Impacts of further electricity interconnection on Great Britain

A Report by Redpoint Energy Limited, a business of Baringa Partners, for the Department of Energy and Climate Change (DECC)

November 2013

www.baringa.com

Version: 1.0 **Date:** 07/11/13

Version History

Version	Date	Description	Prepared by	Approved by
Final	07 November 2013	Final	Pavlos Trichakis Vladimir Parail Ilesh Patel	Ilesh Patel

Contact

www.baringa.com, www.redpointenergy.com
eas@baringa.com
Tel: +44 (0)203 327 4220

Copyright

Disclaimer

Contents

1 Executive summary

Context

Redpoint Energy, a business of Baringa Partners LLP, was commissioned by the Department of Energy and Climate Change (DECC) to undertake analysis to help improve its understanding of the welfare impacts (benefits and costs) on Great Britain (GB) of further electricity interconnection with Continental Europe. The scope of the study included the following components:

- *The impacts on GB net welfare (to include electricity prices and security of electricity supply) including the distribution of costs and benefits between different parties and countries, of different levels of interconnection, to different connected markets, at different rates of deployment and in different orders.*
- *Taking into account the impacts and risks of different interconnections, to find the optimal (for GB net welfare) levels/ranges of interconnection, the optimal order for those interconnections to be deployed (in total and to specific connecting markets), and the no-regrets levels/ranges that should be pursued.*

Scenarios modelled

Our analysis has been undertaken under a range of plausible scenarios and assumptions. The scenario framework was developed jointly with DECC and was designed to be consistent with the UK keeping within its carbon budgets. The modelled time horizon covered the period from 2015 to 2050.

After careful consideration of the main drivers that are likely to have the most significant impact on the welfare effects of further interconnection between GB and neighbouring markets, we developed four main scenarios in order to evaluate different GB interconnection strategies. These scenarios can be summarised as follows:

1. <u>GB importing</u> – this is a scenario where interconnectors are utilised mostly to transfer lower cost electricity from Continental Europe to GB[1]. This is likely to materialise in a world with moderate gas prices, where generators face higher carbon prices in GB compared to Europe, and where it is possible to import through interconnection surplus low carbon electricity (particularly from renewable energy sources) from the Continent.
2. <u>Flexible operation</u> – this is a scenario where significant amounts of flexibility are required, with higher intermittency across European power markets than that seen under the GB importing scenario increasing the extrinsic value of interconnectors[2]. This is likely to

[1] Note that this does not imply that interconnectors would be importing power to GB 100% of the time, merely that there would be a strong tendency for imports into GB to dominate export from GB.

[2] An electricity interconnector is said to have high intrinsic value when a large differential in average prices exists between the two connected markets. Conversely, an electricity interconnector is said to have high extrinsic value when, even though the difference in average prices may be small, significant random hourly price variation exists between the two connected markets.

materialise in a world where very significant amounts of intermittent renewable technologies (particularly onshore and offshore wind) are deployed across Europe, partly due to high fossil fuel prices incentivising their advanced deployment. This scenario also assumes that generators in GB face broadly similar carbon prices as in Continental Europe.

3. Low utilisation – this is a challenging scenario for developing interconnectors since electricity price differences across European markets remain low due to persistently low fossil fuel prices. This scenario also assumes that generators in GB face broadly similar carbon prices as in Continental Europe and that, whilst unabated gas plant dominate in the short- to medium- term, there is an increased role for gas CCS (Carbon Capture and Storage) and coal CCS in the longer term due to low fossil fuel prices and relatively slow progress in offshore wind.

4. Carbon price convergence –we have also modelled a fourth scenario which uses the same fundamental assumptions as Scenario 1 (i.e. moderate fossil fuel prices coupled with a relatively balanced, albeit renewables favouring, generation mix in the UK and Continental Europe), however this scenario assumes that there are no longer significant differences between carbon prices in GB and the rest of Europe.

Interconnector configurations

Potential options for future GB interconnection were formulated as interconnector configurations, which specify the capacity, timing, connected market and GB landing zone of each new interconnector. A total of 15 different configurations were formulated to reflect a variety of possible development paths for future GB interconnection with varying degrees of ambition. The formulation of configurations took into account our knowledge of the actual proposed GB interconnection projects and considerations about the types and features of interconnectors that are likely to be beneficial to GB under the different scenarios considered in our study. Each of these configurations was modelled against each scenario.

Modelling methodology

The modelling was carried out on the basis of spot years (2015, 2020, 2025, 2030, 2035, 2040 and 2050)[3] with full hour by hour dispatch being modelled for each of these years. The model optimised the dispatch of plant and interconnectors across the modelled European markets while meeting: (i) transmission network constraints, both within GB and between different European markets; (ii) plant-level constraints such as ramping times and legislated run time constraints (e.g. the Large Combustion Plant Directive); and (iii) reserve and frequency response requirements across all modelled markets. Outputs from the optimisation (such as generation costs, wholesale

[3] Note that results up to 2040 only were used in the CBA analysis. The results for 2050 are excluded from the calculation of NPV of net welfare because they were deemed to be volatile and the risk of this volatility in the results obscuring the underlying messages is high. The reason for the volatility of 2050 welfare results is that reserve and response constraints become more difficult for the model to meet by 2050. The model is required to take increasingly drastic steps to meet those constraints with potentially large impacts on the welfare results. This is particularly noticeable in Scenario 2, which sees very large amounts of inflexible generation capacity across the modelled markets by 2050. As a result, we felt it was more appropriate to follow a conservative approach and thus only include results up to 2040 in order to ensure that results presented here are as robust as possible.

power prices, carbon emissions and costs, interconnection dispatch schedules and network reinforcement costs) were fed into a separate Cost Benefit Analysis (CBA), described below.

Cost benefit analysis

CBA results were evaluated on a relative basis such that each configuration under a given scenario was compared to a counterfactual case where no additional GB interconnection is built after 2013. This approach isolates the estimated impact of changes in future GB interconnection.

Our CBA was built by measuring the following key components:

- Consumer welfare – representing the change in costs and benefits to GB consumers of electricity;
- Producer welfare – representing the change in costs and benefits to GB producers of electricity;
- Interconnector welfare – representing the change in the GB share[4] of the cost and revenues of interconnectors; and
- Net welfare – representing the change in aggregate net welfare accounting for all costs and benefits attributable to GB.

Modelling results

We also endeavoured to analyse optimal interconnection strategies for GB (on the basis of net welfare) and potential least regret scenarios.

We found the optimal interconnection strategy (based on net welfare) for GB to be very sensitive to assumptions about the state of the world during the horizon modelled. High levels of further interconnection (of up to 15.4 GW) built up over the period to 2040 are beneficial to net welfare in GB in a world with an ambitious roll-out of intermittent renewables across much of Europe, including GB ("Scenario 2 – Flexible Operation"). Similarly high levels of additional interconnection (12.8 GW according to the optimal levels of interconnection analysis) are also beneficial in a world where a large differential in carbon prices prevails between GB and the markets to which it is connected ("Scenario 1 – GB Importing"). In the absence of these factors, more limited amounts of additional interconnection with GB's closest neighbours appear to be optimal. This is particularly the case in a world of low gas prices and abundant CCGT capacity, where only a modest expansion (as low as 2.5 GW) to existing GB interconnection appears optimal ("Scenario 3 – Low Utilisation"). Assuming a world with moderate fossil fuel prices and without significant carbon price differentials between GB and the rest of Europe, the optimal levels of additional interconnection have been estimated at approximately 8.6 GW ("Scenario 4 – Carbon price convergence").

Analysis of the distribution of costs and benefits between different parties (producers, consumers and interconnector owners) has shown that different scenarios and configurations can lead to very

[4] The costs and earnings related to interconnection are assumed to be split evenly between GB and each interconnected market. It is also assumed that interconnectors operate in a fully merchant fashion, i.e. that there are no "cap and floor" policies imposed on their revenues or their rates of return.

different results in the distribution of impacts across groups and across countries. From a GB consumer viewpoint, the most desirable configurations are those that connect to countries with lower electricity prices than GB (particularly so if peak prices across the two countries are also not highly correlated) since these configurations are more likely to lead to electricity cost savings. Conversely, from a GB producer viewpoint, the most desirable configurations are those that connect to countries with higher electricity prices than GB since that can lead both to higher GB electricity prices and also lead to an increase in the amount of generation being produced in GB. Finally, from an interconnector viewpoint, the most desirable connections are those where interconnector capital costs are minimised and where the intrinsic and extrinsic values of the interconnector are maximised.

Our least regret interconnection analysis (on the basis of net welfare) has shown that incremental increases in interconnection with GB's closest neighbours including France, Ireland and Belgium, with a total new additional GB interconnection reaching 5.0 GW by 2040, are likely to be beneficial to GB net welfare under a broad range of future states of the world. But large interconnection projects to distant markets or a rapid expansion in the overall interconnection level are more risky in the absence of a clearer indication of the trends in market fundamentals (such as fossil fuel and carbon prices, generation capacity mix and electricity demand levels). The notable exception to this is Norway which, despite being a relatively distant market, is unlikely to lead to regret at modest levels initially, and could potentially lead to even greater GB net welfare benefits depending on the direction the market fundamentals take. This is due to the shape of prices in Norway, which are considerably more flat compared to GB prices, thus also leading to significant price arbitrage opportunities and lower GB prices overall.

It is worth noting, however, that the appropriate strategy to pursue is a matter of judgement and will reflect the balance of risk and reward given the possible future states of the world and the potential impacts of different levels of interconnection.

Our analysis also considers emerging themes with regards to interconnection, such as that the value of diversification (a larger number of smaller interconnectors to more markets) is relatively low and that further interconnection could reduce the overall level of GB grid reinforcements. The full results of this analysis are set out in detail in Section 6.6.

Sensitivity analysis

In order to assess the robustness of the key results of our analysis to changes in some key modelling assumptions (in addition to the differences in assumptions between different modelled scenarios), sensitivities were carried out on the price used to evaluate changes in carbon emissions as a result of changes in GB interconnection and the capital cost of interconnection.

Under the evaluation of carbon emissions savings sensitivity, the same EUA carbon price assumptions were employed to evaluate savings in carbon emissions as a result of further GB interconnection under all scenarios and for all modelled markets. This differs from our core CBA modelling, where carbon emissions savings are evaluated at the carbon price in the country where those emissions are generated[5]. Although significantly lower levels of additional GB

[5] Here, the Carbon Price Floor level is used to evaluate carbon savings in GB and the EUA price is used to evaluate carbon savings in other EU markets, which means that part of the welfare benefit of GB interconnection is accounted for by carbon price arbitrage.

interconnection are estimated to be optimal for GB net welfare under this sensitivity in the context of Scenario 1, the least regrets interconnection strategy is shown to be robust to changes in assumptions on how carbon emission reductions are evaluated.

Under the capital cost of interconnection sensitivity, we tested the results of +/-25% changes in the cost of interconnection on optimal and least regrets interconnection results for GB. These changes could result from changes to the required capital expenditure on interconnection or the required rate of return on interconnector investment, both of which are highly uncertain. The results of this sensitivity demonstrate that optimal and least regrets interconnection strategies (for net welfare) are very resilient to changes in the capital cost of interconnection, which suggests that the cost of interconnection is not likely to be the main driver towards determining optimal and least regrets interconnection strategies (for net welfare) for GB.

Stress test results

We also carried out two "stress tests" to analyse the impact of changes in GB interconnection on security of supply in GB under different sets of extreme conditions. The assumptions for the stress tests were designed to represent extreme but realistic sets of outcomes that are internally consistent within each stress test. In deriving these assumptions, we have also given consideration to the likelihood of stressed situations in GB being correlated with stressed situations in countries to which GB would be connected. This is likely to be crucial to the difference that interconnectors can make in such situations. The outcomes of the stress test for each of the modelled interconnection configurations and scenarios were measured in terms of system cost and energy unserved.

Stress test results suggest that greater levels of interconnection are generally associated with improved security of supply. Although both low wind and high demand conditions can be correlated across markets, forced plant outages are generally uncorrelated, and hence in times of extreme system stress in GB, most interconnectors are likely to be supplying energy to GB at near full capacity. This finding, however, assumes that there is nothing in the market or regulatory arrangements which prevent interconnectors from flowing energy in the direction which is most economic. This includes appropriate pricing of unserved energy in the connected markets.

Key policy implications

In summary, our key conclusions for interconnector policy are shown in the table below:

Policy area	Implications of analysis
Optimal interconnection capacity	1. There is no single optimum interconnection level for GB (on net welfare or any other criteria) given the uncertainty in fundamental market drivers as measured across the scenarios we have analysed but a minimum additional interconnection capacity of some 5 GW to 2040 returns a significant improvement in GB net welfare across most scenarios, although costs and benefits are not distributed evenly between different groups.
Evaluation of interconnection	2. The results of the analysis undertaken show that different scenarios and configurations can lead to very different results in terms of net welfare and in

Policy area	Implications of analysis
projects	the distribution of impacts across groups. In this context and of overall energy policy, emerging regulated regimes for interconnectors, the development of the European Target Model, and electricity system operation, this has policy implications and GB should consider a system to evaluate interconnection projects as occurs in other European countries.
Regulation of interconnection investment	3. The analysis shows that there are a range of project types with a wide range of impacts on net welfare and distributional effects. Given this and the potential scale of investment in future interconnection that could be beneficial under some scenarios, the regulatory regime may need to accommodate a range of investor types across a wide spectrum of risk-reward preference.
Connected markets	4. Borders with France, Ireland, Belgium and Norway could reasonably be prioritised on the basis of net welfare benefits that accrue for GB. 5. The net welfare benefits of connecting to a diverse set of markets are likely to be limited. 6. Interconnection with Norway and Iceland offers the greatest benefit to GB consumers in terms of lower electricity prices.
Integration of interconnectors into the GB transmission system	7. Given interconnectors are exempt from TNUoS and BSUoS charges, there are few if any market or regulatory based locational investment signals by the current regime. This will impact transmission constraint and/or transmission reinforcement costs in GB (as shown in our analysis) and therefore further consideration needs to be given to ensuring the full social (including wider transmission network) costs and benefits of the connection point into the GB transmission system are taken into account.
Security of supply	8. In the presence of consistent market arrangements across interconnected borders, full market pricing of unserved energy and interconnectors being allowed to respond to market signals, interconnection is likely to exert a significant positive influence on GB security of supply. In addition, interconnection is likely to compare favourably with generation in terms of cost for a given level of deliverability and reliability in times of stress. However, demand-side response and some innovative storage technologies may also compare favourably with generation in this regard.

Report structure

The remainder of this report is structured as follows:

- In Section 2, we set out the background and objectives of the study.
- In Section 3, we summarise our approach to the analysis, including our modelling methodology and approach to scenario analysis.
- In Section 4, we present our modelling assumptions.

- In Section 5, we present our approach to deriving alternative configurations of GB interconnection.
- In Section 6, we present the results of our analysis, including optimal levels of interconnection, welfare results, least regrets level of interconnection and the operation of interconnectors, including security of supply impacts.
- In Section 7, we set out key implications of our analysis for interconnector policy.

2 Introduction and objectives

2.1 Introduction

The EU has legislated to promote greater levels of electricity interconnection between member states through various directives including, most recently, the Third Package[6]. The UK is strongly committed to the single European energy market as the Prime Minister emphasised in a speech at Bloomberg in January of this year. In parallel, Ofgem has published its proposals for a cap and a floor on revenues of regulated interconnectors and pushed ahead with the Integrated Transmission Planning and Regulation (ITPR) project to assess whether any changes to the existing GB electricity transmission arrangements are required to facilitate a future integrated system. DECC has also published its *'Electricity System: Assessment of Future Challenges'*,[7] in which it presented findings from its analysis into the value of flexibility. Hence significant work has been undertaken to promote interconnection and understand the value of discrete projects. However, less than 2 GW of interconnector capacity has been built to connect to GB since IFA came online in 1986.

Today, there are a number of credible new interconnector projects seeking to connect GB to other markets. If all of these projects came to fruition, this would represent a very significant increase in the connectivity of the GB electricity market to other electricity markets in Europe. However, it is not certain that all of these projects being brought to completion would represent a beneficial outcome for GB, or for GB consumers (who would be taking on some risk with them should the project be regulated through a cap and floor approach). The marginal private and social returns to new interconnection capacity are diminishing as prices in the connected markets converge with more capacity and the efficiency benefits of dispatching the most efficient forms of generation across the connected markets are realised.

Therefore, the magnitude and diversity of proposed projects and the changing regulatory landscape at EU and GB level imply a need for government to consider its overall policy in respect of future interconnectors. The purpose of this study, therefore, is to provide an evidence base to DECC on what is likely to be best for GB in terms of the destination, capacity, location and timing of electricity interconnection to GB under a range of potential future scenarios

2.2 Background

2.2.1 Context

The European Commission has identified a need for €1 trillion of investment in the energy system between 2010 and 2020 of which €70 billion is required for an additional 35 GW of electricity

[6] Described in the Preamble Clauses 59 and 60, Article 3(10), Article 21(8b), Article 38(2a) and Article 46 (4).

[7] DECC, August 2012. *Electricity System: Assessment of Future Challenges.*

interconnectors[8]. The EU had agreed an indicative non-binding target that electricity interconnection levels should be at least 10% of each member state's total installed generation capacity by 2010[9]. While the current level of interconnection into some member states exceeds the 10% level, the overall picture is mixed, with Southern Europe, GB and Ireland continuing to experience significant bottlenecks and falling short of that ambition[10]. Interconnection between GB and other countries currently represents less than 4% of total installed generation capacity in GB.

The EU has legislated to promote greater levels of electricity interconnection between member states through various directives including, most recently, the Third Package[11] in which the Cross Border Regulation states "*investments in major new infrastructure should be promoted strongly while ensuring the proper functioning of the internal market in electricity.*"[12]

However, despite member state and EC energy initiatives, only 3.5 GW of capacity has been constructed between GB and other European markets to date. A summary of the known projects that we believe are most likely to go ahead is provided in Table 1 below.

Table 1 List of known interconnector projects in GB[13]

Border	Capacity	Operational Date	Project Name
GB – France	500 – 1000 MW	2016	ElecLink
GB – France	1000 MW	2018	IFA 2
GB – Belgium	1000 MW	2018	NEMO
GB – Norway	1400 MW	2020	NSN
GB – France	1800 MW	2020	FAB
GB – Norway	1400 MW	After 2020	NorthConnect
GB – Iceland	800 - 1200 MW	After 2020	IceLink
GB – Denmark	1000 MW (est)	After 2020	-

8 "The Energy Infrastructure Package – how to deliver investment in energy infrastructure in Europe" – presentation by Sylvia Elisabeth Beyer at the European Autumn Gas Conference, Paris, 15 November 2011

9 Paragraph 37, Presidency Conclusions, Barcelona European Council, 15 and 16 March 2002 - http://ec.europa.eu/research/era/docs/en/council-eu-30.pdf

10 Historically this has also been driven by the geographic location of these countries, since for islands sub-sea electrical cables are required (which are more expensive compared to both over- and under- ground cables of a similar length and size), whilst for Spain interconnection with Central Europe has been compromised by the complexities arising due to the challenging terrain between France and Spain.

11 Described in the Preamble Clauses 59 and 60, Article 3(10), Article 21(8b), Article 38(2a) and Article 46 (4).

12 Recital 23, Cross- Border Regulation

13 This list excludes some multi-purpose projects which are also looking at potentially operating as interconnectors at a later stage of the project life time.

Border	Capacity	Operational Date	Project Name
GB – Ireland	500 MW (est)	After 2020	East West Cable One

What is notable about these proposed projects is:

- The scale, with some projects up to 1.8 GW in size.
- Total interconnection capacity under consideration, with just under 10 GW of interconnection in planning based on the above list of projects alone.
- The diversity in interconnected markets, with potential new interconnection to 6 different markets being considered.
- The geographic distance some of the projects will need to be built over.
- The variety of investors involved, including private equity, TSOs, utilities and institutional investors.

A significant amount of work has already been undertaken by regulators and governments to understand the range of new interconnector projects being proposed. For example, on the form of economic regulation for some projects, Ofgem, together with the Belgian Regulator, CREG, has published its proposals for the design parameters of a new form of economic regulation for interconnectors based around a cap and floor on revenue levels. Regulation of other future projects is being considered through Ofgem's Integrated Transmission Planning and Regulation (ITPR) project.

In August 2012, DECC published its *'Electricity System: Assessment of Future Challenges'*,[14] in which it presented findings from its analysis into the value of flexibility[15]. DECC concludes that interconnection can bring significant benefits in terms of system cost and security of supply, but that further work is needed to assess the likely distribution of benefits (particularly for UK consumers) and the most appropriate development framework.

In addition, separate Memorandum's of Understanding (MOUs) have been signed and joint statements made between the GB government Norway, Iceland and Ireland highlighting the need for further interconnection and specific projects of interest.

2.2.2 The economic drivers of new interconnection

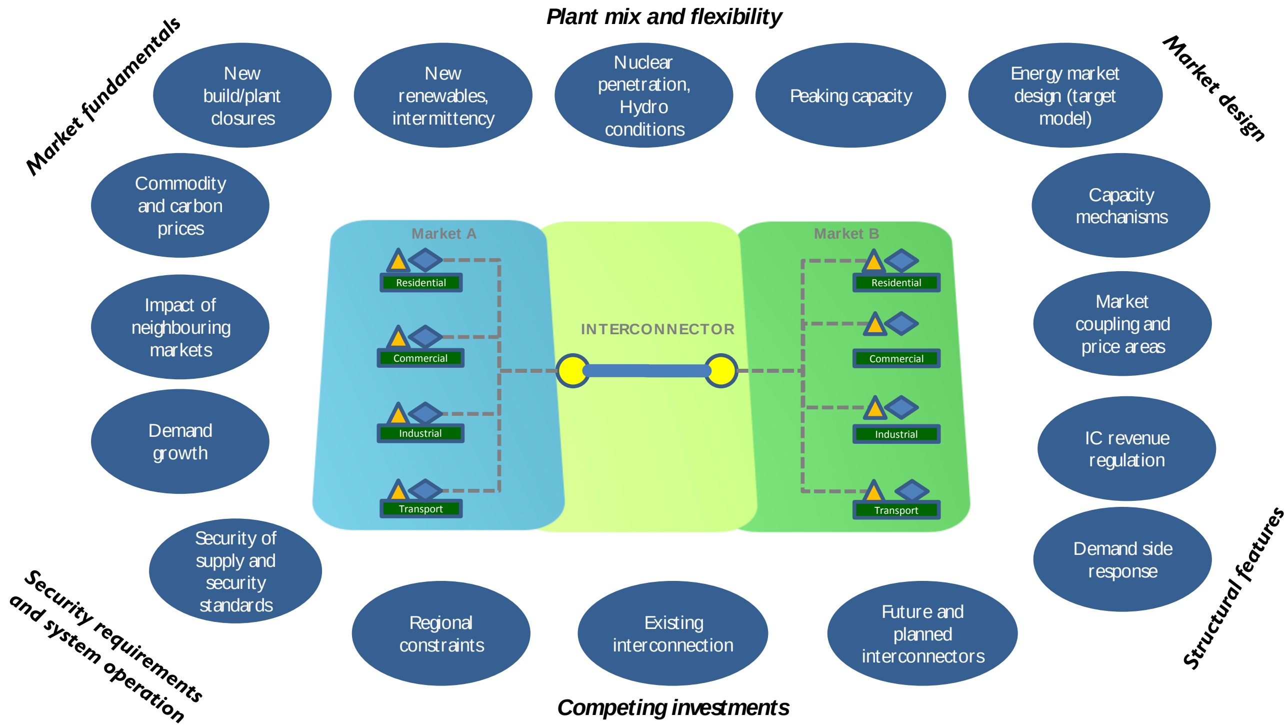
Since interconnectors represent an option on the hour-by-hour price differences between the connected markets, these price differences are broadly indicative of the economic value of interconnectors in the context of energy trading. Price differences depend on the market fundamentals on either side of the cable, the structural attributes of the two systems in terms of

[14] DECC, August 2012. *Electricity System: Assessment of Future Challenges.* [online]

[15] http://www.decc.gov.uk/assets/decc/11/meeting-energy-demand/future-elec-network/6098-electricity-system-assessment-future-chall.pdf

plant mix and demand patterns, the way in which the markets are designed and regulated, and the level of interconnection between the markets concerned. The key value drivers for an interconnector are summarised in Figure 1.

Figure 1 Interconnectors – key value drivers



In this figure, we have categorised the key drivers broadly as follows (the examples are by no means exhaustive and the allocation is not always exact):

- Market fundamentals, such as fuel prices, including gas price variations and CO2 prices, the Carbon Price Floor and market-driven developments.
- Plant mix and flexibility, such as the impact of RES targets and the characteristics of the capacity mix in general.
- Market design, including future capacity mechanisms, regulation and policy drivers, such as the EU Target Model, market coupling and market splitting and interconnector regulation.
- Structural and system features of the market, such as internal bottlenecks, that may impact interconnector flows.
- Existing interconnection.
- Security requirements and system operation, including factors such as limits on maximum amount of wind generation allowed within a given region and potentially cross border trading requirements through forward contracting.

The drivers described above can be expected to affect interconnector value through both energy trading across national borders, and through trading in balancing services such as the provision of reserve and frequency response. At the time of writing, the EU regulatory framework for energy trading though market coupling is in advanced stages of development and implementation, while the equivalent framework for trading of balancing services is at a much earlier stage of development.

ACER's Framework Guidelines on Electricity Balancing (and the subsequent Network Codes) have provided an opportunity to define a common set of balancing rules across Europe[16]. ACER has argued that greater harmonisation can lower barriers to entry for flexibility providers, enhance liquidity in balancing markets, and most importantly enable the integration of renewables under the RES Directive at least cost. It further argues that harmonisation of electricity balancing arrangements is a critical component of the EU Target Model and that cross-border exchange of resources across interconnectors in balancing timeframes can play an important role in maintaining security of supply and in maximising output from intermittent renewable generation sources across Europe. ACER's Framework Guidelines and Impact Assessment recommend its 'Option C' - creating a European exchange of balancing services through a legally binding regulation, which has the following features:

- Balancing energy (full cross-border exchange):
  - TSO-TSO model with common merit order: TSOs gather all balancing bids and offers in a common list and activate according to a common merit order
  - TSOs allowed to maintain a certain 'margin' of energy bids at national level, but cheapest bids must be offered to common merit order
- Reserves (step-by-step given cannot reserve interconnector capacity for balancing):
  - TSOs can still contract in advance, then reserves bid into balancing energy market
  - Initially, exchange surplus reserves bilaterally between two adjacent areas
  - Then seek to implement a multilateral trading model
- Harmonised imbalance settlement

2.2.3 The impacts of new interconnection

Greater electricity interconnection can produce the following benefits:

- **Increased net welfare through the benefits of trading** – increased trade in electricity allows the most efficient sources of generation to be used to meet demand across interconnected markets, reducing overall cost of generation.

[16] Balancing in this context can mean a broad range of operations taken by a System Operator to meet a variety of constraints, including transmission constraints within a price zone, reserve and response constraints to make sure that the system can respond to changes in balance between supply and demand at short notice, as well as taking actions in real time to make sure that voltage is maintained on the system and demand is met.

- **Security of supply** - greater interconnection enables the pooling of energy, reserve and other balancing services between markets and allows supply shocks to be offset by output in the neighbouring interconnected markets, improving security of supply and allowing intermittent renewables to be integrated into the electricity system more easily.

However, electricity interconnection has high associated capital cost and hence the overall benefits must outweigh the costs if it is to contribute to improvement in net welfare. This must also be considered in light of the fact that interconnection competes with flexible generation, electricity storage and demand side response in provision of flexibility and security of supply. In a world where connected markets have a similar generation capacity mix or an abundance of alternative sources of flexibility, the benefits of additional interconnection can be expected to be low.

2.3 Objectives and approach

In this context, DECC commissioned Redpoint Energy to undertake analysis to help improve its understanding of:

- *"The impacts on GB net welfare (to include electricity prices and security of electricity supply) including the distribution of costs and benefits between different parties and countries, of different levels of interconnection, to different connected markets, at different rates of deployment and in different orders;*
- *Taking into account the impacts and risks of different interconnections, to find the optimal (for GB net welfare) level/range of interconnection, the optimal order for those interconnections to be deployed (in total and to specific connecting markets), and the no-regrets levels/ranges that should be pursued."*

Only point-to-point interconnectors were considered for the purposes of this study. Hence, projects which may be of multiple purpose, e.g. co-ordination with offshore renewable generation or renewable imports from other countries using dedicated interconnectors, were not included in our analysis.

The key questions for our analysis can be summarised as:

- What is the economic impact of alternative levels, locations (including markets to which the interconnectors are connected), timings and order of interconnector build?
- How would the new interconnectors operate under a range of scenarios?
- How might interconnectors operate at times of system stress?
- What is the minimum/no-regrets level that should be built and by when?

Each of the above have been quantified in both net welfare impact and security of supply terms, as the key dimensions for evaluation identified by DECC. Our analysis was undertaken under a range of plausible scenarios and assumptions and we have developed a framework for this with DECC. Our analysis was carried out in the context of GB keeping within its carbon budgets and covered the period from 2015 to 2050. Finally, the analysis considered utilisation of interconnectors for system balancing[17] as well as energy trading.

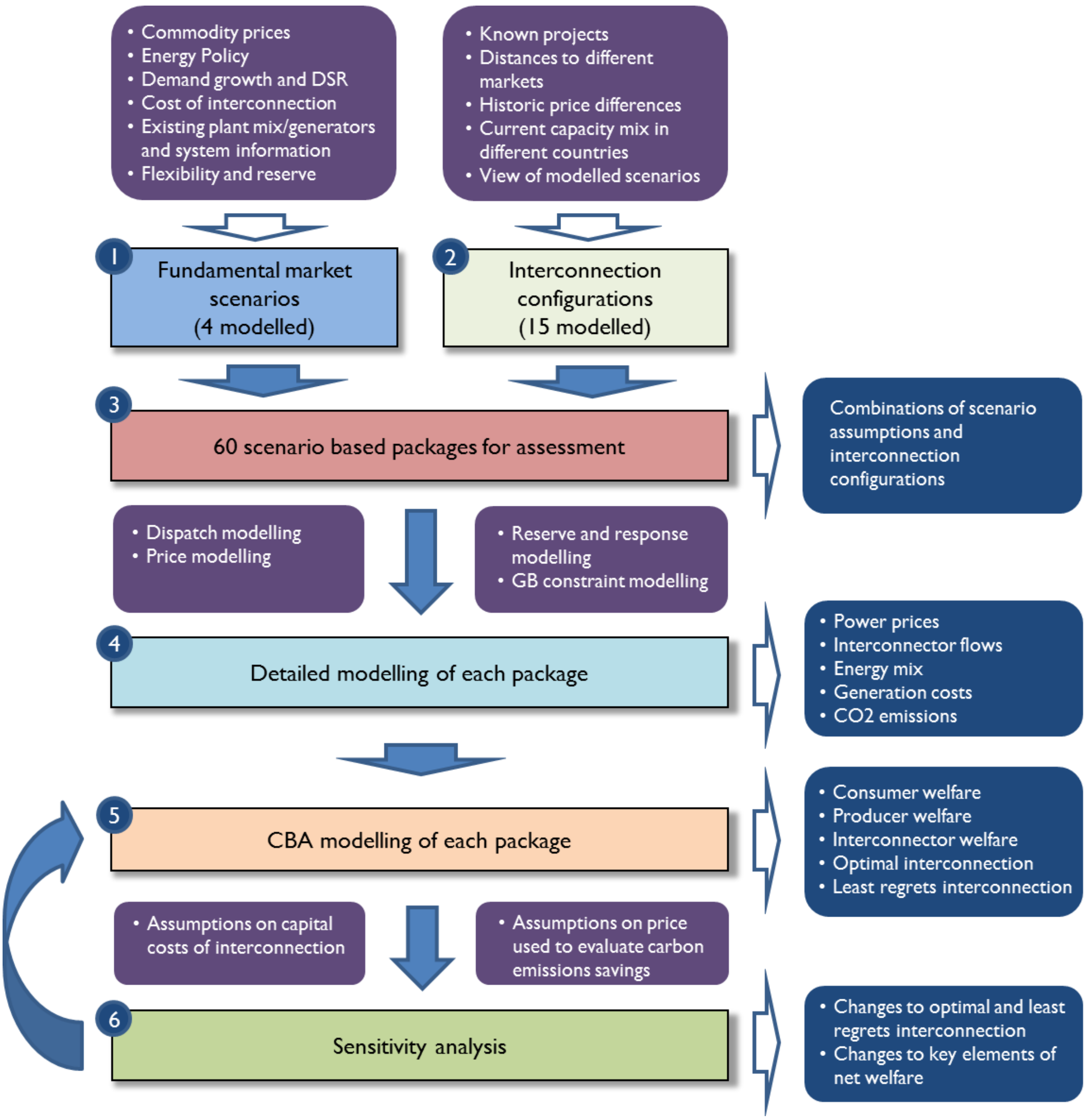
[17] System balancing in this context refers to the requirement to hold reserve and frequency response and the need to meet GB onshore transmission constraints.

3 Analysis and modelling methodology

3.1 Summary

Our approach to analysing different options for GB interconnection is summarised in Figure 2.

Figure 2 Summary of approach



A summary of the key terms is as follows:

Scenario – a potential state of the world defined by assumptions on electricity demand, generation mix, commodity prices and other factors across all modelled markets.

Sensitivity – a variation on a scenario in which only one or two modelling assumptions are altered relative to the original scenario.

Interconnection configuration – interconnection strategy for GB that specifies which markets GB connects to, when each new connection is built, the capacity of each new connection, and finally the landing point in GB of each new connection.

Package – combination of interconnection configuration and scenario.

Our analysis proceeded in the following stages:

Stage 1 – The range of scenarios to be modelled is decided on and associated modelling assumptions in terms of the generation mix in different markets, demand level and flexibility, and commodity prices are determined. The modelled scenarios are described in detail in Section 3.2.

Stage 2 – Interconnection configurations that specify the capacity, timing, connected market and GB landing zone of each new interconnector, are determined. The methodology for deriving the configurations is described in Section 3.3 and the configurations modelled are set out in Section 5.

Stage 3 – Scenarios and interconnection configurations are combined to form packages.

Stage 4 – All packages are modelled using our dispatch modelling methodology described in Section 3.4, accounting for all major plant-level and system constraints, including reserve and response constraints and major constraints on the GB onshore transmission network.

Stage 5 – Results of the modelling are evaluated using our CBA methodology, deriving the changes to consumer, producer, interconnector and overall net welfare as a result of changes in GB interconnection. The overall least regrets GB interconnection strategy, as well as optimal interconnection strategies for each of the modelled scenarios, are determined.

Stage 6 – Sensitivity analysis is carried out on the core modelling results with respect to assumptions on the capital cost of interconnection and the price at which carbon savings in different markets are evaluated. The effect of changes in assumptions on the overall least regrets GB interconnection strategy and optimal interconnection strategies for each of the modelled scenarios is determined.

3.2 Scenarios

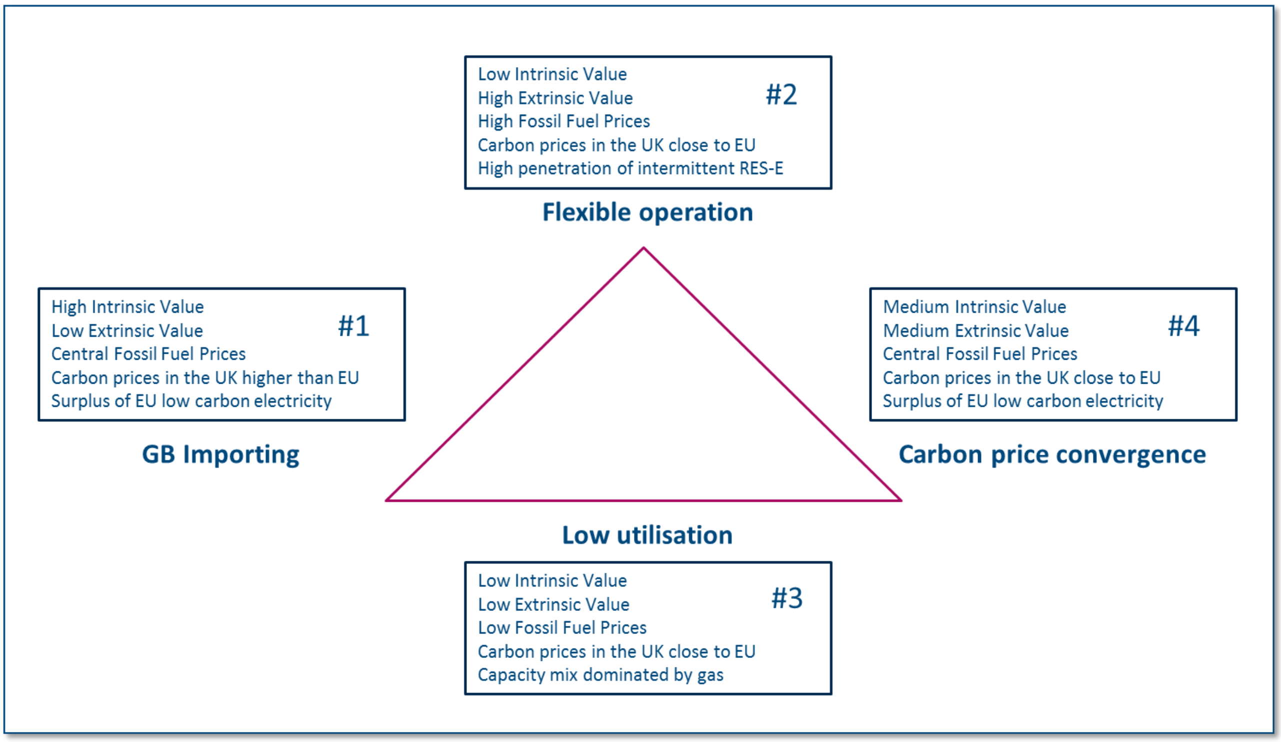
We considered the main drivers that are likely to have the most significant impact on the timing, location and volume of interconnection between GB and neighbouring markets and identified those to be:

1. Gas prices;
2. Carbon prices (and in particular the difference between carbon prices in GB versus Continental Europe, for example due to the Carbon Price Floor policy);
3. HVDC (High Voltage Direct Current) cable cost;
4. Renewable technology costs; and
5. EU commitment to renewables targets by 2020 and beyond.

In addition to those factors, other important drivers must also be taken into account such as overall electricity demand levels and the shape of demand (particularly as demand side response is deployed), developments in electricity storage technologies, internal grid and network reinforcements and balancing arrangements across Europe (and the possibility of sharing reserve for example), among others.

Figure 3 shows the four scenarios modelled for the purposes of this study.

Figure 3 Scenario framework



1. GB importing – this is a scenario where interconnectors are utilised mostly to transfer lower cost electricity from Continental Europe to GB[18]. This is likely to materialise in a world with moderate gas prices, where generators face higher carbon prices in GB compared to Europe, and where it is possible to import through interconnection surplus low carbon electricity (particularly from renewable energy sources) from the Continent.

[18] Note that this does not imply that interconnectors would be importing power to GB 100% of the time, merely that there would be a strong tendency for imports into GB to dominate export from GB.

2. Flexible operation – this is a scenario where significant amounts of flexibility are required, with higher intermittency across European power markets than that seen under the GB importing scenario increasing the extrinsic value of interconnectors[19]. This is likely to materialise in a world where very significant amounts of intermittent renewable technologies (particularly onshore and offshore wind) are deployed across Europe, partly due to high fossil fuel prices incentivising their advanced deployment. This scenario also assumes that generators in GB face broadly similar carbon prices as in Continental Europe.
3. Low utilisation – this is a challenging scenario for developing interconnectors since electricity price differences across European markets remain low due to persistently low fossil fuel prices. This scenario also assumes that generators in GB face broadly similar carbon prices as in Continental Europe and that, whilst unabated gas plant dominate in the short- to medium- term, there is an increased role for gas CCS (Carbon Capture and Storage) and coal CCS in the longer term due to low fossil fuel prices and relatively slow progress in offshore wind.
4. Carbon price convergence –we have also modelled a fourth scenario which uses the same fundamental assumptions as Scenario 1 (i.e. moderate fossil fuel prices coupled with a relatively balanced, albeit renewables favouring, generation mix in the UK and Continental Europe), however this scenario also assumes that there are no longer significant differences between carbon prices in GB and the rest of Europe.

The key assumptions that were used to model these scenarios are described in more detail below.

1. GB Importing

Overview					
A scenario where GB becomes a net importer of electricity over the modelling horizon. This is likely to materialise in a world with moderate gas prices, where generators in GB face higher carbon prices compared to Europe, and where it is possible to import significant surplus low carbon electricity (or renewable electricity more specifically) from the Continent. This scenario assumes that decarbonisation of GB power sector is achieved, but the Government does not consider domestic action to be of paramount importance. There is central electricity demand growth, coupled with central electrification of the heat and transport sector and central progress on DSR.					
Gas prices	**Commodity prices**	**Carbon prices**	**GB capacity mix**	**EU capacity mix**	**Electricity demand**
Central	Central	DECC Central	Balanced	Renewables-favouring	Central (with Central DSR)
Likely overall level of interconnection		Central to High			

[19] An electricity interconnector is said to have high intrinsic value when a large differential in average prices exists between the two connected markets. Conversely, an electricity interconnector is said to have high extrinsic value when, even though the difference in average prices may be small, significant random hourly price variation exists between the two connected markets.

Overview	
GB capacity mix	Significant contribution by nuclear (36 GW by 2050) and renewables (and wind more specifically - 43 GW by 2050), the remainder largely based on unabated gas and some gas CCS (20 GW) towards the later years of the modelling horizon.
EU capacity mix	Decarbonisation is achieved in line with each country's specific targets. Nuclear and CCS (towards the later years) both play an important role towards decarbonisation for some countries, however new build investments are largely dominated by renewables, particularly onshore wind and solar PV.
Electricity demand	Central demand growth with central GDP growth and central progress in the electrification of the heat and transport sector. There is also some impetus for the Government to encourage DSR uptake which is also assumed to occur according to central projections.

2. Flexible operation

Overview					
A scenario where significant amounts of flexibility are required, with high intermittency across Europe increasing the extrinsic value of interconnectors. This is likely to materialise in a world with high gas prices and where significant amounts of intermittent renewable technologies (particularly wind) are deployed across Europe. This is also compatible with a world where significant renewable technology cost reductions are realised, particularly for offshore wind. The Carbon Price Floor policy is maintained in GB. Similarly, other European countries are equally ambitious in pursuing renewable new build, although they achieve their goals without the use of a carbon price floor. There is central view electricity demand growth with central view progress in the electrification of the heat and transport sector. DSR uptake, however, is high in order to provide some of the required flexibility associated with high wind penetration.					
Gas prices	**Commodity prices**	**Carbon prices**	**GB capacity mix**	**EU capacity mix**	**Electricity demand**
High	High	Redpoint Central	Wind-favouring	Wind-favouring	Central (with High DSR)
Likely overall level of interconnection	Central to High				
GB capacity mix	Very strong contribution by onshore and offshore wind (75 GW by 2050) at the expense of gas CCS whose development is limited due to persistently high gas prices. There is also considerable contribution by nuclear (36 GW by 2050), with the remaining capacity largely provided by unabated gas, other renewables (including wave and tidal) and some gas CCS (5 GW) towards the later years of the modelling horizon.				

Overview	
EU capacity mix	Power sector decarbonisation in other European countries is achieved in line with each country's specific targets. Compared to Scenario 1, there is now an even greater penetration of wind (particularly offshore) at the expense mainly of CCS. The contribution of nuclear remains unaffected due to high gas prices, with nuclear playing an important role to the path towards decarbonisation for some EU countries.
Electricity demand	Central demand growth due to central GDP growth and central progress in the electrification of the heat and transport sector. There is now a high uptake of DSR in the residential and commercial sectors in order to provide some of the flexibility required by the introduction of such large quantities of wind power.

3. Low Utilisation

Overview

A challenging scenario for developing interconnectors since electricity price differences across European markets remain low (thereby reducing interconnector intrinsic value) due to persistently low fossil fuel prices. This scenario also assumes that generators in GB face broadly similar carbon prices as in Continental Europe, with the UK Government committed to meet its 2020 targets. In the longer term, the Government's renewable ambitions are somewhat curtailed as renewable technologies are not proven as cost-competitive as unabated gas and CCS. This scenario assumes central view demand growth and central view progress in the electrification of the heat and transport sector, coupled with central DSR uptake.

Gas prices	Commodity prices	Carbon prices	GB capacity mix	EU capacity mix	Electricity demand
Low	Low	Redpoint Central	Gas-favouring	Gas-favouring	Central (with Central DSR)

Likely overall level of interconnection	Low
GB capacity mix	In the medium term (up to 2025), new build investments are similar to Scenario 1 and are largely dominated by unabated CCGT, onshore and offshore wind and solar PV. In the longer term, however, persistently low gas prices mean that decarbonisation is now achieved largely through gas CCS (50 GW by 2050) at the expense of wind (33 GW by 2050) and nuclear (26 GW by 2050). Lower wind penetration also means that less unabated gas is required as back-up capacity in order to ensure that security of supply is maintained at desired levels.

Overview	
EU capacity mix	A similar story can be drawn for the capacity mix of the other European countries we have modelled. Low gas prices result in considerably higher deployment of unabated gas in the short-to-medium term, while decarbonisation in the long term is achieved through greater CCS deployment at the expense of nuclear, wind (particularly offshore) and solar PV.
Electricity demand	Central demand growth due to central GDP growth coupled with central progress in the electrification of the heat and transport sector. DSR uptake in the residential and commercial sector is also assumed to take place according to central projections.

4. Carbon price convergence

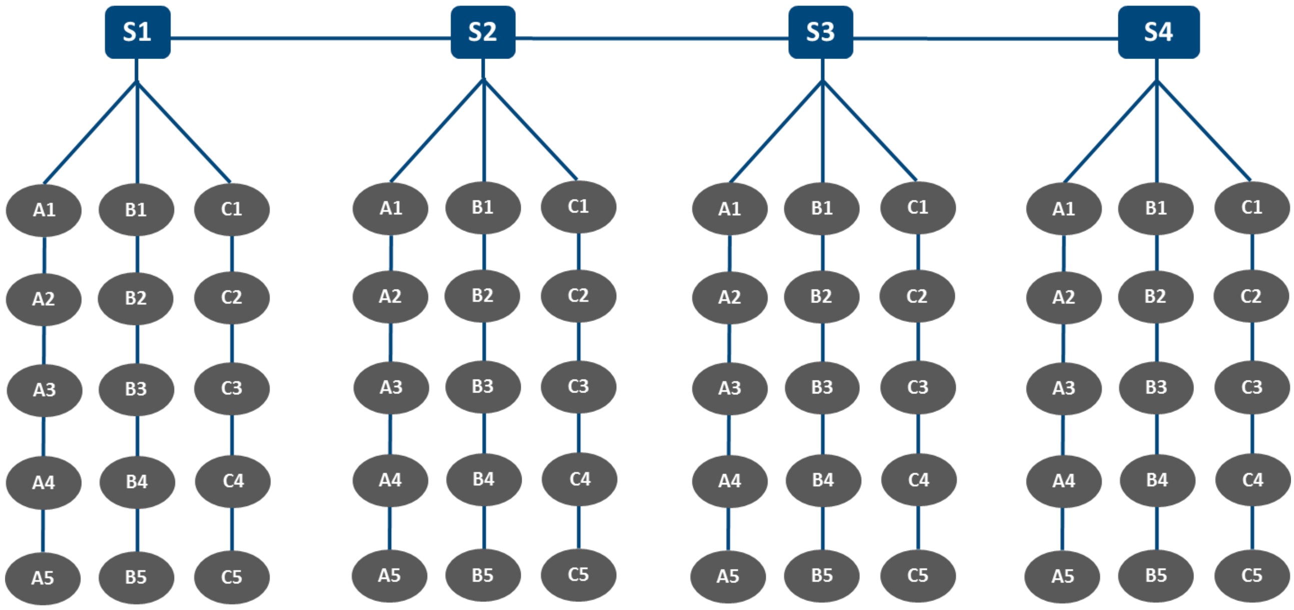
This scenario uses the same fundamental assumptions as Scenario 1 (i.e. moderate fossil fuel prices coupled with a relatively balanced, albeit renewables favouring, generation mix in the UK and Continental Europe) however it is now assumed that generators in GB face broadly similar carbon prices as in Continental Europe. Assumptions on carbon prices are set out in detail in Section 4.

3.3 Interconnection configurations

A summary of the analytical framework for modelling interconnector configurations is depicted in Figure 4. S1-S4 are the four scenarios to be analysed for the purposes of this study (as described in Section 3.2), and A1 to C5 represent 15 different interconnector configurations. Configurations A1 to A5 are tailored to Scenario 1, with A1 being the most conservative configuration and A5 being the most speculative. B1 to B5 is a set of configuration tailored to Scenario 2. Finally, Configurations C1 to C5 are not tailored to any particular scenario but represent a distinct set of configurations from A and B.

The methodology for deriving interconnector configurations, as well as the chosen configurations and their properties, are set out in detail in Section 5.

Figure 4 Interconnector configurations



For configuration categories A and B, lower numbered configurations are the most conservative with incremental expansion of interconnection and higher numbered configuration are the most ambitious, with earlier commissioning of interconnectors. Configurations C1 to C5 do not follow the same pattern as categories A and B and are not tailored to any given scenario

Under our approach to the analysis, interconnection configurations are to some extent tailored to the modelled scenarios, hence the task of identifying the configurations that are optimal for GB under each of the modelled scenarios is made easier[20]. Tailoring interconnection configurations to different scenarios reduces the probability of sub-optimal interconnectors being present in the configuration that is deemed to be optimal overall because some interconnectors may be net welfare-enhancing under one scenario but reduce net welfare under a different scenario.

While splitting the configurations into categories means that the extent of continuity between different configurations is reduced, which may make it more difficult to interpret how differences between different configurations are likely to translate into differences in net welfare, continuity between configurations is retained within categories A and B.

3.4 Dispatch modelling

3.4.1 Overview

Figure 5 gives a summary-level overview of our modelling methodology.

[20] The tailoring process was informed by our own market intelligence based on our extensive experience in modelling European power markets and this approach was agreed beforehand with DECC. Depending on the market fundamentals behind each scenario, we qualitatively assessed which interconnectors could potentially result in a positive net welfare in the context of that scenario and these interconnectors were then selected subject to a range of constraints. These constraints were developed following a wide stakeholder consultation with regards to earliest possible commissioning date, maximum capacity, length, and GB landing point for each potential project we considered. The configurations we selected are described in Section 5 in greater detail.

Figure 5 Overview of modelling methodology

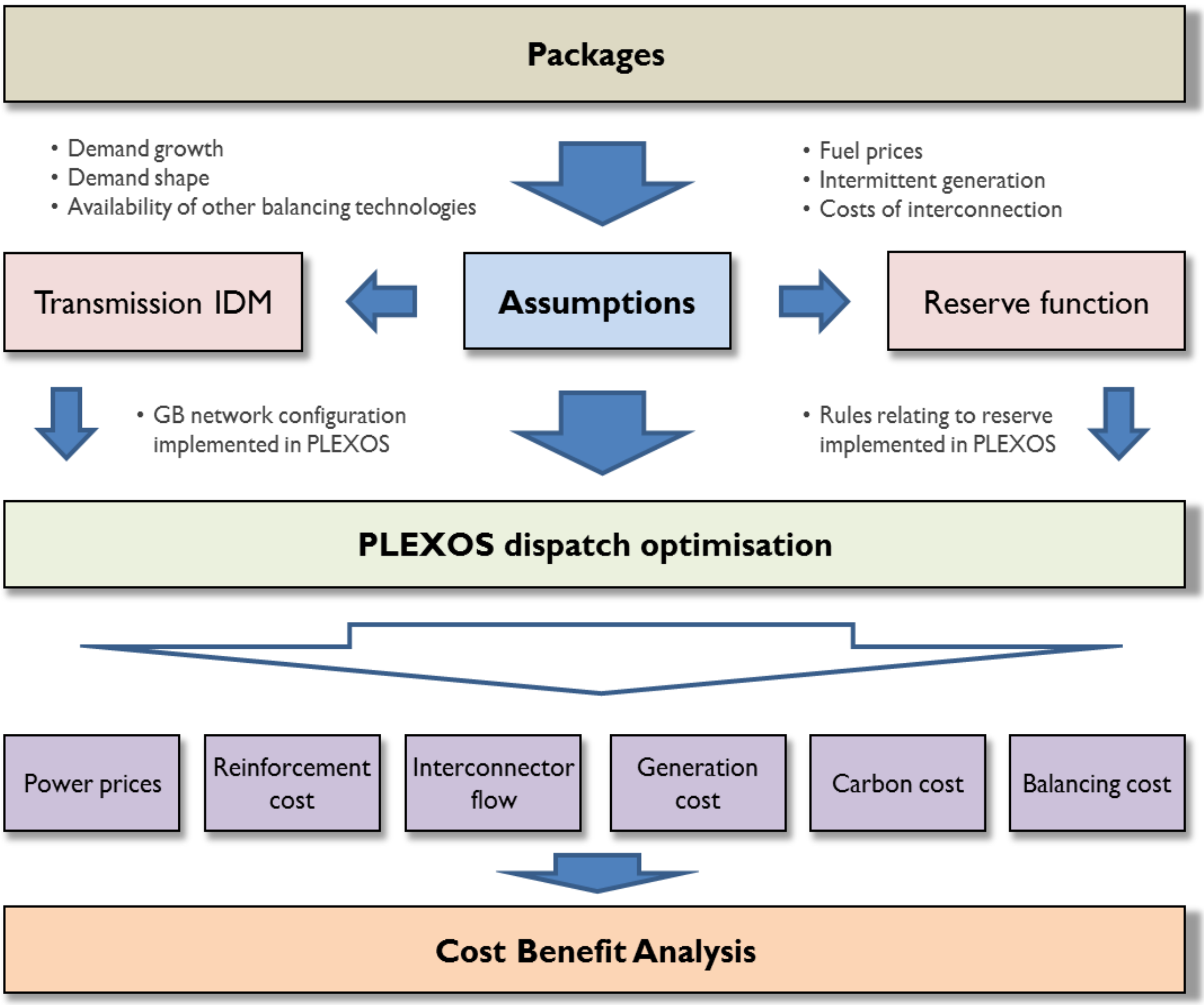
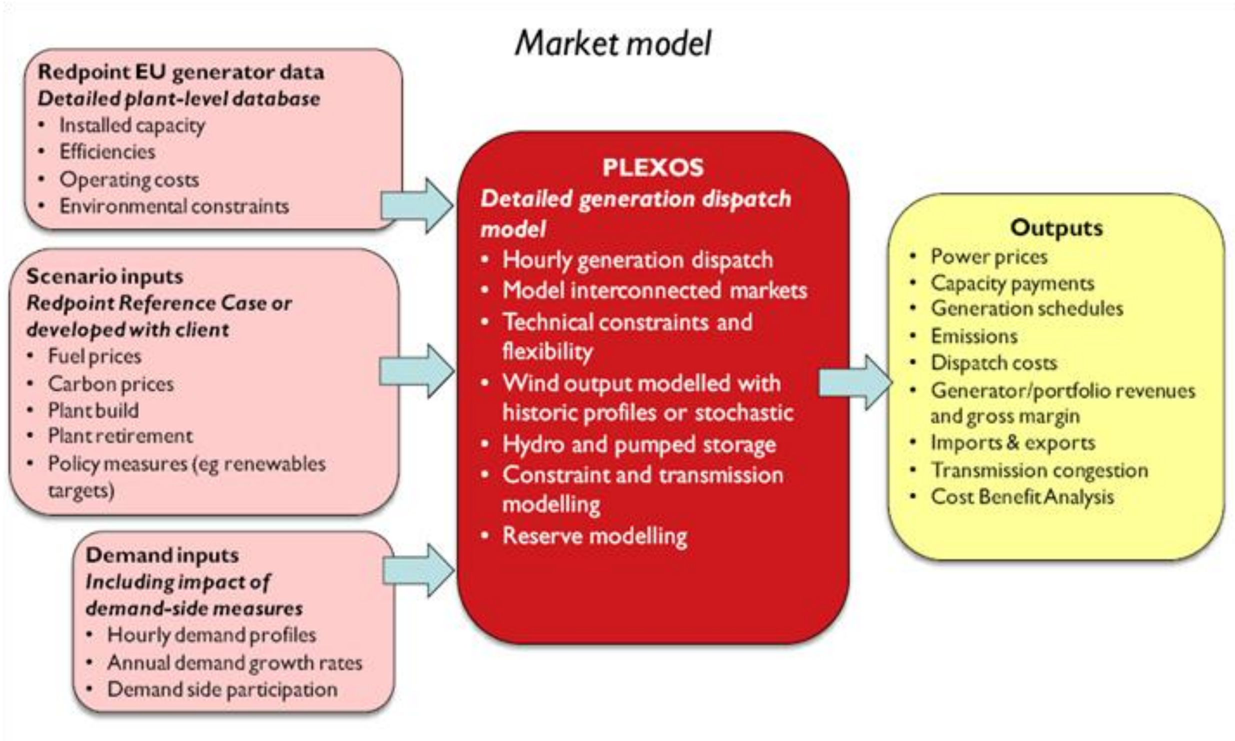


Figure 6 provides an overview of the Redpoint dispatch modelling suite.

Figure 6 Overview of Redpoint dispatch modelling suite



For detailed simulation of the dispatch of power markets at an hourly level, we use a third party product, PLEXOS for Power Systems. PLEXOS is highly regarded power market simulation software used globally by system operators, utilities and commodity traders and we have used it extensively over the last six years to model in detail European power markets.

At its heart lies a dispatch 'engine' based on a detailed representation of market supply and demand fundamentals at an hourly granularity. The supply mix is represented with the operating parameters of generating plant including costs and operational constraints. We model a number of wind profiles which vary hourly across the year in this phase of the modelling. These are calibrated from our historic database of wind speeds across Europe.

The demand side is represented as a projected hourly profile (derived from historic calibration). Market dispatch is then simulated with system-level constraints (e.g. emission limits) optimised to deliver the least cost solution. The marginal cost for each plant is calculated from heat rate curves, fuel costs, transportation costs, non-fuel variable operating costs and carbon costs.

The core of our modelling analysis involves running the PLEXOS dispatch model for different scenarios and different configurations of interconnection for GB using assumptions on transfer capacities in GB, reserve and response requirements across all modelled markets and other modelling assumptions. The model optimises the dispatch of plant and interconnectors across the European markets modelled whilst meeting transmission network constraints within GB and between different European markets, plant-level constraints such as ramping times and legislated run time constraints (e.g. the Large Combustible Plant Directive), and meeting reserve and response requirements.

The boundary transfer capacities on the GB network for the PLEXOS dispatch model and hence the future network reinforcements are determined within the overall modelling framework but outside of the core dispatch model. This calculation is based on assumptions about the existing transfer capacities between different zones on the GB network and planned network reinforcements, as well as all other assumptions about the GB electricity system, including the generation capacity mix. To derive reserve requirements used in the PLEXOS dispatch model, we use a bespoke reserve function, which uses historic data on factors such as wind forecast errors.

The modelling was carried out on the basis of spot years (2015, 2020, 2025, 2030, 2040 and 2050) with full hour by hour dispatch being modelled for each of the spot years.

Modelling outputs that feed into the CBA module include:

- Generation costs
- Wholesale power prices
- Carbon emissions and costs
- Interconnector dispatch
- Network reinforcement costs

The costs of network reinforcement are only calculated for GB[21].

3.4.2 Price modelling

The price of electricity in our modelling is defined as the system Short-Run Marginal Cost (SRMC), or in other words the SRMC of the marginal plant. It is reasonable to expect that capacity payments will mean that a proportion of generators' revenue is taken out of the wholesale markets and lower electricity prices. If capacity payments are sufficiently large, prices may converge to the system Short-Run Marginal Cost (SRMC). Hence modelling wholesale prices on system SRMC basis is consistent with universal capacity mechanisms across all of the modelled markets.

Although the exact form of any capacity mechanisms in GB and other countries is not yet known, one principle that we apply to the way that we reflect such mechanisms in our modelling is that, in the long-run (beyond a 5 year horizon), differences in capacity mechanisms and broader market arrangements between different European markets should not determine interconnector flows.

We consider that the system SRMC based approach is consistent with foreign generators participating in the GB capacity mechanism (and also with non-participation) since interconnector flows are determined by an optimisation that does not favour domestic generation. The effect of the capacity mechanism in GB and other modelled markets on the generation capacity mix and the capacity margin is assumed to be reflected in the capacity mix used as an assumption in our modelling.

[21] It is not clear whether the effect of additional GB interconnection is likely to have a positive or negative effect on the cost of network reinforcement in other countries. However, it is likely that this effect would be minor relative to other welfare effects of further interconnection.

Carbon Price Support is modelled as a cost faced by generators in GB according to their fuel type, fuel use as calculated in the model and carbon intensity of the fuel. It therefore feeds into electricity prices through its effect on the SRMC of marginal plant.

The effect of support for low carbon generation on the generation capacity mix is assumed to be reflected in the capacity mix used as an exogenous assumption in our modelling. The effect of support on the bidding behaviour of low carbon generators is uncertain and depends on a number of factors, including, in the case of GB, any restrictions on bidding behaviour that may be written into CfDs. Our underlying assumption is that differences between renewable or low carbon support regimes in different markets would not be permitted to distort interconnector flows in the long run. Hence, supported generators are dispatched on an economic basis across all markets, which means that they bid their SRMC into the market. This would be zero for most renewables like wind, but would be higher for biomass given the cost of biomass fuel. Since all supported plant would bid their SRMCs into the market, plant under the Renewable Obligation (RO) would bid on the same basis as plant under CfDs.

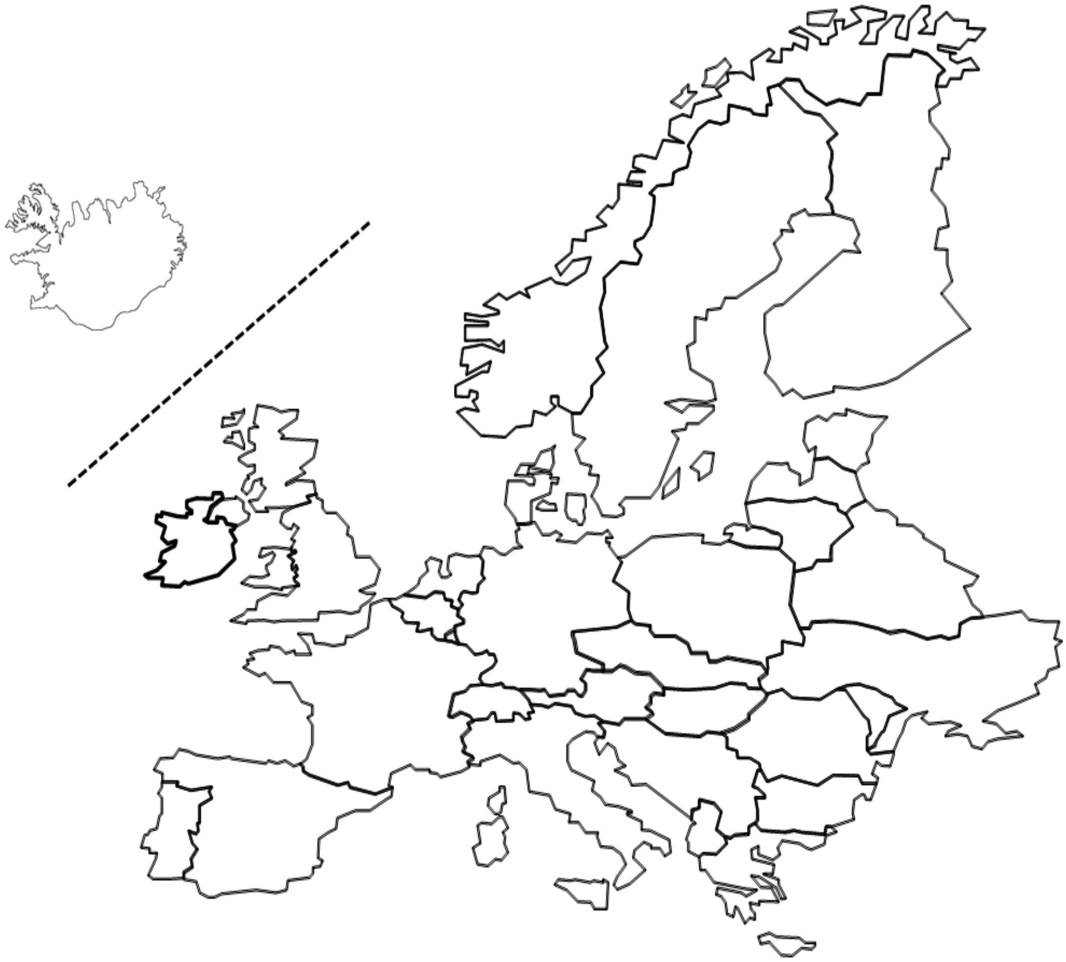
3.4.3 Interconnector modelling

Interconnectors are dispatched optimally in our model on the basis of prices in the connected markets while respecting constraints such as ramping speed, total capacity of the different interconnectors, reserve and response requirements and transmission boundary constraints in GB. Hence the modelled treatment of interconnectors mimics closely their behaviour under full market coupling (both day ahead and within day) combined with actions being taken by TSOs in a common EU within-day electricity market in order to meet reserve and response requirements and internal transmission constraints at least cost.

3.4.4 Geographic coverage

Figure 7 shows the geographic coverage of Redpoint dispatch model.

Figure 7 Geographic coverage of Redpoint PLEXOS based dispatch model



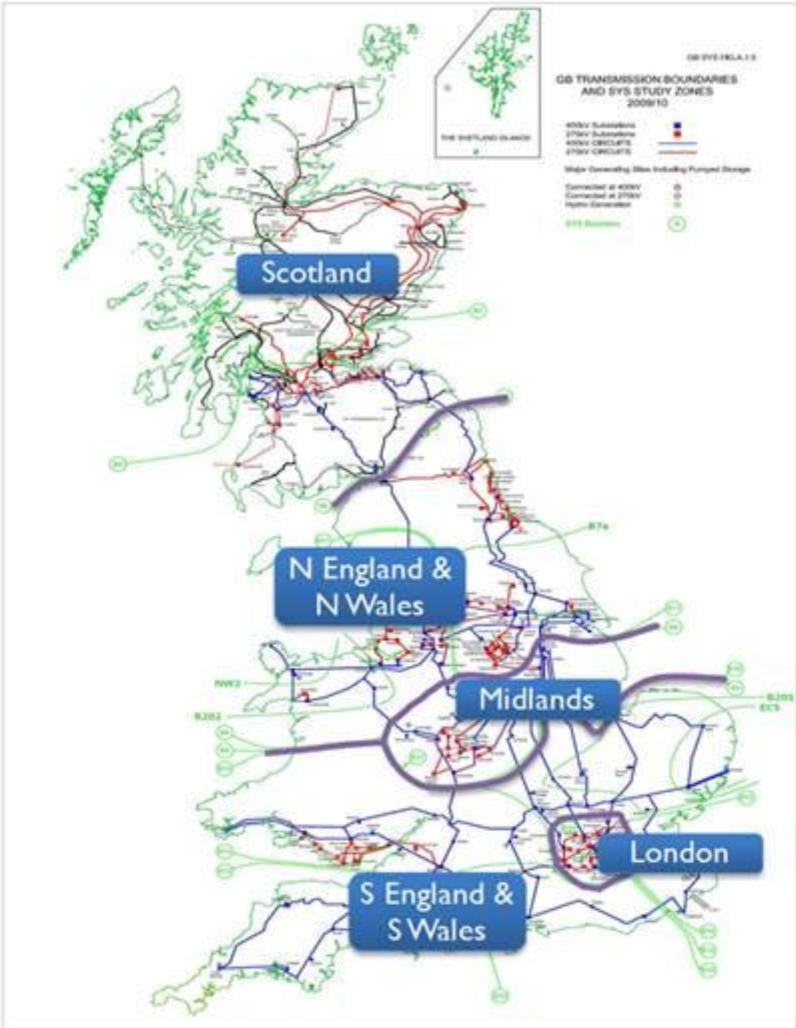
Our extensive database includes a plant-level representation of key European markets, including GB, Germany and France. It includes a detailed representation of the markets to which GB may be interconnected before 2050. This includes Ireland, France, Belgium, The Netherlands, Germany, Denmark, Sweden, Norway, Portugal, Spain and Iceland. Some markets that may not be directly interconnected with GB within the framework study are modelled in a more simplified manner.

3.4.5 Constraint modelling

The dispatch of GB generation can cause significant constraints on the GB electricity transmission system, which are resolved mainly through re-dispatch by the System Operator using the Balancing Mechanism. In the long run, it may be efficient to reinforce the network to resolve a portion of these constraints.

Our model contains a representation of the key GB transmission network constraint boundaries, as shown in Figure 8, along with a zonal breakdown of generation and demand into the corresponding regions.

Figure 8 Zonal representation of GB electricity system



The baseline transfer capacity of each boundary is an input assumption, taken from the National Grid's Ten Year Statement. Changes to the transfer capacity over time are dependent on transmission reinforcement decisions. Our approach to modelling these decisions is described in Section 4.14.

3.4.6 Modelling of reserve and response

We capture both frequency response and reserve in our modelling framework. Frequency response (or just 'response') is held to ensure that the system does not deviate outside of set bounds. The main driver of the response requirement is the potential loss of the largest operating generator. Frequency response can be called upon at very short notice. Reserve is generally provided by generators that require a longer start-up time and is used to relieve the generators providing frequency response, ensuring that response requirements can be met on a continuous basis.

Reserve is held to ensure the system is robust to:

- Deviation of demand from the forecast level
- Deviation of wind generation from forecast
- Generator failures (i.e. replacing frequency response)

The reserve and response requirement is therefore a function of the forecast errors in demand and wind, overall demand level and failure of the largest generator on the system. We use assumptions on each of these three factors for each market under consideration to derive formulas for reserve requirements.

Modelling of the allocation of response and reserve is handled directly in our model. The model allows specification of response and reserve requirements based on the principles above. These minimum reserve and response requirements are calculated for every hour as demand and wind generation fluctuates. Our model co-optimises the provision of reserve with the scheduling of energy dispatch for each generator, ensuring that the total energy, reserve and response requirement is met at lowest cost to the system.

Note that while we model constraints relating to the holding of reserve and response, we do not model the operation of reserve and response. This means that we model a single outcome where generation and interconnectors are dispatched optimally under the assumption of perfect foresight of demand and plant availability, subject to all constraints being met, including the constraints relating to provision of reserve and response. We do not model deviations from expected levels of demand or plant availability that could cause reserve or response to be called upon.

Under current market arrangements, reserve is not provided to GB from other markets via interconnectors. Although ACER's framework guidelines on Electricity Balancing do not explicitly allow for the reservation of cross border capacity for the purpose of balancing, it is possible that in future there may be some sharing of reserves if the interconnectors have spare capacity.

The sharing of reserve will give each market access to a wider range of generators to provide reserve, potentially reducing the total costs of reserve. In addition, for two or more highly interconnected markets there may be a diversification effect which means that the total reserve requirement across two markets is less than the sum of the reserve requirements for the two independent markets.

3.5 Cost benefit analysis

Our CBA of different interconnector configurations is based on outputs from the PLEXOS dispatch model. CBA results are evaluated on a relative basis where each configuration under a given scenario is compared to the equivalent case where no additional GB interconnection is built after 2013. It therefore isolates the estimated impact of changes in future GB interconnection. All CBA line items and results are also evaluated in Net Present Value (NPV) terms using the Green Book discount rate of 3.5% in real terms.

The CBA is built on the basis of the following key components:

- Consumer welfare – representing the change in costs and benefits to GB consumers of electricity;
- Producer welfare – representing the change in costs and benefits to GB producers of electricity;
- Interconnector welfare – representing the change in the GB share of the cost and revenues of interconnectors; and
- Net welfare – represents the change in aggregate net welfare account for all costs and benefits attributable to GB.

The key components of the CBA are made up of the following constituent parts:

- **Producer welfare:**
  - Wholesale revenue of generators – Calculated as total generation in a given market in each hour multiplied by the wholesale spot market price in that hour and then summed over all hours in a given year. The wholesale generator revenue from the no additional interconnection case is then subtracted from its equivalent for the relevant configuration of GB interconnection.
  - Generation cost – This is the change in the total annual variable cost incurred by generators in a given market as a result of a change in GB interconnection under the relevant configuration. Variable costs include fuel costs, start costs, variable operating costs and the cost of emissions. Fixed and capex costs of generation are excluded since the generation mix is fixed across different modelled configurations of interconnection.[22]
  - Net producer welfare – This is given by the sum of the wholesale revenue of generators and generation cost as defined above.

- **Consumer welfare:**
  - Wholesale cost of electricity – Calculated as total demand in a given market in each hour multiplied by the corresponding difference in wholesale spot market prices in that hour between the no additional interconnection case and the relevant configuration of GB interconnection and then summed over all hours in a given year. The implicit assumption would be that any changes in the wholesale price of electricity are passed into the electricity bills of consumers in full and that the price elasticity of firm demand for electricity is zero[23].
  - Network cost (GB only) – Calculated as the change in the total cost of building and operating the GB electricity transmission network as a result of the implied change in GB interconnection, assuming that any change in cost is eventually paid for by consumers.

[22] As the generation mix is fixed across different configurations of interconnection modelled, we do not evaluate the benefits and costs of long-run changes to the generation mix that may be caused by changes to interconnection.

[23] Note that Demand-Side Response is evaluated separately.

– Net consumer welfare – This is equal to the wholesale cost of electricity plus network cost as defined above.

- **Interconnector welfare:**
  - Interconnector revenue – Calculated for both the relevant configuration of GB interconnection and the no additional GB interconnection case as the hourly difference in prices between connected markets times the volume of flow minus thermal losses on the interconnector. Interconnector revenue for the no additional GB interconnection case is then subtracted from interconnector revenue for the relevant configuration of GB interconnection.
  - Interconnector cost – Calculated as the change in total cost of building and operating the interconnectors as a result of the change in GB interconnection implied by the relevant configuration.

- **Net welfare:**
  - Calculated as the sum of net consumer welfare, net producer welfare and net interconnector welfare as defined above.

Note that interconnector welfare is assumed to be split evenly between the connected markets. Note also that we do not explicitly account for capacity payments in our definitions of consumer and producer welfare. The underlying assumption is that these payments are welfare-neutral in the long run. The negative effect of these payments on consumer welfare is assumed to be offset by a corresponding reduction in the total wholesale cost of electricity.

All things being equal, the introduction of capacity mechanisms in the two markets connected by an electricity interconnector would be expected to have a negative impact on interconnector revenues unless that interconnector would also be eligible for capacity payments[24]. This is because capacity markets would be expected to reduce price volatility compared to energy-only markets (and also reduce average prices), thus potentially leading to reduced price arbitrage opportunities for interconnectors. If however interconnectors are eligible for capacity payments, their revenues might be positively affected and this would depend on: (i) the level of capacity payments they would receive[25]; versus (ii) the electricity market revenues lost by the interconnector due to the introduction of the CM.

[24] It is also possible that capacity mechanisms may increase interconnector revenues if they are only introduced in one of the two connected markets (particularly so if they are only introduced in the lower-cost market as they are likely to further reduce average prices in that market). Net welfare impacts arising due to such policy distortions, however, are outside the scope of this report.

[25] By substituting wholesale electricity revenues (which are more uncertain and can be volatile, particularly for merchant interconnectors) with capacity revenues it is possible to reduce earnings-at-risk for interconnectors and thus also improve their risk profile, however this would have to be weighed against potential financial exposures due to under-delivery in the CM. Interconnector availability, the projected volatility in the annual CM auction prices along with the length of CM contracts offered to interconnectors would all be important parameters in determining whether the risk profile of an interconnector would be affected positively or negatively by the introduction of capacity markets.

From a GB consumer and producer point of view, the potential impact of the capacity mechanism has been extensively researched in the latest Impact Assessment[26] showing a positive impact to producers and a negative impact to consumers however these projections are highly uncertain and will be sensitive to assumptions such as: (i) the value of lost load for consumers; (ii) how competitive the auction will be; (iii) whether, following market reform, electricity prices in the future will better reflect scarcity; (iv) whether producers will value scarcity rents when choosing how to price into the capacity auction; and (v) estimates on institutional costs and administrative costs on business.

[26] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66039/7103-energy-bill-capacity-market-impact-assessment.pdf

4 Assumptions

4.1 Introduction

In this section we describe the main assumptions that have been employed for the purposes of this study. These assumptions have been agreed with DECC using a variety of sources as set out below.

All prices stated here are in real 2012 £ terms, except when stated otherwise.

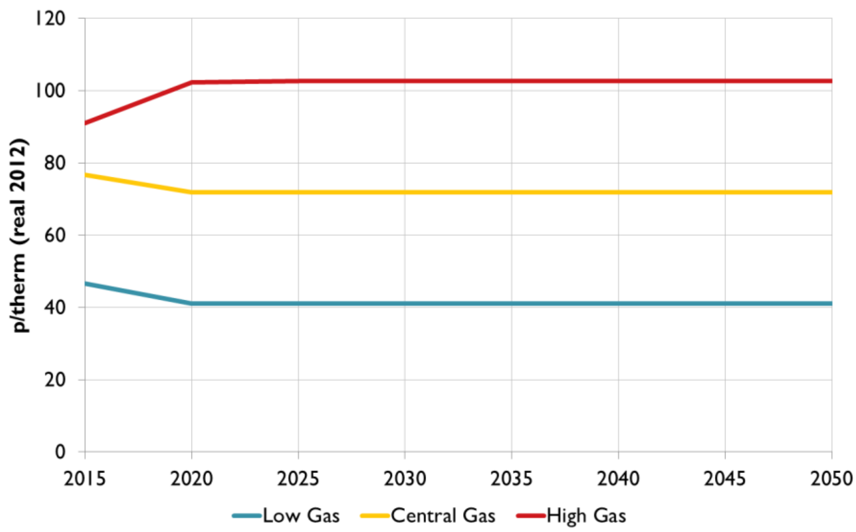
4.2 Gas, coal and Brent crude oil prices

We are using DECC[27] projections (October 2012) until 2030, and then assume that fossil fuel prices remain constant in real terms thereafter.

Scenarios 1 and 4 use the DECC Central projections, with long-term gas prices just above 70 p/therm throughout the modelling horizon. Scenario 2 uses DECC High projections which assumes that long-term gas prices rise above 100 p/therm, while Scenario 3 employs the DECC Low projections under which gas prices remain around 40 p/therm in real 2012 terms. These projections are shown in Figure 9.

Fuel oil and gas oil prices are derived from the Brent crude oil price using standard conversion formulas.

Figure 9 Gas price assumptions



[27] http://www.decc.gov.uk/assets/decc/11/about-us/economics-social-research/6658-decc-fossil-fuel-price-projections.pdf

Figure 10 Coal price assumptions

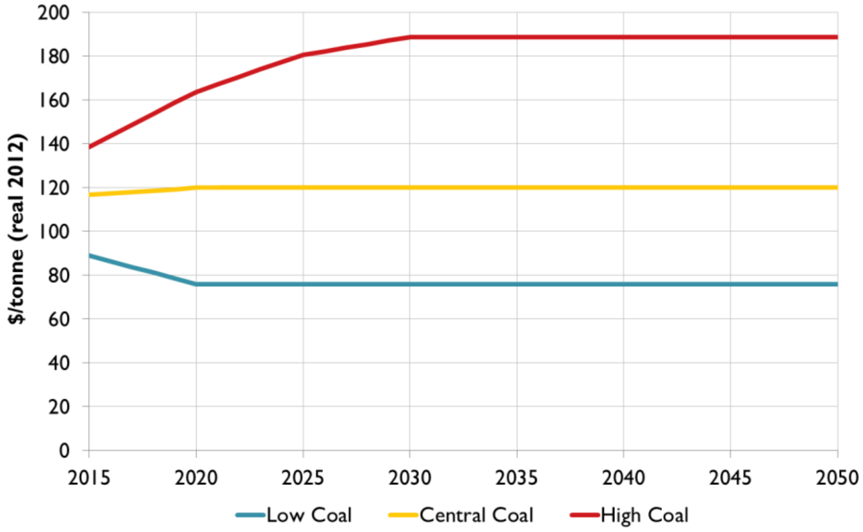
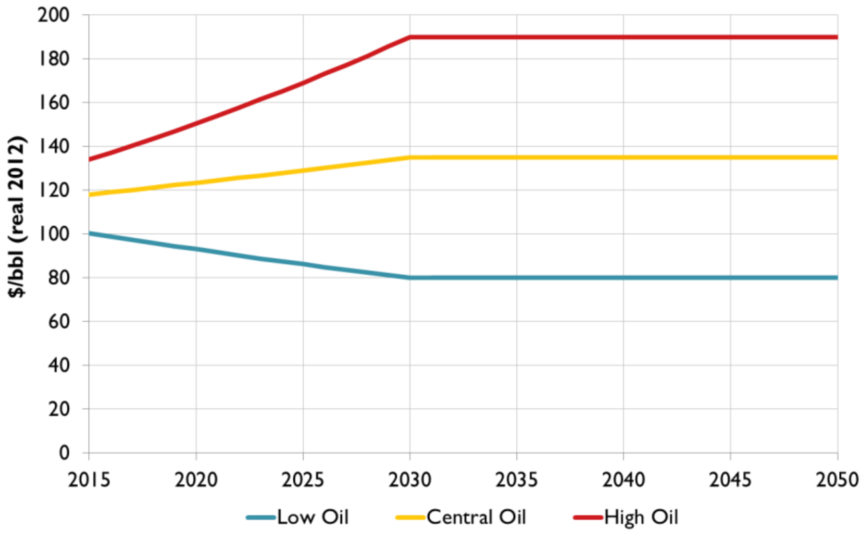


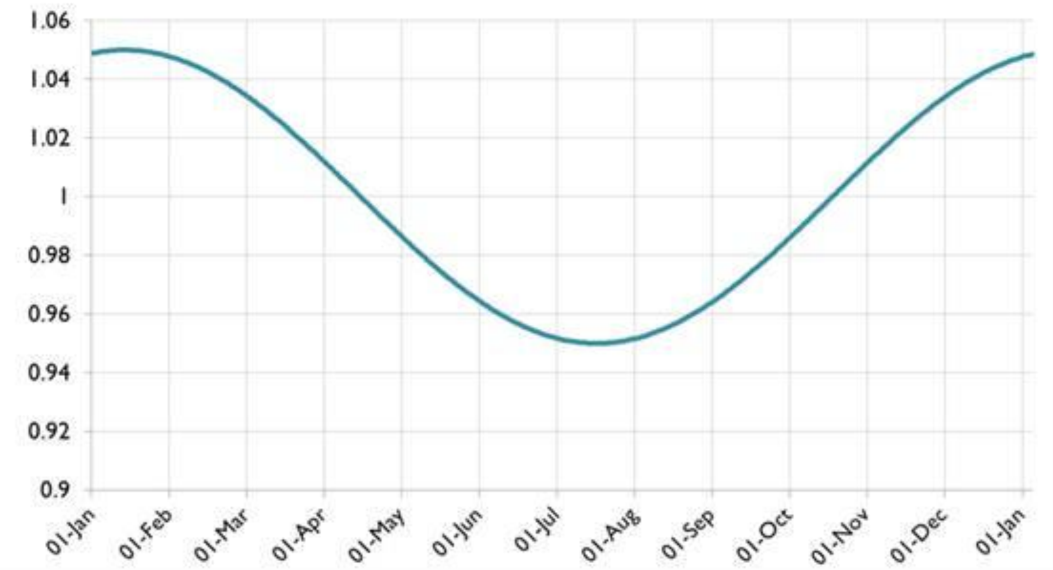
Figure 11 Brent crude oil price assumptions



4.3 Gas price seasonality

Under all modelled years and all modelled markets, we assume that gas price seasonality exists as given by Figure 12.

Figure 12 Gas price seasonal variation relative to annual mean



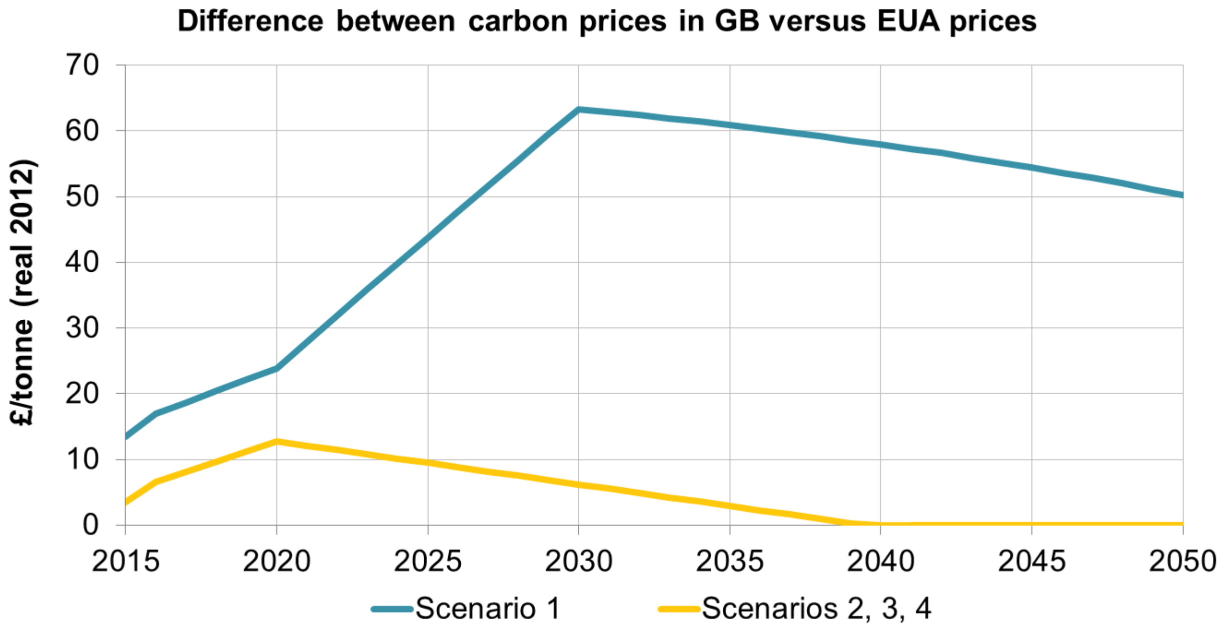
4.4 Carbon prices

For Scenarios 2, 3 and 4 we use the Q4 2012 Redpoint Reference Case EUA assumptions and Redpoint assumptions on the Carbon Price Floor which reflects the view Redpoint takes when working with interconnector developers. It can be seen that GB carbon prices are marginally higher for the majority of the modelling horizon, with convergence between GB carbon prices and EUA prices from approximately 2040 onwards. The greatest differences are observed in 2020, with GB carbon prices around £13/t higher compared to EUA prices.

DECC asked us to model Scenario 1 using DECC[28] projections (October 2012) of EUA prices until 2030, which were then extrapolated to get values for 2035, 2040 and 2050. Moreover, the Carbon Price Floor levels for GB were as in the HMT consultation to 2030, and were assumed to remain constant in real terms thereafter. It can be seen that these assumptions result in consistently higher carbon prices in GB compared to the rest of Europe. By 2030 carbon prices in GB are approximately £63/t higher compared to EUA prices however by 2050 this difference is reduced to approximately £50/t.

28 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65559/6664-carbon-values-used-in-deccs-emission-projections-.pdf

Figure 13 Carbon price assumptions



4.5 Exchange rates

For our exchange rate assumptions, we used Office for Budget Responsibility projections[29] (December 2012) until 2017, after which point we used a constant £:€ exchange rate of 1.25 across all scenarios.

4.6 GDP growth

For GDP growth, we use Office for Budget Responsibility[30] projections (December 2012) until 2017, after which point we are using a GDP growth figure of 2.5% across all scenarios.

4.7 Interconnection costs and losses

Our assumptions on interconnection costs and losses are shown in Table 2. Interconnector losses are derived on the basis of a 1.5% loss due to conversion and a transmission loss of 0.75% per 100km[31]. Interconnector capex costs are estimated using a linear regression of cable length against cost in £/MW terms for 12 known projects with published information on such costs. Results from separate regression analysis suggest that there are no significant economies of scale in interconnector rating and also no significant correlation between copper price, lagged or concurrent, and interconnection costs.

[29] http://cdn.budgetresponsibility.independent.gov.uk/December-2012-Economic-and-fiscal-outlook23423423.pdf

[30] http://cdn.budgetresponsibility.independent.gov.uk/December-2012-Economic-and-fiscal-outlook23423423.pdf

[31] See http://www.greenwire.ie/assets/Internal-site-documents/HVDC-Factsheet-Siemens-2011.pdf

Interconnector capital costs are annuitised, assuming an economic lifetime of 40 years and a discount rate of 8%. In addition to interconnector capital costs, we also include annual fixed costs of 0.0032 £m/MW (i.e. 0.004 €m/MW) per interconnector. The costs of connection to the transmission grid of each of the interconnected counties are assumed to be included in the total cost of interconnection.

Table 2 Interconnection costs and losses assumptions

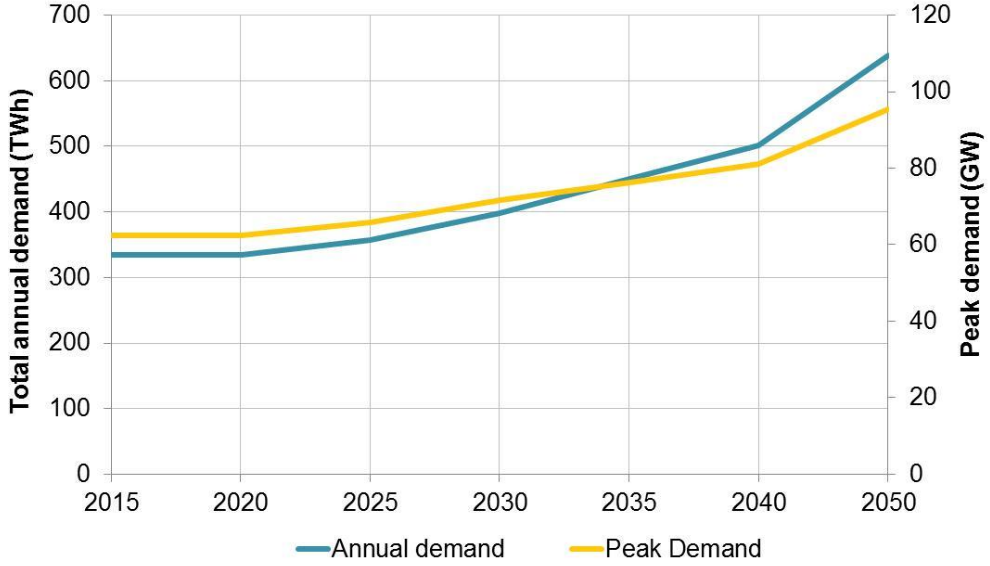
Interconnector	Distance (km)[32]	Cost (£m/MW)	Losses (%)
Belgium	140	0.52	2.55%
Denmark	600	1.00	6.00%
France (long)	195	0.58	2.96%
France (short)	70	0.45	2.03%
Germany	480	0.87	5.10%
Iceland	1200	1.62	10.50%
Ireland	170	0.55	2.78%
Ireland (North)	170	0.55	2.78%
Netherlands	260	0.64	3.45%
Norway (England)	711	1.11	6.83%
Norway (Scotland)	570	0.96	5.78%
Spain	850	1.25	7.88%
Sweden	900	1.31	8.25%

4.8 GB electricity demand

We use DECC projections from DECC's Dynamic Dispatch Model (DDM) with respect to GB electricity demand. GB annual electricity demand figures do not vary across the 4 scenarios, however peak demand is slightly lower for Scenario 2 due to higher assumed levels of DSR uptake (as explained in Section 4.10).

[32] Distances worked out using a Google Maps based tool by drawing a straight line between the landing point of the interconnector. Landing points informed by market intelligence, including interviews with selected interconnector developers.

Figure 14 GB Demand assumptions (Scenarios 1, 3 and 4)



4.9 EU electricity demand

We source EU electricity demand assumptions from NSCOGI33 (The North Seas Countries' Offshore Grid Initiative) and EU34 projections with regards to individual EU countries' demand growth until 2030, after which point we are using Redpoint assumptions as informed by our own market research and analysis.

4.10 Demand side response

For Scenario 2 (high DSR uptake) we have assumed that an additional percentage of electricity demand from the 16 hours with highest demand may be shifted to the 8 hours with the lowest demand compared to the other three scenarios (Scenarios 1, 3 and 4) where central DSR uptake is assumed. The methodology and figures we employ are loosely based on a recent European grid study[35] and have been agreed with DECC.

Table 3 shows the percentage in peak demand reduction that is achieved in Scenario 2 relative to the other 3 scenarios. It is also assumed that similar peak demand reductions are realised across all modelled European markets for that scenario.

[33] http://www.benelux.int/NSCOGI/NSCOGI_WG1_OffshoreGridReport.pdf. It is worth noting that the demand figures quoted in the NSCOGI report refer to transmission-connected demand (i.e. transmission losses and embedded generation are ignored). In our model, however, we account for both transmission losses and embedded generation.

[34] EU Energy trends to 2030 - http://ec.europa.eu/energy/observatory/trends_2030/

[35] http://www.energynautics.com/downloads/competences/energynautics_EUROPEAN-GRID-STUDY-2030-2050.pdf

Table 3 Assumptions on additional peak demand reduction in Scenario 2 relative to Scenarios 1, 2 and 4.

	2015	2020	2025	2030	2035	2040	2050
% of additional peak demand reduction in Scenario 2 (high DSR uptake) compared to Scenarios 1, 3 and 4 (central DSR uptake)	2.0%	2.0%	3.0%	3.0%	4.0%	4.0%	5.0%

4.11 GB installed generation capacity

For the purposes of this study we have not modelled GB generation capacity endogenously within our modelling suite. Scenarios 1 and 4 use GB capacity figures as taken from DECC's DDM. For Scenario 2 we have replaced 15 GW of gas CCS by 2050 with 32 GW of wind (mostly offshore), whereas for Scenario 3 we have replaced 9.6 GW of nuclear, 15 GW of unabated gas and 10 GW of offshore wind with 30 GW of gas CCS. This approach was followed in order to ensure that all scenarios lead to a comparable level of GB carbon intensity by 2050. GB generation capacity figures are shown in Table 44, Table 45, and Table 46 in Appendix A.

It is also worth mentioning that we do not modify the GB generation capacity mix depending on the level of interconnection for each configuration, i.e. under a specific scenario a configuration with only minimal additional interconnection levels is assumed to have the same capacity mix as a configuration with high additional interconnection levels. From a security of supply perspective, this is broadly consistent with Ofgem's view in the recent Electricity Capacity assessment[36] of no net flows to mainland Europe during peak times[37]. In reality, we would expect investment in interconnection and generation capacity to have some influence over each other (depending on, among other factors, the impact of interconnectors on power prices, the de-rating capacity factors used for interconnectors, auction clearing prices and the net cost of new entry in the capacity market etc.), however this assessment was outside the scope of this study.

4.12 EU installed generation capacity

EU installed capacity is based on Redpoint assumptions as informed by our own market research and analysis (including recent studies by NSCOGI[38] and EU[39]). As with GB, the generation capacity of each country has not been modelled endogenously within our modelling suite. Under all scenarios it was assumed that renewable penetration by 2020 followed the trajectory specified by

[36] https://www.ofgem.gov.uk/ofgem-publications/75232/electricity-capacity-assessment-report-2013.pdf

[37] Ofgem's analysis considers the potential contribution of existing interconnectors to GB security of supply over the next six winters. As part of their analysis, Ofgem assume no net flows to mainland Europe during peak times, along with full exports to Ireland.

[38] http://www.benelux.int/NSCOGI/NSCOGI_WG1_OffshoreGridReport.pdf. It is worth noting that the demand figures quoted in the NSCOGI report refer to transmission-connected demand (i.e. transmission losses and embedded generation are ignored). In our model, however, we account for both transmission losses and embedded generation.

[39] EU Energy trends to 2030 - http://ec.europa.eu/energy/observatory/trends_2030/

each country's National Renewable Energy Action plan[40]. Decarbonisation in Scenarios 1 and 4 is achieved mostly by new-build nuclear, wind and solar PV, with unabated gas also required in order to alleviate security of supply concerns. Scenario 2 assumes that considerably more offshore and onshore wind is deployed at the expense of CCS and, to a lesser extent, solar PV. Finally, Scenario 3 assumes that coal CCS and gas CCS play a more important role towards decarbonisation in the longer term (due to lower fuel costs) at the expense of new-build nuclear, wind (particularly offshore) and solar PV.

4.13 Wind load factors

We used historic wind speed data from a single database covering both onshore and offshore regions for the whole of Europe[41] in order to ensure that wind speed correlations between different EU countries are taken into account for system dispatch purposes. Average annual load factors are shown in Table 43 of Appendix A for different onshore and offshore wind locations.

4.14 GB onshore network reinforcement

Our model contains a representation of the key GB transmission network constraint boundaries, as previously shown in Figure 8, along with a zonal breakdown of generation and demand into their corresponding regions. The four key GB transmission network constraint boundaries that we are modelling are as follows:

- **B6** (SPT – NGET) – The SPT (Scottish Power Energy Networks) to NGET (National Grid Electricity Transmission) boundary defines the asset ownership boundary between SPT and NGET. This boundary is normally an exporting boundary and this situation is expected to exacerbate in the future due to contracted renewable energy developments (particularly onshore and offshore wind) throughout Scotland.
- **B8** (North – Midlands) – Boundary B8 is part of the wider group of system boundaries which separate England and Wales generation, approximately midway throughout GB.
- **B9** (Midlands – South) – Boundary B9 defines the boundary between Midlands and South England and South Wales.
- **B14** (London) – Boundary B14 covers Central London and the surrounding outer London areas. Greater London represents a 'high demand, minimal generation' zone and as such it relies heavily on importing electricity from generators outside B14. As National Grid notes[42], additional stress can be placed on the surrounding circuits if the European interconnectors in the Thames Estuary export to the continent, causing increased power flows through London and across B14.

[40] http://ec.europa.eu/energy/renewables/action_plan_en.htm

[41] http://www.anemos.de/en/index.php

[42] http://www.nationalgrid.com/NR/rdonlyres/8F8FA914-A61D-4367-BC42-B8C69C1BC113/47009/NETSSYS2011Chapter8.pdf

For 2015 and 2020, the transfer capacity of each boundary is an input assumption, taken from National Grid's Ten Year Statement. For subsequent modelled years, changes to the transfer capacity over time are dependent on transmission reinforcement decisions.

Our model works on the principle that reinforcements are economic if they reduce the sum of transmission investment costs and constraint costs. Each potential reinforcement is treated as a separate transmission investment decision. These decisions are evaluated on 500 MW intervals for each boundary using the capital cost assumptions shown in Table 4.

Table 4 Assumed network reinforcement costs for the GB onshore network

	Capital costs (£m/MW)
Boundary B06 (SPT – NGET)	0.50
Boundary B08 (North – Midlands)	0.17
Boundary B09 (Midlands – South)	0.17
Boundary B14 (London)	0.25

Network reinforcement costs are annuitised assuming an economic lifetime of 40 years and a discount rate of 5.5%. They are calculated separately for each scenario and each configuration of GB interconnection since interconnectors can influence flows on the GB onshore network and thus also have an effect on the need for network reinforcement. Reinforcements that are deemed to be economic under this framework are incorporated into our dispatch modelling.

4.15 Continental European interconnection

A similar logic to the one used to determine GB onshore network reinforcements was employed for simulating Continental European interconnection investment decisions. Additional interconnection was determined by optimisation logic in our model (based on PLEXOS software) and sense checked against a set of criteria:

- A minimum expected utilisation rate of 60% per interconnector;
- A maximum of 2 GW of interconnection capacity may be developed between two countries over a period of 5 years;
- A maximum of 5 GW of total interconnection capacity may be developed over a period of 5 years for Scenarios 1, 3 and 4; and
- For Scenario 2 it was assumed that up to 7 GW of total interconnection capacity may be developed over a period of 5 years.

As with internal GB network reinforcements, these decisions are evaluated on 500 MW intervals for each possible interconnection using the capital cost assumptions shown in Table 47 of Appendix A. Interconnection capital costs are annuitised assuming an economic lifetime of 40 years and a discount rate of 8%. Different scenarios had different EU interconnection, but EU interconnection did not vary by configuration of GB interconnection. This approach was taken in order to avoid polluting differences in modelling results between different configurations under the same scenario.

Table 5 Assumed capital costs for Continental European interconnection

	Capital costs (£m/MW)
Belgium - Germany	0.17
Belgium - France	0.17
Belgium - Netherlands	0.17
Germany - France	0.17
East Denmark – Germany	0.37
East Denmark – West Denmark	0.25
East Denmark – Sweden	0.17
West Denmark – Germany	0.17
West Denmark – Norway	0.37
West Denmark Sweden	0.37
Germany – Netherlands	0.17
Germany - Norway	0.50
Germany – Sweden	0.50
Spain - France	0.50
Spain - Portugal	0.17
Finland - Norway	0.50
Finland – Sweden	0.37
Netherlands – West Denmark	0.37
Netherlands – Norway	0.50
Netherlands – Sweden	0.25

4.16 ENTSO-E Constraints

The following constraints were taken into account as specified by the Net Transfer Capacities Matrix[43] developed by the European Network of Transmission System Operators for Electricity (ENTSO-E):

[43] https://www.entsoe.eu/publications/market-and-rd-reports/ntc-values/ntc-matrix/

- Germany cannot export more than 8,500 MW. From 2025 onwards this constraint is relaxed to 9,500 MW for Scenarios 1 and 4. For Scenario 2 (high wind penetration scenario) this constraint is relaxed to 10,000 MW from 2025 onwards and to 11,000 MW from 2035 onwards.
- Similarly, there is a 3,850 MW import/export constraint to The Netherlands. For Scenarios 1, 2 and 4 this constraint is relaxed to 5,000 MW from 2025 onwards and to 7,000 MW from 2035 onwards.

5 Interconnector configurations

5.1 Introduction

This section sets out the methodology for deriving interconnector configurations and the rationale for the final choice of configurations, each being modelled for all four scenarios. As set out in Section 3.3, configurations are divided into three categories, Import, Flexible and Alternative. The first two of these are adapted to Scenarios 1 and 2 respectively[44] and the third category represents variation from the tailored configurations in the markets to which GB connects and the timing of connection to ensure that a reasonable number of alternatives to the tailored configurations are considered. Although no configurations are tailored to Scenario 3 (Low utilisation) specifically, the more conservative configurations from all categories are likely to be most suited to that scenario given the expected low utilisation of interconnectors.

The formulation of the configurations (within categories A to B but not across the categories) is rule-based, where changes from more conservative configurations to more speculative configurations can only involve:

- An increase in capacity of interconnectors also present in the more conservative configuration;
- Commissioning of an interconnector that is not present in the more conservative configuration; and
- Earlier commissioning of an interconnector that is also present in the more conservative configuration.

More conservative configurations generally contain interconnectors that are most likely to be economic under all of the modelled scenarios and specify relatively low or zero capacity for the interconnectors that are more likely to be economically marginal. For configurations C1 to C5, the formulation does not necessarily follow the rules set out above.

5.2 Category A – Import

This category of configurations is tailored loosely to the GB Import scenario. This is a scenario where the UK becomes a net importer of electricity over the modelling horizon. This is likely to materialise in a world with moderate gas prices, where generators face higher carbon prices in the UK compared to Europe into the longer term, and where it is possible to import significant surplus

[44] For Scenario 1, given the higher carbon prices assumed in GB (and thus also the anticipated higher electricity prices) we considered which neighbouring European markets have the potential to supply GB with cost-effective baseload electricity. Hence, since the value of diversification is not particularly high under this scenario, a relatively low number of interconnectors is assumed to be developed, however the ones that are developed are likely to be the most economic and their capacity is also large. For Scenario 2, given the high penetration of intermittent wind generation in the GB generation mix, interconnection to markets with a flexible generation mix that is different from that of GB (e.g. Norway) is favoured over interconnection to markets with a potentially inflexible generation mix and one that is likely to be similar to that of GB with correlated intermittent renewable output (e.g. Netherlands or Germany).

low carbon electricity (or renewable electricity more specifically) from the Continent. This scenario assumes that decarbonisation of the UK power sector is, to a degree, achieved, but the Government does not consider domestic action to be of paramount importance. There is moderate electricity demand growth, coupled with moderate electrification of the heat and transport sector and moderate progress on DSR.

For this scenario, given that the penetration of intermittent renewables (and more generally low carbon generation) in the GB capacity mix is lower than in the Flexible Operation scenario, and the carbon price differential between UK and interconnected markets is relatively high, the importance of a flexible generation base in interconnected markets is lower. Rather, the need to import low carbon power at least cost is paramount. Hence, all other factors being equal, fewer interconnectors are built relative to the Flexible Operation scenario due to a lesser need for diversification. However, the ones that are built are likely to be the most economic and larger in capacity.

Configuration A1 – This is the most conservative configuration and only one new interconnector is built. 500 MW of capacity to France is built as it is likely to be the most economic interconnector for GB and increases overall interconnection capacity between GB and Continental Europe to import low carbon electricity.

Table 6 Configuration A1

Interconnector	Year of completion	Landing zone in GB	Capacity (MW)
France (short)	2025	S England & S Wales	500
Total			**500**

Configuration A2 – An additional 1000 MW interconnector to Belgium is built in 2030 as this is a credible project and Belgium is in close geographic proximity with GB. More capacity to France and Ireland is added. This reflects the likelihood that France and Ireland are the most economic markets to connect to in the context of the GB Importing scenario and the fact that both are expected to have an abundance of relatively cheap low carbon energy by 2020 and beyond in Scenario 1.

Table 7 Configuration A2

Interconnector	Year of completion	Landing zone in GB	Capacity (MW)
France (short)	2020	S England & S Wales	1000
Belgium	2030	S England & S Wales	1000
Ireland	2035	N England & N Wales	500
Total			**2500**

Configuration A3 – A 1000 MW interconnector to Norway is also built in 2030. This reflects the relative abundance of cheap low carbon electricity in Norway as well as its distance from GB. The second interconnector to Ireland connects into a different zone in GB from its predecessors to ease the effect of interconnectors on congestion on the GB onshore network. Finally, another 1000 MW interconnector to France is added in 2035, increasing the overall level of interconnection between GB and Continental Europe.

Table 8 Configuration A3

Interconnector	Year of completion	Landing zone in GB	Capacity (MW)
Ireland	2020	N England & N Wales	500
France (short)	2020	S England & S Wales	1000
Belgium	2025	S England & S Wales	1000
Norway	2030	N England & N Wales	1000
Ireland	2035	S England & S Wales	500
France (long)	2035	S England & S Wales	1000
Total			**5000**

Configuration A4 – Additional 700 MW interconnector to Iceland built in 2035. This reflects the benefits of connecting to a market that, although remote, has an abundance of low cost renewable generation. Interconnections to Norway and Ireland are also moved forward and their capacity is increased in relation to Configuration 2. Additional 1000 MW interconnector to Spain is built in 2040. In the context of the GB Importing scenario, this interconnector is built to capture the benefit of importing low cost low carbon electricity, particularly to channel low cost solar energy from Spain itself and from schemes like DESERTEC[45] indirectly. This connection is likely to be less economic than connections built as part of Configuration 3 since it is to a more remote market. Interconnection capacity to Norway and Ireland is increased compared to Configuration 3 to further increase overall GB imports of low carbon electricity. Finally, additional interconnection capacity to The Netherlands is built in this configuration.

Table 9 Configuration A4

Interconnector	Year of completion	Landing zone in GB	Capacity (MW)
Norway	2020	N England & N Wales	1400
Ireland	2020	N England & N Wales	500
France (short)	2020	S England & S Wales	1500
Belgium	2025	S England & S Wales	1000

[45] See https://dl.dropboxusercontent.com/u/2639069/DESERTEC%20Concept.pdf

Interconnector	Year of completion	Landing zone in GB	Capacity (MW)
Ireland	2030	S England & S Wales	1000
France (long)	2030	S England & S Wales	1000
Iceland	2035	Scotland	700
Netherlands	2035	S England & S Wales	500
Spain	2040	S England & S Wales	1000
Total			**8600**

Configuration A5 – This is the most ambitious of the configurations adapted to the GB Importing scenario. Interconnection capacity to Norway, Ireland, France, Belgium, Spain, and Iceland is increased, the aim being to increase the overall GB interconnection level. New interconnectors are built to Denmark and Germany. In the case of Denmark, some of the surplus wind generation from that market is imported into GB directly. The economics of both is likely to be marginal given that the former is a relatively distant market and the latter is likely to be well connected to The Netherlands and France, which would in turn already be connected to GB.

Table 10 Configuration A5

Interconnector	Year of completion	Landing zone in GB	Capacity (MW)
Norway	2020	N England & N Wales	2000
Ireland	2020	N England & N Wales	1000
France (short)	2020	S England & S Wales	2000
France (long)	2025	S England & S Wales	2000
Belgium	2025	S England & S Wales	1500
Ireland	2030	S England & S Wales	1500
Iceland	2030	Scotland	1200
Netherlands	2030	S England & S Wales	500
Denmark	2035	N England & N Wales	1000
Spain	2035	S England & S Wales	2000
Germany	2040	N England & N Wales	700
Total			**15400**

No interconnections are built to Sweden and Portugal in 2040. Given the large distance to these markets to GB and the relative proximity of viable alternatives (Norway and Denmark in the case of the former and Spain in the case of the latter), they are likely to be the least economic markets that GB may connect to.

5.3 Category B – Flexible

This category of configurations is tailored loosely to the Flexible Operation scenario. This is a scenario where significant amounts of flexibility are required, with high intermittency across Europe increasing the extrinsic value of interconnectors. This is likely to materialise in a world with high gas and moderate carbon prices and where significant amounts of intermittent renewable technologies (particularly wind and solar) are deployed across Europe. The Carbon Price Floor policy is maintained in the UK. Similarly, other European countries are equally ambitious and push for the creation of a European super-grid. There is moderate electricity demand growth due to moderate progress in the electrification of the heat and transport sector. DSR uptake is high.

For this scenario, given the high penetration of intermittent wind generation in the GB generation mix, interconnection to markets with a flexible generation mix that is different from that of GB (e.g. Norway) is favoured over interconnection to markets with a potentially inflexible generation mix and one that is likely to be similar to that of GB with correlated intermittent renewable output (e.g. The Netherlands or Germany). Given the volatile renewable generation level in GB and most continental markets in this scenario, the value of diversification provided by interconnectors to different markets is significant. Equally, intermittent transmission constraints between different markets and between different GB zones are likely. Hence the configurations adapted to this scenario are likely to have a greater number of smaller interconnectors to a broader range of markets to realise the benefits of diversification.

Factors such as distance to the connected market and the likely cost of interconnection also play an important role in determining which interconnectors are most likely to be economic and to form part of the most conservative scenarios. These factors may override factors that relate to the capacity mix in the different interconnected markets.

Configuration B1 – This is the most conservative configuration and only 2 new interconnectors are built. Significant wind capacity expansion in Ireland makes increased exports into GB more economic. 500 MW of capacity to France is built as it is likely to be the most economic interconnector for GB and increases overall interconnection capacity between GB and Continental Europe.

Table 11 Configuration B1

Interconnector	Year of completion	Landing zone in GB	Capacity (MW)
Ireland	2030	N England & N Wales	500
France (short)	2025	S England & S Wales	500
Total			**1000**

Configuration B2 – 700 MW of capacity to Norway is built in 2025 to take advantage of Norway's flexible generation base. Timing of the new connection to France is moved forward in relation to Configuration 1 and capacity of the interconnector is increased.

Table 12 Configuration B2

Interconnector	Year of completion	Landing zone in GB	Capacity (MW)
France (short)	2020	S England & S Wales	700
Norway	2025	N England & N Wales	700
Ireland	2030	N England & N Wales	500
Total			**1900**

Configuration B3 – An additional 1000 MW interconnector to Belgium is built in 2030 as this is a credible project and Belgium is in close geographic proximity with GB. Additional 500 MW interconnectors to Iceland and The Netherlands are built in the later part of the modelled period. The former reflects the benefits of connecting to a market that, although remote, has an abundance of low cost and relatively flexible generation[46]. The Iceland interconnector is assumed to connect to Scotland.

Table 13 Configuration B3

Interconnector	Year of completion	Landing zone in GB	Capacity (MW)
France (short)	2020	S England & S Wales	1000
Ireland	2025	N England & N Wales	500
Norway	2025	N England & N Wales	1000
Belgium	2030	S England & S Wales	500
Iceland	2035	Scotland	500
Netherlands	2040	S England & S Wales	500
Total			**4000**

Configuration B4 – Additional 500 MW interconnectors are built to Denmark, Germany and Spain in the latter part of the modelled period. In the context of the Flexible Operation scenario, the first two interconnectors are built to capture the benefit of offsetting fluctuations in the output of partly correlated intermittent renewables. These connections are likely to be less economic than connections built as part of Configuration 3 since they are to more remote markets with capacity mixes that bear a lot of resemblance to that of GB. The third reflects the potential benefit of

[46] Note that the contracts used as the basis to fund an interconnector to Iceland and new Icelandic generation capacity are likely to be based on baseload generation and flows, though this does not necessarily imply operational inflexibility.

importing surplus renewable energy from Spain as well as the likely difficulty in increasing interconnection between Spain and France. Interconnection capacity to Ireland, Iceland and France is increased compared to Configuration 3. An additional interconnector to Norway is built in 2030 and connects in Scotland to ease the pressure on the onshore grid in GB as a result of high intermittent wind generation.

Table 14 Configuration B4

Interconnector	Year of completion	Landing zone in GB	Capacity (MW)
Norway	2020	N England & N Wales	1000
France (short)	2020	S England & S Wales	1000
Ireland	2025	N England & N Wales	500
Belgium	2025	S England & S Wales	700
Iceland	2025	Scotland	700
Norway	2030	Scotland	500
Ireland	2030	S England & S Wales	500
France (long)	2030	S England & S Wales	500
Netherlands	2030	S England & S Wales	500
Spain	2035	S England & S Wales	500
Germany	2035	N England & N Wales	500
Denmark	2040	N England & N Wales	500
Total			**7400**

Configuration B5 – This is the most ambitious of the configurations adapted to the Flexible Operation scenario. An additional 700 MW connection is built to Sweden in 2035. No interconnector to Portugal is built. Given the large distance to these markets to GB and the relative proximity of viable alternatives (Norway and Denmark in the case of the former and Spain in the case of the latter), they are likely to be the least economic markets that GB may connect to. Additional interconnectors are built to Ireland and France in 2040 and capacity of other interconnectors is increased, the aim being to increase the overall GB interconnection level, particularly with markets to which GB is connected to the least extent.

Table 15 Configuration B5

Interconnector	Year of completion	Landing zone in GB	Capacity (MW)
Norway	2020	N England & N Wales	1400
France (short)	2020	S England & S Wales	1000
Belgium	2020	S England & S Wales	1000

Interconnector	Year of completion	Landing zone in GB	Capacity (MW)
Ireland	2025	N England & N Wales	700
Iceland	2025	Scotland	1000
Norway	2025	Scotland	700
Ireland	2030	S England & S Wales	700
France (long)	2030	S England & S Wales	1000
Netherlands	2030	S England & S Wales	700
Denmark	2030	N England & N Wales	1000
Spain	2035	S England & S Wales	1000
Germany	2035	N England & N Wales	700
Sweden	2035	N England & N Wales	700
Ireland	2040	S England & S Wales	700
France (short)	2040	S England & S Wales	500
Total			**12800**

5.4 Category C – Alternative

This category of configurations is not tailored to any specific scenario. Rather it is intended to contain configurations that are formulated using different logic from that used in categories A and B. Hence the build up from C1 to C5 does not necessarily follow the same rules as the other two categories.

Configuration C1 – In this configuration, an interconnector to Belgium is built by 2020. Apart from this, only interconnection to the closest markets is built (France and Ireland), putting an emphasis on lowering the cost of interconnection. Access to other continental markets is assumed to be gained indirectly through France. Interconnection is built out gradually at intervals consistent with the modelled spot years. Total (post 2012) new GB interconnection reaches 7.6 GW by 2040.

Table 16 Configuration C1

Interconnector	Year of completion	Landing zone in GB	Capacity (MW)
Belgium	2020	S England & S Wales	1000
Ireland	2020	N England & N Wales	500
France (short)	2020	S England & S Wales	1000
Ireland	2025	S England & S Wales	500

Interconnector	Year of completion	Landing zone in GB	Capacity (MW)
France (long)	2025	S England & S Wales	700
Ireland	2030	N England & N Wales	500
France (short)	2030	S England & S Wales	1000
Ireland	2035	N England & N Wales	500
France (long)	2035	S England & S Wales	700
Ireland	2040	S England & S Wales	500
France (short)	2040	S England & S Wales	700
Total			**7600**

Configuration C2 – This configuration represents increased focus on import of solar energy from Southern Europe (including imports through France) and, indirectly, from North Africa. Total (post 2012) new GB interconnection reaches 7.3 GW by 2040.

Table 17 Configuration C2

Interconnector	Year of completion	Landing zone in GB	Capacity (MW)
Ireland	2020	N England & N Wales	500
France (short)	2020	S England & S Wales	2000
Belgium	2025	S England & S Wales	1000
Spain	2025	S England & S Wales	1400
France (long)	2030	S England & S Wales	1000
Spain	2035	S England & S Wales	1400
Total			**7300**

Configuration C3 – This configuration is as configuration A3 adapted to the GB Importing scenario but with more interconnection to Ireland.

Table 18 Configuration C3

Interconnector	Year of completion	Landing zone in GB	Capacity (MW)
Ireland	2020	N England & N Wales	1000
France (short)	2020	S England & S Wales	1000
Belgium	2025	S England & S Wales	1000

Interconnector	Year of completion	Landing zone in GB	Capacity (MW)
Ireland	2025	S England & S Wales	1000
Ireland	2030	N England & N Wales	1000
Norway	2030	N England & N Wales	1000
Ireland	2035	S England & S Wales	1000
France (long)	2035	S England & S Wales	1000
Total			**8000**

Configuration C4 – This configuration represents delayed construction of interconnectors that are likely to be less economic, with more incremental construction of interconnector capacity in line with the developing need for interconnection.

Table 19 Configuration C4

Interconnector	Year of completion	Landing zone in GB	Capacity (MW)
Ireland	2020	N England & N Wales	500
France (short)	2020	S England & S Wales	1000
Ireland	2025	S England & S Wales	500
France (long)	2025	S England & S Wales	1000
Norway	2030	N England & N Wales	700
Ireland	2030	N England & N Wales	500
France (short)	2030	S England & S Wales	1000
Norway	2035	N England & N Wales	700
Ireland	2035	S England & S Wales	500
Belgium	2035	S England & S Wales	1000
Iceland	2040	Scotland	700
Total			**8100**

Configuration C5 – This configuration represents a focus on interconnection with cheap and flexible Norwegian and Icelandic markets.

Table 20 Configuration C5

Interconnector	Year of completion	Landing zone in GB	Capacity (MW)
Norway	2020	N England & N Wales	1400
Iceland	2025	Scotland	1200
Norway	2030	Scotland	1400
Total			**4000**

6 Results

6.1 Overview

This section describes and interprets our key modelling results, as follows:.

- Section 6.2 explains how our modelling results should be interpreted.
- Section 6.3 sets out some key characteristics of interconnector operation estimated in our modelling.
- Section 6.4 sets out net welfare and consumer welfare results for all configurations under each of the modelled scenarios and evaluates the optimal GB interconnection configuration for each scenario.
- Section 6.5 sets out the concept of least regrets analysis in the context of this study and evaluates the least regrets configuration of GB interconnection.
- Section 6.6 analyses a number of key themes emerging from the results of our analysis.
- Finally, Section 6.8 sets out the results of stress tests and discusses the implications of different configurations of GB interconnection for security of electricity supply in GB.

6.2 Interpreting the results

When interpreting the modelling results it is important to remember the modelling framework described earlier and what it represents. Recall that in addition to generation, demand and transmission constraints between different markets, we also model zonal transmission constraints within the GB market and reserve and response constraints in all of the modelled markets[47]. Hence the model evaluates the majority of balancing costs alongside the wholesale costs of meeting demand and the model solution is closer to the balancing market solution than the day-ahead market solution, where the latter would not be subject to onshore transmission, reserve and response constraints.

Overall, our net welfare results reflect the changes in total system cost as a result of changes in GB interconnection. Whilst our modelling approach ensures that the absolute levels of net welfare for each country modelled here are robust (according to the assumptions set out in Section 4), the distribution of welfare between consumers, producers and owners of interconnector capacity must be seen as an approximation to actual market arrangements and thus the absolute figures provided here regarding distributional impacts must be interpreted with caution. However, the distributional impact analysis remains useful on a relative basis when comparing different interconnector configurations against each other. As an example, savings in GB generation costs as a result of greater interconnection will be attributed to producer welfare in the CBA and hence shown as a benefit for producers. However, a part of those savings may represent a reduction in

[47] See Section 3.4 for details of our dispatch modelling methodology.

the cost of balancing the system, which in the case of GB would be shared between consumers and producers through changes in the Balancing Services Use of System (BSUoS) charge and hence benefit both consumers and producers.

Another example relates to the evaluation of interconnector welfare. In our modelling, interconnectors sometimes flow against the "spread" in prices between markets. This occurs more frequently in the later years. This is due to the presence of certain constraints in the model that are not explicitly priced, particularly the reserve and response constraints, which can sometimes be met at lower cost by scheduling interconnectors to flow against the underlying spread than by changing generation dispatch. This would be equivalent to TSOs trading against the spread on a common EU balancing market to minimise balancing costs. Evaluating interconnector revenues on the basis of flows that include flows against the price spread is likely to underestimate the welfare of owners of interconnector capacity since the cost of trading against the spread would be expected to flow into balancing costs and, in the case of GB, be shared among consumers and producers.

Taking into account the above factors, it is likely that the approach adopted in this study will over-estimate producer welfare and underestimate interconnector welfare in general. The distribution of welfare between consumers, producers and owners of interconnector capacity must therefore be seen as indicative[48].

Finally, since internal GB transmission constraints are modelled for GB, the model generates different prices for the different zones when those constraints are binding, represented by the lowest marginal cost of meeting an additional incremental unit of demand in each constrained off zone. In general, such periods are rare. Out of the few cases where such constraints are binding, most occur between Northern England and Scotland. Constraints between London and one of its surrounding zones occur much less frequently and it is very rare for any other constraints to be observed.

In light of the above, when reporting the GB system price and evaluating the total wholesale cost of electricity for consumers and the wholesale revenue of generators, we take the price for Southern England as the closest proxy to the day-ahead market price. Where this introduces a discrepancy with the net welfare calculated on the basis of the changes in fundamental system costs, the difference is distributed on an equal basis between estimated producer revenue and the estimated consumer wholesale cost of electricity. This is a proxy of how we would expect GB balancing costs to be distributed going forward.

[48] It is also worth mentioning here that, for some other European countries which GB may interconnect with, the distinction between consumer and producer welfare may be more blurred compared to GB given that a number of electricity supply companies in those countries are state owned.

6.3 Characteristics of interconnector operation

6.3.1 Introduction

In this section, we characterise the operation of different interconnectors in different scenarios, spot years and configurations. Given the wide scenario, geographic and temporal scope of our analysis, it is impossible to do this in a comprehensive way and hence we select examples and characteristics that draw out the most informative messages from our analysis.

6.3.2 Variation in daily pattern of interconnector flows by scenario

Figure 15 shows the average daily pattern of flows between GB and France for the four modelled scenarios. We choose Configuration B2 and the 2030 spot year as an example. The general pattern of flows is consistent across the different scenarios, with the lowest point for net flows from France to GB falling between 5am and 8am GB time. This reflects the morning demand peak in France when the supply-demand balance is relatively tight. Net imports from France are at their highest between 10am and 10pm when GB demand is high.

Scenario 1 results in highest overall net imports from France to GB. Scenario 4 sees a very similar pattern of net flows despite a much smaller differential in carbon prices between the two markets. Net flows to GB are slightly lower still under Scenario 3, where prices are lower across different markets due to low gas prices, but the difference is not large. This reflects the binary nature of interconnector flows. Much lower spreads between connected markets that are the same directionally are consistent with the same interconnector flows, though interconnector revenues and benefits from trade are likely to be much lower.

Net interconnector flows from France to GB, although still positive on an average basis, are significantly lower in Scenario 2. Given the significant roll-out of wind generation capacity in GB under this scenario, the results reflect the effect of surplus generation in GB during windy periods.

Figure 15 France - GB flow as % of total capacity - Configuration B2 (2030)

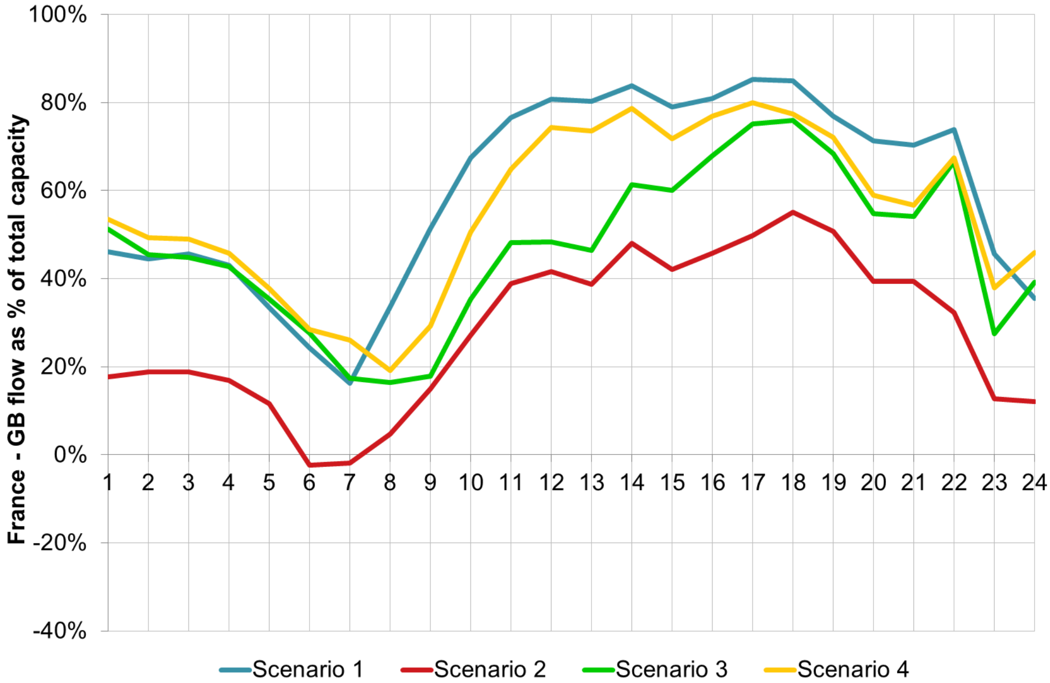


Figure 16 shows the average daily pattern of flows between GB and Ireland for the four modelled scenarios in 2030. In Scenario 1, net imports from Ireland hold at a high rate throughout the day. Given the carbon price differential between the two markets under Scenario 1, it is economic for Ireland to generate extra power by running CCGTs at higher load factors and to export that power to GB. Under other scenarios that do not see such a large differential in carbon prices, the pattern of flows is well defined. Net imports from Ireland peak around the morning and afternoon peaks in GB demand and are at their lowest level in early afternoon.

As with the interconnector to France, the highest level of net imports into GB occurs under Scenario 1. The lowest level occurs under Scenario 3 rather than Scenario 2. The likely reason for this is that under Scenario 2, high wind periods in GB are likely to coincide with high wind periods in Ireland, and hence the interconnectors are unlikely to swing towards exports to Ireland.

Figure 16 Ireland - GB flow as % of total capacity - Configuration B2 (2030) [49]

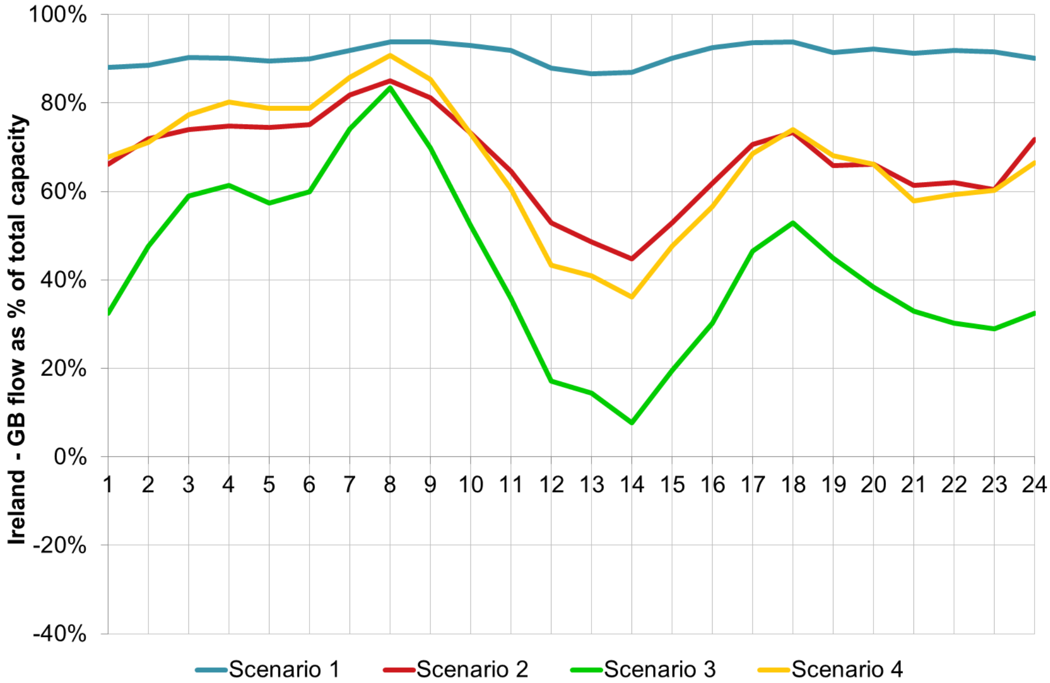
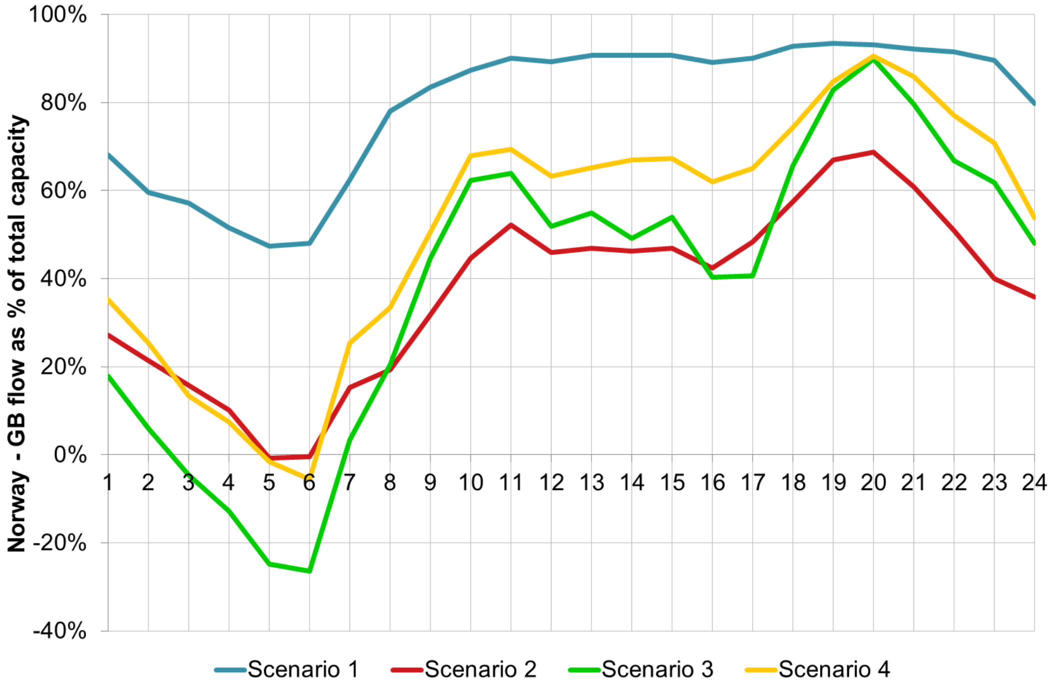


Figure 17 shows the average daily pattern of flows between GB and Norway for the four modelled scenarios in 2030. As with other interconnections, net imports into GB are at their highest in Scenario 1. In other scenarios, net imports into GB are lower and similar between different scenarios. In those cases, the average daily shape of imports closely follows the average daily shape of GB demand.

[49] These results paint a different picture compared to the operation of the two existing Irish interconnectors which are currently mainly used to import electricity from Britain. This is because in our scenarios we have assumed high levels of future wind deployment in Ireland (in line with Ireland's National Renewable Energy Action plan) thus facilitating electricity exports to GB. For Scenario 1, for example, as much as 6.5 GW of onshore wind capacity are developed on the island of Ireland by 2030, together with 2.4 GW of offshore wind capacity, whereas for Scenario 2 these figures are 7.7 GW and 3.7 GW respectively and 5.7 GW and 1.2 GW respectively for Scenario 3. These deployment rates, however, may not be achieved if some of the multi-purpose Irish renewable projects are developed and thus renewable electricity is transferred directly to GB. If this was to materialise, electricity prices in Ireland would be expected to be higher compared to the scenarios we have modelled and thus exports to GB from Ireland would also be reduced.

Figure 17 Norway - GB flow as % of total capacity - Configuration B2 (2030)



6.3.3 Changes in interconnector flows over the modelled horizon

Figure 18 shows the distribution of annual flows between GB and France for Scenario 1 in the case of no additional GB interconnection (i.e. assuming just 2GW of interconnection capacity provided by IFA). It can be seen that flows from France to GB dominate flows in the other direction throughout the modelled period, with flows being only marginally more symmetric in the later modelled years.

Figure 19 shows the same statistics for Scenario 4, which sees a substantially reduced differential in carbon prices between GB and France relative to Scenario 1. In this case, flows on the GB-France border are still heavily asymmetric, especially before 2030, but becoming marginally more symmetric from 2030, with slightly lower utilisation of GB-France interconnection.

Figure 18 Interconnector flow - No additional interconnection – Scenario 1

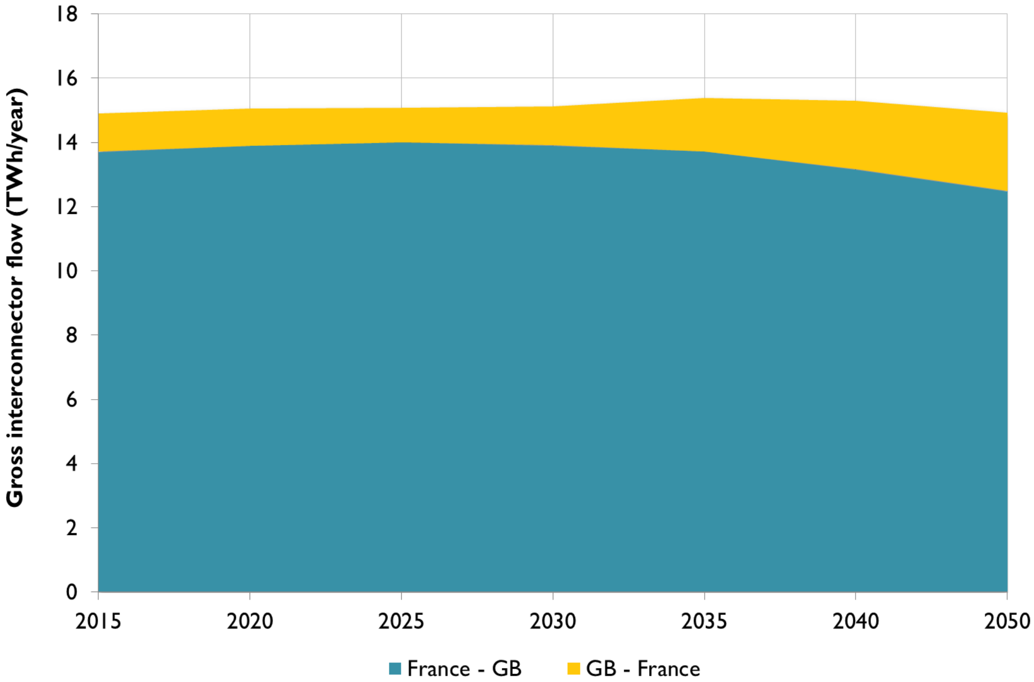


Figure 19 Interconnector flow - No additional interconnection – Scenario 4

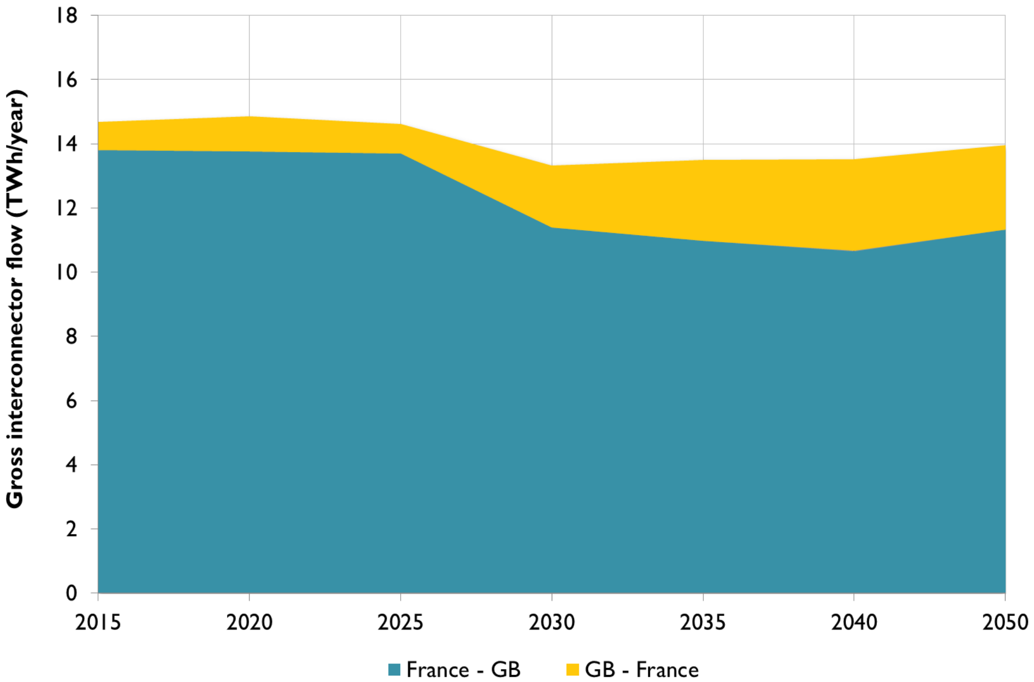
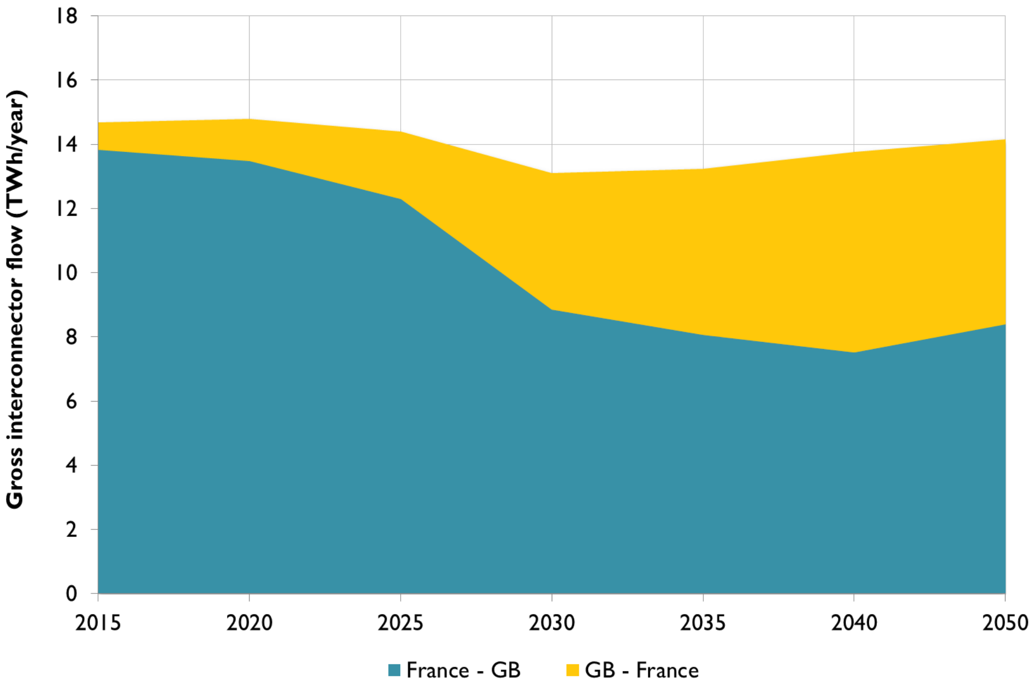


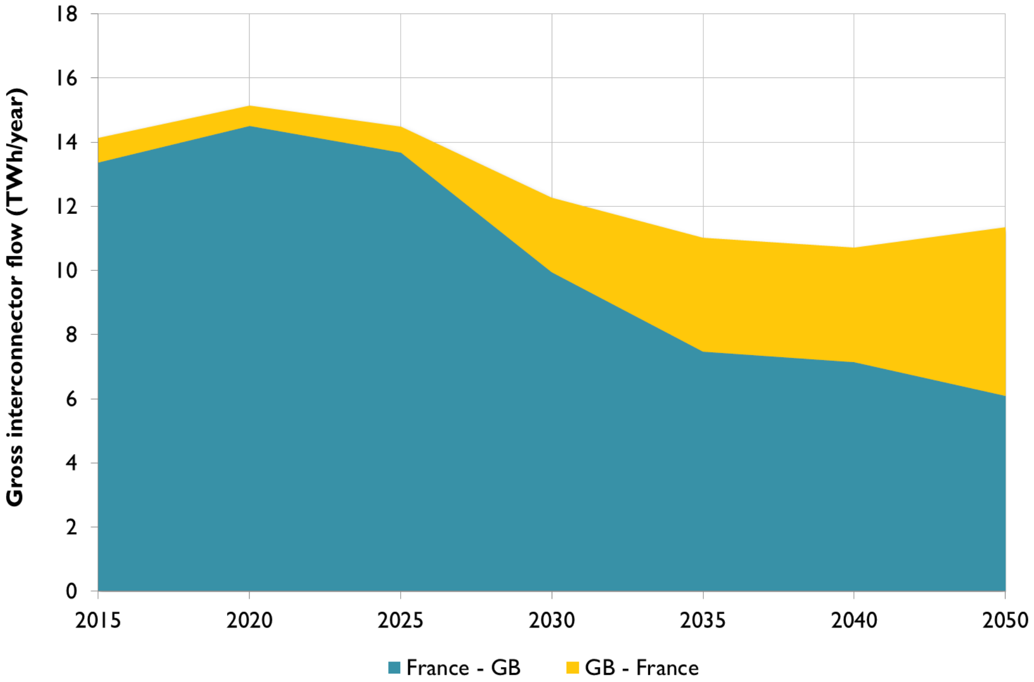
Figure 20 shows the distribution of annual flows between GB and France for Scenario 2. Here, an ambitious roll-out of wind generation in GB significantly increases flows from GB to France, particularly from 2025 onwards. It can be seen that by 2040 annual GB exports to France are almost as high as imports, although that trend is somewhat reversed in 2050 as GB electricity demand increases due to electrification of the heat and transport sector.

Figure 20 Interconnector flow - No additional interconnection – Scenario 2



Finally, Figure 21 shows the same statistics for Scenario 3, which sees a substantially reduced utilisation rate for the GB-France interconnector from 2025 onwards. This is due to significantly reduced power price differentials, coupled with lower penetration of intermittent renewables (which have very low short run marginal costs). Again flows from GB to France are considerably increased towards the later years of the modelling horizon.

Figure 21 Interconnector flow - No additional interconnection – Scenario 3

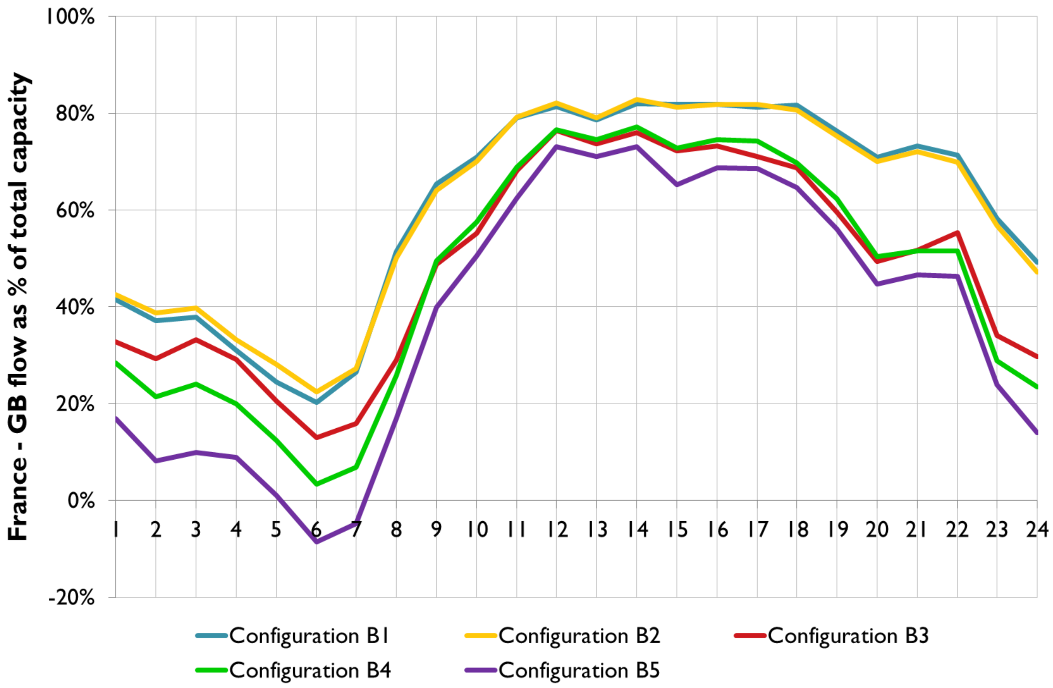


6.3.4 Effect of changes in overall GB interconnection level on interconnector flows

A key question with regards to the economics of developing interconnectors is the extent to which additional interconnectors may negatively impact the utilisation rates of existing interconnectors in the system and as such potentially cannibalise their revenues. In some cases, however, it is also possible that additional interconnectors can increase utilisation rates (as well as revenues) by creating additional price arbitrage opportunities. This may happen where, for example, two GB interconnectors connect to a higher and a lower priced market respectively, pushing GB prices in opposite directions and having a positive effect on each other's revenues.

Figure 22 shows hourly flows on the GB-France interconnector as % of total GB-France interconnection capacity for Scenario 1 and year 2040. It can be seen that the lowest utilisation rates for the GB-France interconnectors are observed under Configuration B5, whilst the highest utilisation rates are observed under Configurations B1 and B2. This suggests that for this particular scenario increased interconnection levels could negatively affect utilisation rates for the GB-France interconnectors, while at the same time also potentially cannibalising their revenues. This trend is particularly evident during off-peak hours, when GB is less reliant on imports and (for scenarios with high interconnection levels) able to select from a diverse set of markets where those imports will come from.

Figure 22 France - GB flow as % of total capacity – Scenario 1 (2040)



A similar picture can be drawn for Scenario 4 (Figure 23), although now to a lesser extent since GB imports less electricity from France under this scenario (due to carbon price differentials no longer existing by 2040). Again utilisation rates have been found to be reduced with increasing levels of interconnection as GB is able to diversify away from French imports and imports more electricity from other markets. It is also interesting to note that the peak level of imports in Scenario 1 (Figure 22) lasts longer (approximately for 7 hours) compared to the peak level of imports in Scenario 4 (approximately for 2 hours as shown in Figure 23). This is due to generators in GB being exposed to higher carbon prices under Scenario 1 compared to their European equivalents, which leads to higher electricity imports from Europe.

Figure 23 France - GB flow as % of total capacity – Scenario 4 (2040)

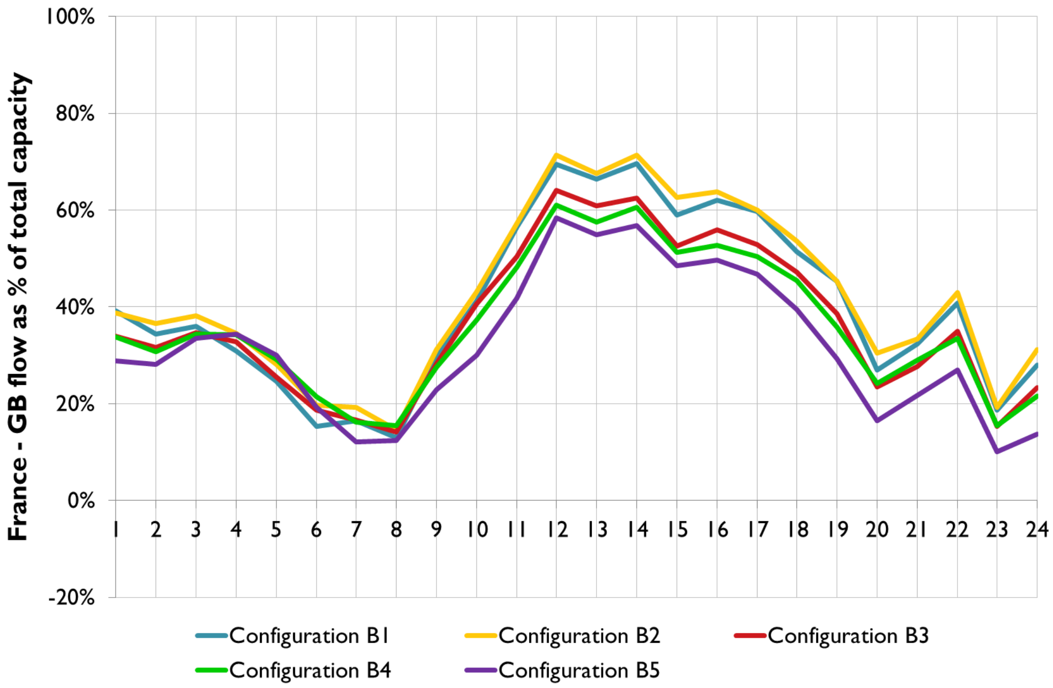
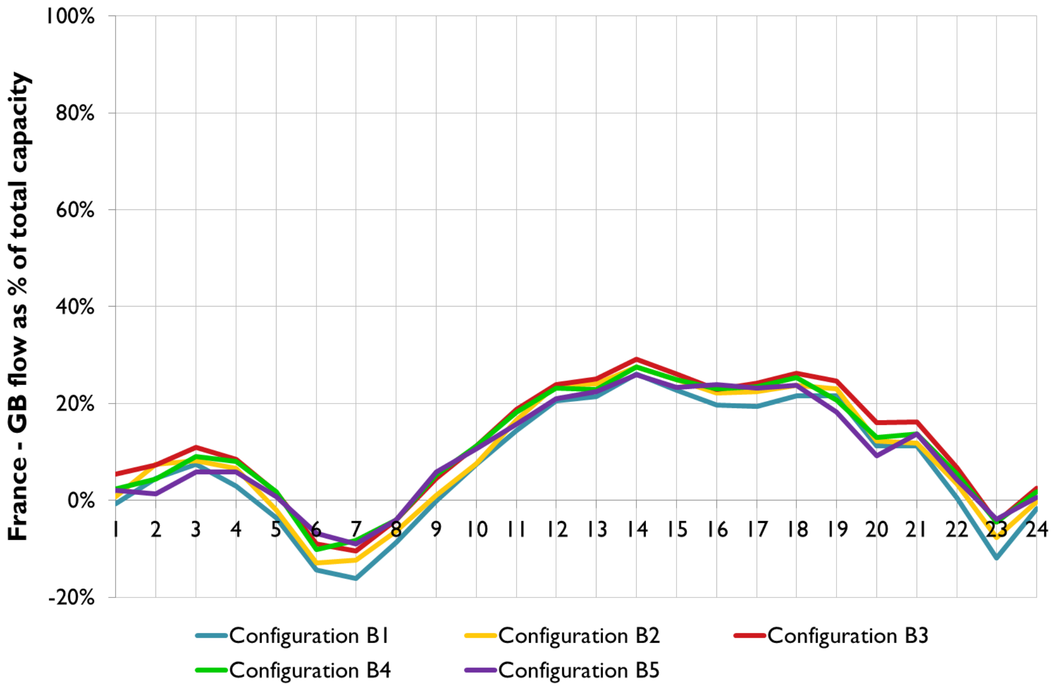


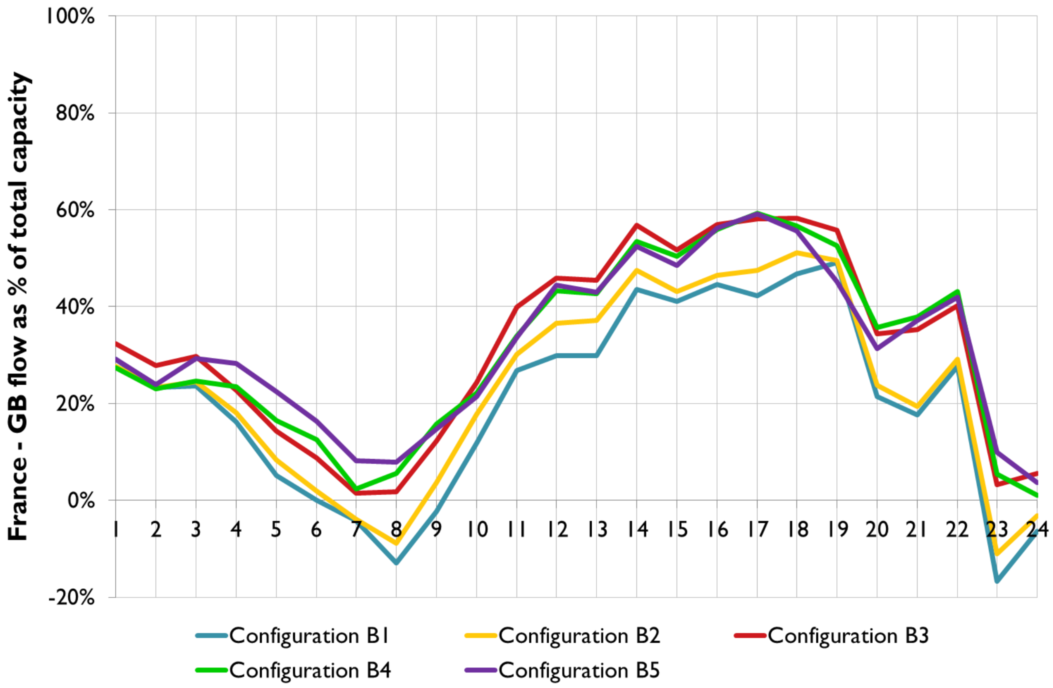
Figure 24 shows the same statistics for Scenario 2. Here, high renewables penetration across Europe means that additional interconnectors may now lead to considerable price arbitrage opportunities and thus flows on the GB-France interconnectors are no longer negatively affected. The configuration with the highest flows has been identified to be B3, whilst the two configurations with the lowest utilisation rates are now B1 and B2.

Figure 24 France - GB flow as % of total capacity – Scenario 2 (2040)



In a similar fashion for Scenario 3, Figure 25 shows that the two configurations with the lowest overall levels of interconnection (B1 and B2) also lead to the lowest utilisation rates for the GB-France interconnector. Despite price differentials in this scenario remaining relatively modest (due to low gas prices), high levels of interconnection can create price arbitrage opportunities and as such interconnector utilisation rates are positively affected.

Figure 25 France - GB flow as % of total capacity – Scenario 3 (2040)



6.4 Optimal levels of interconnection

6.4.1 Introduction

For the purposes of our analysis, the optimal interconnection strategy for GB is defined as the strategy that, for a given scenario, is expected to yield the greatest net welfare in GB, evaluated at its net present value (NPV) over the modelled time horizon, however we acknowledge that there are other ways that an 'optimal interconnection strategy' could be defined. Although our modelling time horizon extended to 2050, the time horizon for calculating NPV of net welfare under each configuration extends to 2040. The results for 2050 are excluded from the calculation of NPV of net welfare because they were deemed to be volatile and the risk of this volatility in the results obscuring the underlying messages is high[50].

[50] The reason for the volatility of 2050 welfare results is that reserve and response constraints become more difficult for the model to meet by 2050. The model is required to take increasingly drastic steps to meet those constraints with potentially large impacts on the welfare results. This is particularly noticeable in Scenario 2, which sees very large amounts of inflexible generation capacity across the modelled markets by 2050. One possible lesson from this is that the way that System Operators evaluate reserve and response may have to change as higher amounts of inflexible generation capacity enter the generation mix.

In order to consider the net welfare effects of incrementally increasing GB interconnection levels, graphical results presented in this section use two axes: (i) the x-axis represents the average annual additional interconnection capacity for each configuration (i.e. existing interconnectors to France, Northern Ireland, Republic of Ireland and The Netherlands are excluded); and (ii) the y-axis represents net welfare NPV levels.

This approach is most relevant for Configurations A1-A5 and B1-B5 which assume continuously increasing GB interconnection levels as illustrated in Table 21 (between 0.5 GW to 15.4 GW for Configurations A1-A5 and between 1 GW to 12.8 GW for Configurations B1 to B5). Comparatively, Configurations C1-C5 assume relatively similar overall levels of interconnection capacity (between 4 GW to 8.1 GW) and thus the focus of this analysis for Configurations C1-C5 should not be on the overall interconnection level but rather on which markets GB is assumed to connect to in those configurations.

Depending on their capacity and the year in which interconnectors are assumed to become operational, we calculate the time-weighted average annual new interconnection capacity for each interconnection configuration for the period from 2020 to 2040. Capacity of an interconnector that is built in 2040 is assigned a weighting of 0.2 whereas an interconnector that is built in 2020 is assigned a weighting of 1[51]. This reflects the greater effect that interconnectors which are present in more of the modelled spot years are expected to have on the NPV of welfare results for the entire modelled period. The results of this calculation are shown in Table 22. For Configuration A1, for example, an additional interconnector to France with a capacity of 0.5 GW is developed in 2025 and therefore the time-weighted average 2020-2040 additional interconnection capacity for that particular configuration is 0.4 GW as shown in Table 22.

Table 21 Assumed total levels of additional interconnection capacity by 2040

IC Capacity (GW)	BE	DE	DK-W	ES	FR	IS	IE	NL	NO	SE	Total
Configuration A1					0.5						0.5
Configuration A2	1.0				1.0		0.5				2.5
Configuration A3	1.0				2.0		1.0		1.0		5.0
Configuration A4	1.0			1.0	2.5	0.7	1.5	0.5	1.4		8.6
Configuration A5	1.5	0.7	1.0	2.0	4.0	1.2	2.5	0.5	2.0		15.4
Configuration B1					0.5		0.5				1.0
Configuration B2					0.7		0.5		0.7		1.9
Configuration B3	0.5				1.0	0.5	0.5	0.5	1.0		4.0
Configuration B4	0.7	0.5	0.5	0.5	1.5	0.7	1.0	0.5	1.5		7.4
Configuration B5	1.0	0.7	1.0	1.0	2.5	1.0	2.1	0.7	2.1	0.7	12.8

[51] It follows that interconnectors completed by 2025, 2030 and 2035 are assigned weightings of 0.8, 0.6 and 0.4 respectively.

IC Capacity (GW)	BE	DE	DK-W	ES	FR	IS	IE	NL	NO	SE	Total
Configuration C1	1.0				4.1		2.5				7.6
Configuration C2	1.0			2.8	3.0		0.5				7.3
Configuration C3	1.0				2.0		4.0		1.0		8.0
Configuration C4	1.0				3.0	0.7	2.0		1.4		8.1
Configuration C5						1.2			2.8		4.0

Table 22 Time-weighted average 2020-2040 additional interconnection capacity (GW)

	Category A	Category B	Category C
Configuration 1	0.4	0.7	5.1
Configuration 2	1.8	1.6	5.6
Configuration 3	3.5	2.8	5.6
Configuration 4	6.1	5.2	5.0
Configuration 5	11.1	8.6	3.2

All welfare results presented in the following sections use the time-weighted average 2020-2040 additional interconnection capacities from Table 22**.**

6.4.2 Scenario 1 - GB importing

Figure 26 shows the net welfare results for Configurations A, B and C for Scenario 1 ("GB importing") and Figure 27 shows the results on a per MW basis.

Figure 26 Net welfare results of increased interconnection – Scenario 1

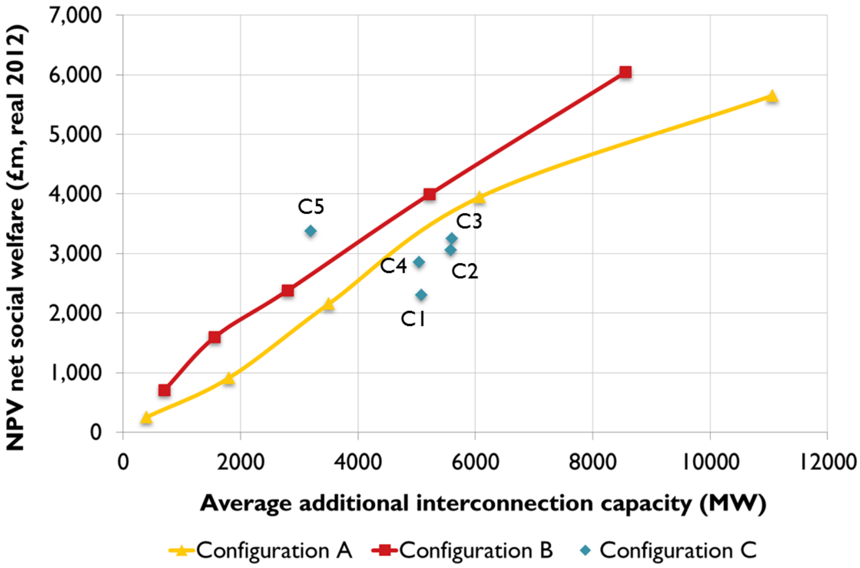
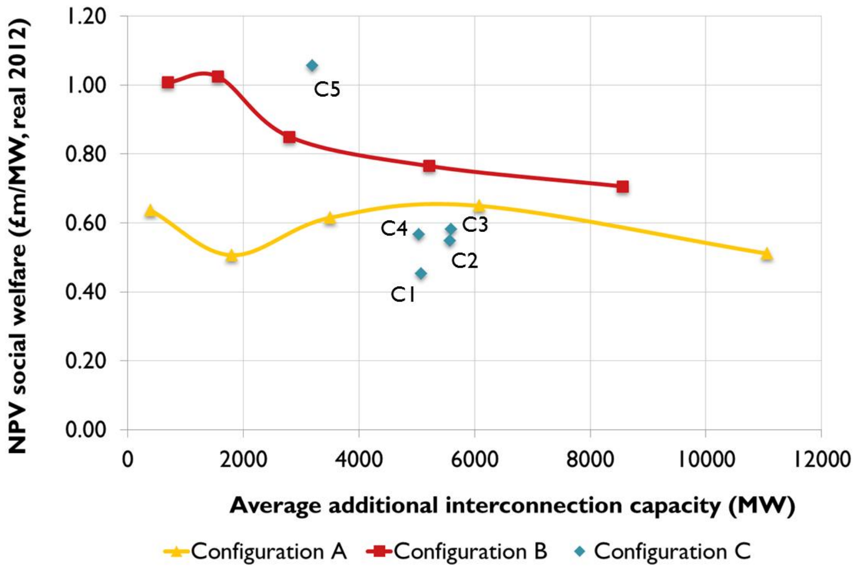


Figure 27 Net welfare results per MW of increased interconnection – Scenario 1



Under both Configuration categories A and B, higher overall levels of GB interconnection result in generally increasing estimated social net welfare. Configuration A1 (0.5 GW to France) results in estimated net welfare benefits of approximately £0.25bn in NPV terms, which increases to approximately £5.6bn under Configuration A5 which assumes that further interconnection to France, Ireland, Belgium, Netherlands, Norway, Iceland, Spain, Denmark and Germany is developed by 2040. Similarly, Configuration B5 results in an estimated net welfare benefit of £6.0bn assuming further interconnections to France, Ireland and new interconnectors to Belgium, Netherlands, Norway, Iceland, Spain, Denmark, Germany and Sweden.

Under this scenario, no apparent optimum is reached in terms of overall interconnection level and higher levels of interconnection than those seen in Configurations A5 and B5 may well result in a higher estimated net welfare benefit. This is mainly due to the large differences in carbon prices between GB and other European markets observed in this scenario. As a result, the developed interconnectors are mostly used to transfer lower-cost power produced elsewhere in Europe to GB, thus, on average, leading to considerable benefits for GB consumers via lower wholesale prices. Configuration B5 (with additional interconnection levels of 12.8 GW) achieves the greatest increase in GB net welfare out of all of the modelled configurations.

For Configurations C1 to C5, the greatest estimated improvement net welfare is observed under Configuration C5 (approximately £3.4bn in NPV terms), with C3 being a close second. Under C5, the two new markets that GB connects to are Iceland and Norway, both of which have an abundance of low carbon energy. By transferring lower cost low carbon power from Iceland/Norway to GB, they result in considerable net welfare benefits to GB despite the significant capital costs associated with developing these interconnectors. A distinguishing feature of C3 is that it has 4 GW of additional interconnection to Ireland. In the context of a large differential in carbon prices between GB and Ireland and central wind build-out in GB, the estimated benefits from trade are significant.

On a per MW basis, social net welfare impact of additional interconnection is high for low amounts of additional interconnection and, on average, diminishes with further additional interconnection. This highlights the diminishing marginal social returns to interconnection in the context of this Scenario 1, noting that this pattern is not strong in the context of Scenario 1.

Figure 28 shows a map of net hourly GB interconnector flows in 2040 for the configuration that yields the greatest increase in GB net welfare (Configuration B5) under this scenario. Blue arrows indicate average net inflows into GB and red arrows indicate average net outflows. Figures in brackets show net flows as a proportion of total interconnection capacity on a given border. The figure shows that by 2040, all GB interconnection flows energy to GB on an average basis for this scenario and configuration. The greatest net flows come from Ireland, France and Norway.

Figure 28 Map of average net GB interconnector flows under Configuration B5 (2040)

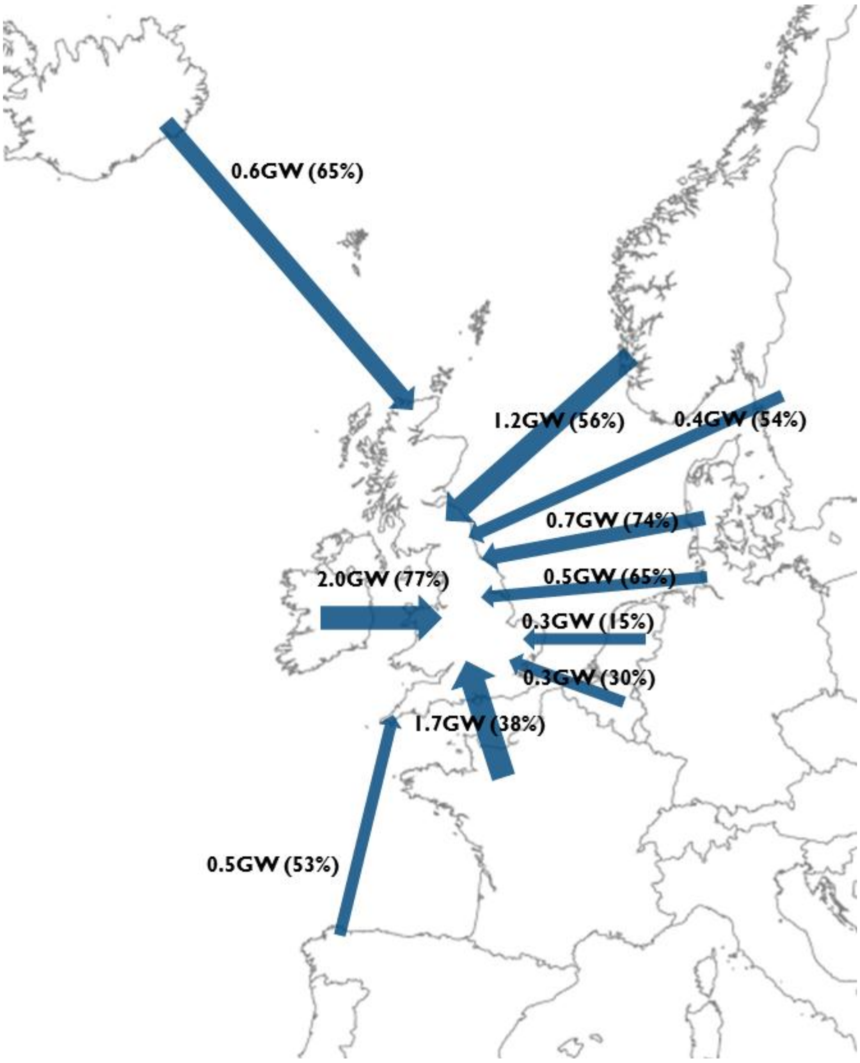
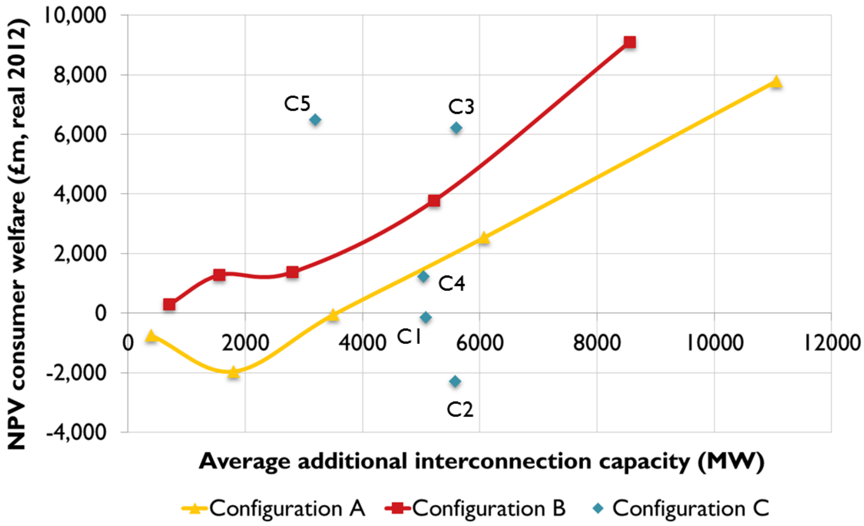


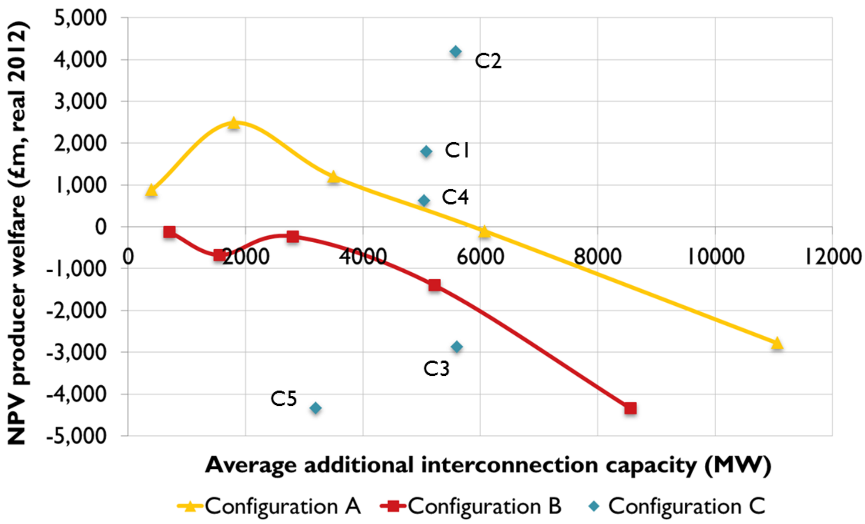
Figure 29 through to Figure 31 show the impact of additional GB interconnection on consumer, producer and interconnector welfare in the context of Scenario 1. Interconnector welfare includes the revenues and costs on new interconnectors built under a given configuration, as well as the effect of the additional interconnection on revenues of existing GB interconnectors. These results should be read in conjunction with the notes on interpreting the results as set out in Section 6.2.

Figure 29 Consumer welfare results of increased interconnection – Scenario 1



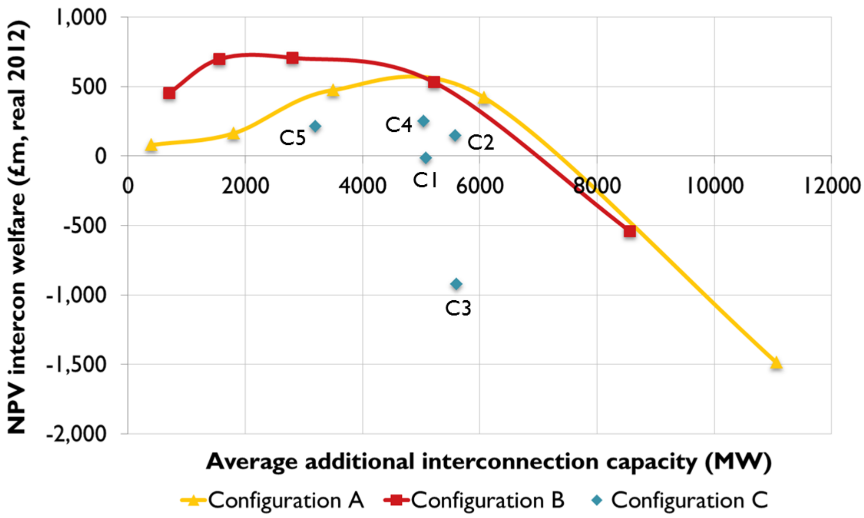
The results demonstrate that consumer welfare is the main driver of net welfare effects of additional interconnection in Scenario 1. It is generally increasing in the average additional interconnection capacity and does not reach an apparent optimum for the modelled configurations. Configuration C5 achieves the greatest improvement in consumer welfare from the C category configurations, and by far the greatest improvement on a per MW basis, demonstrating the effectiveness of interconnection with the hydro-rich markets of Norway and Iceland in lowering the price of electricity for GB consumers.

Figure 30 Producer welfare results of increased interconnection – Scenario 1



Producer welfare results for the different modelled configurations are inversely correlated with consumer welfare results since both are driven (in opposite directions) by changes in average electricity prices in GB. Configuration C2, which sees 2.8 GW of interconnection capacity to Spain by 2035, is the worst configuration for consumers and the best configuration for producers. This is both due to relatively spiky prices in Spain creating price arbitrage opportunities for GB producers (particularly so because the hourly and monthly electricity demand profile in Spain is significantly different compared to the electricity demand profile in GB), but also due to the high costs associated with developing an interconnector to Spain.

Figure 31 Interconnector welfare results of increased interconnection – Scenario 1



Interconnector welfare is declining in additional interconnection capacity beyond a level of around 4-5 GW of average additional capacity across the modelled spot years. This demonstrates the effect of diminishing marginal revenues for new interconnectors and the negative effect of additional interconnection capacity on revenues from existing interconnectors. Configuration C3 which by 2040 contains 4 GW of additional interconnection to Ireland is associated with particularly low interconnector surplus relative to other configurations. This may suggest that recovery of the costs of interconnection to Ireland directly from the associated revenues may be more difficult than for other interconnections.

6.4.3 Scenario 2 - Flexible operation

Figure 32 shows the net welfare results for Configurations A, B and C for Scenario 2 ("Flexible operation") and Figure 33 shows the results on a per MW basis.

Figure 32 Net welfare results of increased interconnection – Scenario 2

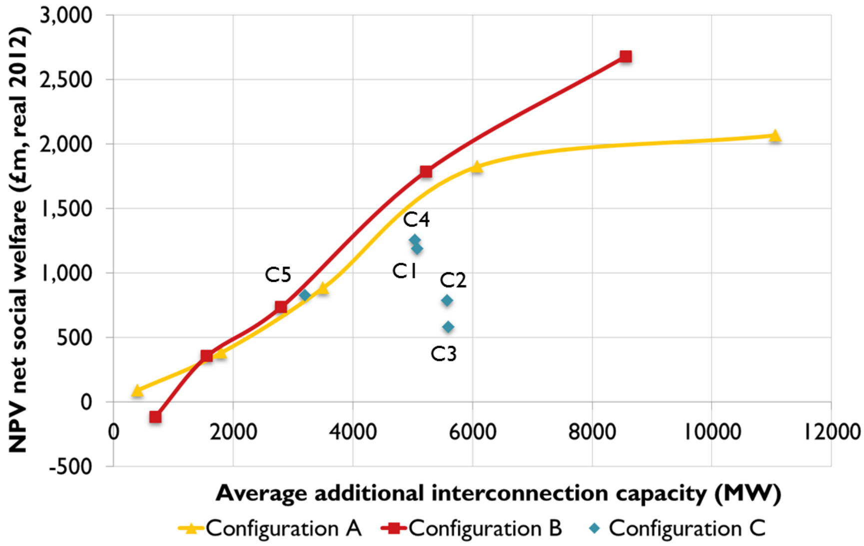
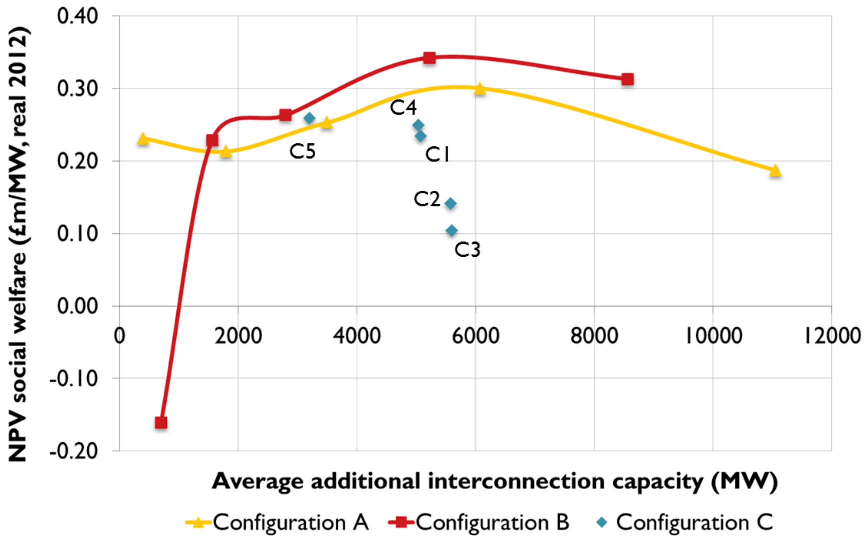


Figure 33 Net welfare results per MW of increased interconnection – Scenario 2



Similarly to Scenario 1, configurations 1 to 5 in categories A and B have been found to result in continuously increasing net welfare in GB with increasing levels of GB interconnection. Configuration B5 (with total additional interconnection levels of 12.8 GW as shown in Table 15) is estimated to lead to the greatest increase in net welfare in GB, hence the optimal interconnection configuration for this scenario may have a greater overall level of interconnection than configuration B5.

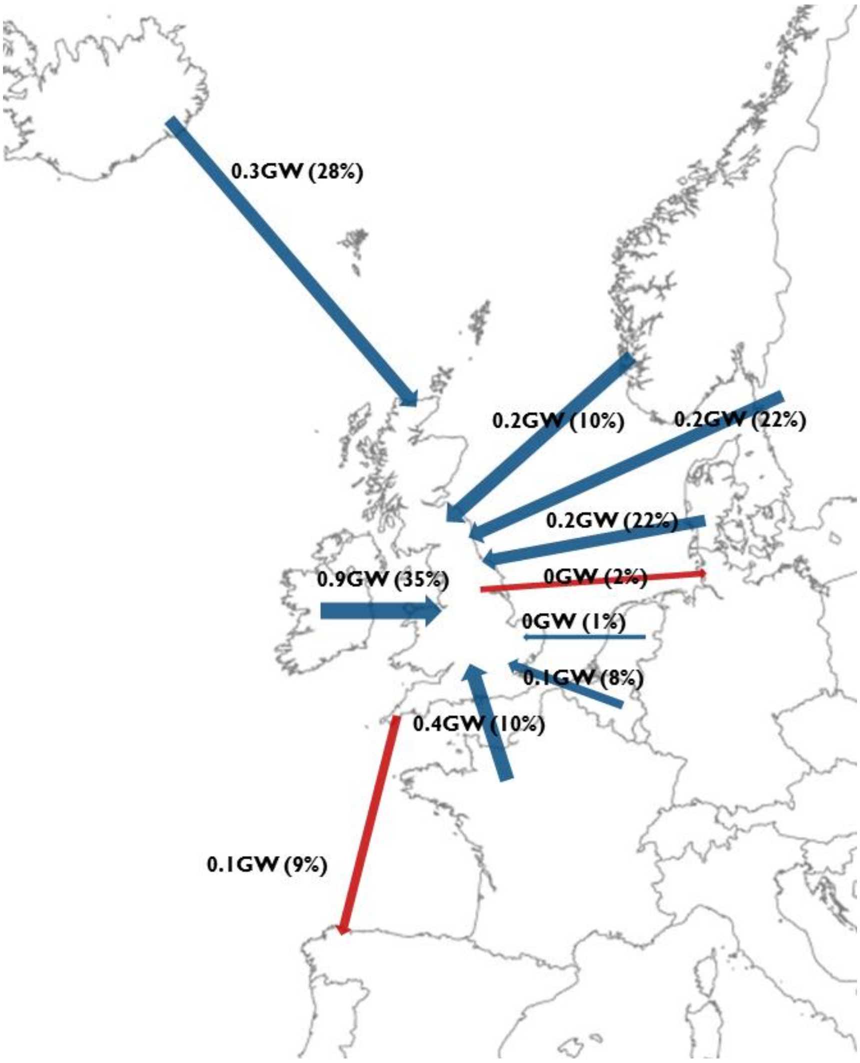
Configurations A1 to A4 show strongly increasing estimates of net welfare as overall interconnection capacity increases. However, configuration A5 sees only slightly higher net welfare in GB than A4. Since in this configuration, the overall level of interconnection of GB with other markets is increased considerably in relation to A4, and much of the increase is accounted for by interconnection to relatively distant markets such as Denmark and Spain, the cost of this extra interconnection appears to be only slightly smaller than the benefit in terms of overall net welfare in GB.

Configuration B1 is estimated to result in a small decrease in net welfare relative to no additional interconnection. It differs from Configuration A1 in having an additional interconnector to Ireland. This would suggest that further interconnection with Ireland may not be beneficial for GB net welfare in a world that sees an aggressive roll-out of GB wind capacity.

From configuration category C, C2 and C3 yield the lowest estimated net welfare for GB. C2 has a large amount of relatively expensive interconnection capacity to Spain, which, in the context of this scenario, does not appear to have an economic justification. C3 has the largest amount of interconnection capacity to Ireland of any configuration. This provides further evidence that, in the context of a scenario that sees a large amount of wind capacity built in GB, a large amount of interconnection capacity to Ireland, which itself has a lot of wind capacity in this scenario, is not likely to be beneficial for GB net welfare. The question of interconnection with Ireland is considered separately in Section 6.6.

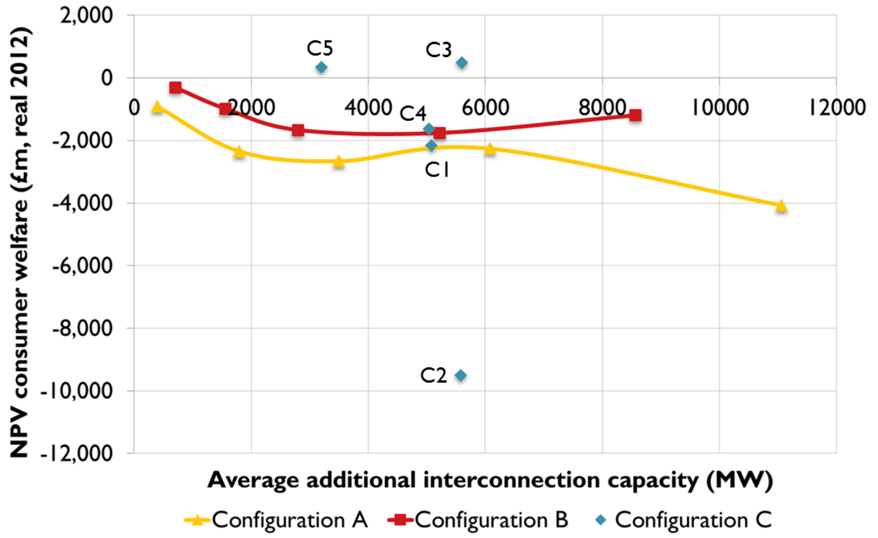
Figure 34 shows a map of net hourly GB interconnector flows in 2040 for the configuration that yields the greatest increase in GB net welfare (Configuration B5) under this scenario. As before, blue arrows indicate average net inflows into GB and red arrows indicate average net outflows. Figures in brackets show net flows as a proportion of total interconnection capacity on a given border.

Figure 34 Map of average net GB interconnector flows under Configuration B5 (2040)



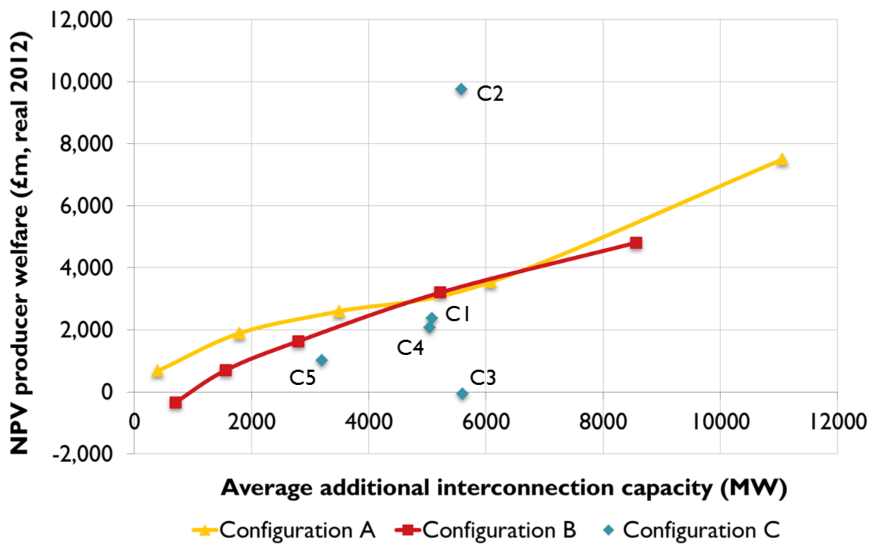
The figure shows that in this scenario and configuration combination, net inflows into GB are considerably lower than under scenario 1 (and Scenario 4 as will later be shown) despite a high overall level of GB interconnection, suggesting that the operation of GB interconnectors is a lot more flexible in this case. For two of the connected markets (Spain and Germany), net interconnector flows are exports from GB.

Figure 35 Consumer welfare results of increased interconnection – Scenario 2



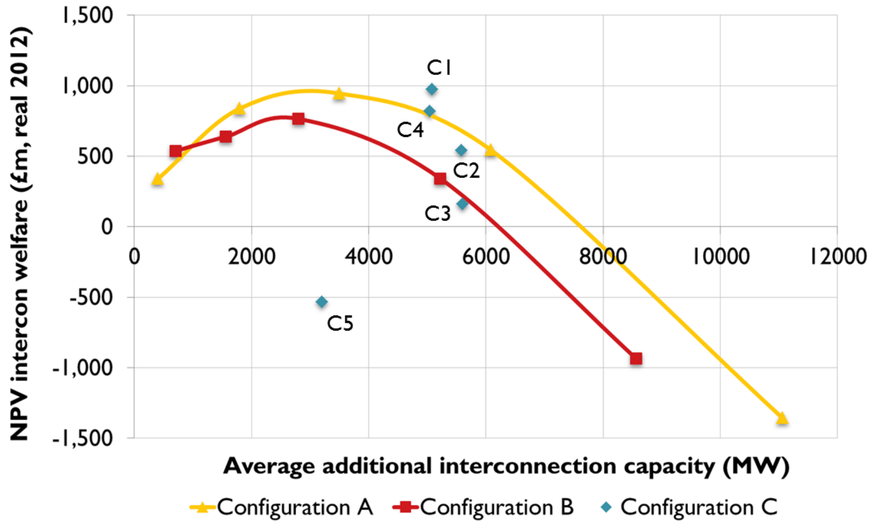
Consumer welfare does not appear to depend significantly on the overall interconnection level. Configurations C3 and C5 result in the greatest improvement to net welfare, implying that interconnections with Ireland, Norway and Iceland are the most effective at reducing GB electricity prices in the context of Scenario 2. Configuration C2, with 2.8 GW of interconnection capacity with Spain, results in the greatest reduction to net welfare of consumers in GB.

Figure 36 Producer welfare results of increased interconnection – Scenario 2



Net producer welfare is estimated to be generally increasing in overall interconnection capacity. Since the opposite trend is not observed for net consumer welfare, this likely reflects the significant reductions in the cost of system balancing in a scenario with an abundance of inflexible renewable generation.

Figure 37 Interconnector welfare results of increased interconnection – Scenario 2



Interconnector welfare is decreasing in additional interconnection capacity beyond 3 GW of new capacity. It is especially low for Configuration C5, which highlights the high cost of connecting to relatively distant markets like Iceland and Norway.

6.4.4 Scenario 3 - Low utilisation

Figure 38 shows the net welfare results for Configurations A, B and C for Scenario 3 ("Low utilisation") and Figure 39 shows the results on a per MW basis.

Figure 38 Net welfare results of increased interconnection – Scenario 3

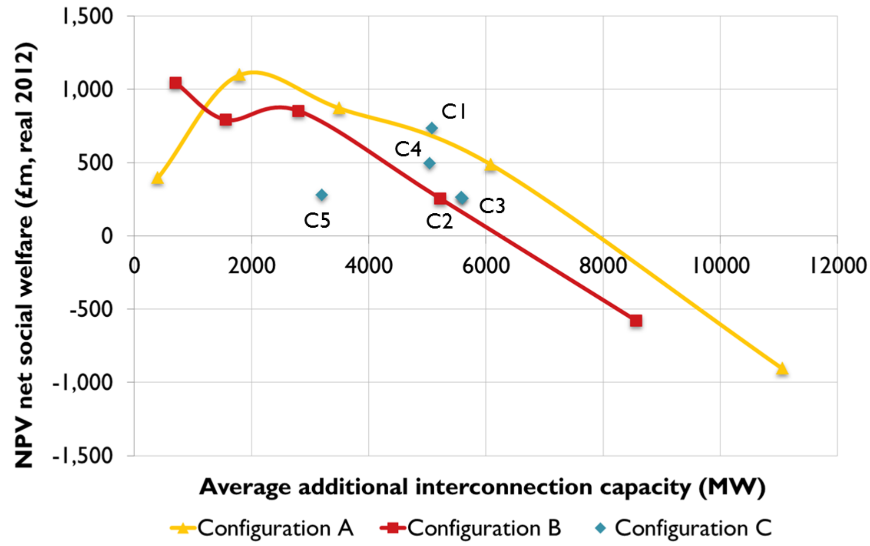
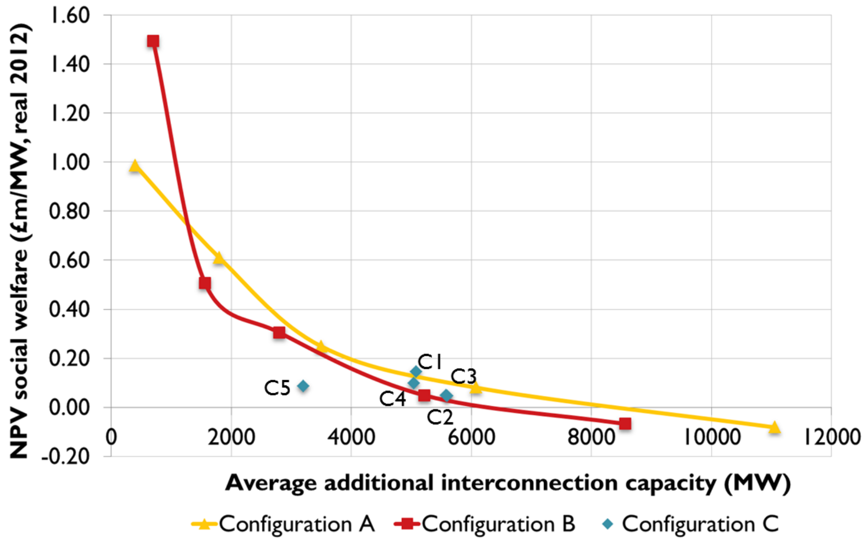


Figure 39 Net welfare results per MW of increased interconnection – Scenario 3



Recall that in this scenario, fossil fuel prices, and particularly gas prices, are low and the amount of flexible generation in different markets is relatively high. The value of additional interconnection for GB net welfare, both in terms of energy trading and system balancing, would therefore be expected to be relatively low. Configuration A2, which sees additional interconnection capacity to France, Belgium and Ireland only (with a total additional interconnection capacity of 2.5 GW as shown in Table 7). is estimated to be optimal in the context of this scenario.

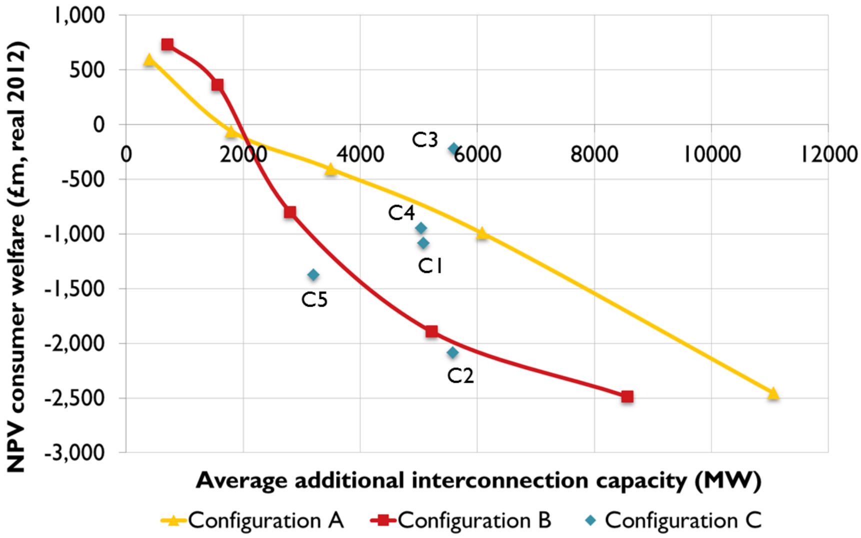
Higher levels of interconnection are generally estimated to result in lower net welfare. Out of category C configurations, C1, which is dominated by interconnection to GB's closest neighbours, France and Ireland, is estimated to yield the highest level of net welfare.

Figure 40 shows a map of net hourly GB interconnector flows in 2040 for the configuration that yields the greatest increase in GB net welfare (Configuration A2) under this scenario. As before, blue arrows indicate average net inflows into GB and red arrows indicate average net outflows. Figures in brackets show net flows as a proportion of total interconnection capacity on a given border.

Figure 40 **Map of average net GB interconnector flows under Configuration A2 (2040)**

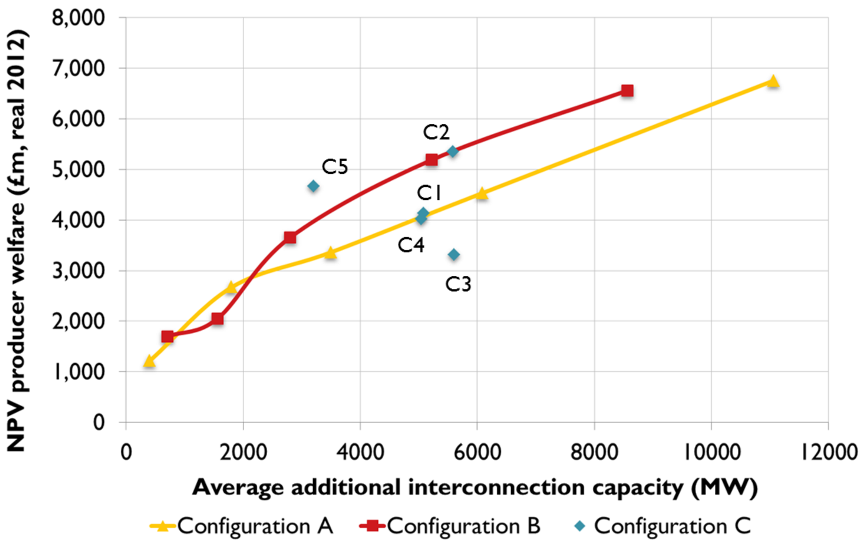
The figure shows that in this scenario and configuration combination, net inflows into GB are relatively modest in line with a low overall level of additional GB interconnection. GB is (marginally) a net exporter to The Netherlands in this case.

Figure 41 Consumer welfare results of increased interconnection – Scenario 3



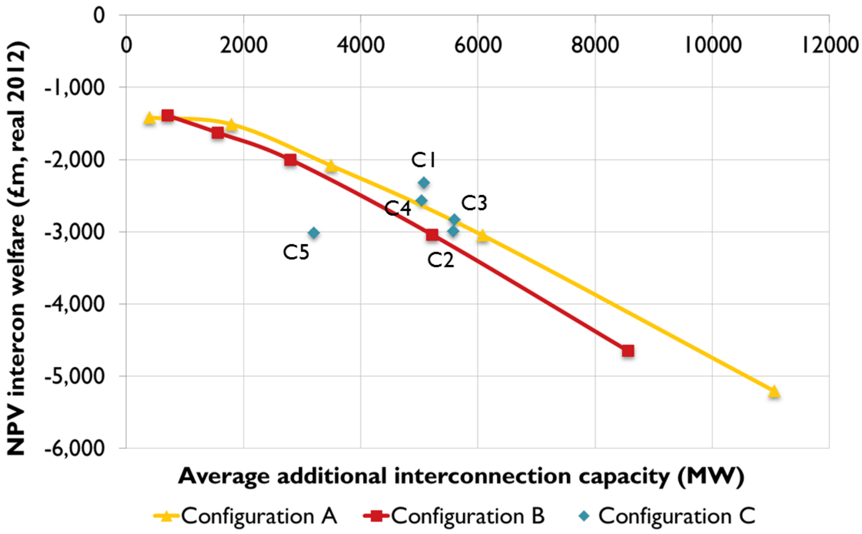
Net consumer welfare is lower for configurations that see greater additional GB interconnection capacity. This is as expected given that GB electricity prices are relatively low in this scenario due to low gas prices. The ability of interconnection to put downward pressure on GB prices is limited in this scenario.

Figure 42 Producer welfare results of increased interconnection – Scenario 3



Producer welfare is increasing in new GB interconnection capacity. This results from a combination of savings in GB balancing costs, which are accounted for under producer welfare, and in some instances, opportunities to export cheap power to other markets.

Figure 43 Interconnector welfare results of increased interconnection – Scenario 3

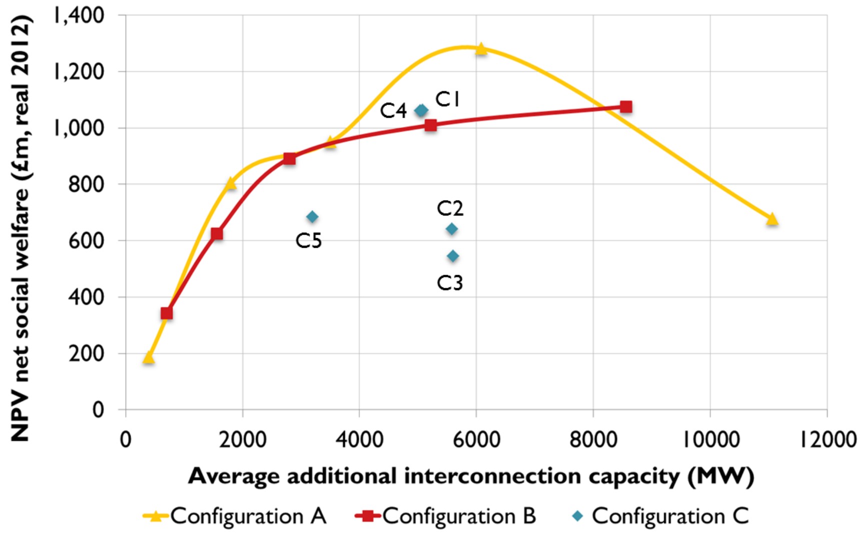


Interconnector welfare is relatively low in this scenario and decreasing in new GB interconnection capacity, though noting the caveats given in Section 6.2, this does not mean that the cost of new GB interconnection always exceeds the revenue from that interconnection under this scenario. Given low gas prices and significant amounts of new CCGT capacity across different markets, arbitrage opportunities on interconnectors are relatively scarce.

6.4.5 Scenario 4 - Carbon price convergence

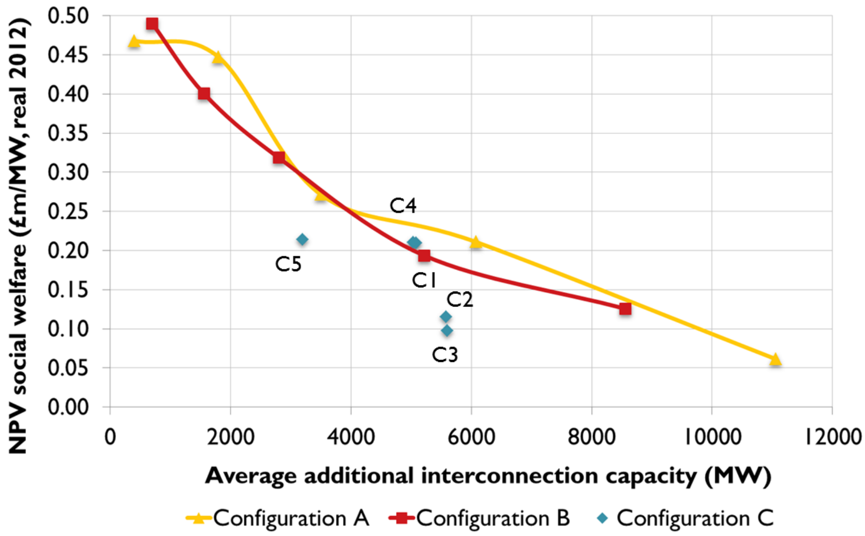
Figure 44 shows the net welfare results for Configurations A, B and C for Scenario 4 ("Carbon price convergence") and Figure 45 shows the results on a per MW basis.

Figure 44 Net welfare results of increased interconnection – Scenario 4



Unlike in Scenario 1, configurations from category B no longer dominate configurations from category A in net welfare terms. This is also the case for other scenarios presented later in this section. This appears to suggest that configurations from category B are better suited to arbitrage on differences in carbon prices than configurations from category A.

Figure 45 Net welfare results per MW of increased interconnection – Scenario 4

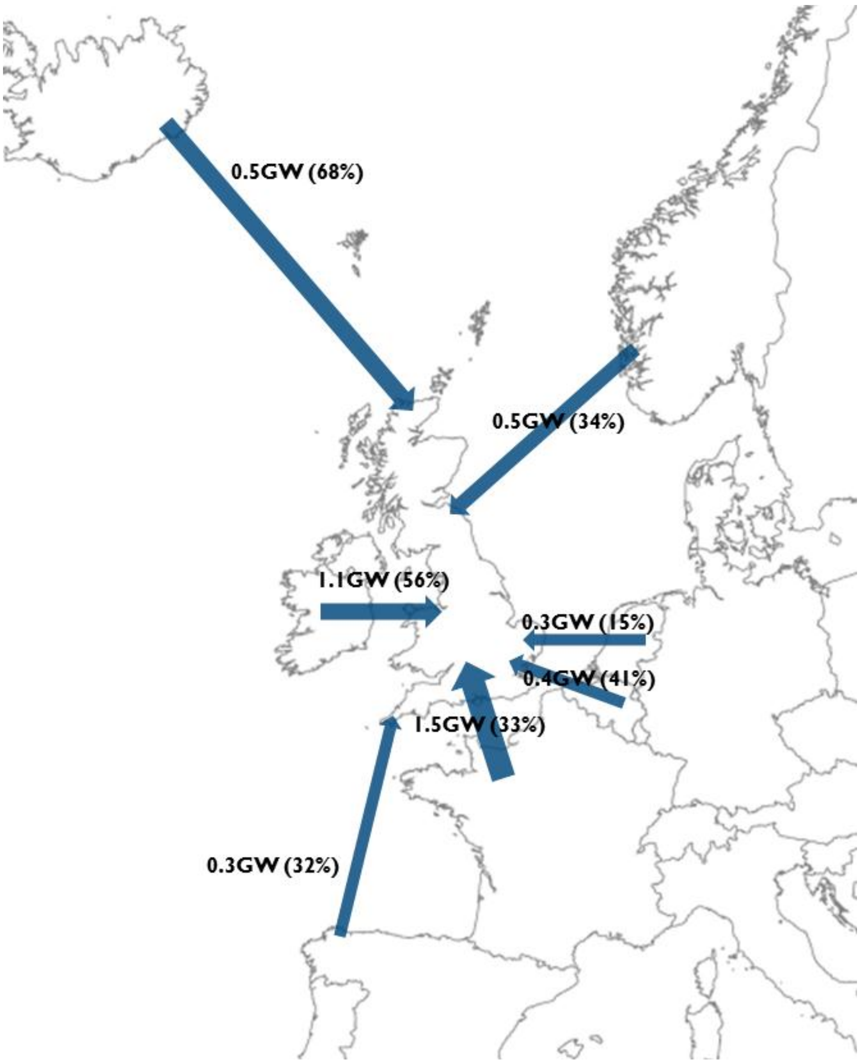


In this scenario, moderately high levels of interconnection appear to be optimal, though the benefit of higher interconnection levels is much lower than in Scenario 1. This reflects the effect of eliminating much of the differential in carbon prices in GB and the markets to which GB connects relative to Scenario 1. For configuration category A, net welfare increases up to configuration 4 and decreases thereafter. For configuration category B, net welfare increases up to configuration 5. Out of all of the configurations modelled, A4, which sees new interconnection to France, Belgium, Ireland, Norway, Iceland, Netherlands and Spain (with a total additional interconnection of 8.6 GW as shown in Table 9), achieves the greatest increase in net welfare.

From configuration category C, configuration C1, where, apart from a 1 GW interconnector to Belgium, only interconnection to France and Ireland is built, achieves the greatest increase in net welfare. A virtually identical result is achieved for C4, which represents delayed construction of interconnectors that are likely to be less economic (e.g. Iceland), with more incremental construction of interconnector capacity.

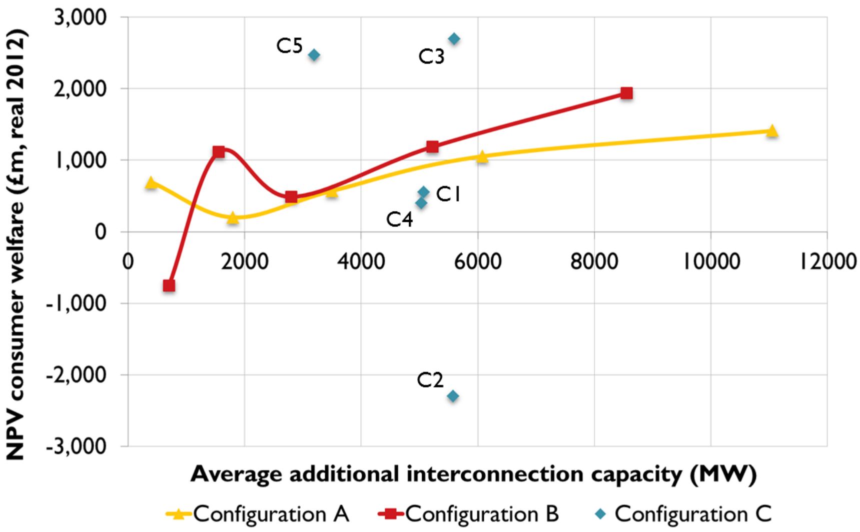
Figure 46 shows a map of net hourly GB interconnector flows in 2040 for the configuration that yields the greatest increase in GB net welfare (Configuration A4) under this scenario. As before, blue arrows indicate average net inflows into GB and red arrows indicate average net outflows. Figures in brackets show net flows as a proportion of total interconnection capacity on a given border.

Figure 46 Map of average net GB interconnector flows under Configuration A4 (2040)



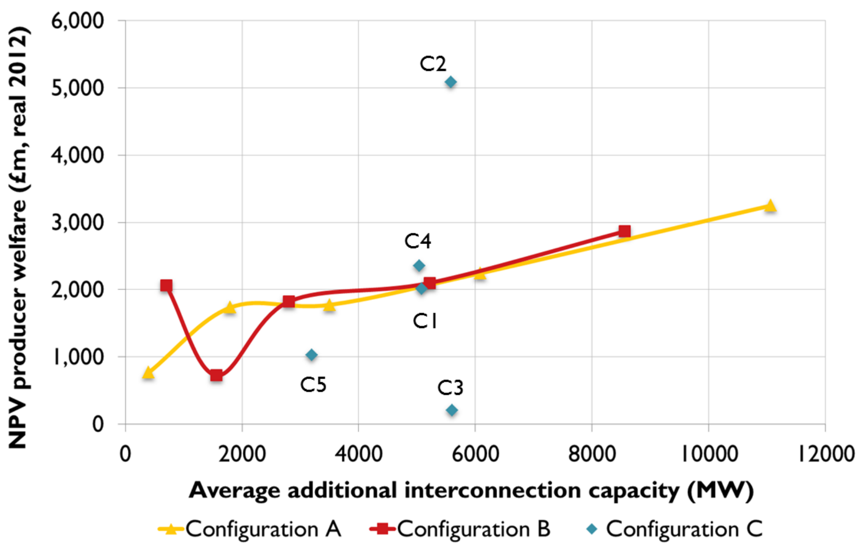
The figure shows that as for Scenario 1, all GB interconnection flows energy to GB on an average basis for this scenario and configuration, with the greatest net inflows coming from France.

Figure 47 Consumer welfare results of increased interconnection – Scenario 4



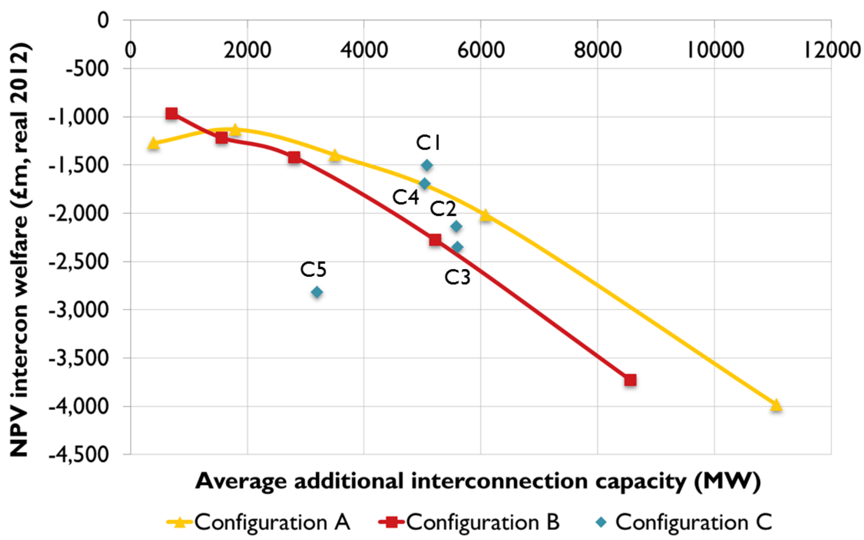
Consumer welfare generally increases with greater levels of interconnection, with some exceptions, but the extent of this increase is significantly less than under Scenario 1. Configuration C3, which sees 4 GW of interconnection with Ireland by 2035, results in the greatest improvement to net consumer welfare. Configuration C5, where GB connects to Norway and Iceland only, is a close second. Configuration C2, which sees 2.8 GW of interconnection with Spain, produces the worst consumer welfare result out of all of the modelled configurations.

Figure 48 Producer welfare results of increased interconnection – Scenario 4



Producer welfare is weakly increasing in the overall level of interconnection for configuration categories A and B with the exception of B2. Here, a notable difference with B1 is an additional 700 MW interconnector with Norway. A corresponding jump in consumer welfare for B2 suggests that interconnection with Norway is effective at reducing electricity prices in GB. Conversely, Configuration C2 (which sees 2.8 GW of interconnection with Spain) produces the greatest producer welfare results out of all of the modelled configurations. This is mainly due to relatively spiky prices in Spain creating price arbitrage opportunities for GB producers as the hourly and monthly electricity demand profile in Spain is significantly different to the electricity demand profile in GB.

Figure 49 Interconnector welfare results of increased interconnection – Scenario 4



Interconnector welfare is relatively low under Scenario 4 and is strongly decreasing in additional interconnection capacity. These figures should be interpreted in light of the caveats set out in Section 6.2. Negative interconnector welfare for all configurations does not necessarily imply that the costs of new interconnection would exceed the change in interconnector revenues, especially if only revenues from new interconnection are considered. Given the significantly reduced differential in carbon prices between GB and other European markets compared to Scenario 1, it is likely that interconnector revenues would be significantly lower under this scenario.

6.4.6 Conclusion

In summary, the optimal interconnection strategy for GB is very sensitive to assumptions about the state of the world in the years up to 2040, and the parameters used to define 'optimal'. Taking net welfare as the basis for our assessment, very high levels of additional interconnection (of between 12.8 GW as shown in Table 15 for Configuration B5 and up to 15.4 GW as shown in Table 10 for Configuration A5) have been found to be beneficial to net welfare in GB in a world with an ambitious roll-out of intermittent renewables across much of Europe, including GB. They are also beneficial in a world where a large differential in carbon prices prevails between GB and the markets to which it is connected. In the absence of these factors, more limited amounts of additional interconnection with GB's closest neighbours are estimated to be optimal, placing an emphasis on lowering the cost of interconnection. This is particularly the case in a world of low gas prices and abundant CCGT capacity, where only a modest expansion to existing GB interconnection is estimated to be optimal (2.5 GW of additional interconnection as shown in Table 7 for Configuration A2). Assuming a world with moderate fossil fuel prices and without significant carbon price differentials between GB and the rest of Europe (Scenario 4), the optimal levels of additional interconnection have been estimated at approximately 8.6 GW (Configuration A4 as shown in Table 9). Other key themes from the results of our analysis are explored in Section 6.6.

Drawing together the net welfare results from different scenarios in a single representation requires some view of the relative probabilities of those different scenarios materialising. Since such an assessment would be subject to a great deal of uncertainty, we draw together two sets of average results. The first puts an equal weighting on all four scenarios under assumption of no prior knowledge about the likelihood of any of the modelled scenarios. The results may be seen in Figure 50. The second is a weighted average of all scenarios excluding Scenario 1. This assumes either that a large differential in carbon prices between GB and other European markets would be unsustainable, or that such a differential should not be a significant driving factor for further GB interconnection. The results for this may be seen in Figure 51.

Figure 50 Average net welfare results

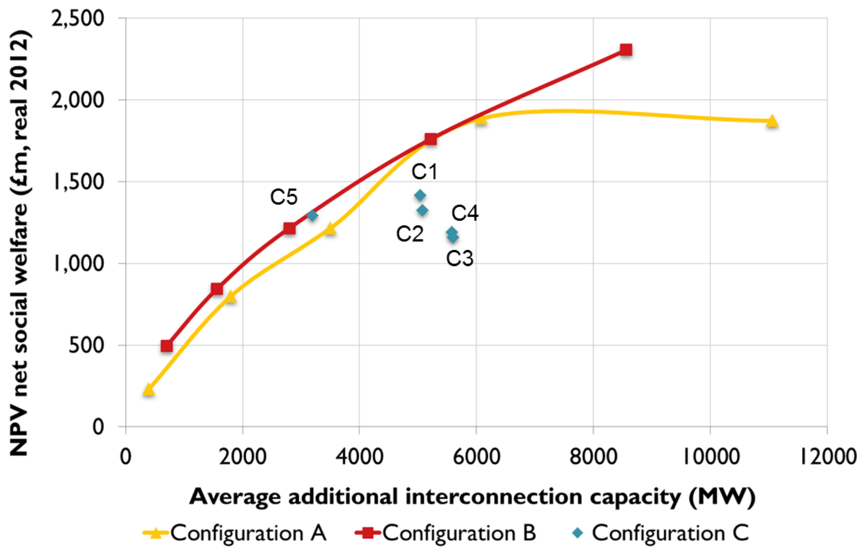
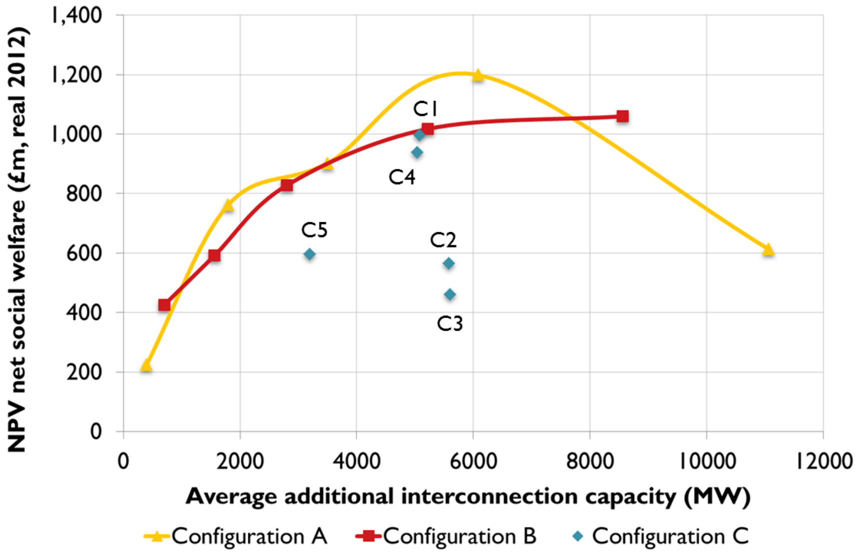


Figure 51 Average net welfare results (ex. Scenario 1)



Averaging over all scenarios, Configuration B5 yields the greatest improvement in net welfare. This is a relatively ambitious configuration with 12.8 GW of new interconnection capacity by 2040 and new interconnections to Belgium, Norway, Iceland and Spain, Denmark, Germany and Sweden, as well as increased interconnection with all markets to which GB is currently connected.

Excluding Scenario 1 from the average results makes a significant difference to the net welfare results, which closely resemble the results for Scenario 4. As in that scenario, Configuration A4, which sees further interconnection with France, Netherlands and Ireland as well as new interconnection with Belgium, Norway, Iceland and Spain, yields the greatest improvement in net welfare.

Analysing the average net welfare results for Configuration A4 on an annual basis reveals that spot years up to 2030 yield a much greater improvement in net welfare (£127m per year on average) than the subsequent two spot years (£56m per year on average). This could mean that the need for additional interconnection is greatest in the short and medium term and does not increase significantly thereafter. It could also mean that the more ambitious projects pursued from 2035 in this configuration (e.g. new interconnectors to Iceland and Spain) contributes less to improvement in net welfare than the relatively more conservative projects built earlier.

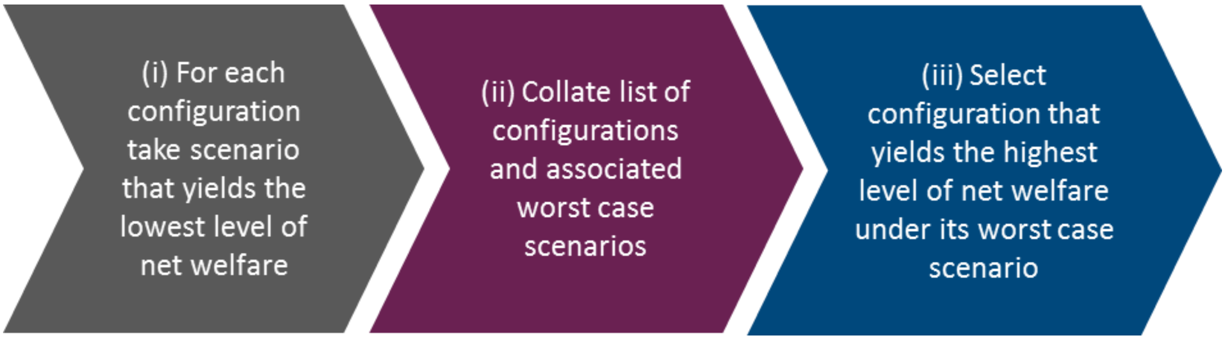
6.5 Least regret level of interconnection

6.5.1 Methodology

Least regrets interconnection analysis can serve as a useful input into policy because it provides an indication of which projects are likely to improve net welfare in GB under a relatively wide range of possible states of the world in terms of fuel prices, emissions prices and generation mixes in different EU markets.

In our analysis, least regrets interconnection configuration is defined as the configuration that yields the greatest net welfare under the worst scenario for that configuration. In other words, it minimises the regret associated with the worst possible outcome occurring for the chosen configuration, where regret is defined as the difference between the expected and the worst possible outcome for that configuration. The methodology for deriving the least regrets interconnection configuration is set out in Figure 52.

Figure 52 Least regrets methodology



6.5.2 Results

Table 23 shows the results of step (ii) as described above. Based on our modelling results, the least regrets interconnection configuration is A3. Here, Interconnectors to Belgium and Norway are built by 2025 and 2030 respectively with 1 GW of capacity each. Apart from these, only interconnection to the closest markets is built (France and Ireland), putting an emphasis on lowering the cost of interconnection. Total new additional GB interconnection reaches 5.0 GW by 2040 and hence the overall level of interconnection of GB with other markets is just below average over all modelled configurations.

Configurations B3 and C1 yield results which are relatively close to A3. Under B3, interconnection to France, Ireland and Norway is built by 2025 and an interconnector to Belgium is built in 2030. Additional 500 MW interconnectors to Iceland and the Netherlands are built in the later part of the modelled period. Under C1, an interconnector to Belgium is built by 2020. Apart from this, only interconnection to the closest markets is built (France and Ireland), putting an emphasis on lowering the cost of interconnection. Total new GB interconnection reaches 7.6 GW by 2040.

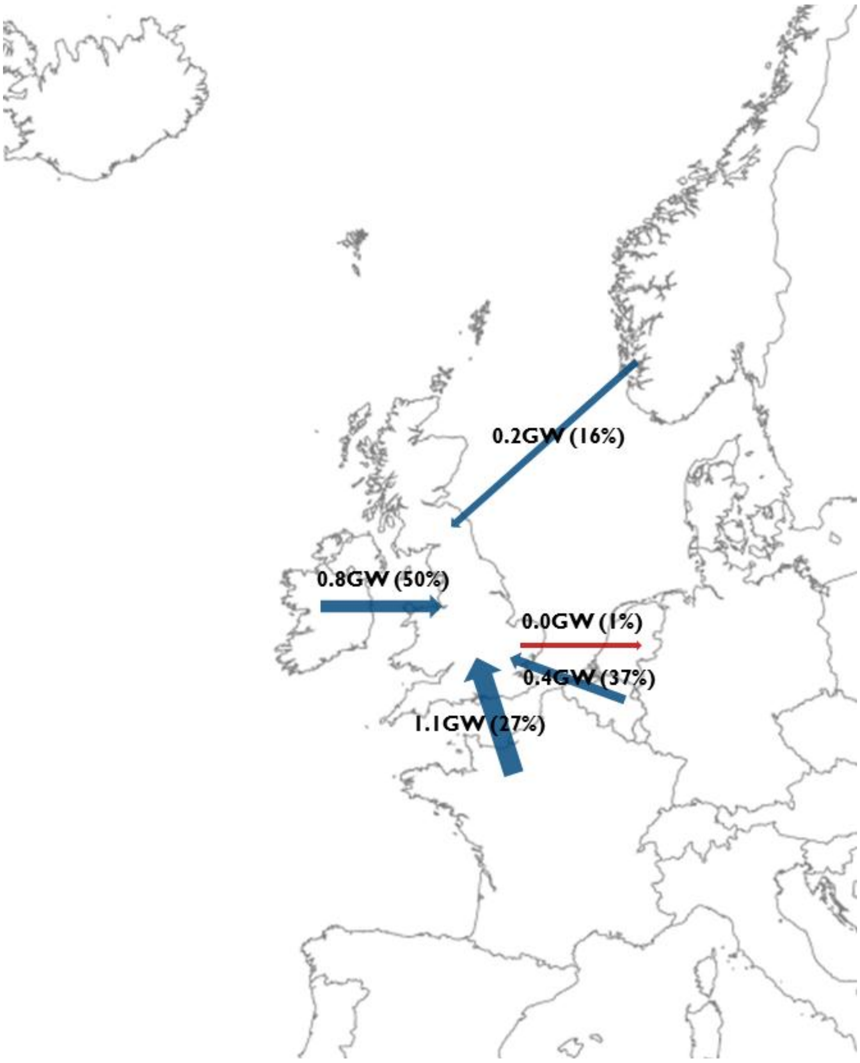
Table 23 Least regrets interconnection across all four scenarios

Configuration	Minimum net welfare	Scenario
A1	92	2
A2	384	2
A3	**871**	**3**
A4	488	3
A5	-906	3
B1	-112	2
B2	357	2
B3	737	2
B4	255	3
B5	-577	3
C1	735	3
C2	264	3
C3	256	3
C4	496	3
C5	278	3

One interesting feature of the results in Table 23 is that only scenarios 2 and 3 define the worst case outcomes for all of the modelled configurations. Scenario 2 is relevant in this context for configurations with a lower overall interconnection level and the opposite is true for Scenario 3. This suggests that a low overall level of interconnection is most likely to lead to regret in a world in which there is a significant roll-out of inflexible renewable capacity across GB and Continental Europe, whereas a high overall level of interconnection is most likely to lead to regret in a world in which fossil fuel prices are low and there is ample flexible generation capacity across different markets.

Figure 53 shows a map of net hourly GB interconnector flows in 2040 for the least regrets configuration (Configuration A3) under the most challenging scenario for this configuration (Scenario 3). As before, blue arrows indicate average net inflows into GB and red arrows indicate average net outflows. Figures in brackets show net flows as a proportion of total interconnection capacity on a given border.

Figure 53 Average net GB interconnector flows – Configuration A3 – Scenario 3 (2040)



6.5.3 Sensitivity

A possible alternative take on the least regrets methodology presented above would be to recognise that it is based on information available to us at present, and as time evolves, that information would be revealed in stages and updated. On the basis of more up-to-date information, alternative decisions can be made. While this does not apply to investment already committed by that stage, if the committed investment turns out to be insufficient on the basis of the newly available information, further investment can be made. The least regrets solution presented above does not account for this option value and assumes that the lack of additional interconnection in the later years of the more modest configurations is pre-committed.

Recognition of the option value associated with least regrets decisions described above may involve looking at a shorter time horizon to check if the decisions that would have to be taken in the near term are likely to lead to regret in a shorter timeframe. This would also be useful in checking the stability of the least regrets solution to changes in the period over which net welfare is considered. Hence, for the three configurations which yield the highest minimum net welfare, as given in Table 23, we repeat the analysis but considering NPV of net welfare up to 2025, 2030 and 2035 respectively. The results are shown in Table 24, Table 25 and Table 26 respectively.

Table 24 Selected least regrets configurations up to 2025

Configuration	Minimum net welfare	Scenario
A3	81	3
B3	74	3
C1	47	3

Table 25 Selected least regrets configurations up to 2030

Configuration	Minimum net welfare	Scenario
A3	466	4
B3	451	4
C1	403	3

Table 26 Selected least regrets configurations up to 2035

Configuration	Minimum net welfare	Scenario
A3	618	2
B3	517	2
C1	738	3

Considering the net welfare results up to 2035 changes the least regrets solution to C1, but A3 remains the least regrets solution when considering NPV of net welfare up to 2025 and 2030. Differences between the three configurations examined above remain small at each stage of the analysis.

6.5.4 Conclusion

Overall, the results presented in this section emphasise the role that lowering the cost of interconnection has on net welfare changes associated with greater interconnection. One conclusion from this is that incremental increases in interconnection with GB's closest neighbours are likely to be beneficial to GB under a broad range of circumstances. But large interconnection projects to distant markets (with the exception of Norway) or a rapid expansion in the overall interconnection level are more risky and a clearer indication of the trends in market fundamentals may be desirable before such strategies are pursued. In the medium term, some interconnection to France, Ireland, Belgium and Norway is unlikely to lead to regret, and further interconnection can be pursued in the later years if clearer indications emerge that the true state of the world is likely to be amenable to higher interconnection levels.

6.6 Emerging themes from our analysis

6.6.1 Value of diversification

One pattern that we could expect to observe in the modelling results is that, particularly for scenarios with high wind penetration, configurations with a more diversified set of interconnections yield higher net welfare due to the benefits of diversification. This hypothesis is tested informally in this section, with the main finding being that that the benefits of connecting to a diverse set of markets may be limited even in the states of the world where the value of diversification is likely to be at its greatest.

Table 27 maps out the interconnection for five configurations with roughly the same overall levels of interconnection by 2050 but with varying degrees of diversification. The configurations are listed in decreasing order of the number of different markets that GB connects to, where a larger number of connected markets implies greater diversity. Table 28 given the NPVs of net welfare for these configurations under the four modelled scenarios.

Table 27 Assumed total levels of interconnection capacity – Diversification analysis

IC Capacity (MW)	FR	IE	BE	NL	NO	IS	ES	DK-W	DE	Total
Configuration B4	1500	1000	700	500	1500	700	500	500	500	7400
Configuration A4	2500	1500	1000	500	1400	700	1000			8600
Configuration C4	3000	2000	1000		1400	700				8100
Configuration C3	2000	4000	1000		1000					8000
Configuration C1	4100	2500	1000							7600

Table 28 NPV results – Diversification analysis

NPV (£m, real 2012)	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Configuration B4	3,994	1,788	255	1,010
Configuration A4	3,950	1,826	488	1,282
Configuration C4	2,851	1,255	496	1,061
Configuration C3	3,252	582	256	546
Configuration C1	2,300	1,191	735	1,063

Although in Scenarios 1 and 2, more diversified interconnection configurations are, on average, associated with higher net welfare, the pattern is not clear cut and does not appear to be present in other scenarios. This may suggest that the benefits of connecting to a diverse set of markets may be limited even in the states of the world where the value of diversification is likely to be at its greatest. One reason for this could be that connecting to a more diverse set of markets involves connecting to markets that are more distant and thus likely to be less economic.

6.6.2 Value of connecting to hydro-based markets

This section examines the benefits for GB of connecting to hydro-based markets such as Norway and Iceland. Although such connections are found to be beneficial for GB consumers under a broad range of scenarios, their benefit for GB in terms of overall net welfare are found to be limited to a narrower range of possible scenarios, particularly in the case of Iceland. However, this assessment does not ascribe any additional value to imported energy coming from renewable sources.

Connecting to markets such as Norway and Iceland, which have an abundance of flexible hydro generation, offers two main potential economic benefits to GB. Firstly, such markets tend to have relatively low electricity prices due to the low cost of electricity generation. This is likely to be beneficial to GB consumers, who would get access to cheap electricity imports. This effect would be even greater in scenarios where GB has a high carbon price. Secondly, hydro reservoir generation is very flexible and generally offers a wide margin of generation capacity over the level of baseload generation. This is likely to be complementary to any inflexible wind generation capacity in GB, offsetting fluctuations in wind power output, and lowering the cost of meeting reserve and response requirements in GB.

This section evaluates the extent to which these benefits are (i) borne out in our modelling and, (ii) justify the high expected capex costs associated with interconnectors to Norway and Iceland, by comparing estimated net welfare and consumer welfare in configurations with similar levels of GB interconnection capacity and differing levels of interconnection to Norway and Iceland. Configurations A3, B3 and C5 are chosen for the purposes of this comparison. These configurations have total new interconnection of 5 GW, 4 GW and 4 GW respectively. A3 contains a single 1 GW interconnector to Norway, B3 contains a 1 GW interconnector to Norway and a 500 MW interconnector to Iceland. C5 contains two 1.4 GW interconnectors to Norway and one 1.2 GW interconnector to Iceland.

Table 29 shows net welfare estimates for configurations A3, B3 and C5 in decreasing order of interconnection to Norway and Iceland. It can be seen that these configurations show comparatively high levels of net welfare compared to other configurations with similar total levels of additional interconnection, suggesting that there is considerable value from a net welfare perspective of connecting to hydro-based markets. Furthermore, while this comparison masks any differences between interconnection to Norway and interconnection to Iceland, on an average basis, it appears to show that increasing levels of interconnection to hydro markets only results in higher net welfare under Scenario 1, which is characterised by a very large differential in carbon prices in GB and the markets to which it connects. Under scenarios 3 and 4, configuration C5 is estimated to have significantly lower net welfare than A3.

Table 29 Net welfare results – Interconnection with hydro markets

NPV (£m, real 2012)	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Total level of interconnection capacity to hydro markets by 2040 (GW)
Configuration C5	3,379	827	278	684	4.0
Configuration B3	2,380	737	854	892	1.5
Configuration A3	2,153	885	871	950	1.0

In Configuration C5, the first 1.4 GW interconnector to Norway is built in 2020, followed by a 1.2 GW interconnector to Iceland in 2025 and a further 1.4 GW to Norway in 2030. For this particular configuration, annual welfare results may contain some information about the relative merits of interconnection to Norway and Iceland. Table 30 sets out the annual GB net welfare results for Configuration C5 for all four scenarios. In all scenarios, interconnection with Norway increases net welfare in 2020 relative to the case with no additional GB interconnection. However, in 2025, when a further 1.2 GW interconnector to Iceland is added, net welfare in GB is lower than in 2020 in all scenarios except Scenario 1 and is negative under Scenario 3. These results suggest that the effects of additional interconnection to Norway on GB net welfare are likely to be more positive than the equivalent effects of additional interconnection to Iceland. This is mainly due to the higher costs (and greater losses) associated with developing an interconnector to Iceland owing to the greater distance of connecting there.

Table 30 Annual GB net welfare results for Configuration C5

£m, real 2012	2020	2025	2030	2035	2040
Scenario 1	133	192	442	426	360
Scenario 2	140	75	9	57	131
Scenario 3	34	-26	139	28	-117
Scenario 4	91	1	121	74	8

Table 31 shows consumer welfare estimates for configurations A3, B3 and C5 in decreasing order of interconnection to Norway and Iceland. On the basis of these results, greater interconnection to Norway and Iceland is clearly beneficial to GB consumers in all scenarios except scenario 3.

Table 31 Consumer welfare results – Interconnection with hydro markets

NPV (£m, real 2012)	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Total level of interconnection capacity to hydro markets by 2040 (GW)
Configuration C5	6,493	336	-1,375	2,471	4.0

NPV (£m, real 2012)	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Total level of interconnection capacity to hydro markets by 2040 (GW)
Configuration B3	1,371	-1,666	-653	488	1.5
Configuration A3	-61	-2,663	-258	571	1.0

Overall, our modelling results show that interconnection to Norway and Iceland can be expected to offer considerable consumer welfare benefits to GB in all scenarios except Scenario 3, where relative abundance of flexible GB generation, coupled with low gas prices, reduces the merits of connecting to Norway and Iceland. Similarly, benefits for GB consumers of a second additional interconnector to Norway and additional interconnection to Iceland appear clear-cut under Scenarios 1, 2 and 4 (with Configuration C5 under those scenarios showing a considerably improved consumer welfare compared to Configuration A3), but far from clear-cut under Scenario 3.

It is important to note that imports from Norway and Iceland are evaluated on the same basis as imports from any other market. This means that there is no specific value attached to imported energy being renewable. In the context of Norway, this is undoubtedly the correct approach since it is well interconnected with other markets (particularly Scandinavian markets), hence the energy imported into GB from Norway may originally have been generated by a coal plant somewhere else. In the context of Iceland, this approach may not be appropriate since Iceland is an isolated market and the imported energy can realistically be verified as being renewable. In this respect, interconnection to Iceland may be more closely related to special purpose projects connecting foreign renewable generation directly into the GB grid.

6.6.3 Value of interconnection to Ireland

One question that the modelling results can help to answer is on the relative merits of further interconnection to Ireland. In this context, it is important to note that projects which propose to build onshore wind in Ireland and transmit the energy directly into the GB grid are considered to be the same as GB offshore wind projects for the purposes of our modelling since these are the types of project that are most comparable directly.

Analysis of our modelling results suggests that the net welfare value to GB of further interconnection to Ireland is likely to be greatest in scenarios that do not see an abundance of GB wind generation capacity. It further suggests that significant amounts of additional capacity may be beneficial to GB net welfare, though this amount is unlikely to be as high as 4 GW.

Given the modelling carried out, the question of the merits of further interconnection to Ireland for GB can be examined from a number of angles. The cleanest comparison we can make is between configurations A1 and B1, which differ only by one 500 MW interconnector to Ireland built by 2030.

Table 32 shows the difference in estimated net welfare in GB created by the additional interconnector to Ireland. It shows that net welfare is improved in all but one of the scenarios.

Scenario 2, where GB itself has a large amount of wind capacity, is the only one that shows a reduction in GB net welfare.

Table 32 Net welfare effect of additional 500 MW interconnection to Ireland

Configuration	Scenario 1	Scenario 2	Scenario 3	Scenario 4
A1	255	92	395	187
B1	706	-112	1,046	343

The disadvantage of the above comparison is that it cannot inform considerations of how much extra interconnection capacity with Ireland would be optimal for GB net welfare. A less clean but potentially more informative comparison is between configuration C3, which has 4 GW of interconnection to Ireland by 2035, and other configurations that have roughly the same amount of interconnection in total but less to Ireland specifically. Configurations A4, B4, C1, C2 and C4 are suitable in this regard.

Table 33 compares net welfare for configuration C3 to net welfare for configurations A4, B4, C1, C2 and C4 across all modelled scenarios. In all scenarios except for Scenario 1, C3 yields a significantly lower net welfare for GB than both the average of these other configurations and also each of those configurations individually. From this result, it may be reasonable to conclude that 4 GW of interconnection to Ireland is likely to be above the level that is optimal for GB net welfare under all scenarios except Scenario 1, assuming that this interconnection does not displace any domestic wind generation in GB. However, since configuration C1 contains 2.5 GW of new interconnection to Ireland, the same thing cannot necessarily be said for lower levels of interconnection to Ireland.

Table 33 Net welfare comparison for interconnection with Ireland

Configuration	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Total level of additional interconnection capacity to Ireland by 2040 (GW)
C3	**3,252**	**582**	**256**	**546**	**4.0**
A4	3,950	1,826	488	1,282	1.5
B4	3,994	1,788	255	1,010	1.0
C1	2,300	1,191	735	1,063	2.5
C2	3,058	787	264	642	0.5
C4	2,851	1,255	496	1,061	2.0
Average - A4, B4, C1, C2, C4	**3,231**	**1,369**	**448**	**1,012**	**1.9**

6.6.4 Value of interconnection in the context of internal GB network reinforcement

In the course of our modelling, two key phenomena have been observed with respect to the effect of further GB interconnection on GB internal boundary constraints:

i) For interconnectors connecting in Scotland, it is possible to reduce B06 (SPT – NGET) flows and thus reduce the need for (expensive) B06 reinforcement, which we assume would have to take place through HVDC bootstraps.

ii) For interconnectors connecting to the South of England, flows via the B14 (London) boundary have been found to increase when GB is exporting to mainland Europe. As a result, the need for B14 reinforcement is also increased.

Overall, a key result from our analysis is that the first point above would tend to dominate the second point, i.e. that further GB interconnection would tend to decrease overall constraint costs on the GB onshore network and thus reduce the total costs associated with further network reinforcement.

B06 Boundary (SPT – NGET)

We compare three cases:

- Configuration A3 where additional interconnection totalling 5 GW to Ireland, France, Belgium and Norway is assumed. The Norwegian interconnector is assumed to connect to England and thus there are no additional interconnectors connecting to Scotland.
- Configuration B4 where additional interconnection totalling 7.4 GW to Ireland, France, Belgium, Spain, Germany, Netherlands, Denmark, Iceland and Norway is assumed. Icelandic interconnector (0.7 GW) and one of the Norwegian interconnectors (0.5 GW) are assumed to connect to Scotland.
- Configuration C5 where additional interconnection totalling 4 GW to Iceland and Norway is assumed, with one of the two 1.4 GW Norwegian interconnectors, along with the Icelandic (1.2 GW) interconnector, connecting to Scotland.

Estimated savings in required B06 boundary reinforcements as a result of differences in configuration of interconnection are given in Table 34 below for Scenario 1.

Table 34 Required B06 boundary capacity (MW) by 2040 – Scenario 1

	Capacity (MW) [52]	Annual savings in transmission boundary reinforcements (£m)	Total additional interconnection capacity connecting to Scotland by 2040 (GW)
Configuration A3	11,500	-	0.0
Configuration B4	10,500	30.4	1.2
Configuration C5	10,000	45.6	2.6

The most likely mechanism by which these estimated savings are generated is as follows. During periods of high wind output in GB, GB prices would tend to be lower than electricity prices in the markets GB is connected to and much of the wind power output would be generated in Scotland (both onshore as well as offshore). With no interconnectors connecting to Scotland, in these periods much of the wind power produced in Scotland would flow via the B06 boundary down to England. If some interconnectors connect in Scotland, Scotland is now able to export via the Scottish interconnectors and thus the need to reinforce B06 can be diminished[53]. Even though only results for Scenario 1 are presented here, similar cost savings were also observed under equivalent Configurations for the other Scenarios modelled since power flows during periods of high wind output remained largely unchanged.

In summary, the extent to which additional interconnectors to Scotland will alleviate the need to reinforce the B06 boundary will mainly depend on the following parameters: (i) the assumed penetration of wind power in Scotland relative to England and Wales, but also relative to the interconnected markets; (ii) the correlation of wind output in Scotland relative to England and Wales and the interconnected markets; (iii) the correlation of electricity demand in Scotland relative to England and Wales and the interconnected markets; and (iv) if GB is connected to hydro markets, the correlation of wind output in GB with hydro conditions in those markets. These factors will all be important in determining electricity prices and interconnector power flows. Our analysis, based on the assumptions described in Section 4, indicates that during periods of high wind output in GB, GB prices would tend to be lower compared to prices in the markets GB is assumed to connect to and thus the need to reinforce the B06 boundary could be diminished if additional interconnectors connect in Scotland.

B14 Boundary (London)

The same three configurations are compared here in order to analyse power flows on the B14 boundary and the associated need for network reinforcement. In terms of the need to reinforce the B14 boundary, the most stressed out of the three configurations considered here is

[52] The capacity figures presented in this Table refer to Winter capacity. For Summer capacity we assume that the rating of overhead lines is reduced by 20%, whereas for DC lines we assume that their rating remains unaffected. Similarly for Spring and Autumn we assume that the rating of overhead lines is reduced by 10%.

[53] Exports via Scottish interconnectors could also reduce wind energy spillage during periods when the B06 boundary is constrained.

Configuration B4, where a number of interconnectors connect in the South of England. Additionally, there are also two interconnectors to Iceland and Norway which connect to Scotland and, in Scenario 1, are mainly used to import lower-cost baseload electricity to GB.

During periods when GB is exporting via the Southern interconnectors, flows on boundary B14 have been found to increase since the majority of GB electricity is produced in the North along with some electricity imported from Norway and Iceland (via Scotland). For Configuration A3, the need to reinforce the B14 boundary is reduced compared to Configuration B4 as exports from GB are also reduced. This is due in part to there not being an interconnector to Iceland pushing down GB power prices. For Configuration C5, the need to reinforce the B14 boundary is also reduced because, whilst there are 4 GW of interconnection capacity importing baseload electricity from Iceland and Norway, there are no additional interconnectors connecting in the South.

The general principle with regards to B14 flows that has been validated by our modelling is that the more GB exports via Southern interconnectors there are, the greater is the need to reinforce the B14 boundary. This has particularly been observed for Scenario 4, where GB exports are increased compared to equivalent Scenario 1 configurations due to reduced carbon price differentials between GB and European markets. As a result, the need to reinforce the B14 boundary is also greater.

Table 35 Required B14 boundary capacity (MW) by 2040 – Scenario 1

	Capacity (MW) [54]	Annual savings (£m)
Configuration B4	14,400	-
Configuration A3	13,900	7.6
Configuration C5	13,900	7.6

Note that the granularity of the zonal representation of the GB transmission network in our modelling, as shown in Figure 8, means that the effect of further interconnection on constraints within those relatively large zones is not accounted for. As a simple example, the choice of landing point within Southern England for a 1 GW interconnector with Continental Europe will make a difference to total GB constraint costs. Assuming for the sake of example that a 1 GW interconnector with Continental Europe supplies electricity to GB at full capacity 80% of the time and assuming further that differences in Wider Zonal Generation TNUoS tariffs[55] represent the difference that the choice of landing point for the interconnector would make to GB constraint costs, locating the GB landing point of the 1 GW interconnector in Wessex (TNUoS Generation Zone #19) rather than Kent (South East, TNUoS Generation Zone #17) would, on the basis of 2011 TNUoS tariffs, reduce GB constraint costs by £3.5m per year. Overall, depending on the landing

[54] The capacity figures presented in this Table refer to Winter capacity. For Summer capacity we assume that the rating of overhead lines is reduced by 20%, whereas for DC lines we assume that their rating remains unaffected. Similarly for Shoulder-Summer and Shoulder-Winter we assume that the rating of overhead lines is reduced by 10%.

[55] See http://www.nationalgrid.com/NR/rdonlyres/0F5FBFA1-A94C-45DD-BAC0-C9A676737176/46235/UoSCI7R0Draft_Issued_FINAL.pdf

point for the interconnector in Continental Europe, this is likely to be less than the corresponding increase in the cost of interconnection as a result of a longer cable being required.

6.7 Sensitivity analysis

6.7.1 Evaluation of carbon emission savings in CBA

Our analysis shows that increased GB interconnection levels can result in considerable carbon savings through more efficient power system dispatch. In the analysis presented so far in Section 6, it has been assumed that any increase or reduction in a country's carbon emissions should be evaluated based on the prevailing carbon prices that the generators of that country are exposed to. Particularly for Scenario 1, where the CPS mechanism results in significantly higher carbon prices in GB (Figure 13), this means that, for example, in 2040, a tonne of CO2 avoided in GB would result in savings of approximately £50 more compared to a tonne of CO2 avoided in any of the other markets modelled.

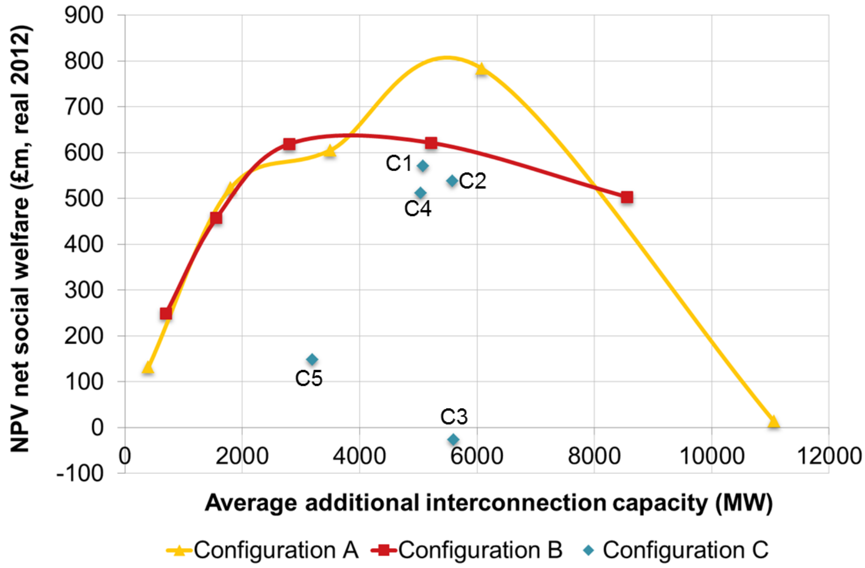
For the purposes of this study, we have also considered an alternative approach where a universal carbon valuation price is used when deriving each country's net welfare changes as a result of changes in GB interconnection. We have used the EUA carbon prices underlying our analysis as the carbon valuation prices to be employed under all scenarios. This ensures that a tonne of carbon avoided in GB is always equally priced with a tonne of carbon avoided in a different market.

In this sensitivity, our model was still run on the basis of differentiated carbon prices in GB and other markets, but the price used to evaluate changes in carbon emissions in the CBA was the same for all markets as described above.

Scenario 1

Figure 54 shows the net welfare results for Configuration sets A, B and C for Scenario 1 ("GB importing") assuming a universal carbon valuation price.

Figure 54 Net welfare results of increased interconnection – Scenario 1 (Carbon Valuation Sensitivity)



For Configuration category A, the greatest social net welfare benefits are realised under Configuration A4 (£0.8bn in NPV terms), which assumes additional interconnectors to France (2.5 GW), Ireland (1.5 GW), Norway (1.4 GW), Belgium (1 GW), Spain (1 GW), Iceland (0.7 GW) and The Netherlands (0.5 GW). Developing further interconnectors as under Configuration A5 (4 GW to France, 2.5 GW to Ireland, 2 GW to Norway, 2 GW to Spain, 1.5 GW to Belgium, 1.2 GW to Iceland, 1 GW to Denmark, 0.7 GW to Germany, 0.5 GW to The Netherlands) has been found to result in almost no GB net welfare benefits.

Similarly, for Configuration category B, relatively high additional interconnection levels appear to be desirable. The greatest social net welfare benefits, approximately £0.6bn in NPV terms, are realised under Configurations B3[56] and B4[57]. Developing further interconnectors as under Configuration B5[58] has been found to slightly reduce GB net welfare benefits (down to £0.5bn).

Configurations C1, C2, C4 and C5 have all been found to increase GB net welfare, ranging between £0.6bn under Configuration C1[59] to £0.1bn under Configuration C5[60]. Configuration C3[61] has been

[56] Configuration B3 sees 1 GW to France, 1 GW to Norway, 0.5 GW to Ireland, 0.5 GW to Belgium, 0.5 GW to Iceland, 0.5 GW to the Netherlands.

[57] Configuration B4 sees 1.5 GW to France, 1.5 GW to Norway, 1 GW to Ireland, 0.7 GW to Belgium, 0.7 GW to Iceland, 0.5 GW to the Netherlands, 0.5 GW to Spain, 0.5 GW to Germany and 0.5 GW to Denmark.

[58] Configuration B5 sees 2.5 GW to France, 2.1 GW to Ireland, 2.1 GW to Norway, 1 GW to Belgium, 1 GW to Iceland, 1 GW to Denmark, 1 GW to Spain, 0.7 GW to Germany, 0.7 GW to the Netherlands and 0.7 GW to Sweden.

[59] Configuration C1 sees 4.1 GW to France, 2.5 GW to Ireland, 1 GW to Belgium.

[60] Configuration C5 sees 2.8 GW to Norway and 1.2 GW to Iceland.

[61] Configuration C3 sees 4 GW to Ireland, 2 GW to France, 1 GW to Belgium, 1 GW to Norway.

found to lead to a very slightly negative GB net welfare hence rather than total interconnection levels, close consideration must also be given to the markets to which GB is connected.

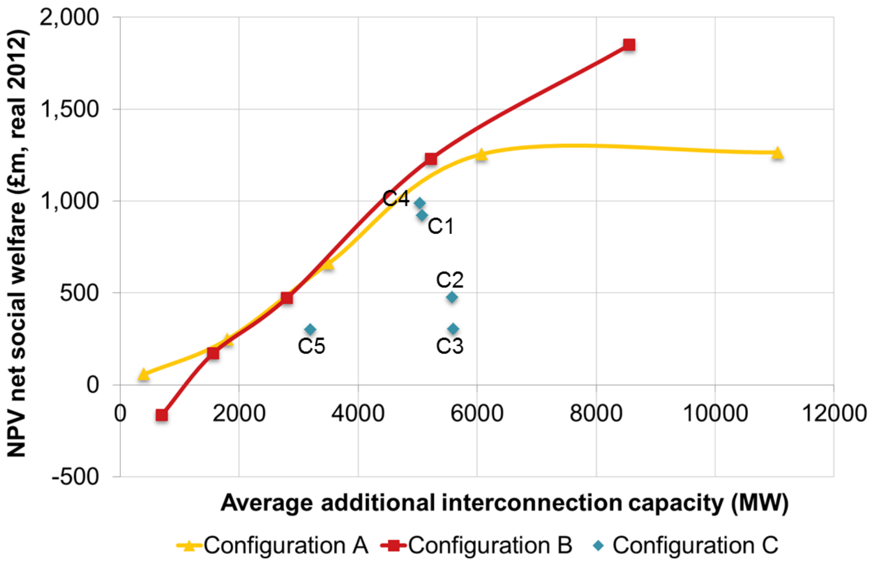
From the results presented here it can be seen that, while using the previous carbon valuation approach, no apparent optimum was reached in terms of overall interconnection levels (Figure 26), using the new approach, this is no longer the case, with increased interconnection levels not necessarily leading to net welfare benefits (Figure 54). In the context of this sensitivity, Scenario 1 represents a world where differences in carbon prices between connected markets distort trade in electricity and reduce the welfare benefits of further interconnection. These findings further demonstrate the importance that must be placed in determining the appropriate carbon price to be used for valuing interconnector investments.

This is also evidenced by the differences in the scale of benefits offered by additional interconnection between this approach and the original approach. Whilst the greatest net welfare benefits are evaluated as £0.8bn in NPV terms using the universal carbon valuation price approach (Configuration A4), under the original approach, the greatest social net welfare benefits are evaluated as significantly higher (£6.0bn in NPV terms under Configuration B5 as shown in Figure 26) due to higher carbon savings.

Scenario 2

Figure 55 shows the net welfare results for Configurations A, B and C for Scenario 2 ("Flexible operation") assuming a universal carbon valuation price.

Figure 55 Net welfare results of increased interconnection – Scenario 2 (Carbon Valuation Sensitivity)



For Configuration category A, the greatest social net welfare benefits are realised under Configurations A4 (close to £1.3bn in NPV terms), whilst developing further interconnectors from that point onwards is estimated not to increase GB social net welfare. Meanwhile, for configuration category B, no optimum appears to be reached, with Configuration B5 offering the greatest GB social net welfare benefits (over £1.8bn). For Configuration category C, configurations C1 and C4 have been found to result in the greatest social net welfare benefits (over £0.9bn) whilst Configurations C3 and C5 result in the lowest net welfare benefits (£0.3bn).

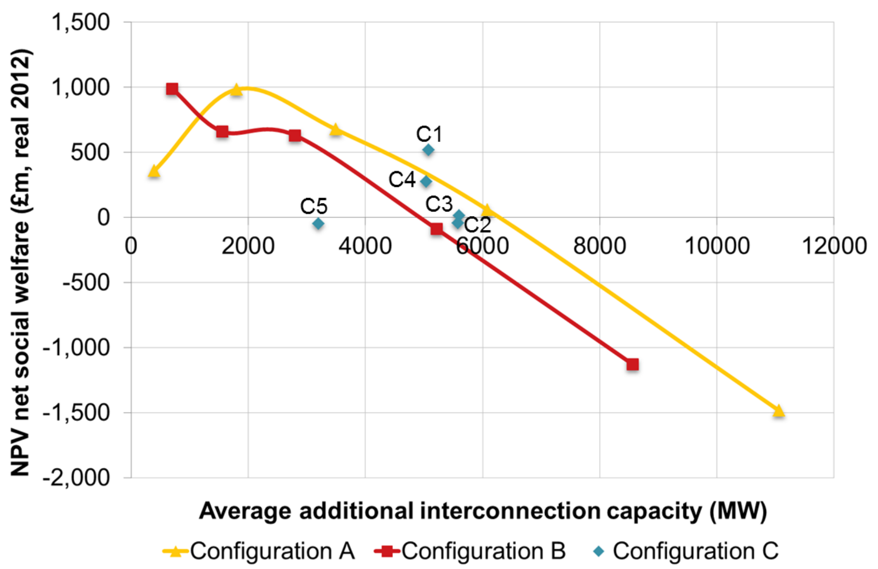
These findings demonstrate the value of additional interconnection for Scenario 2, where net welfare benefits offered by interconnection appear relatively robust to changes in the price used to evaluate carbon emission savings, even at very high interconnection levels. As our results show, this is particularly evident under Configuration category B, thus highlighting the value of connecting to a diverse set of markets if such a scenario were to materialise.

The universal carbon valuation price appears to result in slightly reduced social net welfare benefits compared to the original approach, however differences are not significant since carbon price differences between GB and the rest of EU are also small (with carbon prices assumed to merge from 2040 onwards as shown in Figure 13**Error! Reference source not found.**). The greatest social net welfare benefits are evaluated as £1.8bn in NPV terms using the universal carbon valuation price (Configuration B5), whereas under the original approach the greatest social net welfare benefits are evaluated as £2.6bn (Configuration B5 as shown in Figure 32).

Scenario 3

Figure 56 shows the net welfare results for Configurations A, B and C for Scenario 3 ("Low utilisation"), assuming a universal carbon valuation price.

Figure 56 Net welfare results of increased interconnection – Scenario 3 (Carbon Valuation Sensitivity)



The "Low utilisation" scenario presents a significantly more challenging environment for the economics of interconnectors and as such for Configuration category A the greatest GB net welfare benefits are realised under Configuration A2 (£1.0bn in NPV terms), which assumes very modest additional interconnection levels (1 GW to France, 1 GW to Belgium, 0.5 GW to Ireland).

Developing further interconnections from that point onwards has been found to reduce GB net welfare, down to as low as £-1.5bn under Configuration A5.

A similar story holds true for Configuration category B, where configuration B1 has been found to result in the greatest net welfare (approximately £1.0bn). Configuration B1 also assumes minimal additional interconnection levels, namely 0.5 GW to France and 0.5 GW to Ireland. At the other extreme, Configuration B5 has been found to reduce GB net welfare by as much as £-1.1bn.

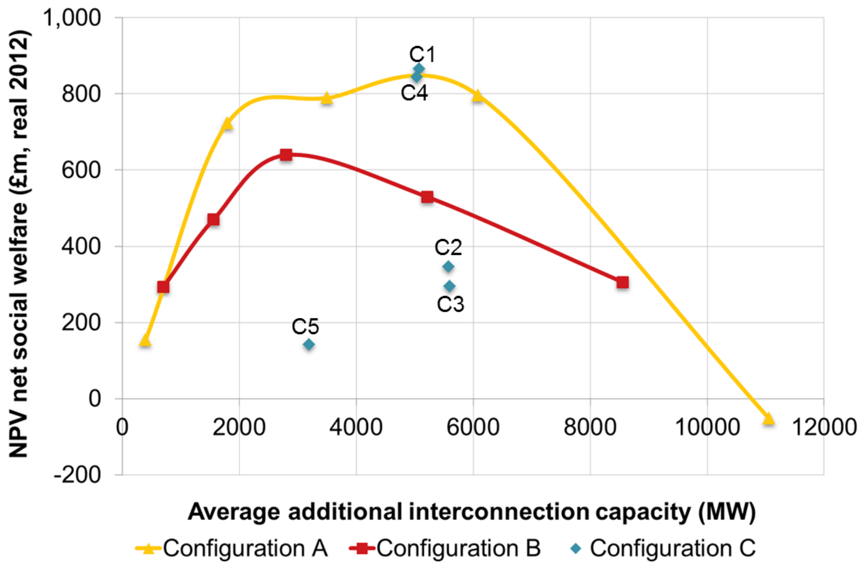
For Configuration category C, configuration C1 has been found to result in the greatest social net welfare benefits (£0.5bn), while Configurations C2 and C5 have been identified as the worst-performing interconnection configurations, leading to a slightly negative GB net welfare.

Again the universal carbon valuation price appears to result in slightly reduced social net welfare benefits compared to the original approach, however differences between the two approaches are now even smaller since the benefits of additional interconnection under Scenario 3 are small. Under both approaches, the greatest social net welfare benefits are evaluated as £1.0bn in NPV terms (Configurations A2 and B1 as shown in Figure 56 and Figure 38 respectively).

Scenario 4

Figure 57 shows the net welfare results for Configurations A, B and C for Scenario 4 ("Carbon price convergence") assuming a universal carbon valuation price.

Figure 57 Net welfare results of increased interconnection – Scenario 4 (Carbon Valuation Sensitivity)



As for Scenario 1, from category A configurations, the greatest social net welfare benefits for GB have been found to be realised under Configuration A4 (£0.8bn in NPV terms), with Configurations A2 and A3 also achieving similar levels of net welfare benefits. From that point onwards, developing additional interconnectors as under Configuration A5 has been found to reduce GB net welfare quite significantly (down to £-0.1bn for that specific interconnection configuration).

For configuration category B, configuration B3 has been identified as the best-performing configuration, resulting in net welfare benefits of approximately £0.6bn. On the other hand, Configurations B4 and B5 have been found to bring lower GB net welfare benefits relative to B3, down to approximately £0.5bn and £0.3bn respectively.

For Configuration category C, configurations C1 and C4[62] are estimated to result in the greatest social net welfare benefits (over £0.8bn), whilst Configuration C5 results in the lowest net welfare benefits (£0.1bn).

As with Scenario 1, the universal carbon valuation price appears to result in reduced social net welfare benefits compared to the original approach, however not to the same extent since carbon price differences between GB and the rest of EU are not as great as under Scenario 1. The greatest social net welfare benefits are evaluated as £0.8bn in NPV terms using the universal carbon valuation price (Configurations A3, A4, C1, and C4), whereas under the original approach the greatest social net welfare benefits are evaluated as £1.2bn (Configuration A4 as shown in Figure 44).

Least regrets interconnection

Table 36 shows results of the least regrets analysis under the assumption of a universal carbon valuation price. Configurations A3 (£0.6bn), C1 (£0.5bn) and B3 (£0.5bn) have been identified as the three most resilient interconnection configurations and as such as the ones offering the greatest potential for 'least regrets'. A3 is estimated to be the lowest regret configuration overall, as it was in the main analysis. These results demonstrate that the price at which carbon emission saving are evaluated is unlikely to significantly alter the least regrets interconnection strategy for GB.

Table 36 Least regrets interconnection (Carbon Valuation Sensitivity)

Configuration	Minimum net welfare	Scenario
A1	58	2
A2	248	2
A3	**605**	**1**
A4	59	3
A5	-1,484	3
B1	-163	2
B2	171	2
B3	472	2
B4	-90	3
B5	-1,128	3
C1	517	3
C2	-44	3

[62] Configuration C4 sees 3 GW to France, 2 GW to Ireland, 1.4 GW to Norway, 1 GW to Belgium, 0.7 GW to Iceland.

Configuration	Minimum net welfare	Scenario
C3	-26	1
C4	277	3
C5	-47	3

Conclusion

The main message from the sensitivity on evaluation of carbon emission savings is that it is important to consider how carbon savings are evaluated in the context of additional GB interconnection if those savings are one of the key drivers for interconnection. In the previous section, comparison of results between Scenario 1 and 4 has shown that differentiated carbon pricing can create distortions in trade in electricity, and these distortions are likely to be felt more strongly with further interconnection. Conversely, whilst the price used for carbon valuation does not impact outturn electricity prices or interconnector power flows (and as such it does not have a direct impact on net welfare for producers or interconnector owners), it is very important in determining carbon savings for consumers and hence also overall net welfare. This has been observed particularly when GB is importing considerable parts of its electricity needs since this would also lead to the greatest carbon savings for GB due to a reduction in the total amount of electricity generated in GB.

6.7.2 Capital cost sensitivity

The cost of interconnection is a key factor in determining a country's optimal level of interconnection. However, there is considerable uncertainty with regards to those future costs (both in engineering as well as in financial terms), and hence, for the purposes of this report, we explored two further sensitivities where the total annuitised costs[63] of developing additional interconnectors is increased or decreased by 25% compared to the central cost scenario presented earlier (Table 2).

Table 37, Table 38 and Table 39 illustrate what a 25% increase or decrease in annuitised costs might mean in terms of interconnection capital costs and investor hurdle rates. Table 37 shows annuitised costs (in £m/year) for an interconnector with total capital costs of £1.15bn[64]. Assuming a hurdle rate of 8% and fixed annual O&M costs of £7m/year, total annuitised costs for that interconnector are estimated at approximately £100m/year.

Table 38 demonstrates a 'High interconnection costs' scenario, where annuitised costs are now increased by 25%, thus resulting in total annuitised costs of approximately £125m/year. This could be either due to:

[63] This includes annuitized capital costs plus fixed annual O&M costs. The interconnector economic lifetime is assumed to be 40 years.

[64] This figure was chosen as annuitized costs work out at roughly £100m/year assuming a hurdle rate of 8%, an economic lifetime of 40 years and fixed annual O&M costs of £7m/year.

- an increase in investor hurdle rates to 10.6% (which for example might be due to increased perceived risks with the development of the interconnector or due to higher cost of capital reflecting challenging financing and/or market conditions);
- an increase in capex costs up to £1.47bn (which, for example, may be due to an increase in technology costs, increase in copper and steel prices or unfavourable exchange rate movements etc); or
- an increase in investor hurdle rates to 9% coupled with an increase in capital costs to £1.33bn.

Table 37 Illustrative annuitised cost calculation – Central interconnection costs

Capex Costs (£m)	Fixed Annual O&M Costs (£m)	Hurdle Rate (%)	Annuitised Costs (£m/year)
1,150	7	8.0%	100

Table 38 Illustrative annuitised cost calculation – High interconnection costs

Capex Costs (£m)	Fixed Annual O&M Costs (£m)	Hurdle Rate (%)	Annuitised Costs (£/kW/year)
1,150	7	10.6%	125
1,325	7	9.0%	125
1,465	7	8.0%	125

Conversely, Table 39 demonstrates a 'Low interconnection costs' scenario, where annuitised costs are now decreased by 25%, thus resulting at total annuitised costs of approximately £75m/year. This could be either due to:

- a reduction in investor hurdle rates to 5.3%;
- a reduction in capital costs down to £0.85bn; or
- a reduction in investor hurdle rates to 7% coupled with a reduction in capital costs to £0.94bn.

Table 39 Illustrative annuitised cost calculation – Low interconnection costs

Capex Costs (£m)	Fixed Annual O&M Costs (£m)	Hurdle Rate (%)	Annuitised Costs (£/kW/year)
1,150	7	5.3%	75
940	7	7.0%	75
845	7	8.0%	75

Scenario 1

Figure 58 shows the net welfare results for Configurations A, B and C for Scenario 1 ("GB importing") assuming high interconnection costs, whilst Figure 59 shows equivalent net welfare results assuming low interconnection costs. It can be seen that whilst GB net welfare benefits are considerably higher in the 'Low interconnection costs' sensitivity, there are no significant changes in the order by which different configurations are ranked.

Figure 58 Net welfare results of increased interconnection – Scenario 1 (High interconnection costs)

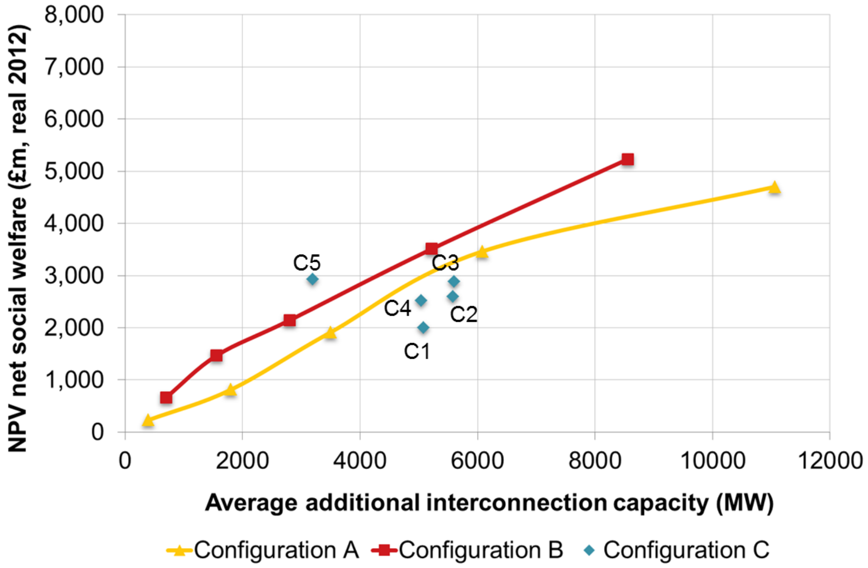
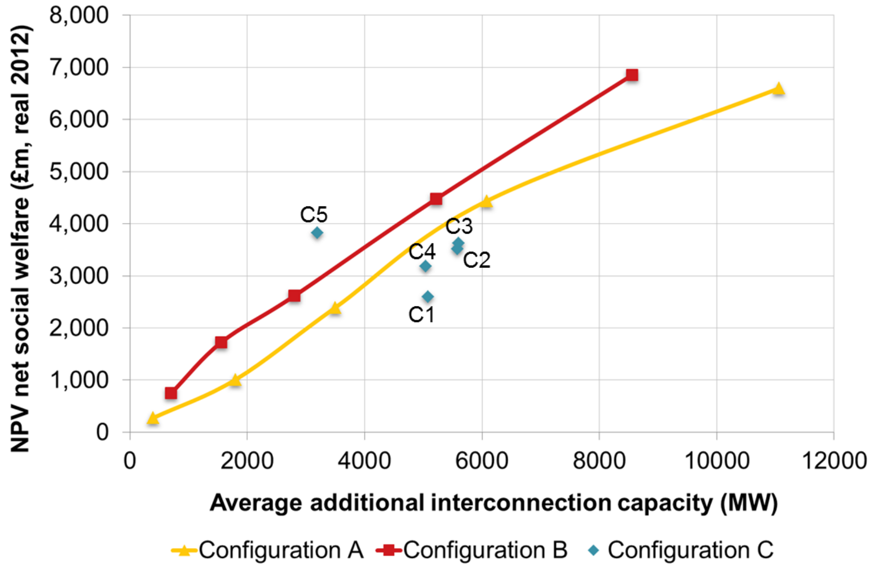


Figure 59 Net welfare results of increased interconnection – Scenario 1 (Low interconnection costs)



For Configuration category A, no optimum appears to be reached, with increased levels of interconnection resulting in increased GB net welfare benefits. Configuration A5 has been found to increase net welfare by £6.6bn under the 'Low cost' sensitivity and £4.7bn under the 'High cost' sensitivity.

Similarly, increased levels of interconnection lead to GB net welfare benefits also under Configuration category B. Here, configuration B5 has been found to increase net welfare by £6.9bn under the 'Low cost' and £5.2bn under the 'High cost' sensitivity.

Finally, configuration C5 has been found to result in the greatest net welfare benefits (£3.8bn under the 'Low cost' and £2.9bn under the 'High cost' sensitivity) whilst configuration C1 has been identified as the configuration offering the lowest net welfare benefits (£2.6bn and £2.0bn respectively).

Scenario 2

Figure 60 shows the net welfare results for Configurations A, B and C for Scenario 2 ("Flexible operation") assuming high interconnection costs, whilstFigure 61 shows equivalent net welfare results assuming low interconnection costs. GB net welfare benefits are considerably higher in the 'Low interconnection costs' sensitivity, and also, as with Scenario 1, there do not appear to be any significant changes in the order by which different configurations are ranked.

Figure 60 Net welfare results of increased interconnection – Scenario 2 (High interconnection costs)

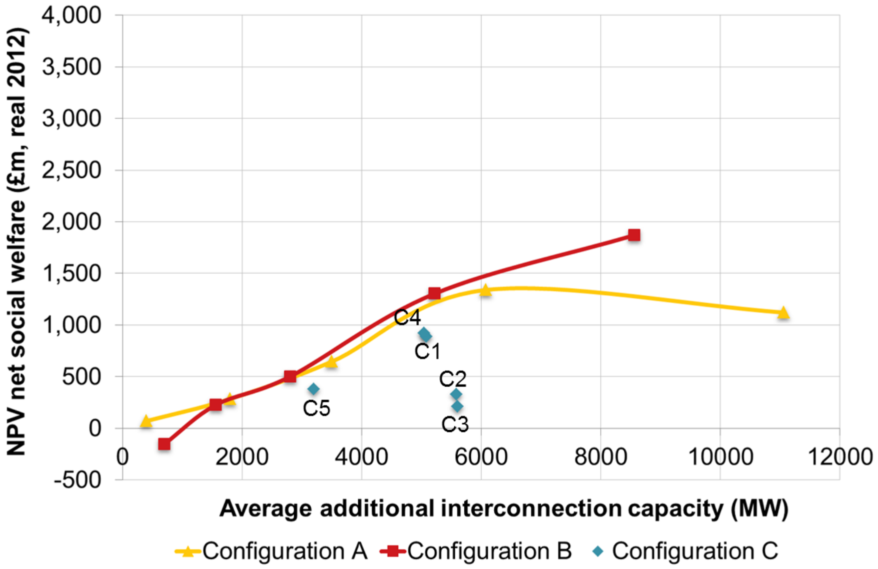
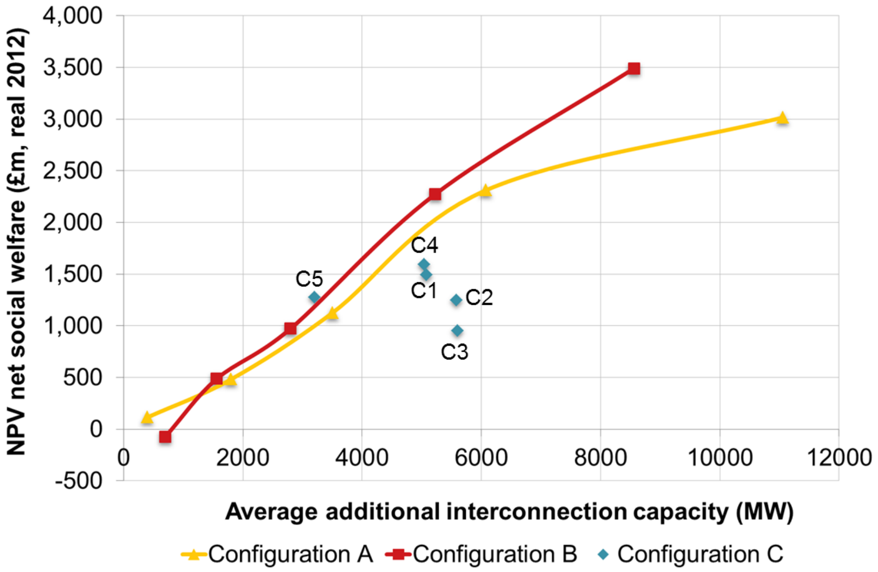


Figure 61 Net welfare results of increased interconnection – Scenario 2 (Low interconnection costs)



For Configuration category A, the greatest social net welfare benefits for the 'Low cost' sensitivity have been found to be realised under Configuration A5 (£3bn), which is also a high-performing configuration under the 'High cost' sensitivity (£1.1bn), albeit slightly lower compared to Configuration A4 (£1.3bn). In general, however, the net welfare benefits offered by additional interconnection levels appear relatively robust despite increased interconnection costs.

In a similar fashion, no optimum appears to be reached under Configuration category B, with increased interconnection levels appearing to increase net welfare under both the low and high cost sensitivities. As such, Configuration B5 is the best-performing configuration with net welfare benefits of £3.5bn and £1.9bn respectively, whilst Configuration B1 results in the lowest GB net welfare (approximately £-0.1bn and £-0.2bn respectively).

For Configuration category C, configurations C4 (£1.6bn under the 'Low cost' and £0.9bn under the 'High cost' sensitivity) and C1 (£1.5bn and £0.9bn respectively) appear as the best-performing configurations, while Configuration C3 has been found to result to the lowest net welfare benefits (£1.0bn and £0.2bn respectively).

Scenario 3

Figure 62 shows the net welfare results for Configurations A, B and C for Scenario 3 ("Low utilisation") assuming high interconnection costs, whilst Figure 63 shows equivalent net welfare results assuming low interconnection costs. GB net welfare benefits are considerably higher in the 'Low interconnection costs' sensitivity, and also, as with Scenarios 1 and 2, there do not appear to be any significant changes in the order by which different configurations are ranked.

Figure 62 Net welfare results of increased interconnection – Scenario 3 (High interconnection costs)

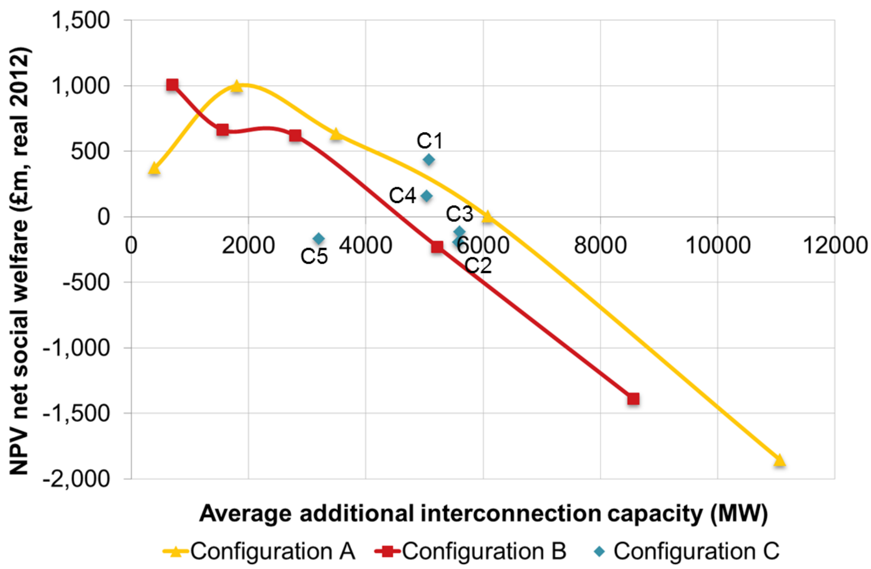
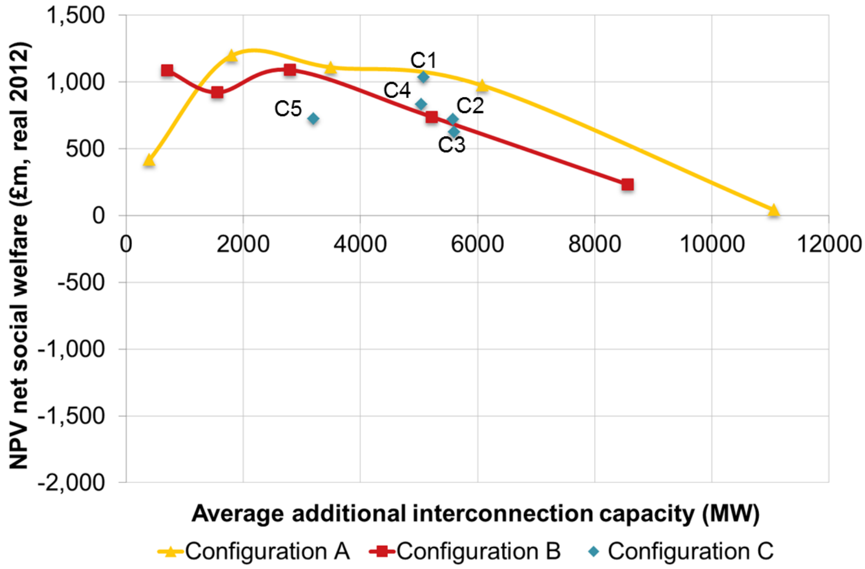


Figure 63 Net welfare results of increased interconnection – Scenario 3 (Low interconnection costs)



For Configuration category A, the greatest social net welfare benefits for both the 'Low cost' as well as the 'High cost' sensitivity have been found to be realised under Configuration A2 (£1.2bn and £1bn respectively). From that point onwards, additional interconnection has been found to reduce GB net welfare, although at a considerably slower rate assuming low interconnection costs. Configuration A5, for example, results in a very small (<£0.1bn) net welfare benefit under the 'Low cost' sensitivity, whilst it results in a substantial net welfare loss of £1.9bn under the 'High cost' sensitivity.

In a similar fashion, low interconnection levels appear to be desirable under Configuration category B, particularly assuming high interconnection costs. Under the 'High cost' sensitivity, Configuration B1 has been identified as the best-performing configuration (offering net welfare benefits of £1bn), whereas under the 'Low cost' sensitivity, configurations B1 and B3 offer the greatest benefits (roughly £1.1bn).

For Configuration category C, configurations C1 (£1.0bn under the 'Low cost' and £0.4bn under the 'High cost' sensitivity) and C4 (£0.8bn and £0.2bn respectively) appear as the best-performing configurations, while Configuration C3 has been found to result to the lowest net welfare under the 'Low cost' sensitivity (£0.6bn) and Configuration C2 under the 'High cost' sensitivity (£-0.2bn).

Scenario 4

Figure 64 shows the net welfare results for Configurations A, B and C for Scenario 4 ("Carbon price convergence") assuming high interconnection costs, whilst Figure 65 shows equivalent net welfare results assuming low interconnection costs. As expected (and as shown under Scenario 1 results), GB net welfare benefits are considerably higher in the 'Low interconnection costs' sensitivity, however now there are also differences in the order by which different configurations are ranked with configurations with high interconnection levels performing noticeably better under the 'Low costs' sensitivity.

Figure 64 Net welfare results of increased interconnection – Scenario 4 (High interconnection costs)

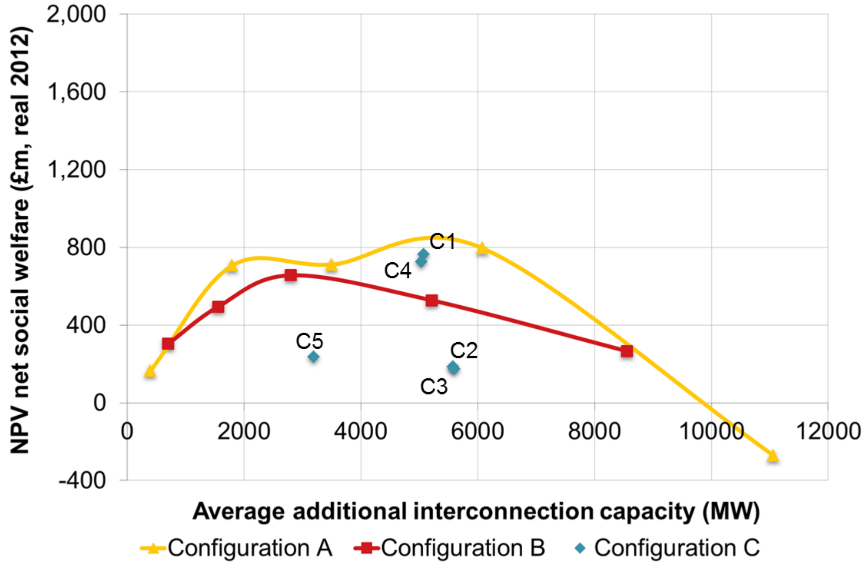
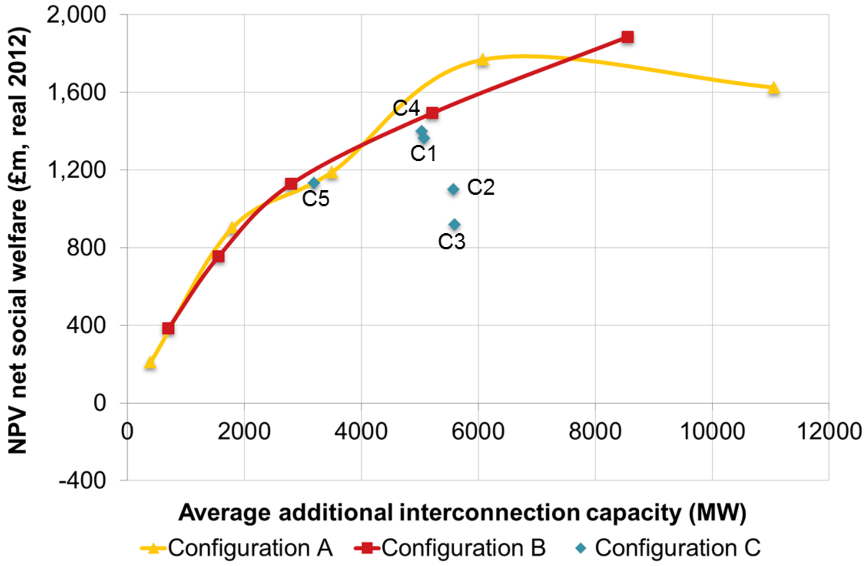


Figure 65 Net welfare results of increased interconnection – Scenario 4 (Low interconnection costs)



For Configuration category A, the greatest social net welfare benefits have been found to be realised under Configuration A4 for both the 'Low cost' as well as the 'High cost' sensitivity (£1.8bn and £0.8bn respectively). However whereas the configuration with the highest levels of interconnection (Configuration A5) results in the lowest net welfare under the 'High cost' sensitivity (leading to a net welfare loss of £-0.3bn), under the 'Low cost' sensitivity, it performs as the second-best configuration with net welfare benefits of £1.6bn.

Assuming low interconnection costs, no optimum appears to be reached under Configuration category B, with increased interconnection levels leading to increased net welfare for all configurations modelled in this category. As such, Configuration B5 is the best-performing configuration with net welfare benefits of £1.9bn. Assuming high interconnection costs, however, changes this picture quite drastically, with Configuration B5 now resulting in the lowest GB net welfare benefits (£0.3bn). Under the 'High cost' sensitivity, the best-performing configuration has been found to be Configuration B3 with net welfare benefits of approximately £0.7bn.

For Configuration category C, configurations C1 (£1.4bn under the 'Low cost' and £0.8bn under the 'High cost') and C4 (£1.4bn and £0.7bn respectively) appear as the best-performing configurations, while Configuration C3 has been found to result to the lowest net welfare benefits (£0.9bn and £0.2bn respectively).

Least regrets interconnection

Table 40 shows results for the least regrets analysis under the 'High cost' and 'Low cost' sensitivities. As in our core analysis, Configuration A3 (£1.1bn and £0.6bn respectively) has been identified as the most resilient interconnection configuration with respect to interconnection costs.

Table 40 Least regrets interconnection (High and low interconnection costs)

	High interconnection costs sensitivity		Low interconnection costs sensitivity	
Configuration	**Minimum net welfare**	**Scenario**	**Minimum net welfare**	**Scenario**
A1	70	2	115	2
A2	285	2	482	2
A3	**632**	**3**	**1,110**	**3**
A4	2	3	974	3
A5	-1,854	3	41	3
B1	-152	2	-72	2
B2	227	2	486	2
B3	501	2	972	2
B4	-228	3	738	3
B5	-1,387	3	233	3
C1	435	3	1,035	3
C2	-193	3	722	3
C3	-116	3	627	3
C4	160	3	832	3
C5	-170	3	725	3

Conclusion

The main message from the capital cost sensitivity appears to be that while the absolute net welfare impact of GB interconnection can change significantly as a result of a change in the capital costs of interconnection, the optimal and least regrets interconnection strategies for GB appear relatively stable in the face of such changes. In this regard, overall scenario assumptions as represented by differences between the scenarios modelled in our study appear to play a much more important role in determining the optimal interconnection strategy for GB.

From a distributional analysis viewpoint, higher interconnector capital costs do not change power flows in the system (or outturn electricity prices) and as such do not directly impact producer or consumer welfare[65]. They do, however, have a negative impact on the welfare of interconnector owners and hence also on overall net welfare levels.

6.8 Security of supply modelling

6.8.1 Overview

We have carried out two stress tests to analyse the impact of changes in GB interconnection on security of supply in GB under different sets of extreme conditions. We conducted two stress tests for a given period of a given spot year in each interconnection configuration modelled. These were modelled for scenarios 1 and 2 only. Scenario 4 was not considered since the only difference with Scenario 1 is in the carbon price assumptions, which are unlikely to make a difference in high-stress situations. Scenario 3 was not considered as it sees an abundance of flexible generation in GB and therefore the results were likely to be less informative than Scenarios 1 and 2.

Each stress test represents a different combination of events that are likely to challenge security of supply in GB. The stress tests conducted are as follows:

- Combination of low wind output, plant outages and high demand due to cold weather that challenge the ability of the system to supply all firm demand and maintain voltage on the grid.
- Large and rapid changes in wind power output and demand combined with line outages that challenge the ability of the network to respond.

The assumptions for the stress tests were designed to represent extreme but realistic sets of outcomes that are internally consistent within each stress test. In deriving the assumptions for the stress tests, we have also given consideration to the likelihood of stressed situations in GB being correlated with stressed situations in countries to which GB would be connected. This is likely to be crucial to the difference that interconnectors are likely make in such situations.

We have used the same modelling framework used throughout our analysis to model the stress tests. The outcomes of the stress test for each of the modelled interconnection configurations and

[65] In reality it is possible to envisage scenarios where, if new-build interconnectors are loss-making, their owners would seek to change their bidding behaviour in order to maximise their revenues during the periods they would be operating and this could make the cost of electricity more expensive for consumers. However, changes in interconnector bidding behaviour are outside the scope of this report.

scenarios are measured in terms of system cost and energy unserved[66]. These outcomes are compared between different configurations of interconnection for each scenario. We also report interconnector flows to give an indication of the likely behaviour of interconnectors in such situations.

6.8.2 Stress test 1

Assumptions

For this stress test, which is modelled over a period of five winter working days, we have assumed that GB wind output is given by the lowest wind 5 winter days in a recent 3 year period. Actual wind speed observations were taken for the same period for other sites across Europe to reflect prevailing correlations in wind power output.

GB demand is assumed to be given by highest 5 winter days in the same 3 year period and demand for other modelled European countries is taken for the corresponding period to reflect prevailing correlations in demand across Europe. In our actual historic dataset, these two periods do not coincide. Finally, we assume 95% availability for all non-intermittent plant plus unplanned interruption for 9.5 GW of flexible capacity in 2020 and 8.5 GW in 2030 in GB. Plant availability in other modelled markets is assumed to be consistent with the seasonal average. The further unplanned outages are required to ensure that the stress test results in some unserved energy under all configurations and hence we can differentiate between different configurations with respect to this important security of supply metric.

Assuming that the average availability of non-intermittent generation plant in GB is 90%, the estimated probability of occurrence of the outages modelled in this stress test is less than 0.01% (1 in 10,000) for both of the modelled scenarios and spot years. Under a more pessimistic assumption of 85% average availability, that probability becomes 0.35% under both scenarios in 2020. In 2030, it becomes 1.0% under Scenario 1 and 0.9% under Scenario 2. Given that thermal and nuclear plant forced outages in GB are generally independent of weather conditions, even under the very pessimistic assumptions that low wind conditions are 100% correlated with high demand conditions and average plant availability is 85%, the estimated annual probability of the modelled stress test situation occurring in 2030 under Scenario 1 is around 0.33% (1 in 300 years)[67]. Assuming no correlation between wind power output and demand reduces this probability to around 0.002% (1 in 47,000 years).

Figure 66 shows total unserved energy in 2020 in this stress test for the different modelled configurations under scenarios 1 and 2 and Figure 67 does the same for 2030. With only a few exceptions, each configuration is associated with a different overall interconnection level. Illustratively, the daily level of energy assumed for 2020 is approximately 1,200 GWh (roughly 6,000

[66] The term energy unserved (typically expressed in GWh terms) is used here to refer to involuntary curtailment of customer demand due to supply deficits (i.e. customer black outs during periods where total demand exceeds available generation). For the purposes of this report we also modelled voluntary Demand Side Response measures (see Section 4.10) which however do not count as unserved energy, but we did not model any voltage control actions taken by TSOs (typically referred to as 'brown outs').

[67] This result is based on a 1% probability of the modelled plant availability prevailing in any given week and low wind and high demand conditions prevailing in one week of a three year period.

GWh for the 5 days) rising to approximately 1,360 GWh in 2030 (roughly 6,800 GWh for the 5 days). Depending on the specific interconnection configuration, unserved energy in percentage terms has therefore been found to range between 0.2-0.6% for a 5-day winter week in 2020, and between 0-3.2% for a 5-day winter week in 2030.

Figure 66 Total unserved energy in 2020 under Stress test 1

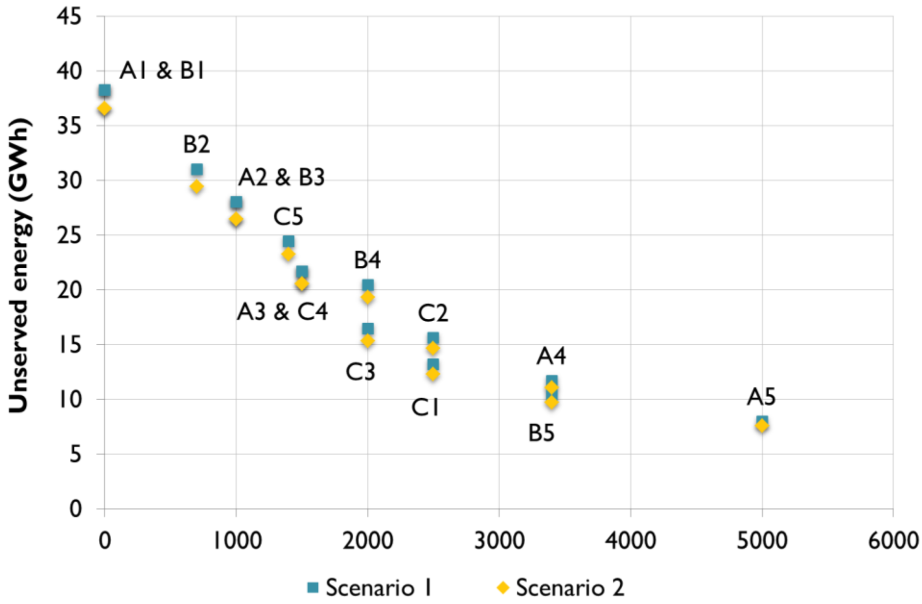
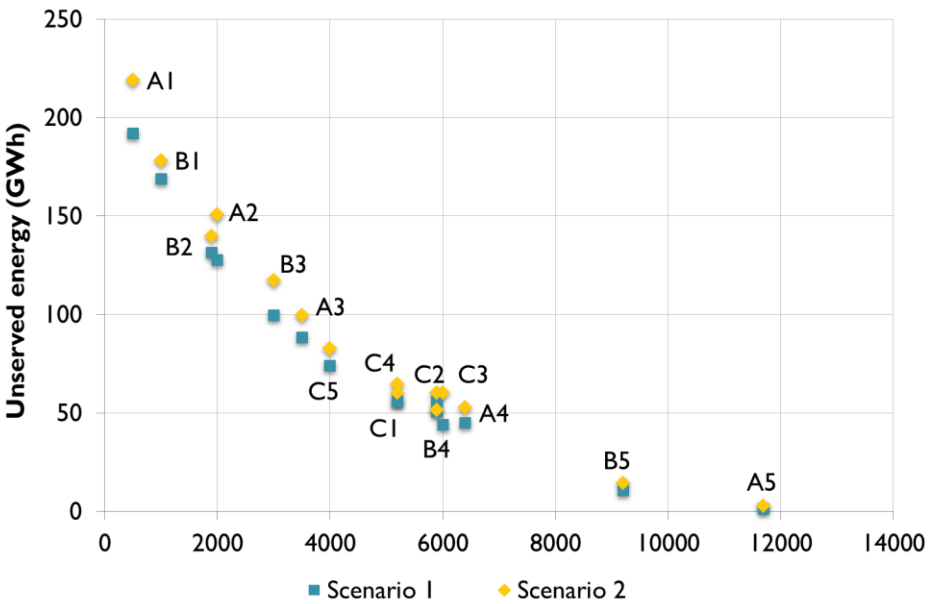


Figure 67 Total unserved energy in 2030 under Stress test 1



Several interesting messages emerge from these results. Unserved energy is generally decreasing with the level of GB interconnection. This is as expected given that, while there is a positive correlation between low wind and high demand conditions in GB and in other European markets, this correlation is not perfect and there is no correlation between plant outages in GB and other markets. Hence, at times of high stress in GB, interconnectors can be expected to flow electricity to GB and contribute significantly to a reduction in unserved energy.

Differences in the security of supply effect of additional interconnection between Scenario 1 and Scenario 2 are minor for 2030 and virtually non-existent for 2020. 2030 sees a much greater level of unserved energy for a broadly equivalent set of stress test assumptions. In large part, this is due to the much larger wind penetration by 2030 under both of the scenarios modelled.

Finally, Table 41 shows the utilisation of every individual interconnection with respect to flows into GB during periods when there is some unserved energy in GB. These numbers are calculated as an average across all configurations and periods in which the relevant interconnection capacity is above zero (i.e. that there is an interconnection to that market) and unserved energy is also above zero.

The results show that the majority of interconnectors are flowing to GB at times of extreme stress. The only exception to this is interconnection with France, which achieves import utilisation below 100%. There are two possible drivers for this. One is that France (along with Ireland) is the market that shows the greatest extent of correlation with GB in terms of system stress. The other is that France is the market which has the greatest amount of interconnection with GB on average across all modelled configurations, and hence full exports to GB at times of system stress are themselves likely to put the French electricity system under stress.

It is also notable that the 2020 results are extremely similar for Scenarios 1 and 2, and the 2030 results are similar overall, which implies that fuel prices and the generation mix in the connected markets are unlikely to make a large difference to interconnector flows at times of extreme stress.

Table 41 Interconnector import utilisation in outage periods – Stress test 1

Connected market	% utilisation in outage periods (Scenario 1)		% utilisation in outage periods (Scenario 2)	
	2020	2030	2020	2030
France	89.4%	91.2%	89.3%	93.4%
Netherlands	100.0%	100.0%	100.0%	100.0%
Northern Ireland	100.0%	99.6%	100.0%	100.0%
Republic of Ireland	100.0%	97.6%	100.0%	97.9%
Belgium	100.0%	100.0%	100.0%	100.0%
Denmark	N/a	100.0%	N/a	100.0%
Spain	N/a	100.0%	N/a	100.0%
Iceland	N/a	100.0%	N/a	100.0%
Norway	100.0%	100.0%	100.0%	100.0%

6.8.3 Stress test 2

Assumptions

For this stress test, which is also modelled over a period of five winter working days, the demand and plant availability assumptions are the same as for Stress test 1. The assumptions on wind speeds are the same as for Stress test 1 for the first two days, followed by one normal wind day and then two high wind days. At the end of day 3, we assume that one of the Scotland to England bootstraps fails, corresponding to a loss of 2GW on the B6 (Scotland to England) boundary.

Figure 68 shows total unserved energy in 2020 in this stress test for the different modelled configurations under scenarios 1 and 2 Figure 69 does the same for 2030. Depending on the specific interconnection configuration, unserved energy in percentage terms has been found to range between 0.1-0.4% for a 5-day winter week in 2020, and between 0-1.7% for a 5-day winter week in 2030.

Figure 68 Total unserved energy in 2020 under Stress test 2

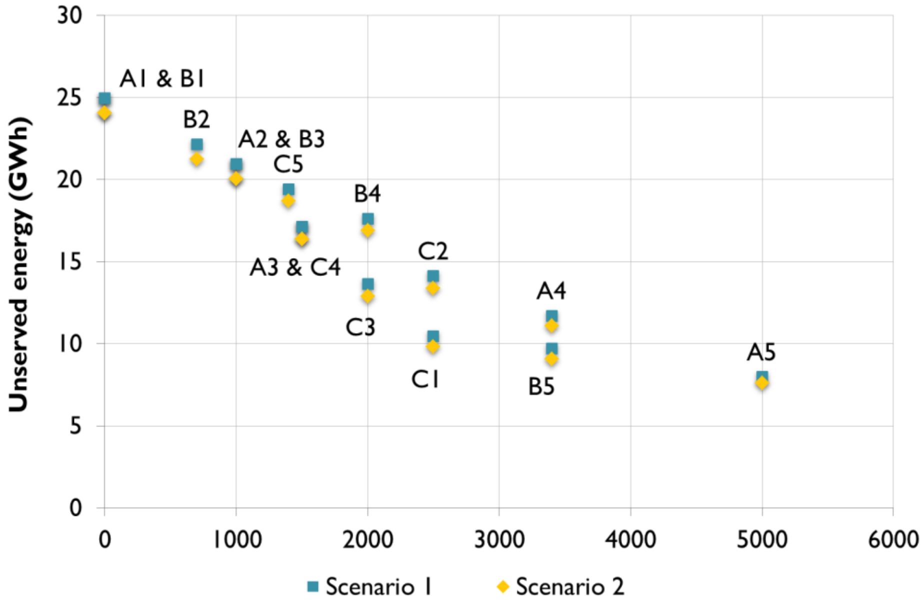
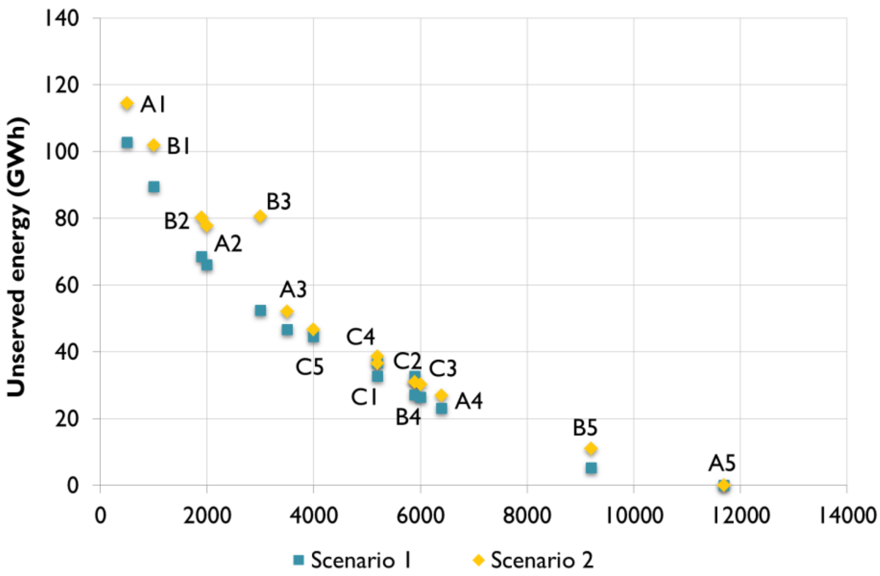


Figure 69 Total unserved energy in 2030 under Stress test 2



Many of the messages emerging from these results are the same as for Stress test 1. Here, we focus on the differences. The overall levels of unserved energy are lower in the second stress test, which is as expected given that half of the period is characterised by average or above average wind conditions. Differences in unserved energy between different configurations in 2020 appear to be greater than under Stress test 1, so these are discussed below.

Configurations B4 and C3 see an identical overall level of GB interconnection by 2020 and yet C3 sees lower level of unserved energy than B4. One notable difference between these configurations is that C3 sees 1 GW of additional interconnection to Ireland by 2020, which replaces 1 GW of interconnection capacity with Norway seen in B4. Hence in 2020, the ability of Irish interconnection to deliver electricity to GB at times of extreme stress is greater than that of interconnection with Norway. This is a surprising result and is clearly very sensitive to the specific assumptions used for the purposes of the security of supply analysis (particularly with regards to demand conditions as well as Irish wind plant load factors and hydro conditions in Norway during that week). Full stochastic analysis of the key variables affecting interconnector power flows would be required to further validate these findings and derive a probability distribution. This, however, was outside the scope of our work.

Total unserved energy under configuration C1 is lower than under configuration C2. In C1, 1 GW of interconnection capacity with France is replaced by 1 GW interconnection with Belgium. Hence the capacity of an interconnector to Belgium to provide energy to GB at times of extreme stress is estimated to be greater than that of an interconnector to France. This can be seen in Table 42 which shows the utilisation of every individual interconnection with respect to flows into GB during periods when there is some unserved energy in GB. As for Stress test 1, these numbers are calculated as an average across all configurations and periods in which the relevant interconnection capacity is above zero and unserved energy is also above zero.

Table 42 Interconnector import utilisation in outage periods – Stress test 2

Connected market	% utilisation in outage periods (Scenario 1)		% utilisation in outage periods (Scenario 2)	
	2020	2030	2020	2030
France[68]	83.6%	99.2%	83.6%	95.9%
Netherlands	100.0%	100.0%	100.0%	100.0%
Northern Ireland	100.0%	100.0%	100.0%	100.0%
Republic of Ireland	100.0%	99.9%	100.0%	99.3%
Belgium	100.0%	100.0%	100.0%	100.0%
Denmark	N/a	100.0%	N/a	100.0%
Spain	N/a	100.0%	N/a	100.0%
Iceland	N/a	100.0%	N/a	100.0%
Norway	100.0%	100.0%	100.0%	100.0%

The results are similar to Stress test 1 overall, with a similar set of conclusions being drawn.

6.8.4 Conclusion

The strongest message that can be drawn from the stress testing exercise is that greater levels of interconnection are generally associated with better security of supply. Although both low wind and high demand conditions can be correlated across markets, forced plant outages are generally uncorrelated and hence in times of extreme system stress in GB, most interconnectors are likely to be supplying energy to GB at near full capacity. This finding, however, assumes that there are no provisions in the market or regulatory arrangements which prevent interconnectors from flowing energy in the direction which is most economic. We believe that this is consistent with current draft ENTSO-E network codes.

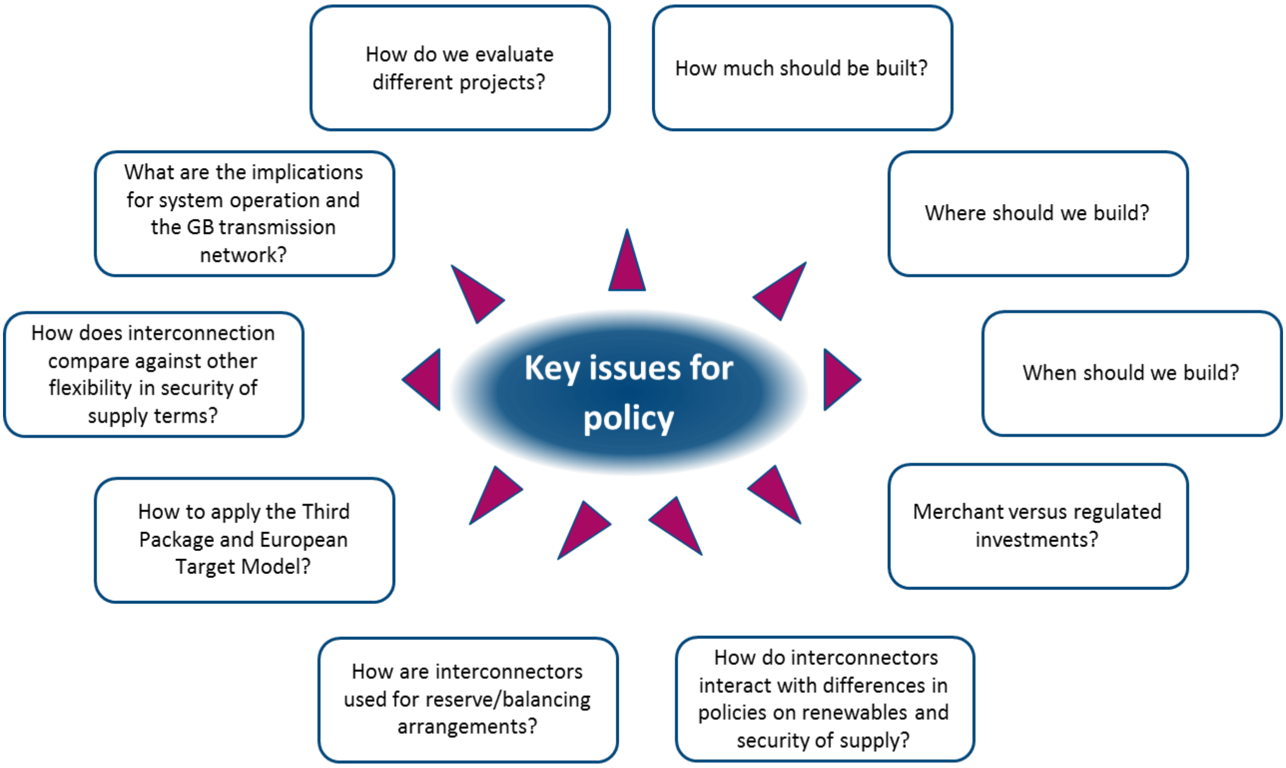
[68] It can be seen that for both scenarios the utilisation for the French interconnector during the illustrative 2020 week is considerably lower (roughly 12-16% lower) compared to the illustrative 2030 week. This is because in our model the French electricity system during the 2020 week is more stressed compared to the 2030 week. This finding is clearly very sensitive to the specific assumptions used for the purposes of the security of supply analysis (particularly with regards to French demand conditions as well as wind and thermal plant availabilities during that week) and should therefore be interpreted with caution.

7 Implications for Policy

7.1 Introduction

There are a number of key issues in interconnector policy that we believe would merit government and regulatory consideration. Figure 70 sets out a detailed list of issues for interconnector policy that we believe are relevant to this study. We expand on the key issues below and set out how our analysis helps to establish a framework to address them.

Figure 70 Issues for interconnector policy



7.2 Optimal interconnection capacity

As described earlier, a more regulated approach to development of interconnectors increases the necessity for evaluation of different projects on a like-for-like basis to drive the decisions on which interconnectors should be developed. Implicit in that decision is the overall level of interconnection being sought, the connected markets and the timing of new connections. In that context, the main implications from our analysis for the optimal overall level of GB interconnection are as follows.

Implication 1: *There is no single optimum interconnection level for GB (on net welfare or any other criteria) given the uncertainty in fundamental market drivers as measured across the scenarios* *we have analysed but a minimum additional interconnection capacity of some 5 GW to 2040 returns a significant improvement in GB net welfare across most scenarios, although costs and benefits are not distributed evenly between different groups.*

Least regrets analysis can be a useful guide for policy-makers in the short and medium term. Our analysis suggests (on the basis of net welfare) that a moderate build-out of interconnection capacity that sees 2.5 GW of additional capacity by 2025 and a further 1 GW by 2030 minimises regret under a range of plausible scenarios and retains the option to accelerate development of interconnection at a later stage when clearer signals about the state of the world become available. Investment decisions on interconnectors will of course be driven by a careful balance of risk and reward and our analysis shows that market fundamentals and new interconnector build will interact to influence that risk and reward balance for individual projects.

Further, on the issue of timing of new interconnector development, modest expansion in the overall level of GB interconnection capacity results in an increase in net welfare under all of the scenarios modelled in our study. This result suggests that the current level of GB interconnection is either sub-optimal under the current market conditions or is likely to become sub-optimal in the medium term under a wide range of plausible scenarios.

7.3 Evaluation of interconnection projects

Although GB is one of the few (but not only) European markets in which privately funded (i.e. without recourse to a regulated asset base) or "merchant" interconnectors have been pursued, this has been against the direction of travel in most EU countries and indeed of the default position under European Directives. There has been wide-ranging debate on the role of such private investment in determining which interconnectors are developed, how they are financed, and how the risks and rewards of such investments are shared. Under a regulated approach, developers of interconnectors do not bear the full risk associated with their projects (part of which, at least, is borne by consumers) and under this approach, market forces no longer drive investment decisions. This places more responsibility for deciding which projects should go ahead on those responsible for network planning and on effective evaluation of projects and their relative merits in the context of a view on the desired level of interconnection.

The main implications emerging from our analysis for the evaluation of potential interconnection projects are as follows.

Implication 2: *The results of the analysis undertaken show that different scenarios and configurations can lead to very different results in terms of net welfare and in the distribution of impacts across groups. In this context and of overall energy policy, emerging regulated regimes for interconnectors, the development of the European Target Model, and electricity system operation, this has policy implications and GB should consider a system to evaluate interconnection projects as occurs in other European countries.*

A key policy questions in this context are: how should different, potentially competing, projects be evaluated; what evaluation criteria should be used; and who should carry out this evaluation. In our analysis, we have carried out detailed CBA assessment of different configurations of interconnection that is in line with the guidelines developed by ENTSO-E for evaluation of individual interconnection projects. It estimates changes in welfare of electricity consumers, producers and owners of interconnection capacity under a range of scenarios, accounting for the effect of interconnectors on energy trading, the holding of reserve and response and the cost of onshore transmission constraints in GB. This framework captures all of the main primary welfare effects of new interconnection and hence can be used to evaluate interconnection projects both on a stand-alone basis and relative to each other.

7.4 Regulation of interconnection investment

The results of our analysis suggest that under some plausible scenarios, the amount of new GB interconnection that is optimal for GB from a net welfare perspective could exceed 13 GW by 2040. Given that only 2 GW of new interconnection capacity has been built between GB and other EU countries since IFA came online in 1986, it is unlikely that a single private sector investor could undertake investment on this scale. Hence, one of the key implications for the regulation of interconnection investment is as follows.

Implication 3: *The analysis shows that there are a range of project types with a wide range of impacts on net welfare and distributional effects. Given this and the potential scale of investment in future interconnection that could be beneficial under some scenarios, the regulatory regime may need to accommodate a range of investor types across a wide spectrum of risk-reward preference.*

7.5 Connected markets

In our analysis, we have considered a very broad range of markets to which GB could feasibly connect in the future. The main implications for the optimal choice of connected markets for GB on the measure of net welfare are as follows.

Implication 4: *Borders with France, Ireland, Belgium and Norway could reasonably be prioritised on the basis of net welfare benefits that accrue for GB.*

Implication 5: *The net welfare benefits of connecting to a diverse set of markets (in terms of countries and distances) are likely to be limited.*

Implication 6: *Interconnection with Norway and Iceland offers the greatest benefit to GB consumers in terms of lower electricity prices.*

A key overall theme emerging from our analysis is that the logic of connecting to markets that are geographically close to GB to minimise the cost of interconnection and retain option value associated with future interconnection is very compelling. Least regrets analysis demonstrates that connection to some of the more distant markets is only beneficial for GB net welfare in a sub-set of possible future states of the world. Interconnection to Norway is likely to be an exception in this regard. In this case, the benefits of connecting to a market with a significantly lower cost and more flexible generation mix appear to outweigh the cost of interconnection under all scenarios considered in this study.

Another theme emerging from our analysis is that the benefit of connecting to a diverse range of different countries (and distances) rather than a more limited range of markets does not appear to be significant. This is underpinned by the simple fact that connecting to a broader range of markets would involve connecting to more distant markets where the logic of interconnection is potentially less compelling.

Finally, given low average electricity prices in Norway and Iceland, interconnection with these markets is likely to offer the greatest benefit to GB consumers in terms of lower electricity prices. However, the economics of these interconnections are more nuanced when other aspects of net welfare are taken into account.

7.6 Integration of interconnectors into the GB transmission system

Our modelling of the impact of interconnectors on transmission constraints and transmission reinforcement has accounted for some of the locational impacts of where such projects connect. Whilst it is difficult to draw firm conclusions from this analysis, what evidence there is suggests that social (particularly consumer) welfare will be influenced by the locational decisions made by interconnector projects. key constraining factor with regard to incentivising the locational decision of interconnectors in GB is the EU Third Energy Package, and specifically the treatment of interconnectors as a TSO and the consequent inability of the NETSOs to levy transmission charges on interconnectors. To the extent that the choice of landing point for an interconnector imposes an externality on other network users by changing the system balancing costs, this externality cannot be internalised in the interconnector’s location decision through the use of locational charges.

Implication 7: *Given interconnectors are exempt from TNUoS and BSUoS charges, there are few if any market or regulatory based locational investment signals by the current regime. This will impact transmission constraint and/or transmission reinforcement costs in GB (as shown in our analysis) and therefore further consideration needs to be given to ensuring the full social (including wider transmission network) costs and benefits of the connection point into the GB transmission system are taken into account..*

The choice of landing zone at the level of granularity of the GB transmission network represented in our modelling is limited for most interconnectors by geographic considerations. Interconnectors to Norway and Ireland are the only notable exceptions in this regard. However, at a more granular level, the choice of landing zone can still have a significant effect on overall cost of system operation and transmission reinforcement.

7.7 Security of supply

The key implications from our analysis with regard to the effect of further GB interconnection on physical supply security in the GB electricity market are as follows.

Implication 8: *In the presence of consistent market arrangements across interconnected borders, full market pricing of unserved energy and interconnectors being allowed to respond to market signals, interconnection is likely to exert a significant positive influence on GB security of supply. In addition, interconnection is likely to compare favourably with generation in terms of cost for a given level of* *deliverability and reliability in times of stress. However, demand-side response and some innovative storage technologies may also compare favourably with generation in this regard..*

The results of our stress test analysis, which was carried out separately from the CBA analysis of interconnection under normal conditions, suggest that, given appropriate market pricing arrangements that reflect the value of unserved energy and allow interconnectors to respond to those prices[69], interconnectors are likely to be supplying energy to GB up to their full capacity in times of extreme stress[70]. This is likely to make interconnectors a relatively cost-effective way of ensuring physical supply security relative to flexible generation. This is because additional flexible generation that is only required to supply demand in stressed periods would add little value in more normal market conditions, which would not be the case for interconnectors. However, it should be noted that interconnection may itself be more expensive than other means of ensuring security of supply, such as DSR or certain innovative storage technologies. A comparison of different technologies in this regard is outside of the scope of this study.

Although the results of the stress tests are not reflected in our CBA assessment of further GB interconnection, to the extent that increased interconnection levels can substitute for more expensive sources of supply security, the implication for policy-makers should be that further interconnection should be facilitated to improve GB physical supply security and thus improve GB economic welfare as a consequence.

[69] The current arrangements in the balancing mechanisms of GB and other markets do not necessarily reflect the full value of unserved energy and interconnectors are not currently fully responsive to signals from balancing markets. However, significant changes are taking place to these arrangements, among them the Electricity Balancing Significant Code Review being undertaken by Ofgem at the time of writing.

[70] Times of extreme stress are defined here as times when there is some unserved energy in GB.

A Assumptions

Table 43 Average annual load factors for onshore and offshore wind plant

	Average load factor (%)
Belgium - Offshore Central	32%
Belgium - Onshore North East	24%
Belgium - Onshore North West	24%
East Denmark - Offshore Central	35%
East Denmark - Onshore Central	27%
Finland - Offshore Central	35%
Finland - Onshore Central	27%
France - Offshore Central	32%
France - Onshore North East	25%
France - Onshore North West	25%
France - Onshore South	22%
GB - Offshore Central	35%
GB - Offshore Central	35%
GB - Offshore North	38%
GB - Offshore North	38%
GB - Offshore South	35%
GB - Offshore South	35%
GB - Onshore East	27%
GB - Onshore North	30%
GB - Onshore West	27%
Germany - Offshore Central	32%
Germany - Offshore Central	32%
Germany - Onshore East	21%
Germany - Onshore East	21%
Germany - Onshore North West	23%
Germany - Onshore West	21%
Iceland - Onshore Central	27%

	Average load factor (%)
Netherlands - Offshore Central	32%
Netherlands - Onshore North East	24%
Netherlands - Onshore North West	24%
Northern Ireland - Offshore Central	35%
Northern Ireland - Onshore Central	30%
Norway - Offshore Central	35%
Norway - Onshore Central	27%
Portugal - Offshore Central	32%
Portugal - Onshore Central	25%
Rep of Ireland - Offshore Central	35%
Rep of Ireland - Onshore Central	30%
Spain - Offshore North	32%
Spain - Offshore South	32%
Sweden - Offshore Central	35%
Sweden - Offshore Central	35%
Sweden - Onshore Central	27%
Sweden - Onshore Central	27%
West Denmark - Offshore Central	35%
West Denmark - Onshore Central	27%

Table 44 GB installed generation capacity – Scenarios 1 and 4

	2015	2020	2025	2030	2035	2040	2050
CCGT	29.3	26.5	36.9	42.0	44.2	47.1	54.9
Coal unabated	16.9	15.2	4.6	2.6	0.0	0.0	0.0
Gas CCS	0.0	0.4	0.4	3.5	7.4	11.4	20.4
Coal CCS	0.0	0.4	0.4	0.4	0.4	0.4	0.0
Nuclear	9.6	11.3	8.1	13.6	19.4	24.3	35.9
Onshore Wind	8.4	13.0	14.4	15.1	15.1	13.1	11.1
Offshore Wind	4.2	8.6	11.8	17.8	18.7	23.3	32.3
Biomass	4.7	4.6	4.5	0.4	0.3	0.0	0.0

	2015	2020	2025	2030	2035	2040	2050
Marine	0.0	0.2	0.2	0.2	0.3	0.2	0.2
Hydro	1.7	1.8	1.8	1.8	1.8	1.8	1.8
Pumped Storage	2.8	2.8	2.8	2.8	2.8	2.8	2.8
OCGT	0.9	0.7	0.5	0.3	0.0	0.0	0.0
Auto-generation	2.7	4.3	4.3	4.3	4.3	4.3	4.3
Other RES (large)	3.2	4.0	4.3	4.4	4.4	4.4	4.4
Other RES (small)	5.4	12.1	14.3	15.0	15.0	15.0	15.0

Table 45 GB installed generation capacity – Scenario 2

	2015	2020	2025	2030	2035	2040	2050
CCGT	29.3	26.5	36.9	42.0	44.2	47.1	54.9
Coal unabated	16.9	15.2	4.6	2.6	0.0	0.0	0.0
Gas CCS	0.0	0.4	0.4	1.6	2.8	3.6	5.4
Coal CCS	0.0	0.4	0.4	0.4	0.4	0.4	0.0
Nuclear	9.6	11.3	8.1	13.6	19.4	24.3	35.9
Onshore Wind	8.4	13.0	14.4	15.1	15.1	15.1	15.1
Offshore Wind	4.2	11.0	22.0	32.0	38.0	45.0	60.0
Biomass	4.7	4.6	4.5	0.4	0.3	0.0	0.0
Marine	0.0	0.2	0.2	0.2	0.3	0.2	0.2
Hydro	1.7	1.8	1.8	1.8	1.8	1.8	1.8
Pumped Storage	2.8	2.8	2.8	2.8	2.8	2.8	2.8
OCGT	0.9	0.7	0.5	0.3	0.0	0.0	0.0
Auto-generation	2.7	4.3	4.3	4.3	4.3	4.3	4.3
Other RES (large)	3.2	4.0	4.3	4.4	4.4	4.4	4.4
Other RES (small)	5.4	12.1	14.3	15.0	15.0	15.0	15.0

Table 46 GB installed generation capacity – Scenario 3

	2015	2020	2025	2030	2035	2040	2050
CCGT	29.3	26.5	36.9	42.0	42.2	42.2	40.0
Coal unabated	16.9	15.2	4.6	2.6	0.0	0.0	0.0
Gas CCS	0.0	0.4	0.4	5.5	11.4	20.0	50.0
Coal CCS	0.0	0.4	0.4	0.4	0.4	0.4	0.0
Nuclear	9.6	11.3	8.1	12.0	16.2	19.5	26.3
Onshore Wind	8.4	13.0	14.4	15.1	15.1	13.1	11.1
Offshore Wind	4.2	8.6	11.8	17.8	18.7	20.3	22.3
Biomass	4.7	4.6	4.5	0.4	0.3	0.0	0.0
Marine	0.0	0.2	0.2	0.2	0.3	0.2	0.2
Hydro	1.7	1.8	1.8	1.8	1.8	1.8	1.8
Pumped Storage	2.8	2.8	2.8	2.8	2.8	2.8	2.8
OCGT	0.9	0.7	0.5	0.3	0.0	0.0	0.0
Auto-generation	2.7	4.3	4.3	4.3	4.3	4.3	4.3
Other RES (large)	3.2	4.0	4.3	4.4	4.4	4.4	4.4
Other RES (small)	5.4	12.1	14.3	15.0	15.0	15.0	15.0

Table 47 Assumed interconnection costs for the Continental European network

	Capital costs (£m/MW)
Belgium – France	0.17
Belgium – Germany	0.17
Belgium – Netherlands	0.17
East Denmark – Germany	0.37
East Denmark – Sweden	0.17
East Denmark – West Denmark	0.25
Finland – Norway	0.5
Finland – Sweden	0.37
Germany – France	0.17
Germany – Netherlands	0.17
Germany – Norway	0.5

	Capital costs (£m/MW)
Germany – Sweden	0.5
Netherlands – Norway	0.5
Netherlands – West Denmark	0.37
Norway – Sweden	0.25
Spain – France	0.5
Spain – Portugal	0.17
West Denmark – Germany	0.17
West Denmark – Norway	0.37
West Denmark – Sweden	0.37

B Summary results tables

This section presents the net welfare results for the scenarios modelled for the purposes of this study, focusing on net welfare in GB only. All results presented here are in real £ 2012 values.

Table 48 Net welfare results summary

Configuration	NPV (£ million – real 2012)			
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
A1	205	42	345	137
A2	690	163	878	584
A3	1,615	348	333	413
A4	2,856	732	-606	188
A5	3,518	-63	-3,038	-1,454
B1	616	-202	956	253
B2	1,307	65	501	333
B3	1,850	207	324	362
B4	2,906	700	-832	-77
B5	4,220	857	-2,400	-747
C1	1,625	515	59	387
C2	2,028	-243	-765	-388
C3	2,416	-254	-580	-290
C4	2,095	498	-261	305
C5	2,372	-180	-730	-323

Table 49 Net consumer welfare results summary

Configuration	NPV (£ million – real 2012)			
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
A1	-757	-927	597	693
A2	-1,962	-2,353	-60	201
A3	-61	-2,663	-408	571

Configuration	NPV (£ million – real 2012)			
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
A4	2,540	-2,262	-992	1,055
A5	7,786	-4,074	-2,454	1,411
B1	285	-313	734	-757
B2	1,281	-986	366	1,114
B3	1,371	-1,666	-800	488
B4	3,776	-1,759	-1,894	1,186
B5	9,106	-1,196	-2,487	1,937
C1	-151	-2,164	-1,083	556
C2	-2,304	-9,510	-2,085	-2,303
C3	6,219	475	-222	2,699
C4	1,222	-1,631	-946	400
C5	6,493	336	-1,375	2,471

Table 50 Net producer welfare results summary

Configuration	NPV (£ million – real 2012)			
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
A1	882	680	1,215	767
A2	2,489	1,898	2,672	1,736
A3	1,201	2,603	3,364	1,775
A4	-104	3,543	4,530	2,244
A5	-2,782	7,498	6,755	3,251
B1	-124	-337	1,700	2,065
B2	-673	704	2,054	728
B3	-229	1,638	3,656	1,823
B4	-1,401	3,204	5,190	2,102
B5	-4,344	4,810	6,559	2,869
C1	1,792	2,380	4,137	2,013
C2	4,183	9,757	5,347	5,086

Configuration	NPV (£ million – real 2012)			
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
C3	-2,879	-56	3,309	203
C4	623	2,066	4,017	2,358
C5	-4,332	1,024	4,671	1,030

Table 51 Net interconnector welfare results summary

Configuration	NPV (£ million – real 2012)			
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
A1	80	290	-1,467	-1,323
A2	164	618	-1,733	-1,353
A3	475	407	-2,623	-1,933
A4	419	-548	-4,144	-3,112
A5	-1,487	-3,488	-7,339	-6,116
B1	455	448	-1,478	-1,056
B2	699	347	-1,919	-1,509
B3	708	235	-2,531	-1,949
B4	532	-745	-4,128	-3,365
B5	-542	-2,757	-6,472	-5,552
C1	-16	298	-2,995	-2,182
C2	149	-490	-4,028	-3,170
C3	-923	-674	-3,668	-3,192
C4	250	63	-3,331	-2,453
C5	212	-1,540	-4,026	-3,824

C About Baringa and Redpoint Reference case

C.1 Redpoint Reference case

Our Redpoint Reference reports provide a comprehensive overview of European power markets together with forward looking price projections for wholesale commodity prices and renewable incentives (eg ROCs, LECs and Embedded Benefits for the GB market and equivalent for other markets). The reports are produced by our team of energy professionals who are working closely with developers, investors, lenders, utilities, consumers, Government and regulators.

Our clients use the Reference reports for a range of purposes including:

- To inform and support investment strategies,
- To support analysis of individual buy or sell decisions,
- To support lending cases (where it is recognised for reliance purposes by banks),
- To support operational decision making,
- To benchmark in-house views, and
- To contrast with other third party views in the market.

We deploy state of the art modelling tools to analyse the market from the formation of energy policy, investment decisions under uncertain conditions and hour-to- hour dispatch to provide a fully endogenous, consistent forward-looking perspective on the market.

The analysis presented in this report has been based on our Q4 2012 Reference Case.

Scenarios

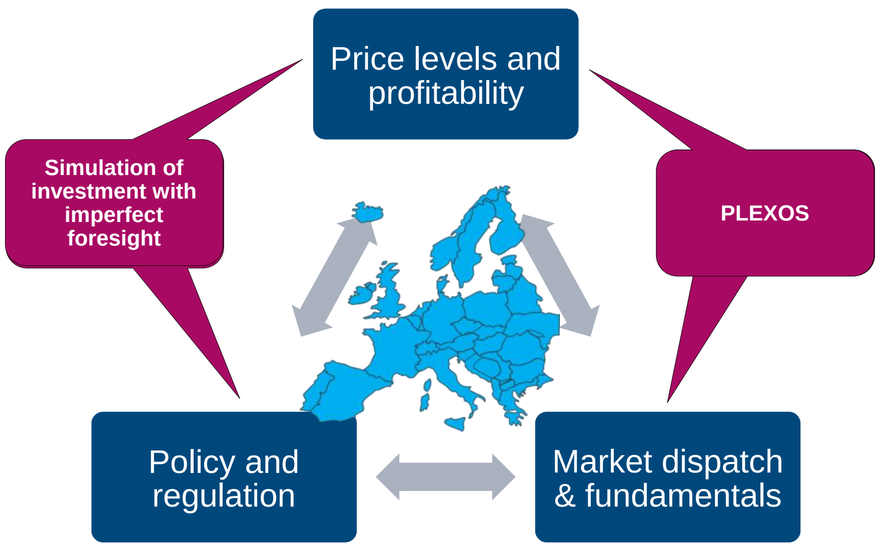
We present five forward-looking scenarios of the market to explore the interactions between policy objectives, macro-economic conditions, commodity prices and technology pathways. In addition to our standard scenarios we are able develop bespoke scenarios for clients.

The scenario analysis is presented in a comprehensive report which includes a detailed description of the market, the key players, historical prices and the regulation of the sector. We also provide detailed numerical datasets including hourly price profiles, generation and capacity mix, spark and dark spreads and commodity price projections.

Our modelling approach

We apply leading-edge, innovative, quantitative tools for the analysis of the markets. We regularly backcast our models help ensure accuracy in the forward looking analysis as well as explaining historic market conditions.

Our modelling suite combines policy analysis, generation and transmission investment analysis, hour to hour market dispatch and the detailed modelling of the electricity network.



C.2 About Baringa Partners

We understand energy

Europe's rapidly evolving energy sector presents a complex array of economic, financial, strategic and regulatory challenges. Baringa's Energy Advisory Services (EAS) practice empowers businesses to meet those challenges and take advantage of the opportunities they present.

Formed by the merger of Baringa Partners - an award-winning consultancy spanning the energy, financial services and utilities markets - with Redpoint Energy, the EAS practice offers a full spectrum of specialist advisory and analytical services, and transaction execution support. We bring together an unparalleled knowledge of the European energy sector and a quantitative approach built on evidence-based insight and powerful analytics. Our work is informed by knowledge of markets, regulation, assets, operations and capital, and in-depth insight into their interdependencies and the impact of their interactions. We provide our clients with a unique combination of flexibility, pragmatism and intellectual rigour.

Our expertise covers the entire gas and power value chain, upstream, generation, networks and retail. We count leading organisations in the European energy sector among our clients. We are proud to be the trusted advisors to network operators, utilities, developers, investors, lenders and government bodies, and proud of the results we have delivered for these clients.

Our multi-disciplinary teams consist of specialists with backgrounds in consultancy, finance, private equity, law, regulation and utilities. The EAS practice gives our clients access to an unrivalled collection of skills and experience in economics, finance, business, science and engineering. The EAS practice is led by partners who are recognised as some of the leading experts in the European energy sector.