Shetland Strategic Wider Works

Needs Case: Cost Benefit Analysis

6th April 2020

Redacted for Public Release

National Grid

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

System Operator Functions Information (SOFI) Confidential

GB Economic Assessment, Network Development, Network Capability

Faraday House
Gallows Hill
Warwick
CV34 6DA
www.nationalgrideso.com

The analysis presented in this report is based on the most relevant and appropriate information available at the time of the production. This document is classified as System Operator Functions Information (SOFI) confidential to SHE Transmission and National Grid ESO and is therefore confidential to these parties and the regulator Ofgem and its agents. It should not be circulated or reproduced in any format without prior written permission from both National Grid ESO and SHE Transmission

Shetland Strategic Wider Works

Needs Case: Cost Benefit Analysis

Contents Amendment Record

The report has been issued and amended as follows:

Contents Amendment Record

Issue	Revision	Description	Date	Approved by
First draft		First complete draft	23/1/2020	-
Final		MV comments addressed	24/1/2020	Marc Vincent
Final v2		Error corrected	06/4/2020	Marc Vincent

Page left intentionally blank

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 Shetland.
- 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[2] 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[3] 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 Shetland.
    - Undertake robustness analysis including a reduction or increase in capital expenditure among others.
- 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

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

[3] 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.

- 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
- Chapter 8: Appendices, providing supporting information

2 Background

2.1 Introduction

The Shetland Isles have long been recognised as an attractive area for potential renewable development given the high wind yields. Currently there is minimal renewable generation connected in Shetland. A limiting factor to renewable development on Shetland has been the isolation of the islands from the Main Integrated Transmission System (MITS). Currently, there is no distribution or transmission connection to the GB mainland network. Without a substantial new transmission connection, development of larger scale renewable projects will not go ahead and as such, the renewable generation potential of Shetland will remain untapped.

It is possible that over 800MW of generation may be commissioned on the islands. Three potential connection options between Shetland and the mainland have been proposed by SHE Transmission to be analysed in this CBA.

SHE Transmission is required to submit a formal needs case to Ofgem, through the SWW process for the proposed connection to Shetland. Full construction funding will only be granted if Ofgem approve the project needs 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. National Grid ESO (NGESO) 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 Shetland 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 NGESO 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.

SHE Transmission's Final Needs Case submission of September 2018 stated that the need for the project was conditional upon Viking Energy Wind Farm being awarded a Contract for Difference (CfD) in the 2019 auction. In their March 2019 consultation Ofgem stated that, subject to this condition being met, they were minded to approve the Final Needs Case as being sufficiently well justified and value for money. As Viking were not successful in the CfD Round 3 auction, this condition has not been met. Hence Ofgem stated that before reaching a decision on the Final Needs Case, it would be in the interests of consumers for Ofgem to consider any revised Final Needs Case that SHET may wish to submit. This CBA is to support SHE Transmission's Shetland SWW revised Final Needs Case submission.

2.2 Network Capabilities

The ESO'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 NOA 2018/19, as published on the 31st of January 2019. Please see www.nationalgrid.com/noa/ for more detail.

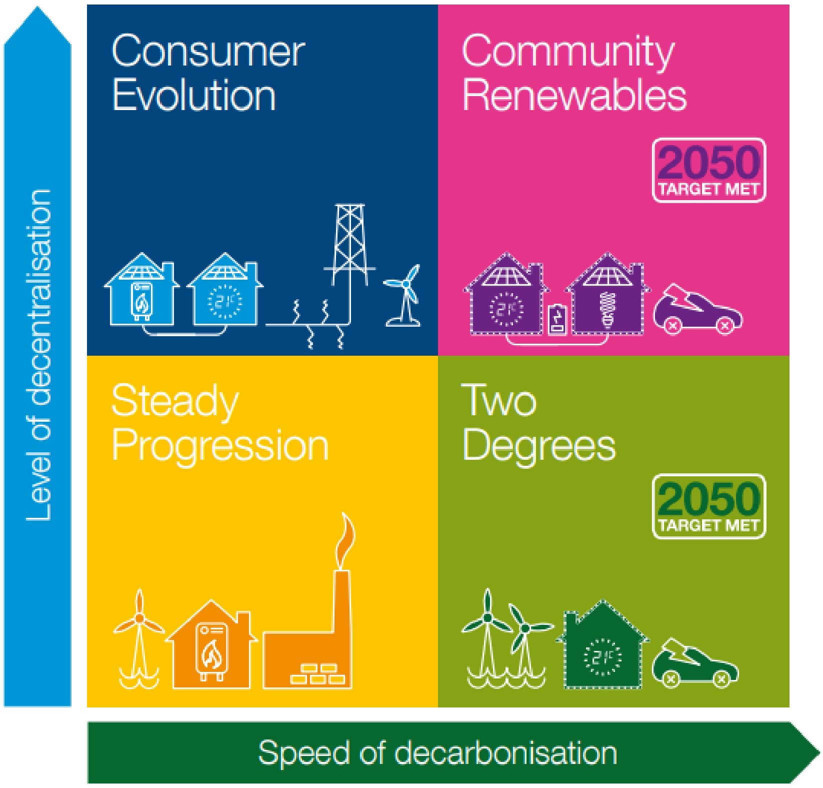
Three connection options are studied in this CBA and comprise of a subsea cable extending from Shetland to the Scottish mainland. All three options considered are point-point HVDC cables between Kergord and Noss Head substations. None of the options were considered to have a material impact on any major 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 Shetland are placed behind this boundary. Forecast flows across this boundary are therefore equivalent to forecast flows through the cables considered. All options considered in this CBA consider the build of a new GSP on Shetland such that Shetland demand can be supported through the new transmission connection to the mainland during times of low renewable output.

2.3 Future Energy Scenario 2018 background

All modelling within this CBA has been undertaken on a FES 2018 background. FES is developed with our stakeholders input to create a range of scenarios highlighting what the future of energy could look like. The four scenarios are based on speed of decarbonisation and level of decentralisation. Two of the FES2018 scenarios achieve an 80% reduction in carbon by 2050: Two Degrees, based on centralised and transmission connected technology; and Community Renewables, based on more decentralised technology. The scenarios and the axes are shown in Figure 1.

Figure 1: FES2018 scenario matrix



The speed of decarbonisation axis is driven by policy, economics and consumer attitudes. All scenarios show progress towards decarbonisation from today, with the two scenarios on the right achieving an 80% reduction in carbon by 2050.The level of decentralisation axis indicates how close the production and management of energy is to the end consumer, moving up the axis from large scale central, to smaller scale local solutions. All scenarios show an increase in decentralised production of energy, compared with today. All our scenarios consider energy demand and supply on a whole system basis, incorporating gas and electricity across the transmission and distribution networks.

For this CBA, GB mainland has been modelled using Steady Progression (SP), as used in the previous iteration of the CBA. Steady Progression is a more centralised scenario than Consumer Evolution or Community Renewables, and does not achieve an 80% reduction in carbon emissions by 2050, compared to 1990 levels. Transmission network build on the mainland increases in capacity in line with the optimal build recommended in Network Options Assessment 2018/19.

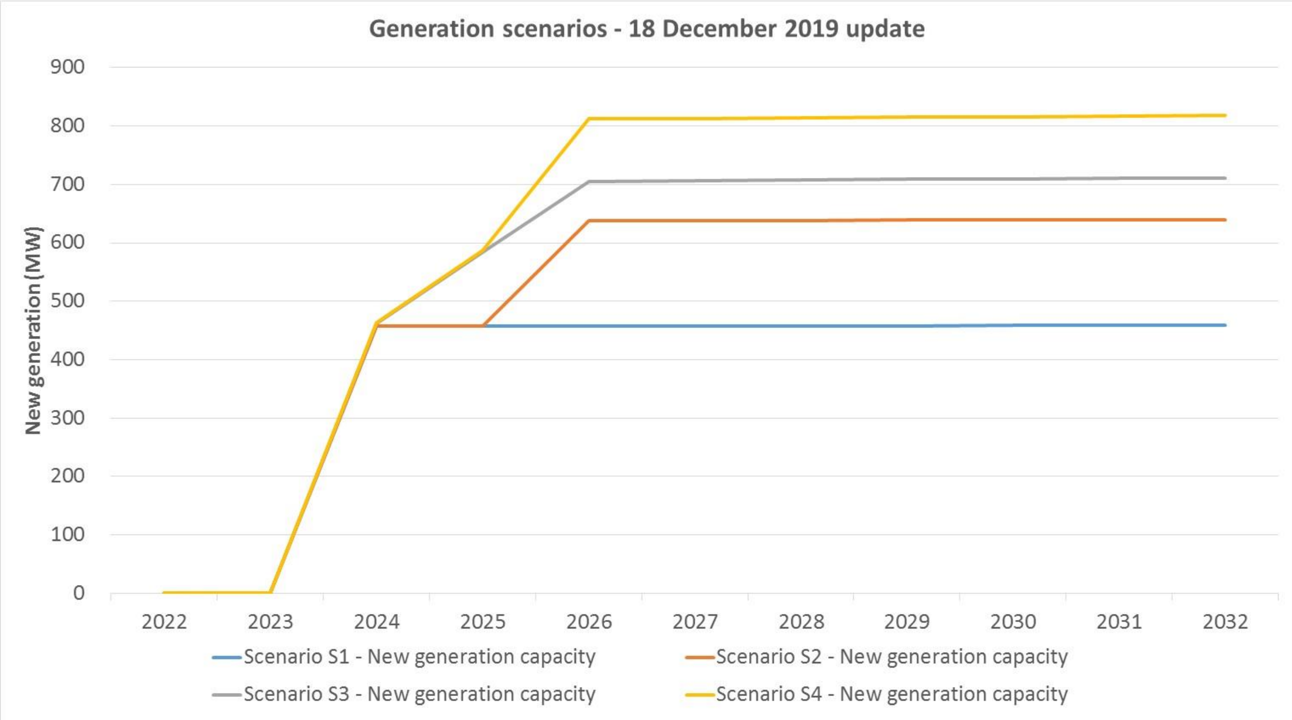
Most important to this study is the view of the generation background on Shetland when combined with Steady Progression, as this will drive usage of the cable; without transmission level generation this rating of cable is unneeded, whilst if generation capacity outstrips the cable capacity too much, then significant constraint costs could be incurred.

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

2.4 Shetland generation backgrounds

As the generation levels on Shetland are so pivotal to the correct sizing of the cable, a wide range of possible capacity profiles has been studied. SHE Transmission 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 Shetland, increasing the robustness of the result obtained. Figure 2 below shows the generation capacity build up on Shetland for the four generation backgrounds.

Figure 2: Generation capacity growth on Shetland across GHD scenarios



Existing generation on Shetland has also been modelled. As stated previously, for each Shetland generation 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 Shetland, without a second degree of freedom in the scenario background. Hence the four generation scenarios used for the CBA are named SP – S1 to SP – S4. A breakdown of the Shetland new generation capacity scenarios is shown in Appendix A.

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 Shetland 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 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 a useful 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 Shetland is in the form of onshore wind.

SHE Transmission have provided 5 years' worth of historic measured wind power output data on Shetland which have been used to construct profiles for generation on the island. 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 CBA as it provides average wind, solar, interconnector flows and constraint costs when comparted to the last 30 weather years.

2.7 Shetland demand

In addition to the updated wind farm development on Shetland is the impact of potentially significant electricity demand resulting from powering offshore oil and gas (O&G) projects with Shetland renewables. SHE Transmission has indicated an electricity demand of 200MW in incremental phases over the period 2026 to 2034, with a profile shown below.

Table 1: possible demand build-up on Shetland

Year	Demand (MW)
2026	50
2030	100
2032	150
2034	200

This potential demand has been modelled as a variable in the CBA.

3 Options for economic appraisal

3.1 Introduction

This chapter presents the options submitted for assessment by SHE Transmission to the ESO. They consist of three subsea cable options of varying capacity.

Table 2: Options submitted to CBA process

Option	Decription	Capability	Capex (£m)[4]
Option 1	Kergord – Noss Head Switching Station HVDC	450MW	**redacted**
Option 2	Kergord – Noss Head Switching Station HVDC	600MW	**redacted**
Option 3	Kergord – Noss Head Switching Station HVDC	800MW	**redacted**

For the main cases considered within the CBA, Option 2 is assumed to have an earliest in service date (EISD) of 2024, and Options 1 and 3 are assumed to have an EISD of 2026. The results of sensitivities where the EISDs of all three options are modelled as 2024 and 2026, are shown in Chapter 6.

3.2 Option capability

The range of capabilities above ensures that almost all of the new generation in the most onerous scenario (817.8MW in scenario S4) would be exportable by the highest capability 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.

Table 3: PV of CAPEX of Options

Option	PV EISD 2024 (£m)	PV EISD 2026 (£m)
Option 1	**redacted**	**redacted**
Option 2	**redacted**	**redacted**
Option 3	**redacted**	**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** for SHE Transmission, and
- **Social Time Preference Rate** or **STPR**, which is estimated at 3.5% p.a. by HM Treasury.

[4] Note that the CAPEX numbers are the summation of annual spend profiles and do not include the effect of discounting.

3.5 Contracts for Difference (CfD)

One of the key drivers for this CBA is to investigate the potential impact of the Contract for Difference (CfD) allocation Round 3 auction results on constraint costs. CfDs are the mechanism for subsidising wind, replacing Renewable Obligation Certificates (ROC) previously used. A key factor in forecasting constraint costs is the ‘bid’ price the ESO needs to pay for a generator to turndown their output. Historically the assumptions for the bid price of wind plant has been based on ROCs. This CBA has been undertaken using generator bid pricing strategies based on both ROCs and CfDs, using the ESO’s current best understanding of a CfD pricing strategy. The ESO is working with various industry parties to understand potential bidding strategies to support our development of robust assumptions for subsidy free bids. It is currently assumed that compared to the ROC arrangement the bid prices for wind generation will reduce under the CfD and non-subsidised arrangements.

3.6 Main cases for economic appraisal

This section highlights the four main cases considered. The cases flex two key variables: modelling with ROCs or CfDs, and including or excluding additional electricity demand on Shetland due to oil and gas industrial demand. Each case is numbered for ease of reference.

- **Case 1:** Option 2 (600MW) with an EISD of 2024, Option 1 (450MW) and Option 3 (800MW) with an EISD of 2026, with **no O&G** demand, modelled with **ROCs**
- **Case 2:** Option 2 (600MW) with an EISD of 2024, Option 1 (450MW) and Option 3 (800MW) with an EISD of 2026, **with O&G** demand, modelled with **ROCs**
- **Case 3:** Option 2 (600MW) with an EISD of 2024, Option 1 (450MW) and Option 3 (800MW) with an EISD of 2026, with **no O&G** demand, modelled with **CfDs**
- **Case 4:** Option 2 (600MW) with an EISD of 2024, Option 1 (450MW) and Option 3 (800MW) with an EISD of 2026, **with O&G** demand, modelled with **CfDs**

Additional sensitivity cases were modelled to investigate the impact of changes to the EISD of the three options, with the results presented within Chapter 6.

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 ESO'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 ESO 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

As discussed in section 2.5, to provide a reference value of total constraint costs a counterfactual has been simulated, wherein all generation on Shetland is curtailed for all of the time as no cable has been deployed. This leads to very large constraint costs, of which the Shetland 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 out to 2038, the end of the 20 year period to which the SO models as standard.

Figure 3: Counterfactual constraint costs (undiscounted)

redacted

4.4 Constraint savings

The constraint savings associated with each reinforcement option (i.e. the HVDC link) is the difference between its base/counterfactual constraint cost and the corresponding constraint costs with the link included.

Figure 4: Case 1 constraint savings (undiscounted)

redacted

Figure 5: Case 2 constraint savings (undiscounted)

Redacted

Figure 6: Case 3 constraint savings (undiscounted)

redacted

Figure 7: Case 4 constraint savings (undiscounted)

redacted

5 Cost benefit assessment

5.1 Introduction

The CBA compares the Present Value (PV) of the HVDC link option costs with the PV of forecasted constraint cost savings. Where constraint cost savings exceed the investment cost, the option may be considered economic. For each reinforcement option, the PV of both the annual constraint savings and the associated capital 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 in Chapters 3 and 4 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 option based on a Least Worst Regret (LWR) approach.

5.2 Model results, extrapolation and CBA timeframes

FES 2018 generation backgrounds do not extend in detail beyond 2038, and so that is the extent to which detailed BID3 constraint forecast modelling can project. Constraint savings have been extrapolated from 2038 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 **redacted** 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.

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.

Tables 4 to 7 shows the net present value and least worst regret results for the four main cases 1 to 4.

Table 4: Case 1 - 600MW (Option 2) with an EISD of 2024, 450MW (Option 1) and 800MW (Option 3) with an EISD of 2026, with no O&G demand, modelled with ROCs

NPVs (£m)	SP - S1	SP - S2	SP - S3	SP - S4
Option 1	redacted	redacted	redacted	redacted
Option 2	redacted	redacted	redacted	redacted
Option 3	redacted	redacted	redacted	redacted

Regrets (£m)	SP - S1	SP - S2	SP - S3	SP - S4	WR
Option 1	0.00	52.24	94.86	141.45	141.45
Option 2	7.59	0.00	0.00	0.00	7.59
Option 3	82.27	60.31	52.13	8.82	82.27

Least worst regret for Case 1 is Option 2.

Option 2 produces the highest NPVs for three of the four scenarios in case 1.

Table 5: Case 2 - 600MW with an EISD of 2024, 450MW and 800MW with an EISD of 2026, with O&G demand, modelled with ROCs

NPVs (£m)	SP - S1	SP - S2	SP - S3	SP - S4
Option 1	redacted	redacted	redacted	redacted
Option 2	redacted	redacted	redacted	redacted
Option 3	redacted	redacted	redacted	redacted

Regrets (£m)	SP - S1	SP - S2	SP - S3	SP - S4	WR
Option 1	13.19	10.99	40.13	74.92	74.92
Option 2	0.00	0.00	0.00	0.00	0.00
Option 3	95.77	85.35	99.48	84.03	99.48

Least worst regret for Case 2 is Option 2.

Option 2 produces the highest NPVs for all the scenarios. Scenario SP S1 results in negative NPVs for all link options, i.e. the PV of constraint savings are less than the PV of capital costs.

Table 6: Case 3 - 600MW with an EISD of 2024, 450MW and 800MW with an EISD of 2026, with no O&G demand, modelled with CfDs

NPVs (£m)	SP - S1	SP - S2	SP - S3	SP - S4
Option 1	redacted	redacted	redacted	redacted
Option 2	redacted	redacted	redacted	redacted
Option 3	redacted	redacted	redacted	redacted

Regrets (£m)	SP - S1	SP - S2	SP - S3	SP - S4	WR
Option 1	0.00	0.00	0.00	0.00	0.00
Option 2	56.19	33.01	17.08	2.01	56.19
Option 3	85.41	59.03	42.12	11.65	85.41

Least worst regret for Case 3 is Option 1.

In Case 3 there are negative NPVs for all options for scenarios SP - S1 and SP – S2. This is because the levels of constraint costs and hence constraint cost savings are reduced with the use of generator bid pricing strategies based on Round 3 CfD results.

Table 7: Case 4 - 600MW with an EISD of 2024, 450MW and 800MW with an EISD of 2026, with O&G demand, modelled with CfDs

NPVs (£m)	SP - S1	SP - S2	SP - S3	SP - S4
Option 1	redacted	redacted	redacted	redacted
Option 2	redacted	redacted	redacted	redacted
Option 3	redacted	redacted	redacted	redacted

Regrets (£m)	SP - S1	SP - S2	SP - S3	SP - S4	WR
Option 1	0.00	0.00	0.00	0.00	0.00
Option 2	39.49	39.82	36.59	26.20	39.82
Option 3	85.42	82.70	82.13	67.87	85.42

Least worst regret for Case 4 is Option 1.

In case 4 the effect of reduced constraint costs due to CfDs is compounded by the oil and gas demand on Shetland reducing the level of electricity exports from the island, resulting in a further reduction in constraint savings. All NPVs are negative for Case 4, i.e. for all link options with all scenarios. Not surprisingly, NPVs for generation scenario SP – S1 are the most negative, as this scenario has the lowest level of generation capacity on the island, resulting in the lowest levels of generation output.

For cases 1 to 4, the Least Worst Regret solution is Option 1, the 450MW link for two cases and Option 2, the 600MW for the other two cases. Option 1 is optimal in nine of the sixteen scenarios, whilst Option 2 is optimal in the remaining seven. Option 3 is not optimal in any of the scenarios. Option 1 is the LWR solution in Cases 3 and 4, that is the cases where generator bid pricing strategies are based on CfDs because the reduced constraint cost savings in these scenario result in the lower cost HVDC link option producing the highest NPVs relative to the other two options, even though the absolute NPVs are negative.

5.6 Drivers of the Least Worst Regret Solutions

The reasons that Options 1 and 2 are the least worst regret solutions are:

- For Case 1: High regrets of building Option 1 (450MW) with high generation scenarios S3 and S4, with the larger generation capacities driving high levels of constraint costs with the smaller HVDC link. High regrets of building the largest HVDC link Option 3 (800MW) with the smallest generation scenario S1.
- For Case 2: High regrets of building Option 1 or Option 3. Regrets with Option 3 are increased with the inclusion of Oil and Gas demand on Shetland, as reduced generation export volumes are transported from Shetland.
- For Case 3: High regrets of building Options 2 and 3 with the smallest generation scenario S1, driven by reduced constraint savings with CfDs.
- For Case 4: High regrets of building Option 3 with any of the generation scenarios, driven by reduced constraint savings with CfDs and reduced export volumes due to O&G electricity demand on Shetland.

6 Sensitivities

6.1 Introduction

Additional sensitivity cases were modelled to investigate the impact of changes to the EISD on the CBA LWR results.

6.2 Earliest in service date (EISD) analysis

This section compares the LWR CBA result when the EISD of the option are varied. The sensitivities explore the effect of all three options being delivered in 2024, or all three options being delivered in 2026.

The cases exploring the EISD variations are:

- **Case 1a:** Option 1 (450MW), Option 2 (600MW) and Option 3 (800MW) with an EISD of **2024**, **no O&G** demand, modelled with **ROCs**
- **Case 1b:** Option 1 (450MW), Option 2 (600MW) and Option 3 (800MW) with an EISD of **2026**, **no O&G** demand, modelled with **ROCs**
- **Case 2a:** Option 1 (450MW), Option 2 (600MW) and Option 3 (800MW) with an EISD of **2024, with O&G** demand, modelled with **ROCs**
- **Case 2b:** Option 1 (450MW), Option 2 (600MW) and Option 3 (800MW) with an EISD of **2026, with O&G** demand, modelled with **ROCs**
- **Case 3a:** Option 1 (450MW), Option 2 (600MW) and Option 3 (800MW) with an EISD of **2024**, **no O&G** demand, modelled with **CfDs**
- **Case 3b:** Option 1 (450MW), Option 2 (600MW) and Option 3 (800MW) with an EISD of **2026**, **no O&G** demand, modelled with **CfDs**
- **Case 4a:** Option 1 (450MW), Option 2 (600MW) and Option 3 (800MW) with an EISD of **2024, with O&G** demand, modelled with **CfDs**
- **Case 4b:** Option 1 (450MW), Option 2 (600MW) and Option 3 (800MW) with an EISD of **2026, with O&G** demand, modelled with **CfDs**

Tables 8 to 15 show the NPVs and LWRs for sensitivity cases 1a to 4b.

Table 8: Case 1a: 450MW, 600MW and 800MW with an EISD of 2024 with no O&G demand, modelled with ROCs

NPVs (£m)	SP - S1	SP - S2	SP - S3	SP - S4
Option 1	redacted	redacted	redacted	redacted
Option 2	redacted	redacted	redacted	redacted
Option 3	redacted	redacted	redacted	redacted

Regrets (£m)	SP - S1	SP - S2	SP - S3	SP - S4	WR
Option 1	0.00	26.63	59.59	123.30	123.30
Option 2	42.18	0.00	0.00	13.76	42.18
Option 3	87.99	41.85	24.32	0.00	87.99

Least worst regret for Case 1a is Option 2.

Option 2 has the highest NPV for two of the scenarios, with Option 1 and Option 3 each having the highest NPV for one of the other two scenarios.

Table 9: Case 1b: 450MW, 600MW and 800MW with an EISD of 2026 with no O&G demand, modelled with ROCs

NPVs (£m)	SP - S1	SP - S2	SP - S3	SP - S4
Option 1	redacted	redacted	redacted	redacted
Option 2	redacted	redacted	redacted	redacted
Option 3	redacted	redacted	redacted	redacted

Regrets (£m)	SP - S1	SP - S2	SP - S3	SP - S4	WR
Option 1	0.00	31.10	63.87	132.63	132.63
Option 2	38.93	0.00	0.00	17.80	38.93
Option 3	82.27	39.17	21.15	0.00	82.27

Least worst regret for Case 1b is Option 2.

Option 2 is the optimal solution for two of the scenarios. Option 1 drives high regrets with the highest Shetland generation scenario SP – S4, and Option 3 drives high regrets with the lowest Shetland generation scenario SP – S1.

Table 10: Case 2a: 450MW, 600MW and 800MW with an EISD of 2024 with O&G demand, modelled with ROCs

NPVs (£m)	SP - S1	SP - S2	SP - S3	SP - S4
Option 1	redacted	redacted	redacted	redacted
Option 2	redacted	redacted	redacted	redacted
Option 3	redacted	redacted	redacted	redacted

Regrets (£m)	SP - S1	SP - S2	SP - S3	SP - S4	WR
Option 1	0.00	0.00	0.00	19.94	19.94
Option 2	44.85	38.56	19.09	0.00	44.85
Option 3	88.36	79.80	64.04	34.27	88.36

Least worst regret for Case 2a is Option 1.

Option 1 is optimal in 3 out of 4 of the scenarios.

Table 11: Case 2b: 450MW, 600MW and 800MW with an EISD of 2026 with O&G demand, modelled with ROCs

NPVs (£m)	SP - S1	SP - S2	SP - S3	SP - S4
Option 1	redacted	redacted	redacted	redacted
Option 2	redacted	redacted	redacted	redacted
Option 3	redacted	redacted	redacted	redacted

Regrets (£m)	SP - S1	SP - S2	SP - S3	SP - S4	WR
Option 1	0.00	0.00	0.00	22.67	22.67
Option 2	41.72	35.85	17.16	0.00	41.72
Option 3	82.57	74.36	59.35	31.78	82.57

Least worst regret for Case 2b is Option 1.

Option 1 is optimal in 3 out of 4 of the scenarios.

Table 12: Case 3a: 450MW, 600MW and 800MW with an EISD of 2024 with no O&G demand, modelled with CfDs

NPVs (£m)	SP - S1	SP - S2	SP - S3	SP - S4
Option 1	redacted	redacted	redacted	redacted
Option 2	redacted	redacted	redacted	redacted
Option 3	redacted	redacted	redacted	redacted

Regrets (£m)	SP - S1	SP - S2	SP - S3	SP - S4	WR
Option 1	0.00	0.00	0.00	5.12	5.12
Option 2	50.25	23.20	11.23	0.00	50.25
Option 3	91.55	65.99	48.18	24.41	91.55

Least worst regret for Case 3a is Option 1.

Option 1 is optimal in 3 out of 4 of the scenarios. Scenarios SP – S1 and SP – S2 both result in all link options resulting in negative NPVs, as CfDs result in lower constraint savings.

Table 13: Case 3b: 450MW, 600MW and 800MW with an EISD of 2026 with no O&G demand, modelled with CfDs

NPVs (£m)	SP - S1	SP - S2	SP - S3	SP - S4
Option 1	redacted	redacted	redacted	redacted
Option 2	redacted	redacted	redacted	redacted
Option 3	redacted	redacted	redacted	redacted

Regrets (£m)	SP - S1	SP - S2	SP - S3	SP - S4	WR
Option 1	0.00	0.00	0.00	9.66	9.66
Option 2	47.08	19.55	7.98	0.00	47.08
Option 3	85.41	59.03	42.12	21.31	85.41

Least worst regret for Case 3b is Option 1.

Option 1 is optimal in 3 out of 4 of the scenarios. Option 3 results in high regrets with the lowest Shetland generation scenario SP – S1

Table 14: Case 4a: 450MW, 600MW and 800MW with an EISD of 2024 with O&G demand, modelled with CfDs

NPVs (£m)	SP - S1	SP - S2	SP - S3	SP - S4
Option 1	redacted	redacted	redacted	redacted
Option 2	redacted	redacted	redacted	redacted
Option 3	redacted	redacted	redacted	redacted

Regrets (£m)	SP - S1	SP - S2	SP - S3	SP - S4	WR
Option 1	0.00	0.00	0.00	0.00	0.00
Option 2	47.02	44.05	44.79	32.66	47.02
Option 3	91.58	88.98	86.96	73.91	91.58

Least worst regret for Case 4a is Option 1.

Option 1 is optimal in all four scenarios, with Option 3 producing high regrets for all the generation scenarios.

Table 15: Case 4b: 450MW, 600MW and 800MW with an EISD of 2026 with O&G demand, modelled with CfDs

NPVs (£m)	SP - S1	SP - S2	SP - S3	SP - S4
Option 1	redacted	redacted	redacted	redacted
Option 2	redacted	redacted	redacted	redacted
Option 3	redacted	redacted	redacted	redacted

Regrets (£m)	SP - S1	SP - S2	SP - S3	SP - S4	WR
Option 1	0.00	0.00	0.00	0.00	0.00
Option 2	43.84	41.12	42.73	29.25	43.84
Option 3	85.42	82.70	82.13	67.87	85.42

Least worst regret for Case 4b is Option 1.

Option 1 is optimal in all four scenarios.

Tables 8 to 15 show that in six out of eight of the cases where Options 1, 2 and 3 are all delivered in the same year, the changes in constraint savings result in Option 1 being the LWR recommendation.

Table 16 provides a summary of which link option is the least worst regret recommendation for all the cases studied.

Table 16: Least worst regret recommendation for all cases

	Least worst regret		
Case	Option 1	Option 2	Option 3
Case 1			
Case 2			
Case 3			
Case 4			
Case 1a			
Case 1b			
Case 2a			
Case 2b			
Case 3a			
Case 3b			
Case 4a			
Case 4b			

Table 16 shows that Option1, the 450MW link results in the least worst regret recommendation for two of the main cases (Cases 3 and 4) and Option 2, the 600MW link results in the least worst regret recommendation for the other two main cases (Cases 1 and 2). Of the other eight cases, Option 1 is the LWR recommendation for six of the cases (2a, 2b, 3a, 3b, 4a, 4b) and Option 2 is the LWR recommendation for the remaining two cases (1a and 1b). Option 3 is not the LWR recommendation for any of the cases in the sensitivity analysis.

The analysis shows that delaying Option 2 to 2026, or the earlier delivery of Option 1 in 2024 is significant, with 75% of the sensitivities (i.e. 6 of the 8) showing the LWR solution as Option 1. In addition, all of the cases which use the generator bid pricing strategies based on Round 3 CfD results (cases 3a, 3b, 4a, 4b) show the LWR recommendation being Option 1.

6.3 Generation capacity tipping point analysis

For the four main cases, the optimal link size option for each scenario is indicated by a 0 in the column in Tables 4 to 7. Option 2 is the optimal solution for 15 out of the 16 scenarios, i.e. produces the highest NPV. Only scenario SP S1 for Case 1 results in Option 1 being the optimal solution, i.e. the 450MW link is optimal for the lowest level of generation with no oil and gas industrial demand and modelling with ROCs. Option 3 is not optimal for any of the scenarios: it is possible that for a higher, untested level of generation Option 3 would become optimal.

To find the exact level of generation at which the optimal link size changes from Option 1 to Option 2, or from Option 2 to Option 3, simulations would have to be performed iteratively for a build-up of generation that made the NPV of the two best options exactly equivalent. An approximation to this exercise can be obtained, however, using linear interpolation of the difference in the NPV between options being used to scale the entire capacity profile to where the difference would be zero. The year 2026 is chosen, as this the first year in all four generation scenarios where the final level of generation is achieved. Note that this can only be undertaken for balance point between Options which have an optimal solution.

The results of the analysis are shown in Table 17.

Table 17: Calculated capacity tipping point between optimal solutions

Case	Change in Option	Change in generation	Tipping point (MW)
1	1 to 2	S1 to S2	480.1
1a	1 to 2	S1 to S2	567.6
1a	2 to 3	S3 to S4	770.6
1b	1 to 2	S1 to S2	557.3
1b	2 to 3	S3 to S4	760.6
2a	1 to 2	S3 to S4	754.9
2b	1 to 2	S3 to S4	748.9
3a	1 to 2	S3 to S4	775.6
3b	1 to 2	S3 to S4	751.1

Table 17 shows the only scenarios where Option 3 is optimal is case 1a with SP S4 and case 1b with SP S4, and the tipping point in generation capacity to change the optimal solution from Option 2 to Option 3 is 770.6 MW and 760.6 MW respectively. The tipping point in generation capacity required to change the optimal solution from Option 1 to 2 varies between 480.1 MW to 775.6 MW. The wide range in tipping point value is driven by the tipping point occurring between generation capacities S1 to S2 and S3 to S4.

7 Conclusions

This CBA uses the 'savings approach' to assess the optimal connection capacity option across a range of future energy scenarios. The report does not assess whether a connection to the islands is in the economic interest of the GB consumer and only compares the economic benefit of each connection option relative to each other.

For the four main cases within this CBA there are two options for the least worst regret recommendation. For two of the four main cases, the Least Worst Regret recommendation is Option 1, the 450MW link: for the other two cases Option 2, the 600MW link is the LWR recommendation. Option 1 is optimal in nine of the sixteen scenarios, whilst Option 2 is optimal in the remaining seven. Option 3 is never the LWR recommendation and is not optimal in any of the scenarios. However, a larger generation background on Shetland may result in Option 3 becoming optimal in certain scenarios.

The impact of modelling the Contract for Difference (CfD) Round 3 auction results, the impact of potential electricity demand on Shetland from the oil and gas industry and the impact of varying the EISD of the various HVDC links are all significant in terms of NPV results and ultimately the least worst regret recommendation.

Many of the cases result in negative NPVs, with several cases showing all combinations of link option and generation scenario producing negative NPVs. This is the consequence of the modelling of the Round 3 auction CfDs and oil and gas demand on Shetland.

8 Appendix A: Breakdown of Shetland generation scenarios

Table 18: Breakdown of new connected Transmission level generation on Shetland

redacted

Faraday House, Warwick Technology Park,
Gallows Hill, Warwick, CV346DA

nationalgrideso.com