different parameters. Whilst this is most obvious in Orkney and Shetland where the capacity factor uncertainty is highest, it is also true in the mainland and Western Isles, where the range of capacity factors used is relatively tight. The range of equity IRRs for the identified range of capacity factors is shown in the following table.

Table 31: Range of Equity IRRs at Range of Capacity Factors

	Mainland	W. Isles	Shetland	Orkney
Capacity Factor Range, %	28% - 32%	33% - 37%	45% - 54%	42% - 50%
Equity IRR Range, %	12.6% - 16.6%	11.5% - 15.0%	32.2% - 51.5%	27.0% - 42.7%

The effect of a Zonal Losses scheme would detrimentally affect the project economics of projects situated on the Islands, most significantly on Shetland, where the cable losses are highest.

There is more uncertainty in the sensitivity results for projects in Shetland and Orkney, than in the Western Isles or the mainland. However the economics are fairly robust to variations in the major parameters that feed into the economic analyses, with results indicating that it could be marginal as to whether a s185 scheme would also be required for projects on Shetland under a scenario with a combination of low power and ROC prices, and low capacity factors. This is, however, a relatively low probability, pessimistic scenario.

8.10 TNUoS Variation

Sensitivity analyses were carried to investigate the impact of varying the TNUoS charges on the equity IRR of the projects.

We have varied the TNUoS charge ranging between £22.09/kW/annum (the average of the mainland charges for the landing points for all the subsea cables for the three Islands – provided by NGET) and the levels provided by NGET for the single and double circuit connections for all the Island projects.

Results, using the base case power and ROC price assumptions, are shown in the following figures.

Figure 12: Western Isles Range of Equity IRRs expected with varying TNUoS Charges

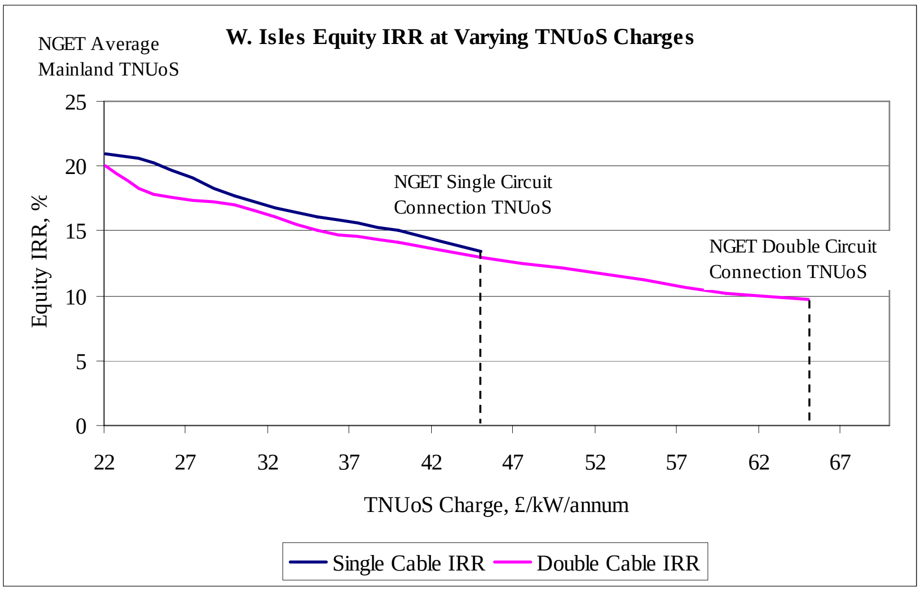


Figure 13: Shetland Range of Equity IRRs expected with varying TNUoS Charges

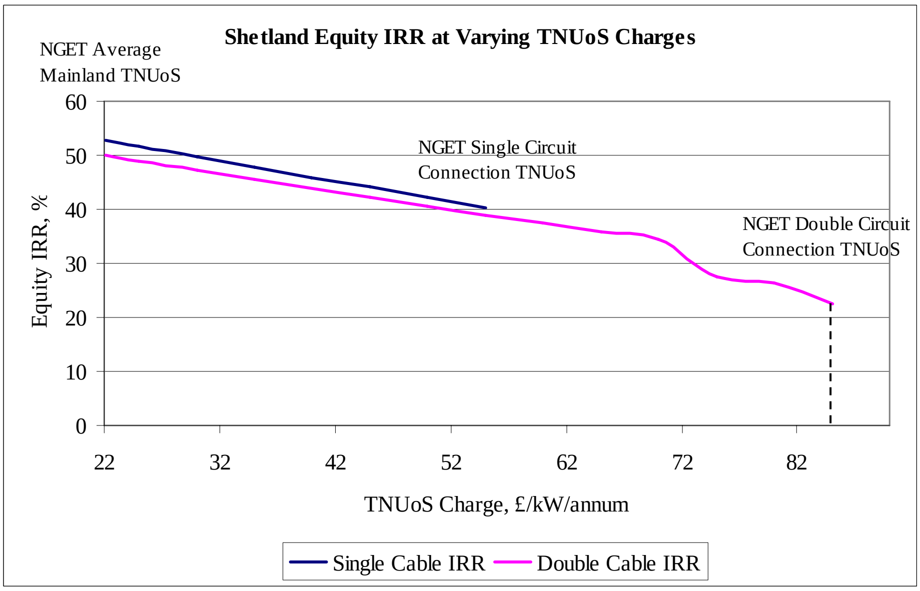
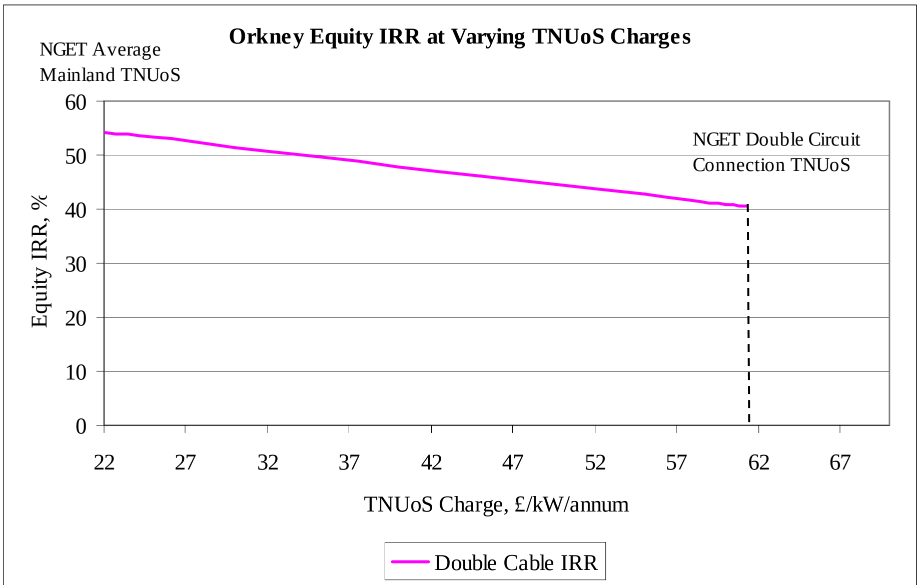


Figure 14: Orkney Range of Equity IRRs expected with varying TNUoS Charges



The results presented above are based on current assumptions regarding the costs and operating parameters of the links provided by SHETL and the transmission charges provided by NGET. It should be recognised that these have been developed for the current regulatory framework and charging methodology, both of which could be subject to change. In addition, they are based on wind farm cost and revenue estimates, based on current expectations, which could also change.

It should also be noted that the implementation of S185 could serve to dampen the financial incentives put in place to ensure that, where the generator can influence the choice of transmission investment, the most economic reinforcement scheme is selected.

APPENDIX A: CONSULTATION QUESTIONS

Wind Farm Developments

1. We have identified your company as one involved in wind farm developments in the Northern Highlands and Scottish Islands. We are aware of your proposed developments at {list}. Are you developing other wind projects in the Northern Highlands, Orkney, Shetland or the Western Isles?

   If yes, to what stage? Where? And what scale?

Transmission

S185 of the Energy Act gives the Secretary of State the powers to limit the transmission charges for renewable generators in particular areas, and could be used to reduce transmission charges in the Scottish Islands

2. Would a Transmission Charge Adjustment scheme to 2024 be likely to have a significant impact on your decision of whether to invest in a development on the Islands?
3. What level of transmission charges do you think would make your wind developments on the Orkney/Shetland/W. Isles economically infeasible?

   Would you see this as an absolute amount or a premium level on mainland charges?

4. How critical to your investment choices now will it be if a decision is not made in the near future? *(In the context that transmission connections may not be available on the Islands until 2014+)*
5. There are a number of potential regulatory options for connecting the Islands. Do you have a preference for a particular option, do you believe this could have an impact upon transmission charges or your decision to develop Island wind projects?
6. To what extent are the level of current credit cover /Final Sums liabilities a significant issue in terms of the development?

Key Development Issues

7. What do you consider the primary differences, both positive and negative, to be between developing projects on the mainland and on the Islands?
8. Do you believe there is a difference in the level of risk associated with developing wind projects in Orkney/Shetland/W. Isles/Northern Highlands?

   What are the main causes of the differences in risk?

   Would they impact upon the developer's required returns?

Would they influence the final project financing structures in terms of project gearing?

9. Do you see any factors that would influence the scale of wind farm developments on the Islands relative to mainland locations?

Detailed Development Issues

10. There are a number of factors that may differentiate project development between the Orkney/Shetland/W. Isles/Northern Highlands. It would be very helpful if you could indicate to us whether you see these as significant factors and the resulting cost differences:

- Wind Resource

  Wind speed / load factor

  Turbine Certification: site classification and certification for the turbines;

- Development Issues

  Planning Permission: Attitude of LAs, communities, stakeholders to developments;

  Land access & contracts;

  Community Benefit;

  Transmission availability/connection timing and cost;

- Construction Costs

  Transportation Issues: Physical transportation of turbines and towers;

  Civil Engineering: Availability and cost of aggregates, concrete and equipment;

  Site geography: Ground conditions, accessibility for construction;

  Labour Issues: Cost and availability of labour (construction and operation);

  Cost of EPC Contract

  Timeline: Accessibility of site and planning construction work;

  Local grid connection issues

- Operating Costs

  Maintenance: Availability and cost of labour

Maintenance: Availability and cost of parts, capital cost associated with spare parts warehouse;

Availability: Downtime for maintenance/repair;

Contractual Issues: Contract terms (construction or O+M);

Land (lease) costs: Turbine sites and connection;

- Other Factors

Off Take Contracts

11. With respect to offtake contracts:

What options would you expect for length of contract?

Would you expect these contracts be pegged to market values? (e.g. % of CCL, % ROC buyout, % ROC recycle, power market index etc.)

Would you look for fixed price contracts or floor price levels?

Is there any difference between mainland and island projects?

APPENDIX B: SHETL SUBMISSION

18th January 2008

Re: Charge capping study by IPA

Indicative island transmission reinforcement costs

The following costs represent budget cost estimates for the transmission reinforcement schemes described. In the case of HVDC cable circuits (High Voltage Direct Current) for Shetland and the Western Isles the costs are based on budget prices obtained by SHETL from manufacturers in a costing exercise in 2006 to which allowances have been added to take account of the following costs that would ultimately be capitalised into the value of the asset for charging purposes;

- Land and permissions for substation sites and cable routes
- Onshore and offshore route investigations and surveys
- Overall project management and scheme engineering
- Project insurances during construction
- Interest during construction, i.e. the loss of interest on (or cost of borrowing) the capital required to fund construction prior to the completed asset becoming chargeable.

Indicative budget costs quoted below are all subject to tender.

Funding provision

Pre-construction development costs are currently being incurred by SHETL on technical design and route survey work in respect of three island transmission reinforcement schemes. SHETL's development costs are allowed for under its current regulatory funding settlement on the basis of them being underwritten (through National Grid) by those contracted generation projects which have applied for connection to the GB system on the islands.

Background assumptions for indicative TNUoS calculation

It is understood that the exercise being undertaken by IPA will include National Grid as GBSO deriving indicative TNUoS tariffs for the islands. If this is undertaken on the basis of a whole system TNUoS model then it will rely on a set of assumptions in respect of other connected generation and corresponding transmission. For example, it would be misleading to simply inject 500MW of new generation on an island group and drop in a new cable to the Scottish mainland without also including the anticipated generation pattern in the year of connection and other system upgrades upon which the island generation might also be reliant.

Regardless of what happens to generation projects on the islands the transmission system on the Scottish mainland requires to be reinforced to accommodate requests for the connection of renewable generation across the Scottish mainland. Large scale generation projects on the islands not only require new local circuits but are also dependent to varying degrees on those mainland system upgrades. Since there is uncertainty over the timing and consenting of both island and mainland generation schemes and therefore also in respect of corresponding transmission system upgrades, the simplest assumption for the generation and system background to calculate TNUoS might be to assume a 2016 study year. The relevant elements for the GBSO's TNUoS calculation would therefore be:

- All contracted island generation developments and island transmission reinforcements as costed in this note
- The GBSO's 2016 generation and demand background
- Transmission system in the north of Scotland based on a completed 400kV ring and re-strung second circuit of the existing Beauly-Dounreay 275kV route.

An alternative approach to whole system modelling might simply be to identify the amount of annual revenue that would need to be recovered to fund the transmission investments in question (as described in the paper by National Grid that is referenced (p10) in the DTI's July 2005 public consultation on charge capping). For example, a £100m link investment would require £8.43m to be recovered annually which, if it was charged exclusively to a 200MW generation development project would translate to an increment of £42/kW to the prevailing rate at the receiving end of the link. This simplistic approach however raises other issues.

New island links are in reality reinforcements of an integrated GB transmission system serving both demand and generation, and potentially also accommodate through-flows under certain circumstances and configurations. These links could be avoiding the need for other network reinforcements that might otherwise be required to secure demand. To divide an annual funding amount exclusively by the generation would therefore not be recognising the full role of such links and therefore indicate an unduly high generation TNUoS.

The issue of charging for peripheral transmission is neither new nor unique. For example, charging for generation at Pembroke in South Wales was the subject of discussion and dispute in the early 90's. Pembroke lies at the western end of long transmission circuits serving both generation and demand.

Detailed discussion of TNUoS methodologies is beyond the scope of this note which is intended to provide budget costs for island transmission reinforcements to be used in TNUoS calculations by the GBSO. The subject of assumptions was introduced in order to highlight the requirement for a consistent network if whole system TNUoS calculations are anticipated.

<u>Firm vs non-firm</u>

The HVDC options for which indicative costs are provided below include configurations that are both firm and non-firm for generation output, i.e. non-firm options are those that would not be capable of accommodating the full generation export when one cable circuit was unavailable because of fault or maintenance.

The current licensing framework requires that firm arrangements are provided and as it is bound to do, SHETL is progressing schemes that could accommodate that requirement.

However SHETL has also identified that there is an economic case for providing less assets than required by current standards. In the case of Shetland for example, there is a difference of some £100m over the project life between providing assets to the level required by current standards versus the total costs of a lesser asset provision and restricting generation on the occasions when a cable circuit may be unavailable.

The analysis takes into account the economic cost of renewable generation being unable to generate when link export capacity is reduced, i.e. the lost value of renewable energy plus the cost of replacement energy from the wholesale market. The analysis does not however seek to allocate that cost to either generators or consumers, it just recognises and estimates it to enable .

Shetland

Contracted generation: Viking Energy Ltd 300MW
SSE Generation (North Nesting) 250MW

Transmission reinforcement scheme status:

Onshore survey work and on-site investigations underway now
Seabed survey scheduled to commence Q2 2008

Indicative route length assumed:

330km Subsea, Shetland to North Morayshire coast
15km Combined onshore underground cable route lengths from landfalls to HVDC converter locations on Shetland and at Blackhillock near Keith.

Sums below exclude costs of connections at 33kV and or 132kV between the clusters of wind turbines and the converter station site on Shetland (indicative costs £35m). The responsibility for providing these assets and their ownership are subject to ongoing discussions between the parties (generation applicants, transmission owner licensee and system operator licensee) and so may or may not be subject to transmission charges.

Link option (100% = 550MW rating)	HVDC link indicative capital cost (£m)[1]
1 x 100%	237
2 x 50%	372
2 x 100%	473
3 x 50%	552

1. HVDC link costs only, excludes 132kV collection costs on Shetland

Firm vs non firm illustration for Shetland

For illustration, the following table compares indicative numbers relating to the lifetime costs associated with link different link configurations.

It includes the following elements:

i) *Capital costs*. Indicative capital costs from the table above

ii) *Hours of no HVDC link capacity*. An average number of hours per year when, given certain assumptions about the availability of the converter and cable elements, there would be no HVDC link capacity. It is an average number based on statistical failure rates and so for example, it is entirely possible that a single HVDC module might not suffer a cable fault for 20 years but if and when it did occur the subsea cable repair could take up to 3 months.

iii) *The economic cost associated with restricting generation*. The estimated restricted link capacity is combined with the economic cost of restricting renewable energy (i.e. the cost of lost ROCs and LECs: £45/MWh, plus the cost of replacement energy £35/MWh). The result is capitalised to give a lifetime cost associated with restricting generation because of reduced link capacity.

iv) *Link losses*. Different link configurations result in different levels of electrical losses. For any one configuration the level of losses will also vary with the level of link loading but central assumptions have been used to give the percentage indication of energy losses quoted in the table.

v) *Cost of losses*. The cost of electrical losses (£35/MWh) capitalised to give the lifetime cost of electrical losses on the link.

Link configuration (100% = 550MW)	**Indicative capital cost (HVDC link only) (£m)**	**Average hours per year of no HVDC link capacity**	**Lifetime economic cost of restricted generation (£m)**	**Indicative level of losses (as %age of energy put onto link)**	**Lifetime cost of losses (£m)**	Total lifetime cost
1 x 100%	237	435	127	6.1	68	**432**
2 x 50%	372	26	76	8.0	90	**538**
2 x 100%	473	26	8	5.8	65	**546**
3 x 50%	552	2	7	7.0	79	**638**

NB. As requested for the purposes of S185 charge capping investigation the above firm vs non-firm analysis is only highlighted with respect to generation export. However as noted above, HVDC links could also have a role in securing island demand and therefore SSE has undertaken comparisons of wider, whole-Shetland integrated solutions which are beyond the scope of this note but do not alter the conclusion that a single HVDC link combined with appropriate back-up generation potentially offers the most economic overall solution.

Western Isles (already connected by 33kV cable rated at 20MW)

Contracted generation: Beinn Mhor Power 300MW
SSE Generation (Pairc) 250MW

Other: 50MW (approximately)

Notes:

i) *Beinn Mhor Power's revised Section 36 application in April 2006 which is scheduled to be the subject of a Public Inquiry in 2008 was for 159MW.*

ii) *Western Isles Council has recommended endorsement of the Pairc project's application for S36 consent but on the basis of it being reduced in size to around 26 turbines (94MW).*

iii) *Lewis Wind Power submitted a revised application for S36 consent in November 2006 for 651MW but has not applied for connection to the GB transmission system.*

iv) *Scheme development to date and costs quoted below relate to options for connection of contracted generation.*

Transmission reinforcement scheme status:

Seabed survey completed 2007
Applications for planning consent scheduled for submission Q2 2008

Indicative route length assumed:

76km Subsea, Loch Odhairn on Isle of Lewis to Little Loch Broom on the Scottish mainland
79km Combined onshore underground cable route lengths from landfalls to HVDC converter locations on Lewis at Grabhair and at Beauly, west of Inverness.

Sums below exclude costs of connections at 132kV between the clusters of wind turbines and the converter station site on Lewis (indicative cost £15m). The responsibility for providing these assets and their ownership are subject to ongoing discussions between the parties (generation applicants, transmission owner licensee and system operator licensee) and so may or may not be subject to transmission charges.

Link option (100% = 550MW rating)	HVDC link indicative capital cost (£m)[1]
1 x 100%	163
2 x 50%	245
2 x 100%	326
3 x 50%	367

1. HVDC link costs only, excludes 132kV collection costs on Lewis

Firm vs non firm illustration for Western Isles

For illustration, the following table compares indicative numbers relating to the lifetime costs associated with link different link configurations.

It includes the following elements:

i) *Capital costs*. Indicative capital costs from the table above

ii) *Hours of no HVDC link capacity*. An average number of hours per year when, given certain assumptions about the availability of the converter and cable elements, there would be no HVDC link capacity. It is an average number based on statistical failure rates and so for example, it is entirely possible that a single HVDC module might not suffer a cable fault for 20 years but if and when it did occur the subsea cable repair could take up to 3 months.

iii) *The economic cost associated with restricting generation*. The estimated restricted link capacity is combined with the economic cost of restricting renewable energy (i.e. the cost of lost ROCs and LECs: £45/MWh, plus the cost of replacement energy £35/MWh). The result is capitalised to give a lifetime cost associated with restricting generation because of reduced link capacity.

iv) *Link losses*. Different link configurations result in different levels of electrical losses. For any one configuration the level of losses will also vary with the level of link loading but central assumptions have been used to give the percentage indication of energy losses quoted in the table.

v) *Cost of losses*. The cost of electrical losses (£35/MWh) capitalised to give the lifetime cost of electrical losses on the link.

Link configuration (100% = 550MW)	**Indicative capital cost (HVDC link only) (£m)**	**Average hours per year of no HVDC link capacity**	**Lifetime economic cost of restricted generation (£m)**	**Indicative level of losses (as %age of energy put onto link)**	**Lifetime cost of losses (£m)**	Total lifetime cost
1 x 100%	163	230	67	4.9	55	**285**
2 x 50%	245	9	39	5.7	64	**348**
2 x 100%	326	9	2	5.2	59	**387**
3 x 50%	367	1	2	5.5	62	**431**

Orkney (already connected by 2 x 33kV cables rated at 20MW and at 30MW)

Contracted generation: Fairwind Statkraft Orkney Ltd (FSOL) 126MW

Transmission reinforcement scheme status:

Environmental and route investigations ongoing
Public consultation scheduled Spring 2008

Indicative route length assumed:

50km subsea
30km combined route lengths on Scottish mainland and on Orkney.

Configuration

2 x 132kV subsea cables and onshore circuits (circuit rating 180MVA)

Indicative budget cost £86m

Losses

Losses on the new AC cable circuits are estimated at between 2.5 – 3% of energy at the sending end but vary with the level of circuit loading.

APPENDIX C: NGET SUBMISSION

Submission 1

As promised, we have recently undertaken a study involving TNUoS modelling to produce indicative TNUoS tariffs for island located wind farm generators. The base data was provided by Scottish and Southern and as I am sure you appreciate a number of assumptions had to be undertaken. I have attempted to list the assumption below although with a number of other deliverables going out this week, I have been unfortunately pressed for time.

When calculating forecast tariffs some distance into the future, it is important to recognise the limitations of such forecasts due to the high level of uncertainty over a number of factors which will influence the TNUoS generation tariffs such as the prevailing generation and demand backgrounds, transmission network and allowed revenue for the relevant charging year. The forecast figures provided have therefore been calculated on the following basis and should be regarded as indicative tariffs only:

- Respective volumes of generation added to the DCLF Transport Model at the relevant onshore node simultaneously
    - Shetland: 550MW at Keith
    - Western Island: 600MW at Beauly
    - Orkney: 126MW at Dounreay
- A marginal km figure has been calculated for each of the relevant onshore nodes using the 2007/8 DCLF transport model inputs (including demand and generation backgrounds, transmission network and expansion factors)
- The derived nodal marginal km for each node is converted into a TNUoS tariff using the following methodology:
    - Marginal km is re-referenced using 2007/8 re-referencing quantity
    - Multiplied by the 2007/8 global locational security factor of 1.8
    - Multiplied by the 2007/8 expansion constant of 9.88
    - 2007/8 Residual tariff of £3.87/kW applied
- Having calculated an onshore TNUoS tariff, the overall tariff has been derived by calculating an offshore marginal tariff and adding this to the onshore tariff.
- The offshore marginal tariff has been calculated consistently with the methodology proposed for the Offshore Charging regime (see current live Offshore Charging Consultation for exact details - http://www.nationalgrid.com/NR/rdonlyres/5A5364ED-5EF5-4D37-9FA6-DEB41C16F717/22313/GBECM08OffshoreChargingConsultation.pdf). Relevant features include:
    - Circuit Specific Expansion factors derived such that the actual annuitised capital cost for a cable is precisely recovered from the TNUoS tariffs.
    - If the spare capacity exceeds that of the average for onshore connections (namely 80%), the additional capacity is charged as a one-off capital cost. For this example this only includes the n-1 offshore connections (2 x 100%).

TNUoS tariffs (£/kW):

	Shetland (£/kW)	Western Isles (£/kW)	Orkney (£/kW)
1 x 100%	55.5	46.6	N/A
2 x 50%	76.0	59.0	N/A
2 x 100%	84.2	66.4	61.3
3 x 50%	103.4	77.6	N/A
Onshore base tariff	19.2	21.8	25.33

One off capital costs for full redundancy connections:

	Shetland (£m)	Western Isles (£m)	Orkney (£m)
2 x 100%	47.3	32.6	8.6

Submission 2

Just to confirm the methodology for the derivation of the Orkney TNUoS tariff:

- Capital cost of 2 x 180 MVA link: £86m
- Assume unity power factor
- Annuitised over 50 years with a 1.8% Maintenance factor. (same as onshore) = £7.20m pa
- TNUoS = (£7.20m/126MW) * (126MW/180MW) * (1.8/2.0) * 1000 = £35.98/kW differential to be added to the onshore base TNUoS
- Looking at each of these elements individually:
    - Annuitised capital cost / generator TEC
    - Generator TEC / Cable Capacity (this reflecting the onshore principle that you pay for the capacity used and not the capacity installed for your connection)
    - 1.8/2.0 = This makes the assumption that only 80% additional redundancy will be funded through TNUoS and the remainder will be funded through a one off capital cost. Nb. This is just one possible approach and this has not in any way been agreed upon or fully tested.
    - X1000. This changes the unit to £/kW from MWs.
    - The one off capital cost funds the last 20% of additional redundancy and therefore is equal to 10% of the entire capital cost.

APPENDIX D: GLOSSARY

BERR	Department for Business, Enterprise and Regulatory Reform
BETTA	British Electricity Trading and Transmission Arrangements
BMRS	Balancing Mechanism Reporting Service
BSC	Balancing and Settlement Code
BSUoS	Balancing Services Use of System (charges)
CAP	CUSC Amendment Proposal
CAPEX	Capital Expenditure
CUSC	Connection and Use of System Code
CCL	Climate Change Levy
DCLF	Direct Current Load Flow
DSCR	Debt Service Cover Ratio
DTI	Department of Trade and Industry
ECLIPSE	Emissions Constraints and Policy Interactions in Power System Economics
EPC	Engineer, Procure, Construct
EU	European Union
FSL	Final Sums Liability
GB	Great Britain
GBSO	Great Britain System Operator
HVDC	High Voltage Direct Current
IRR	Internal Rate of Return
LEC	Levy Exemption Certificate
LF	Load Factor
MIP	Market Index Price
NGET	National Grid Electricity Transmission plc
NOABL	Numerical Objective Analysis of Boundary Layer
O&M	Operation & Maintenance
Ofgem	Office of Gas and Electricity Markets
RCRC	Residual Cashflow Reallocation Cashflow
‘REFER	Renewable Energy Financer
REGO	Renewable Energy Guarantee of Origin
RO	Renewable Obligation
ROC	Renewable Obligation Certificate
RPI	Retail Price Index

RPZ	Renewable Power Zone
SHETL	Scottish Hydro Electric Transmission Limited
SSE	Scottish and Southern Energy
SQSS	Security and Quality of Supply Standards
TAR	Transmission Access Review
TEC	Transmission Entry Capacity
TLM	Transmission Loss Multipliers
TNUoS	Transmission Network Use of System (charges)
TO	Transmission Owner
TSO	Transmission System Operator
UK	United Kingdom