Western Isles Strategic Wider Works

Needs Case: Cost Benefit Analysis

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National Grid

On behalf of Scottish Hydro Electric Transmission Limited (SHE Transmission)

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Contents Amendment Record

This report has been issued and amended as follows:

Issue	Revision	Description	Date	Approved by
First draft	1	First complete draft of report for feedback	18/7/2018	
Second Draft	1	Updated with SHE Transmission comments and sensitivity studies	7/8/2018	
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Contents

1 Introduction

1.1 Context

As outlined in **the Guidance on the Strategic Wider Works arrangements in the electricity transmission price control, RIIO-T1**, published by Ofgem, when a TO wishes to bring forward a transmission project for consideration under the SWW arrangements, it must give notice to Ofgem, in its role as the government regulator for the electricity and downstream natural gas markets in Great Britain, that it is proposing a new network development for regulatory approval. It must also submit supporting information to justify the reinforcement and the efficient costs of delivering the proposed transmission project.

If the project proposal is eligible, Ofgem will assess the Needs Case. As part of this assessment the Regulator looks at the factors supporting the need for the new transmission project. This includes the expected increase in generation relative to the existing transmission capacity, as well as the forecast cost to consumers if transmission capability is insufficient and constraint payments are incurred. To ensure that the investment case is robust Ofgem will also review the uncertainties that have been taken into account, for example, different generation scenarios.

Within this context, this document presents the details of the CBA undertaken by National Grid on behalf of SHE Transmission to determine economic connection options.

1.2 Economic Objectives of the Project

This CBA uses a ‘savings approach’[1] to assess the optimal connection option and it’s optimal in service date. In order to use the savings approach, a counterfactual has been established. That is that no new link to the mainland is built, and any excess generation on the island, is constrained off by the System Operator. By assessing the total expenditure over the reinforcement’s lifetime, and the associated constraint savings this CBA aims to find the optimal connection option and associated connection date using the least worst regret methodology.

Within this scope, the overarching economic objectives of the project are twofold:

- Ensure value for money for GB consumers by delivering a cost effective connection option to the Western Isles.
- Timely delivery of the appropriate connection to minimise GB consumer exposure to either early investment or delayed implementation.

[1] The savings approach is where potential projects are compared against a base/counterfactual

1.3 Study Objectives and Scope

The context outlined above drives the CBA objectives and economic analysis for the Needs Case preparation process. Furthermore, consistent with the **Guidance on Strategic Wider Works arrangements in the electricity transmission price control, RIIO – TI,** the objectives of this CBA are to:

- promote economic and efficient investment
- present economic justification for the preferred option and an explanation of the proposed option compared with the alternatives
- present evidence on expected long-term value for money for consumers considering a range of sensitivities, and
- present evidence on optimal timing of the preferred connection option.

Driven by these objectives the scope of the CBA is outlined below:

- Model[1] and forecast the economic impact, measured as constraint cost savings versus investment costs, of a range of connection options, across the studied generation scenarios and sensitivities
- To undertake a CBA by:
  - Appraising the economic case of the options by adopting the Spackman[2] approach and determining respective net present values (NPVs) across the studied generation scenarios and sensitivities
  - Determining optimal timing of each option across each scenario and sensitivity
  - Establish the worst regrets associated with each option and Least Worst Regret (LWR) alternative(s)
  - Assessing the impact of credible local generation sensitivities relating to renewable generation on the Western Isles.
  - Undertake robustness analysis including a reduction or increase in capital expenditure among others.

[1] The necessary modelling for the CBA is undertaken using the SO's electricity market modelling software, BID3. A description of the software and how the SO uses it is available at www.nationalgrid.com/noa/,

[2]The Joint Regulators Group on behalf of UK's economic and competition regulators recommend a discounting approach that discounts all costs (including financing costs as calculated based on a Weighted Average Cost of Capital or WACC) and benefits at the Social Time Preference Rate (STPR). This is known as the Spackman approach. Further details of our assumptions regarding WACC and STPR are presented later in this document.

- Where supported by the analysis, to make recommendation(s) on the preferred option(s), and optimal timing, noting any other pertinent considerations that best meets the project objectives outlined in 1.2.

1.4 Structure of the Document

The structure of this CBA document is outlined below:

- **Chapter 1: Introduction**, outlines the aims and objectives of the study
- **Chapter 2: Background**, presents the scenarios being employed and the key sensitivities
- **Chapter 3: Options for Economic Appraisal**, summarises details of options considered in the CBA
- **Chapter 4: Modelling of Constraint Costs,** presents constraint cost forecasts under each connection option considered in the CBA
- **Chapter 5: Cost Benefit Assessment**, brings together the analysis presented in the earlier chapters using the Spackman approach to develop net present values (NPVs), and performs least regret analysis to determine the most economic option and optimal timing of delivery
- **Chapter 6: Sensitivities,** presents the impact of sensitivities on the LWR analysis of Chapter 5
- **Chapter 7: Conclusions** presents a summary of the preferred option

Supporting information is provided in appendices.

2 Background

2.1 Introduction

The Western Isles has long been recognised as an attractive area for potential renewable development given the strong tides, wave heights and high wind yields. Currently less than 50MW of renewable generation is connected in the Western Isles – almost all of which is relatively small scale onshore wind. A limiting factor to renewable development on the Western Isles has been the isolation of the islands from the Main Integrated Transmission System (MITS). Currently, the transmission connection between the Western Isles and the mainland is only 20MVA via a 33kV link. Without a substantial new transmission connection, development of larger scale renewable projects will not go ahead and as such, the renewable generation potential of the Western Isles will remain untapped.

Currently, approximately **redacted** of generation has been contracted on the Western Isles. Further to this it is possible that up to 630MW of generation may be commissioned on the islands. Six potential connection options between the Western Isles and the mainland have been proposed by SHE Transmission to be analysed in this CBA.

SHE Transmission is required to submit a formal need case to Ofgem, through the SWW process for the proposed connection to the Western Isles. Full construction funding will only be granted if Ofgem approve the project need case, with the final scope and timing for delivery being determined through this process. As part of the SWW process a CBA of the options has been conducted by the System Operator. The objective of this CBA is to identify the most economic and efficient option from those identified by SHE Transmission. NGSO will be assessing the whole system impact on forecasted constraint costs as a result of each reinforcement, and comparing this with the total expenditure of each option. Whilst the proposed options do not provide wider boundary capabilities, and are primarily a connection for Western Isles based generation, it is important to consider the wider impact on constraint costs of greater amounts of generation flowing south. We therefore use our European market dispatch constraints forecasting tool, BID3, to model the system wide constraint cost forecasts for each option. The CBA approach of the NGSO is then to calculate NPV of each project by taking the constraint cost forecasts, described above, and the total costs of the projects, and perform least worst regret (LWR) analysis. Optimal timing analysis is then performed on the optimal solution.

Aside from the cost benefit analysis of each options effect on constraint costs, there is a wider consideration of whether generation of the scale already consented will connect on the Western Isles. The proposed generators are subject to the Contract for Differences (CfD) process, and the economic viability of the generators is highly dependent upon the result of this. As such SHE Transmission have proposed a conditional needs case approach which is dependent on the outcome of the upcoming CfD auction. The SO supports this approach to the needs submission and this CBA has been tailored to provide tipping point analysis such that further certainty over generation scenarios on the islands can result in the optimal connection option being developed.

Furthermore, each wind farm must pay a Transmission Network Use of System (TNUoS) charge, which among other things, is allocated according to the proportion the generator's capacity is of the link size. For example a generator which was the same capacity as the link would be liable for the full value of the TNUoS charge. The economies of scale present in this project mean that the greater the transmission capacity the lower the TNUoS each wind farm pays, and so the greater likelihood generation connects. Therefore, the realisation of each generation scenario explored in this analysis is highly dependent upon both the size of the link and resulting TNUoS, and whether the CfD they receive is great enough to cover TNUoS and make the generation projects economically viable. It is therefore likely that generation scenarios will become firmer as the value of the CfDs are decided.

2.2 Network Capabilities

The SO's Network Options Assessment optimises network capacity for future years based on TO submissions of possible reinforcements, future requirements as detailed in the Electricity Ten Year Statement, and the Future Energy Scenarios. This produces an optimised network per scenario, and therefore the systems boundary capabilities for each year and scenario. This study uses the output networks of NOA3, as published on the 31st of January. Please see www.nationalgrid.com/noa/ for more detail.

All proposed options studied in this CBA are comprised of a subsea cable extending from the Western Isles to the Scottish mainland. This is then routed to Beauly substation via overhead lines or cabling. None of the options were considered to have a material impact on any major system boundaries.

For the purpose of modelling the options in this study, a new boundary was created in the SO's constraint forecasting tool BID3. This boundary has the transfer capability of the option being investigated, and associated demand and generation on the Western Isles are placed behind this boundary. Forecast flows across this boundary are therefore equivalent to forecast flows through the cables considered.

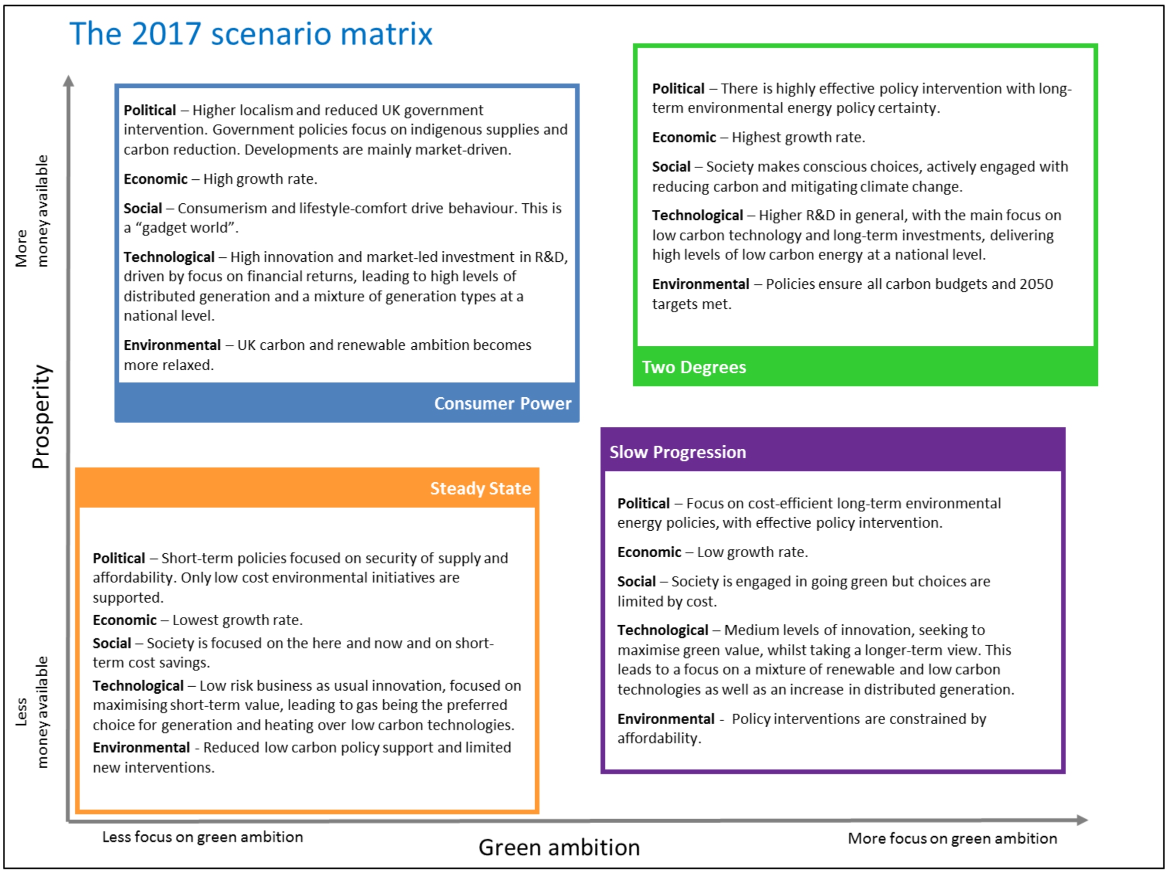
2.3 Future Energy Scenario 2017 Core Backgrounds

National Grid annually produces Future Energy Scenarios against which to plan the future system; while briefly summarised below, full details are available at: http://fes.nationalgrid.com.

The Four Scenarios are based on flexing two main factors; prosperity and green ambition. This creates an envelope of credible futures that consider a range of possible network conditions; under a future with higher green ambition, more renewable power and volatility in flows can be expected, for instance. In general Two Degrees presents the highest constraint costs to manage and therefore justifies developing the most transmission capability, whilst Steady State has the lowest associated constraint costs and need for transmission capacity.

Most important to this study is the view of the generation background on the Western Isles under these scenarios, as this will drive usage of the cable; without transmission level generation the cable is unneeded, whilst if generation capacity outstrips the cable capacity too much, then significant constraint costs could be incurred.

The generation on the Western Isles under each scenario is shown in the next section.



Rules:
1) Security of supply (electricity): Abide by the security standard as prescribed by the secretary of state (currently three hours/year loss of load expectation)
2) Security of supply (gas): There will be sufficient capacity to ensure that the N-1 test will continue to be satisfied

Figure 1- Future Energy Scenarios 2017 descriptions

2.4 Local Generation Backgrounds

As the generation levels on the Western Isles are so pivotal to the correct sizing of the cable, a wider range of possible capacity profiles to study was deemed necessary. SHE Transmission therefore provided four local generation backgrounds, produced by the consultants GHD at SHE Transmission's behest. These provide more detailed insight into the future of generation on the Western Isles, increasing the robustness of the result obtained.

A full breakdown of the projects that make up the capacities in figure 2 can be found in Appendix A.

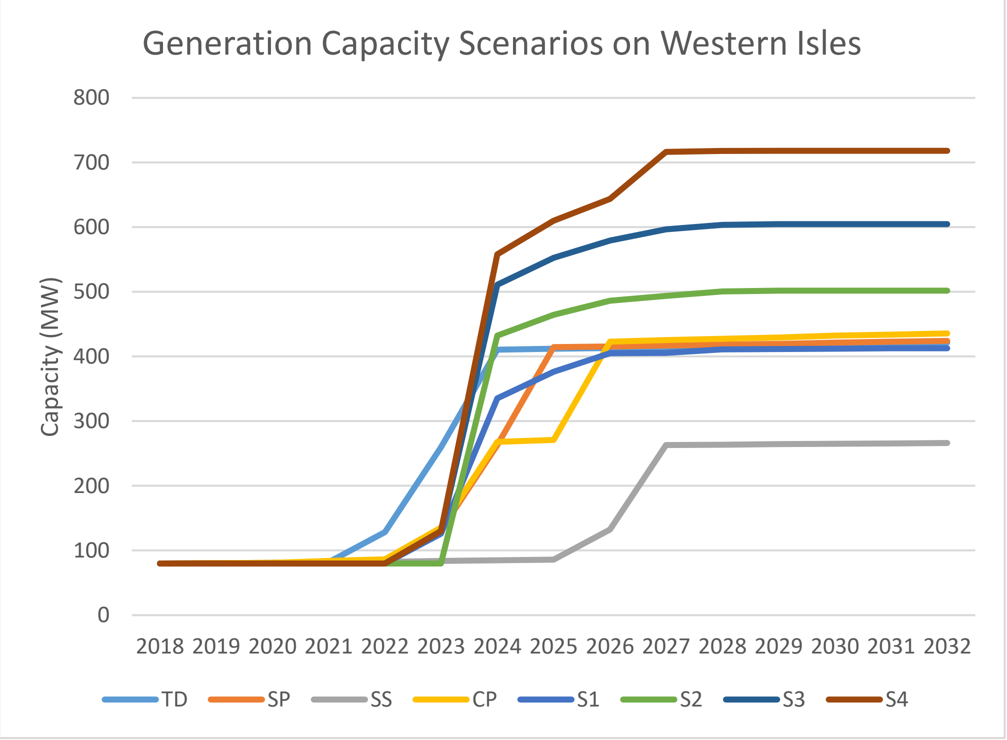


Figure 2- Generation scenarios on the Western Isles

For each SHE Transmission scenario, the rest of the GB network was set to the Slow Progression scenario. This allowed a comparison of the effect of different generation levels on the Western Isles, without a second degree of freedom in the scenario background.

2.5 The Counterfactual

The savings approach taken necessitates the definition of a ‘do-nothing’ option to compare the constraint costs against; it is therefore possible to demonstrate the savings obtained by constructing a cable. The implication is that if SHE Transmission were to not construct a cable, and the Western Isles generation were constructed anyway, the SO would be obliged to constrain off all generation on the island for its lifetime at a considerable cost.

Whilst this is unlikely to be the case in reality, in the event of the cable not being constructed, it is to a degree moot as to which of the cable options is the best. The economic calculations of the savings approach reach the same outcome as if an absolute approach was taken (one where no counterfactual is employed). The counterfactual provides an interesting reference point of the total constraint costs possible under each generation scenario tested.

2.6 Wind Profiles

In addition to the capacity of installed generation on the island, the weather profiles applied are of some importance; as almost all the new build generation on the Western Isles is in the form of onshore wind.

The SO's datasets of historic wind and tidal were employed in this study, with these having been discussed with SHE Transmission and wind developers on the Western Isles. These were felt to provide wind load factors reflective of those that the developers expect for their projects. One weather year (2013) has been chosen for the main CBA as it provides average wind, solar, interconnector flows and constraint costs when compared to the last 30 weather years. As one of the key sensitivities of the study was the use of the windiest and least windy historic years in the SO's dataset, it was felt this was sufficient to fully account for the impact of the weather on the CBA.

3 Options for Economic Appraisal

3.1 Introduction

This chapter presents the options submitted for assessment by SHE Transmission to the SO. They consist of 6 subsea cable options of varying capacity and technology. They all follow the same route, having been optioneered to this point by SHE Transmission. The SO has reviewed the optioneering documents provided by SHE Transmission and agreed to study the single route deemed most feasible by SHE Transmission.

Table 1- Options submitted to CBA process

Name	Description	Capability	EISD
Option 1	450MW HVDC Arnish - Dundonnell - Beauly Single Circuit	450MW	2023
Option 2	600MW HVDC Arnish - Dundonnell - Beauly Single Circuit	600MW	2023
Option 3	237MW HVAC Arnish - Dundonnell - Beauly Single Circuit 220kV	237MW	2024
Option 4	237MW HVAC Arnish - Dundonnell (SSC) - Dundonnell - Beauly Single Circuit Composite Pole 220kV	237MW	2025
Option 5	138MW HVAC Arnish - Dundonnell SSC - Dundonnell - Beauly Single Circuit 132kV	138MW	2024
Option 6	138MW HVAC Arnish - Dundonnell (SSC) - Dundonnell - Beauly Single Circuit Trident H Pole 132kV	138MW	2025

3.2 Option Capability

TThe range of capabilities above ensures that almost all of the generation in the most onerous scenario (780MW (excluding Diesel generators, as in section 2.4) would be exportable by the cable, while testing a wide range of capabilities under that value.

3.3 Option Costs

A capital cost summary associated with the reinforcement options is shown below. These values represent Present Values of building the cables on their earliest possible dates, including cost of capital, and amortising and discounting the spend. In the sections of the CBA involving determining the optimal delivery date of the options, these values would thus change slightly as annuitized payments further in the future would be discounted at a greater factor.

Table 2- PV of CAPEX of submitted options

Option	PV of CAPEX

1	redacted
2	redacted
3	redacted
4	redacted
5	redacted
6	redacted

3.4 Financing Assumptions

Financing assumptions have been adopted to develop Spackman compliant cost estimates of the options. These estimates include the following assumptions:

- **Weighted Average Cost of Capital** or **WACC**, which is currently estimated at **redacted p.a**. for SHE Transmission, and
- **Social Time Preference Rate** or **STPR**, which is estimated at **3.5% p.a**. by HM Treasury.

4 Modelling of Constraint Costs

4.1 Introduction

The Guidance on the Strategic Wider Works arrangements in the electricity transmission price control, RIIO-T1, states that a reinforcement option is economic when the cost of the project is less than the cost consumers would otherwise pay under the counterfactual case.

This section outlines the forecasts of constraint costs likely to be incurred by consumers for each option against each generation background, together with the corresponding counterfactual case.

4.2 BID3

The necessary modelling for the CBA is undertaken using the SO's electricity market modelling software, BID3. It is used to derive constraint costs based upon a given scenario and network background.

The model derives future constraint costs in a two-step process. First, it models the future market dispatch based upon whatever plants are most economical meeting demand first, subject to physical constraints. Next, it tests the resultant flows implied by the first step against the capabilities of the system boundaries. If it finds flows are excessive across any boundary, it finds the lowest cost solution to rebalance the network such that no boundary capabilities are being exceeded. The sum of these costs is called the Total Balancing Mechanism or Total Constraint Cost (TCC) for that run. The way TCC varies as network capabilities are altered (for instance, through the addition of the options assessed in this CBA) allows the SO to infer the value of constraint alleviation associated with network development options.

The use of this software for network planning purposes has been carefully validated through audit and back casting activities. The software has been successfully deployed in the SO's key network development processes, including the Network Options Assessment.

A more detailed description of the software, and how the SO uses it is available online: www.nationalgrid.com/noa/.

4.3 Forecasts of Constraint Costs: Counterfactual / Base

As discussed in section 2.5, to provide a reference value of total constraint costs a counterfactual has been simulated, wherein all generation on the Western Isles is curtailed all of the time as no cable has been deployed. This leads to very large constraint costs, of which the Western Isles curtailment is a significant factor. This is not the only factor, however- TCC is driven by modelled congestion across the entire GB network. The savings are modelled up to 2037, the end of the 20 year period to which the SO models as standard.

Redacted

Figure 3- Counterfactual constraint costs (undiscounted)

4.4 Constraint Savings

The constraint savings associated with each reinforcement option is the difference between its base/counterfactual constraint cost and the corresponding constraint costs with the reinforcement active.

Redacted

Figure 4- Option 1 constraint savings (undiscounted)

Redacted

Figure 5- Option 2 constraint savings (undiscounted)

Redacted

Figure 6- Option 3 constraint savings (undiscounted)

Redacted

Figure 7- Option 4 constraint savings (undiscounted)

Redacted

Figure 8- Option 5 constraint savings (undiscounted)

Redacted

Figure 9- Option 6 constraint savings (undiscounted)

5 Cost Benefit Assessment

5.1 Introduction

Fundamentally, the CBA compares the Present Value (PV) of reinforcement costs with the PV of forecasted constraint cost savings. Where constraint cost savings exceed the investment cost, then the reinforcement may be economic. In order to develop robust conclusions a range of generation backgrounds, design options and sensitivities have been considered.

For each reinforcement option, the PV of both the annual constraint savings and the associated transmission reinforcement cost is calculated; their difference gives the option's Net Present Value (NPV). A positive NPV implies the investment could be cost effective.

This chapter brings together the analysis presented earlier of investment costs and constraint savings to establish an overall Net Present Value (NPV) for each of the different options. The options' NPVs are used to perform Regret analysis, and subsequently to determine the preferred reinforcement option based on a Least Worst Regret (LWR) approach.

5.2 Model Results, Extrapolation and CBA Timeframes

FES generation backgrounds do not extend in detail beyond 2037, and so that is the extent to which detailed BID3 constraint forecast modelling can project. Constraint savings have been extrapolated from 2037 until the end of the CBA assessment period, based on a 40 year asset life.

5.3 Present Value of Capital Costs

Under the Spackman methodology, future investment costs associated with reinforcement options and constraint savings both have to be represented by a PV.

To achieve this for the investment costs: -

- The annual investment costs across the construction phase are annuitised at a post-tax real WACC of **redcated** over 40 years in line with SHE Transmission values;
- Future payments on investments are discounted at HM Treasury's Social Time Preference Rate (STPR) of 3.5%.

5.4 Net Present Value of Reinforcement Options

NPV measures the value of an investment, with both costs and benefits properly accounted for.

To compare the relative economic merits of the reinforcement options, the investment PV is deducted from the constraint saving PV to give a relative Net Present Value (NPV) for each option.

Table 3- NPV of options

Redacted

Options 1, 2 and 4 all perform favourably in the CBA depending on the generation scenario. Option 4 is favoured in lower generation scenarios, option 2 covers medium generation forecasts and option 2 is optimal in the highest of generation scenarios. The NPVs in the table above have been calculated based on the optimal connection date. The calculated optimal date for each option under each scenario is shown in the table below.

Table 4- Optimal connection date of options

Redcated

5.5 Regret Analysis

Regret analysis is designed to identify solutions which are least likely to be wrong across the range of scenarios/uncertainties studied. Regret analysis does not pick options with the largest net benefit (NPV), although this could occur coincidentally. The approach provides a robust decision against the range of uncertainties examined, and minimises the chance of particularly adverse outcomes impacting consumers.

In this analysis the regret is defined as the difference in NPV between 'the option being considered' and 'the best possible option for that scenario', i.e. all options are considered against the option which provides the maximum NPV in that scenario (taking into account the investment and operational costs). It follows that the best alternative has zero regret against which all other options are compared.

This analysis is repeated for all scenarios, across which it is possible that different options represent the zero regret alternative in each scenario.

The Least Worst Regret (LWR) methodology requires that design preference is based on the option that is least likely to result in an adverse outcome across all the backgrounds considered. The underlying philosophy is that it is advantageous to pick the solution that has the lowest adverse consequence of being wrong across the range of eventualities, given uncertainties in forecasts and assumptions. This approach ensures that particularly unfavourable combinations are avoided. It assumes that all eventualities are possible at the investment decision stage. The LWR philosophy can also be seen as risk aversion in the face of an uncertain future we are unable to place a probability distribution on.

Table 5- Regret analysis of options

Option regrets (£m)	TD	SP	SS	CP	S1	S2	S3	S4	Worst Regret
Opt1 - 450MW	*43*	*39*	*179*	*4*	*47*	*0*	*6*	*90*	**£179m**
Opt2 - 600MW	*84*	*80*	*215*	*44*	*87*	*44*	*0*	*0*	**£215m**
Opt3 - 237MW	*44*	*47*	*42*	*45*	*44*	*157*	*335*	*542*	**£542m**
Opt4 - 237MW	*0*	*0*	*0*	*0*	*0*	*120*	*303*	*510*	**£510m**
Opt5 - 138MW	*232*	*278*	*83*	*288*	*267*	*465*	*722*	*987*	**£987m**
Opt6 - 138MW	*166*	*208*	*19*	*220*	*203*	*404*	*663*	*928*	**£928m**
Least Worst Regret:	***Opt1***								***£179m***

This table shows that under the current range of scenario uncertainty, option 1 is the least regret option.

5.6 Drivers of the optimal solution

The reasons that option has come out on top across this wide range of scenarios can be attributed to:

- The large regret of building the largest HVDC option under the SS FES 2017 scenario
- The large regret of building any of options 3-6 in the S4 scenario
- Congestion on the GB mainland attributing to a reduction in savings across all the larger capacity options as the additional exported generation from the Western Isles is constrained elsewhere on the GB network (further detail later in section 5.6)

By inspecting the flow duration curve below from 2035 (once all generation capacity has been built in all scenarios), it becomes clear why the regret analysis recommends the 450MW option under the full range of scenarios. Option 1 captures the effect of uncertainty by allowing all flows to be exported from the island under all scenarios except S3 and S4 where up to approximately 25% of these flows are constrained. The flows below show to what extent Steady State is an outlier in this analysis as its exports never exceed 200MW and hence large regrets are present for all larger capacity options since their capacity is never used despite the high Capex spend to put the export capacity there in the first place.

Redacted

Figure 3- Flow duration curves in 2035 of unconstrained exports from the Western Isles

Redacted

Figure 11- Figure of the differences between the constrained GB network runs and unconstrained.

Figure 11 shows the additional savings realised from removing the consideration of onshore network constraints. This demonstrates the effects congestion on the GB mainland has in reducing the NPV of each option since not all generation can freely flow to demand once it has been exported from the Western Isles.

Since one of the main drivers of Option 1 in this analysis is the wide range in generation scenarios resulting from uncertainty in upcoming CfD auctions, table 6 below shows the same LWR regret analysis with all scenarios except SS. On the assumption that a few of the major projects on Western Isles are successful, there would be more certainty around the range of potential generation scenarios which could eliminate SS as a valid consideration of the future on Western Isles.

Table 6- Regret analysis of options without SS

Option regrets (£m)	TD	SP	SS	CP	S1	S2	S3	S4	Worst Regret
Opt1 - 450MW	43	39		4	47	0	6	90	£90m
Opt2 - 600MW	84	80		44	87	44	0	0	£87m
Opt3 - 237MW	44	47		45	44	157	335	542	£542m
Opt4 - 237MW	0	0		0	0	120	303	510	£510m
Opt5 - 138MW	232	278		288	267	465	722	987	£987m
Opt6 - 138MW	166	208		220	203	404	663	928	£928m
Least Worst Regret:	*Opt2*								*£87m*

It can be seen in this table that the removal of the lowest generation scenario results in a change of the LWR option to option 2. This is due to the highest regret of option 1 now being under the S4 scenario where exports from the Western Isles are constrained due to them exceeding the 450MW limit. This additional analysis shows the importance of consideration of these projects once more certainty has been gained over future generation scenarios on the island after upcoming CfD auctions.

Similarly, by removing the two highest generation scenarios (S3 and S4) in a future where CfD auctions indicate there may not be many successful projects on the Western Isles, table 7 shows us that Option 4 immediately becomes favourable since the large regrets being driven by S3 and S4 are no longer present for this option.

Table 7- Regret analysis of options without S3 and S4

Option regrets (£m)	TD	SP	SS	CP	S1	S2	S3	S4	Worst Regret
Opt1 - 450MW	43	39	179	4	47	0			£179m
Opt2 - 600MW	84	80	215	44	87	44			£215m
Opt3 - 237MW	44	47	42	45	44	157			£157m
Opt4 - 237MW	0	0	0	0	0	120			£120m
Opt5 - 138MW	232	278	83	288	267	465			£465m
Opt6 - 138MW	166	208	19	220	203	404			£404m
Least Worst Regret:	*Opt4*								*£120m*

This additional analysis shows the importance of consideration of these projects once more certainty has been gained over future generation scenarios on the island after upcoming CfD auctions.

5.7 Optimal Timing Analysis

To perform the optimal timing analysis the year which the cable(s) will be delivered has been varied and the subsequent Net Present Value of each option was calculated. This revised NPV takes into account reduced CAPEX from finance timing savings and reduced OPEX savings due to forfeited constraint benefits of the delay.

Redcated

Figure 12 - Optimal timing analysis

Figure 12 shows the optimal timing analysis for the commissioning of option 1 across the full range of scenarios. The year of **Redacted** is being driven by the large regret of building option 1 under the SS scenario in earlier years where there is little generation being built and it is being built at much later dates.

5.8 Additional benefits: GB consumer welfare and CO_2

Alongside the avoided constraint costs, any cable to the Western Isles facilitates the connection of renewable resources with the potential to positively impact the market as marked by two further indicators- consumer welfare and CO_2 reduction. These figures are derived from analysis assuming the FES levels of generation arise in future years, and counterfactuals with the Western Isles generation removed entirely.

Consumer welfare (or increase in consumer surplus) measures the money saved by consumers through wholesale price reductions driven by the generators on the Western Isles. As with most renewable projects, as the short run marginal cost for these technologies is so low they always serve to reduce the wholesale price during high renewable periods. This benefit would be eroded by any subsidies given to the generators funded by the UK consumer, and the amount of curtailment of this power that may occur (again at a cost to the consumer). This figure is directly output from the BID3 software package, and is not used to evaluate the merit of specific projects over alternatives by the SO.

Table 1- Maximum lifetime GB consumer welfare associated with generation on the Western Isles

Redacted

The transmission level generation on the island is all from renewable technologies, and therefore liable to displace carbon generating technologies in the overall GB market under certain conditions. This effect is quantified by measuring the total CO_2 emissions with and without the Western Isles generation, and attributing the reduction in emissions to the presence of Western Isles generation in future years.

Table 2- Lifetime CO_2 reduction associated with the Western Isles generation

Redacted

6 Sensitivities

CFD Strike Price (£/MWh)	Recommended Option
50	Option 4
60	Option 4
70	Option 1
80	Option 1
90	Option 1
100	Option 1
110	Option 1
120	Option 2

6.1 Strike Price Analysis

This section presents identical analysis to the main CBA, with the exception being the variation in the assumed strike prices received by the generators connecting to the Western Isles. The CfD received by the generators on the island directly affects the price at which they would be willing to come off the system in the balancing mechanism and hence is a very important lever I determining the economic viability of each option. The greater the strike price received by each generator the more expensive each MWh of wind becomes to constrain on the Western Isles.

The main CBA uses the same assumption for subsidy prices for wind generation as in the NOA methodology. The analysis presented below presents the main CBA analysis conducted for 8 different strike prices.

Table 8 below presents the results from this sensitivity. Each row in the table represents a full iteration of the CBA with column 2 presenting the LWR recommendation given each strike price.

As show in the table, option 1 (the LWR solution across all scenarios in the main CBA) is recommended for strike prices ranging between £70/MWh and £110/MWh. Across the full range of scenarios, a strike price as high as £120/MWh would be needed to favour option 2. As with the main CBA however, the results in table 8 are driven by the large uncertainty in generation scenarios. The results presented here solidify option 1 as the LWR solution across the full range of uncertainty, however once this uncertainty is reduced following CfD auctions the recommended option here would be likely to change in the same way as presented in the main CBA.

Table 8- CfD Strike Price Analysis LWR results

6.2 Tipping Point Analysis

The 3 options considered favourable across any of the 8 scenarios considered options 1, 2 and 4. This analysis shows how many MW of additional generation on the Western Isles would be required in order to tip the answer to either of the 3 options.

The answers presented here are based on analysis against a SP 2017 FES background but are unlikely to change much for other FES scenarios.

- <370MW – Option 4 (237MW)
- 370MW - 530MW – Option 1 (450MW)
- >530MW – Option 2 (600MW)

6.3 Removal of onshore network constraints

As discussed previously, one of the drivers for the 450MW being preferred over the 600MW option in the main CBA, is the reduction in value created by the 600MW option due to congestion elsewhere on the GB network caused by additional exports from the Western Isles. Table 9 shows the LWR analysis with these constraints removed from the model.

Table 9- LWR analysis when onshore network constraints are not considered (Options 5 and 6 were excluded from the analysis)

Redacted

7 Conclusions

Across the full range of scenarios studied in this CBA, the Least Worst Regret option for connection of the Western Isles to the GB mainland is the 450MW HVDC cable (option 1). This answer is driven by the current wide range of scenarios studied, as it represents an option that covers both the lower and higher generation scenarios in terms of regret. Further clarification on future generation scenarios on the Western Isles would have a very meaningful impact on this CBA, and as demonstrated in this report, elimination of the higher or lower end scenarios would result in the optimal choice of connection changing to either option 2 (600MW) or option 4 (237MW).

While the main CBA under the current range of uncertainty recommends the 450MW link, it is clear from this CBA that this recommendation should be reconsidered once the CfD auction provides further clarity on the future of Western Isles generation.

The timing analysis presented in this report selects an optimal date for connection as 2026 due to the large regret of building the link early in some of the FES scenarios where connection of generation is delayed. Again, the SO would advise revising this recommendation as clarity over major developments on the Western Isles becomes clearer.

SHE Transmission are submitting a needs case to Ofgem based on the 600MW HVDC cable (option 2), on the conditional aspect that CfDs are awarded to some of the major projects on the island. The SO would agree with this approach as the awarding of these CfDs would eliminate SS as a viable future on the Western Isles and change the LWR answer to option 2. However, if major projects on the Western Isles were not successful it would likely eliminate the higher end scenarios (S3 and S4) from consideration and result in option 4 (237MW) being optimal under the remaining set of viable futures.

8 Appendix A: Breakdown of Scenarios

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