NEAR-TERM INTERCONNECTOR COST-BENEFIT ANALYSIS: INDEPENDENT REPORT (CAP & FLOOR WINDOW 2)

A Pöyry report for Ofgem

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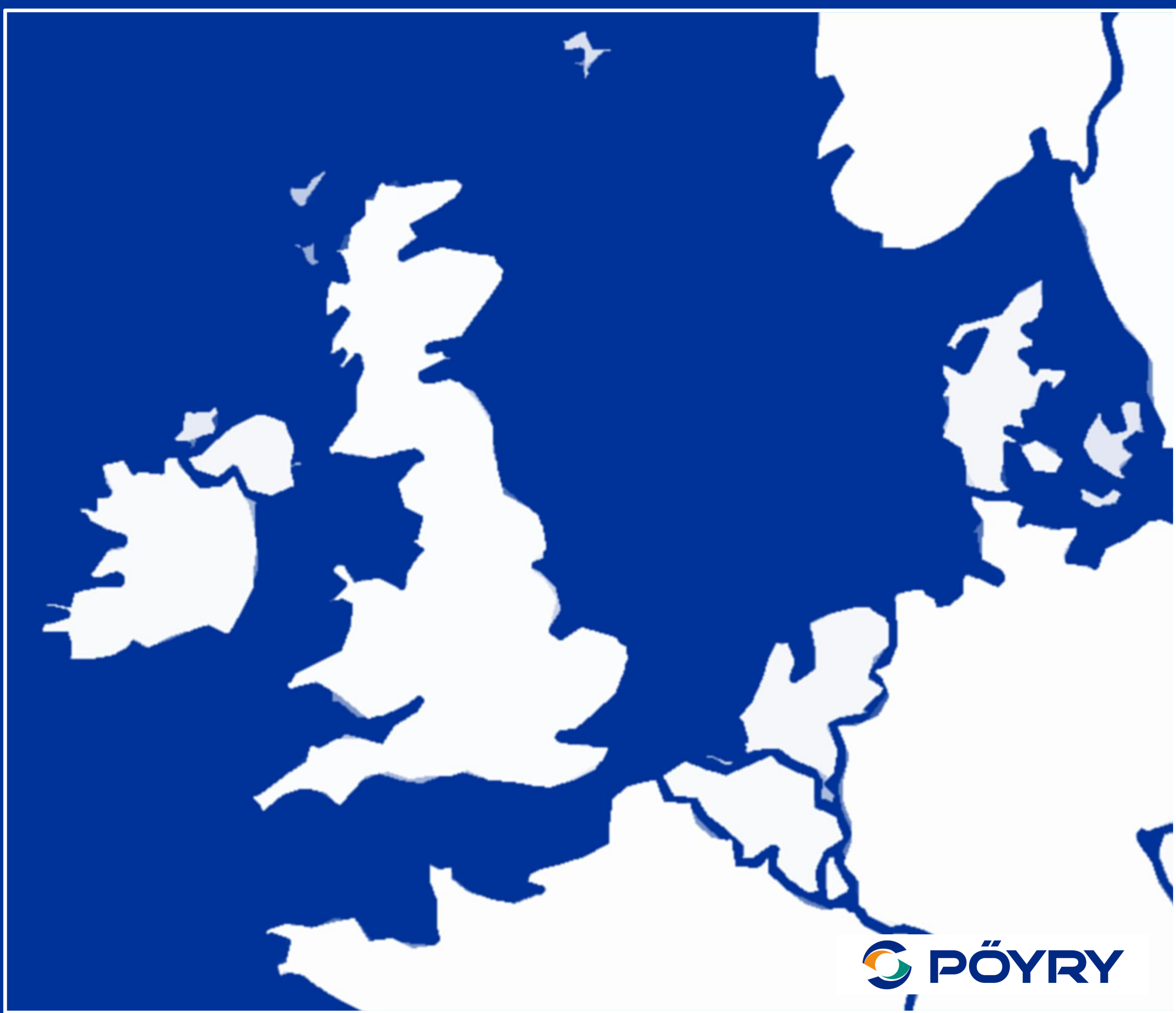

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EXECUTIVE SUMMARY

Project background

After supporting Ofgem during the roll-out of its cap and floor regime for electrical interconnectors in 2014, Pöyry Management Consulting (UK) Ltd. (Pöyry) has been commissioned to provide the cost-benefit analysis for interconnectors applying for the regime in the second window.

Interconnectors derive revenue both from hourly price differentials between two connected electricity markets, as well as participating in capacity markets in both countries, if applicable. The cap and floor regime provides revenue protection for interconnectors successful in their application up to the level of an agreed floor. Where revenue earned is below the floor there will be a transfer from consumers to interconnector owners. In exchange, any revenues earned by interconnector owners above the agreed cap result in a money transfer to consumers (via network tariffs).

Three eligible applications were received as part of the second application window:

- NorthConnect – a proposed 1,400MW link between Great Britain and Norway;
- NeuConnect – a proposed 1,400MW link between Great Britain and Germany; and
- Gridlink – a proposed 1,000MW link between Great Britain and France.

In order to assess the economic needs cases for each project, Ofgem must understand:

- where project value arises (both costs and revenues), the key drivers and how this is impacted by the cap and floor provisions; and
- what the economic impact of these projects could be; including the impact on consumer surplus, producer surplus and revenues for other interconnectors, including those regulated under a cap and floor.

We have analysed the impact of each individual project under a set of pre-agreed scenarios designed to reflect a range of feasible out-turns of interconnector value; the price and flow impacts are then used to derive the component welfare impacts and assessed for two cases with regards to the progress of other interconnectors.

Approach Overview

Market development scenarios

From the perspective of interconnector value, the fundamental driver is the price difference between two markets. We have conducted the CBA using three core market development scenarios, varying key drivers of hourly price differences between countries, to span a range of interconnector welfare values. The scenarios draw on existing published data sources including National Grid's 2016 Future Energy Scenarios, ENTSO-E's 2016 TYNDP Visions and DECC's Scenarios for fuel and carbon prices.

- The **Base Case** represents a future with moderate economic growth in both GB and Europe but a continuation of energy efficiency and gradual electrification of heat and transport sectors leads to stagnating demand over time in GB. The fuel prices used in this scenario are based on the DECC Reference Scenario while the thermal and renewable capacities for GB come from National Grid's FES 2016 'Slow Progression' and No Progression cases respectively. **This scenario aims to represent an**

internally consistent moderate view of future drivers and a reasonable baseline against which interconnector projects can be valued.

- The **High interconnector value (High) scenario** is driven by high GDP growth across Europe which leads, along with accelerated electrification of heat and transport, to growing electricity demand. The growth rate of renewables and other low carbon technologies (including nuclear and CCS[1]) is relatively high in GB and Europe. The fuel prices used in this scenario come from DECC's High scenario, while we base the demand and capacity projections on the 'National Green Transition' scenario of the final TYNDP 2016 Scenario Development Report. **This scenario is designed to represent a plausible extreme high view of future value drivers that can represent an upside case for the commercial and economic value of interconnector projects in GB.**
- The **Low interconnector value (Low) scenario** represents a future of stagnating GB and wider European economies, which leads to falling electricity demand and a general lack of progression in the electricity market. The fuel prices used in this scenario come from DECC's Low scenario. The demand and capacity mix assumptions both in GB and the rest of Europe are based on the 'Slowest Progress' scenario of the final TYNDP 2016 Scenario Development Report. **This scenario is designed as a plausible extreme low view of future value drivers to represent a downside case for the commercial and economic value of interconnectors in GB.**

Table 1 summarises the main characteristics for each of the three main scenarios. In all our scenarios capacity payment mechanisms proceed as planned in GB, Ireland and France, having a dampening effect on wholesale electricity market prices.

We have also examined a series of sensitivities on a project specific basis to test the robustness of interconnector welfare and value, covering policy drivers (e.g. removal of CPS), interconnector project delays and network issues (i.e. firmness of connection). The **Policy normalisation sensitivity**, which is also referred to as the key sensitivity in this report, is a sensitivity on the Base Case whereby the carbon price support in GB has been assumed to be abandoned and GB balancing charges will no longer be applied to generators in Great Britain.

1 CCS: Carbon capture and storage

Table 1 – Overview of scenario assumptions

Driver	Base Case	High IC value scenario	Low IC value scenario
GB Demand	• EVs and electrification of heat increase demand until 2040 [avg. 0.7% p.a.] • Based on NG's 'Slow Progression' scenario	• High GDP, EVs & heat electrification increase demand [avg. 4.5% p.a.] • Based on Vision 3 (V3) TYNDP 2016	• Stagnating GDP leading to continued falling demand [avg. -2.4% p.a.] • Based on lowest TYNDP 2016 vision (V2)
GB thermal Capacity	• Mainly gas, some new nuclear • Based on NG's 'Slow Progression' scenario	• Large-scale build of new nuclear, CCS and CCGT • Based on V3 TYNDP 2016	• Gas only, capacity only required for replacement • Based on lowest TYNDP 2016 vision (V1)
GB Renewables Capacity	• Moderate growth: 2020 targets hit few years late • 34GW 2022, 43GW 2030 • NG 'No Progression' scenario	• Very fast RES build • 40GW 2022, 67GW 2030 • Based on V3 TYNDP 2016	• 33GW 2020 & 30GW 2030 • Based on lowest TYNDP 2016 vision for GB (V1)
NWE demand & Capacity mix	• Continuation of current policy framework • Based on Vision 2 TYNDP 2016	• Favourable economic conditions, large low carbon roll-out • Based on V3 TYNDP 2016	• Low demand leads to little new capacity • Lowest TYNDP vision for each country (V1 or V2)
Fuel prices	• DECC Reference Prices (similar but higher than Pöyry Central)	• DECC High Prices (similar but lower than Pöyry High)	• DECC Low Prices (similar but higher than Pöyry Low)
Carbon prices	• ETS and CPS following Pöyry Central: Q1 2016 • CPS & EU ETS reach parity at €57/tCO_2 in 2040	• ETS and CPS following Pöyry High: Q1 2016 • CPS always €15-25 above EU ETS price	• CPS is zero until 2040 • ETS following Pöyry Low: Q1 2016 – EU ETS rises to €17/tCO_2 in 2040

Cost Benefit Analysis approach

In order to assess the societal impact of each interconnector, we have conducted a Cost Benefit Analysis (CBA), comparing the net present values (using a 3.5% discount rate over a 25 year project life) of social welfare in the scenario without the assessed interconnector (the 'counterfactual') and with the assessed interconnector (the 'target case'). To show the impact of the particular interconnector being examined, all other factors are held constant between runs (e.g. other interconnector build, generation capacities and fuel prices).

One presumed driver of interconnector value is the pre-existence and future development of other interconnectors to GB. In order to take account of this effect, we have assessed the eligible interconnectors in this application window using two different approaches: 'first additional' (FA) and 'marginal' (MA).

FA CBA approach

With this approach we examine the value of each interconnector in turn as if it is the only new interconnector to be built in 2022. No other interconnection is assumed to come online after that point in any scenario. The FA methodology illustrates the potential upper bound of value of the interconnector and is examined across the three market scenarios to obtain the range of maximum values in different market conditions (corresponding to the High, Base Case and Low scenarios).

MA CBA approach

In contrast to the above, with the MA approach we examine the value of each interconnector in turn as if it is the last of four additional interconnectors (three submissions plus Aquind) to be built in 2022. No other interconnection is assumed to come online after that point in any scenario.

The MA methodology illustrates the lower bound of value of the interconnector across each of the three market scenarios to obtain the range of minimum values in different market conditions (corresponding to the High, Base Case and Low scenarios).

Key CBA metrics

The CBA looks at the impact of the interconnector on the main socio-economic stakeholders – consumers, producers and interconnector owners. The NPV of the impacts on the welfare of each of these stakeholders is calculated within CARAMEL Light.

- Net consumer welfare change derives primarily from changes in costs due to wholesale electricity price movements from the introduction of the new interconnector. In addition, under the cap and floor regime, any payments to or from consumers under this regime also represent a net change in the consumer welfare.
- Net producer welfare change derives from changes in the gross margins for electricity production (that is changes in revenues from electricity production less changes in costs of fuel and carbon from generation where applicable) from the introduction of new interconnection. In addition, capacity market revenues captured by new interconnectors are reducing capacity market revenues for producers.
- Interconnector welfare is the flow across an interconnector multiplied by the remaining wholesale price differential between the markets after the flow of electricity. Net interconnector welfare change from the introduction of the new interconnector is the sum of:
  - direct revenues from
    - arbitrage payments which are assumed to be captured by the interconnector owner, and
    - capacity revenues, which (for GB) depend on the capacity clearing price for the respective year, and the de-rating factor applied to the interconnector (determining the share of the cable’s capacity to be eligible for capacity payments);
  - costs associated with the construction and operation of the interconnector (for which we have used developer estimates), including electricity transmission losses when flowing energy between markets (based on developer estimates);
  - payments made or received under the cap and floor regime for which this assessment has been developed– this is fundamentally a value transfer between interconnector owners and consumers; and
  - indirect revenue impacts on other interconnector owners (i.e. the ‘cannibalisation’ effect) where a flow on one interconnector may lead to greater or lesser revenue on another interconnector.

Overview of Results

All interconnectors examined as part of this CBA assessment have a significant welfare impact on different stakeholder groups. While any given interconnector in a given scenario presents a net welfare gain for some groups in some countries it will, generally cause a net welfare loss for other stakeholders in other countries. Furthermore, it is worth noting that even when there are payments made by consumers to interconnectors under the cap and floor mechanism, the project can still deliver a net gain for GB consumers because of the significant benefit arising from wholesale price effects.

Figure 1, Figure 2 and Figure 3 show the resulting project comparison expressed as the impact of the interconnector on the NPV (at a 3.5% discount rate, over a 25 year project life) for three measures of net social welfare change:

- GB consumer welfare impact (GB consumers only);
- GB net welfare impact (GB consumers, GB producers and GB interconnector owners); and
- total net welfare impact (consumers, producers and interconnectors in GB and the connected country).

These are expressed on a normalised basis i.e. per GW of interconnection capacity installed.

It should be noted that this CBA excludes certain potential costs and benefits such as changes in required network reinforcements as a result of the interconnector and security of supply benefits. Some of these factors are considered elsewhere by Ofgem as part of the overall IPA consultation.

Figure 1 – GB consumer welfare impact: project comparison (€m/GW)[2]

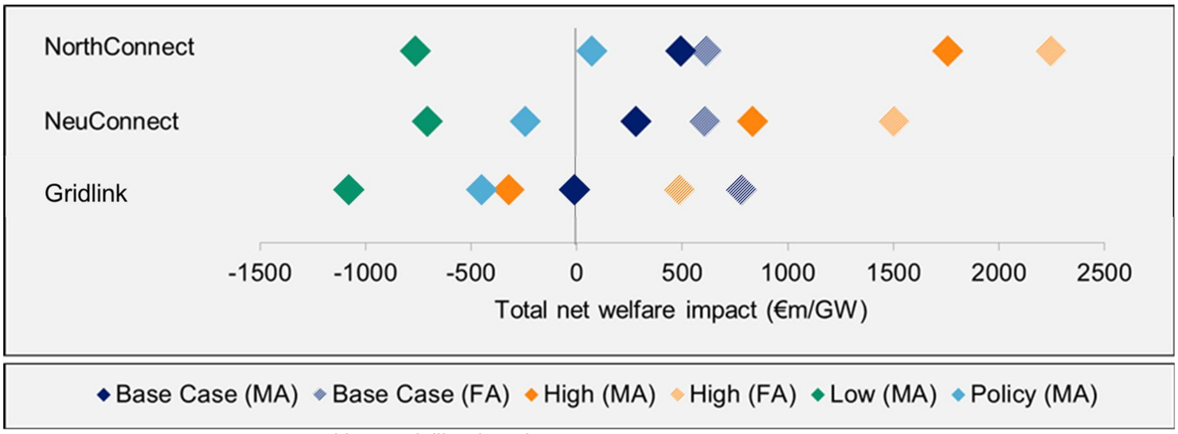
Source: Pöyry Management Consulting modelling for Ofgem

2 Notes: FA and MA refer to the analysis approaches assessing the interconnectors either as the only one commissioned in 2022 (FA = 'first additional') or one out of four (MA = 'marginal additional'). 'Policy' refers to the Policy sensitivity, that is equal to the Base Case with the exception of the carbon price support (CPS) and the Balancing Services Use of System charge (BSUoS) having been removed in Great Britain.

Figure 2 – GB net welfare impact: project comparison (€m/GW)

Source: Pöyry Management Consulting modelling for Ofgem

Figure 3 – Total net welfare impact: project comparison (€m/GW)



Source: Pöyry Management Consulting modelling for Ofgem

Comparing the interconnector performance on their impact on GB consumer welfare, GB net welfare and total net welfare our modelling suggests the following:

- In the Base Case, **all projects provide a significant benefit for GB consumers** (between €2bn and €2.7bn in the MA case).
- However, **none of the projects provides a benefit to GB overall** in the Base Case (net position for GB in the MA cases ranges between -€0.3bn and -€0.1bn). This is due to the fact that lower gross margins for generators and revenue cannibalisation for other GB interconnectors is greater than the added benefit for GB consumers.
- The **total net impact on both connected countries** in the Base Case **ranges between zero** (Gridlink) **and €0.5bn** (NorthConnect).
- There is a limited downside risk for GB consumers, compared to potential benefits.
- From a GB net welfare perspective, the scenario risk appears largely symmetrical for all projects, as the Base Case sits in the middle of the High and Low results. For NorthConnect, the downside risk indicated by the Low scenario results is less severe than the upside potential indicated by the High scenario.

- With the exception of Gridlink – which has a lower upside – the same is the case for the total net welfare results. In Gridlink's case, the benefits in the High scenario appear to be captured outside of GB and France, as the total net impact is lower than in the Base Case.
- In all scenarios and metrics, the difference between the MA and FA cases is greatest for Gridlink. This is due to the direct competition of Gridlink and Aquind (both interconnectors to France) in the MA case.
- Capacity market revenues represent a significant share of overall revenues for NorthConnect (25% in the Base Case MA) and Gridlink (48%). For both projects, capacity market revenues are required to reach the floor in the Base Case and the Policy normalisation sensitivity. As NeuConnect is assumed to have a lower de-rating factor, capacity market revenues are less substantial for this project.
- All interconnectors are impacted by the cap and floor regime in at least some of the future market scenarios, but only NeuConnect requires floor payments in the Base Case.

Final Conclusions

The main conclusions from this assessment are as follows:

- All projects assessed in this study are based on a similar premise: connecting Great Britain to countries with lower average wholesale prices, indicative of less expensive sources of electricity generation. In the vast majority of assessed scenarios and sensitivities, all projects provide large benefits for consumers as they lead to lower wholesale electricity prices in GB.
- The High scenario represents a downside for GB consumer welfare for all projects. This is due to the strong increase in GB renewables capacity towards the end of the modelled period which leads to frequent low price periods in Britain. Other things being equal, the resulting exports increase wholesale electricity prices in GB and reduce consumer welfare.
- All projects show a large imbalance of flows in most scenarios towards imports to GB, however:
  - In the High scenario, exports from GB steadily increase on all assessed projects, due to the continued strong renewables development in GB. For NeuConnect, this means that exports exceed imports by the late 2030s.
  - NorthConnect and especially NeuConnect show a relatively low cable utilisation. Their long distance and consequently relatively high loss factors[3] mean that these projects require large price differentials to make flows economic.
- While all projects are based on a similar premise, there are some important differences in the detailed characteristics, leading to differences in results:
  - NorthConnect has the longest distance and therefore higher costs and loss factors, but connects to the market with the largest average price differential.
  - NeuConnect is similar to NorthConnect in distance, costs and loss factor, but connects to a market with a much lower average price differential.

3 Shorter cables, for example connecting Great Britain to Ireland, France, Belgium or the Netherlands, typically have low loss factors (i.e. the amount of energy lost in transmission). Longer cables have far higher loss factors and therefore need a higher price spread to overcome this volume loss.

  - Gridlink connects to the market with the lowest average price differential, but has much lower costs and loss factor due to the significantly shorter distance.

- It is noteworthy that the comparative positions of the projects change based on which metric is looked at:
  - From considering the GB consumer welfare, NorthConnect and Gridlink perform more strongly. The downside risk is most severe for NeuConnect and Gridlink.
  - NeuConnect and Gridlink provide the largest benefit and highest upside for GB net welfare but all projects are negative in most cases in this metric.
  - Comparing the results from the total net welfare impacts (i.e. net welfare impact in Great Britain and the respective connected country), NorthConnect has the highest benefit in the Base Case and provides the largest upside. Gridlink's impact is only slightly positive in the Base Case (MA) and the project exhibits the largest downside of any project on this metric. NeuConnect is in between the other two projects for the Base Case and High scenarios, but has the least negative downside in the Low scenario.
- The highest floor payments to a single interconnector are €674m (NPV) to NeuConnect in the Low scenario.
- In the Base Case and High scenarios, only NeuConnect requires floor payments, while in the Low scenario, all three projects require support in all years. In the Low scenario, 48% of floor payments to Window 2 projects go to NeuConnect, while NorthConnect and Gridlink receive 24% and 28%, respectively.
- No payments are received for revenues exceeding a cap until the mid-2030s in any scenario.

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1. INTRODUCTION AND CONTEXT

1.1 Introduction

In August 2014 Ofgem issued a decision to roll out a cap and floor regulatory framework for near-term electricity interconnectors. Under the cap and floor regime, new interconnectors will be subject to a revenue cap, while also receiving protection against downside risks via a floor. Put simply, if revenues rise above the level defined in the cap payments are made by the interconnector owner to electricity consumers in GB. Alternatively, if revenues fall below the floor level payments are made by GB consumers to the interconnector owner.

Because of the risk of consumer liability for floor payments, Ofgem assesses the economic needs case of eligible interconnector projects as part of the Initial Project Assessment (IPA) process. In the initial window, five projects applied for cap and floor and were accepted by Ofgem after the IPA process.

In March 2016, Ofgem opened a second window for cap and floor projects with a connection date before the end of 2022[4].

Submitted projects are assessed regarding their economic needs case and the efficiency of their costs. Based on the outcome of this assessment, the projects may receive a cap and floor that would remain fixed for the duration of the regime (25 years).

Three eligible applications were received as part of the second application window[5]:

- NorthConnect – proposed 1,400MW link between GB and Norway;
- NeuConnect – proposed 1,400MW link a proposed between GB and Germany; and
- Gridlink – proposed 1,400MW link a proposed between GB and France.

Ofgem has commissioned Pöyry Management Consulting (UK) Ltd. (Pöyry) to conduct a social welfare Cost Benefit Analysis (CBA) to support the decision making process regarding the IPA of these new interconnector projects, investigating:

- the value of the interconnector projects (both costs and revenues) to the developer, important drivers of this value and how it is impacted by the cap and floor provisions;
- the socio-economic impact of these projects on Great Britain, the connected country, and the wider European region; including impact on wholesale electricity prices, consumer surplus, producer surplus and other interconnector owner profits; and
- the impact of these new interconnector projects on each other and on previous cap and floor projects.

4 Other criteria are a realistic project plan, an interconnector licence acquired or in the process of acquiring one and an existing connection agreement.

5 In addition, the Aquind project, a proposed 2,000MW link between GB and France, is considered in this study, as it has been included in National Grid's Interconnector Register (updated 18 November 2016). While this project is not directly assessed in the same way as the submission projects listed above, it has been included alongside the submissions in some cases (as explained in Section 4.1.2), to assess the impact of all proposed links.

This report presents the findings of Pöyry's independent CBAs of the three interconnectors which have submitted applications under the cap and floor framework.

1.2 Project context

In 2014, when Ofgem rolled out its cap and floor regime for interconnectors, the electricity market of Great Britain was relatively isolated, when compared to other European countries. After the completion of the BritNed and East West projects, the total capacity of GB interconnectors was still only 4GW, or roughly 7% of peak demand.

In the first window of cap and floor submissions and assessments, all projects therefore benefited from a relatively low competition. The assessment showed that there was a socio-economic rationale for building more interconnection, and all five projects were granted a cap and floor regime.

Since then, the landscape of GB interconnection has transformed. In addition to the existing projects (4GW), Nemo (the first cap and floor project, 1GW), the Window 1 projects (5.7GW), and Eleclink, a 1GW interconnector through the Channel Tunnel, are being developed, which together would lead to increasing the total interconnection capacity of the GB market to 11.7GW, or roughly 20% of domestic generation capacity, by 2022. Because of this transformation, additional GB interconnector projects will face stronger competition, which could lead to higher scrutiny and complexity in assessing these projects.

In this report, Pöyry presents the results of the cost benefit analysis carried out to support Ofgem's decisions on Window 2 applications.

1.3 Conventions and validity

The following conventions are used throughout this report:

- Money base is real (average) 2015 money Euros unless otherwise specified.
- All years are calendar years.
- Where not specifically sourced, figures, tables and diagrams should be attributed to Pöyry.
- For the calculations in this report, values for each project's cap and floor levels had to be assumed. These are indicative and subject to change by Ofgem as market conditions change. As a result figures presented in the report are accurate at the time produced but may differ from figures used by Ofgem in the future.

1.4 Report structure

The remainder of the body of the report is structured as follows:

- Section 2 presents the approach taken to analyse the social welfare impacts of proposed new interconnectors;
- Section 3 outlines the market development scenarios in which the future operation of the interconnection has been modelled. It also discusses the sensitivities modelled and the potential emerging role for capacity markets;
- Section 4 contains the resulting Cost Benefit Analysis for each interconnector; and
- Section 5 compares and contrasts the welfare impacts of the interconnectors and summarises the main results and conclusions.

In addition, there are a number of annexes that complete the report:

- Annex A describes our detailed modelling approach applied in this CBA;
- Annex B provides an overview of BID3, our pan-European electricity market dispatch and optimisation model;
- Annex C contains the detailed model inputs;
- Annex D presents the capacity market modelling and the role interconnectors play within capacity mechanisms;
- Annex E provides results for an extra sensitivity on GB capacity reduction; and
- Annex F provides information about our quality assurance process and our quality assurance statement.

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2. INTERCONNECTOR CBA: APPROACH

2.1 Conceptual overview

In order to assess the economic needs case for electrical interconnector projects, one needs to analyse the impact of these projects on consumers, producers (generators) and interconnector owners on both sides of the link.

To conduct this analysis and consider the impact on various parties, Pöyry has developed an economic model for Ofgem (CARAMEL Light), which is used to assess the economic impacts of a number of interconnector projects and the interactions between these projects. This model has been used to conduct analysis of the economic needs case for a number of future market scenarios presented in Section 3. The underlying electricity market modelling for this study has been conducted using Pöyry's in-house model BID3 (described in Annex B). The remainder of this section describes the theoretical benefits; provides an overview of our modelling approach and its limitations and; introduces the assessment approach we have used to assess interconnector welfare for near-term electricity interconnectors that have applied for the cap and floor regime.

2.2 Theoretical costs and benefits of interconnection

2.2.1 Theoretical benefits of increased interconnection

Interconnectors are connected between two distinct electricity markets and, assuming efficient operation, will generally flow based on price differentials between these markets generating arbitrage revenues for the owner.

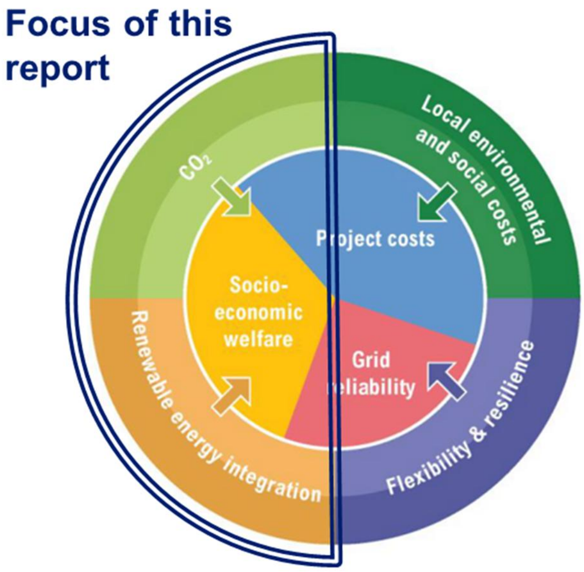
For subsea interconnectors with GB – given relatively mature technologies and relatively straightforward project designs – the main challenges and complexities for developers relate to predicting and accessing arbitrage revenues between markets which are the most important determinant of projects proceeding. However, interconnector projects also face challenges from potential future policy developments at a national and international level.

A full social welfare assessment should include not only the viewpoint of the interconnector developer but also other interconnector owners, consumers and producers in both of the interconnected countries. In this section we outline some of the major categories of costs and benefits of interconnectors and how they apply in an economic needs assessment.

Pöyry's assessment approach is broadly aligned with ENTSO-E's Cost Benefit Analysis (CBA) guideline for grid development projects[6], with a focus on the socio-economic welfare elements, as indicated in Figure 4.

6 'ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects', February 2015

Figure 4 – Scope in broader ENTSO-E CBA context



Electrical interconnector projects can potentially realise a large and diverse range of benefits, for developers, power generators, consumers and governments. However, while an interconnector will provide benefits to certain parties it will also create costs for others largely dictated by the direction of flow of the interconnector in a given period. For this reason we measure the net benefit, that is the sum of the benefits less the sum of the costs to a particular party or set of parties.

It should be noted that the economic costs and benefits of interconnection can be categorised in different ways and there is no 'correct' value split between sub-categories. Some elements are welfare creating and can have benefits on both sides of an interconnector (such as efficiency gains from generating using a more efficient plant to generate in Country A rather than a less efficient plant in country B). Other benefit categories are better regarded as welfare transfers between stakeholder groups (such as an interconnector capturing a capacity payment instead of a producer, thereby transferring benefits from producers to interconnector owners).

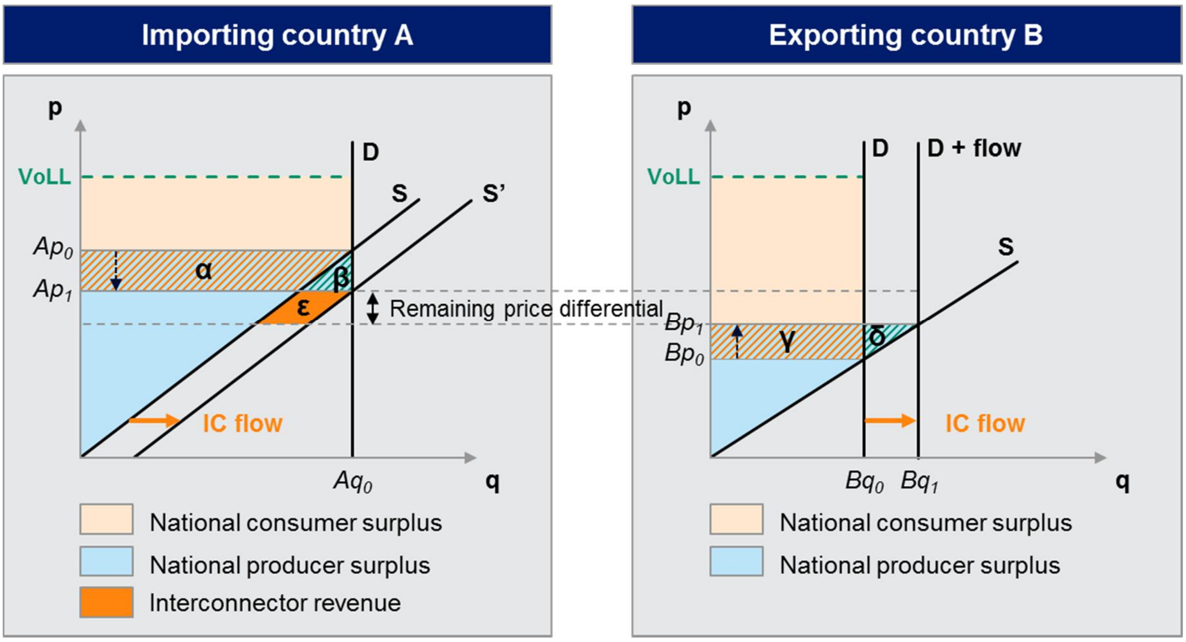
2.2.2 Welfare split into consumer, producer and interconnector owner welfare

The fundamental sources of economic value for an interconnector flowing from country B to country A in a particular hour are shown in Figure 5 below and derive from an increase in the economic efficiency of electricity markets through the building of interconnection. These categories of benefits form the basis of the interconnection CBA and are discussed in more detail in section 2.2.3:

- Consumer surplus (light orange area) is shown in the diagram as the total electricity demand in a country multiplied by the difference between the price charged for electricity and the value of lost load (VoLL).
- Producer surplus (light blue area) is the difference between the price received for each unit of electricity produced and the marginal cost of producing that unit of electricity as represented by the upward sloping supply curve.

- Interconnector revenue (dark orange area) is the remaining price differential after the flow of electricity between markets, multiplied by the interconnector flow.

Figure 5 – Fundamental economic value of interconnectors



2.2.3 *Main costs/benefits included in the CBA*

The following costs and benefits have been modelled as part of the CBA, split by the main stakeholder categories. These are the largest elements of costs and benefits reflecting the fundamental value creation proposition for new interconnectors. They are generally calculated using the CARAMEL model provided to Ofgem as part of this work (see Section 2.3). We then go on to describe some additional potential costs and benefits not included in the CBA.

- Net consumer welfare change:
  - Savings [Area α + β in Figure 5] or increases [Area γ in Figure 5] in costs for electricity consumers due to changes in the **wholesale electricity prices** from the introduction of the new interconnector.
  - Payments to or from consumers as part of the forthcoming **cap and floor** regime – where revenue is earned by interconnector owners subject to the regime above the cap level there is a transfer to consumers (via network tariffs). Where revenue earned is below the floor there will be a transfer from consumers to interconnector owners. It should be noted that, to the extent that payments occur, such payments can be a wealth transfer between countries: as interconnector revenues are shared equally (or according to a different ratio) between two countries, while the cap and floor regime applies to only the GB side. Therefore, (floor) payments towards the interconnector are made by GB stakeholders but then split and therefore flowing out of GB, while cap payments flow back to GB. This effect is further detailed in Figure 9.
- Net producer welfare change:

  - The addition of new interconnection capacity will influence electricity producers through changes in their **gross margin for energy production** (that is increased revenues from electricity production less increased costs of fuel and carbon for additional generation where applicable). This can be an increase [Area γ + δ in Figure 5] in gross margin from increased exports and/or higher prices in hours when they generate or a decrease [Area α in Figure 5] from increased imports and lower prices.

- Net interconnector welfare change:
  - **Direct revenues from arbitrage payments** which can be captured by the interconnector owner (and thereby do not accrue to producers) [Area ε in Figure 5]. We assume in the CBA that interconnectors receive all arbitrage payments directly as they would in an implicitly coupled market structure.
  - Costs associated with the **construction and operation** of the interconnector, including electricity transmission losses when flowing energy between markets – these costs are based on developer submissions to Ofgem.
  - Payments made or received under the **cap and floor regime** for which this assessment has been developed will create additional costs and benefits for interconnector owners depending on the flow of payments between parties. Consumers will benefit where the interconnector owner makes payments when revenues are above the cap and vice versa – this is fundamentally a value transfer between interconnector owners and consumers.
  - **Indirect revenue impacts** on other interconnector owners (i.e. 'cannibalisation' effect) where a flow on one interconnector may lead to greater or lesser revenue on another interconnector.

2.2.4 Additional potential costs/benefits included in CBA

A large number of other potential benefits from increased interconnection can be identified and some merit a separate mention. However, many such benefits overlap with the quantified benefits in the CBA (i.e. they are a subset of the main categories of welfare value) and the benefits are often more difficult to define and/or act only as transfers[7] between groups rather than fundamental welfare creation. The overall value of these elements is also sometimes several orders of magnitude lower than those analysed in the main CBA modelling.

There are three elements of welfare that are not straightforward to include in CBA studies but can have a significant impact on the CBA results, and have therefore been included in the results presented in this report. These elements are as follows:

- Changes in **Low carbon support payments** – In the previous sections, the effect of interconnectors on prices feeds through to all consumers and producers. However, if low carbon producers are able to access higher market prices the burden on consumer support is reduced under low carbon support schemes such as UK Contracts for Difference (CfD) or broader Feed in Tariff (FiT) mechanisms. This is, in effect, a transfer of value between producers (who despite the increased revenue from the electricity market are no better off) and consumers. The opposite can also

[7] Some elements in a CBA can act simply as welfare transfers from one stakeholder group to another – we have considered these in the CBA where they are of particular import to GB consumer welfare in our analysis (for example in the application of the cap and floor) but otherwise they are generally excluded.

be true, if captured wholesale prices for low carbon generators fall the burden on consumers can increase under a FiT scheme to maintain margins for low carbon generators.
While this element can shift welfare impacts between consumers and producers within once country, the split of welfare between countries and the overall effect on both countries is unchanged.

- Interconnectors can access additional revenues by participating in **capacity mechanisms** on one or both sides of an interconnector. This revenue would then contribute towards the calculation of cap or floor payments and reduce the likelihood of floor payments. We include capacity payment impacts in our analysis including their impacts on other stakeholders where applicable (see Annex D.3).
- New projects can significantly change the **cap & floor payments** from and to existing interconnector projects under the regime (from Window 1 and Nemo). More detail on how the cap and floor regime is represented in this study is presented in Section 2.5.

2.2.5 Additional potential costs/benefits not included in CBA

The following potential costs and benefits have not been included in the CBA performed in this study:

- Additional consumer welfare changes:
  - Changes in **network reinforcement costs, balancing costs, and other network related costs such as network driven curtailment**, that arise from the interconnector – in theory these could be a cost if additional 'onshore' network reinforcement is required due to the interconnector or a benefit if it avoids a more expensive alternative. We understand that National Grid is evaluating the impact of near-term interconnectors on network costs in a separate study.
  - **Improved security of supply**, benefiting consumers by avoiding the likelihood and therefore expected costs from unserved energy in certain periods – this benefit is very hard to quantify as the counterfactual situation (i.e. what would be done instead of building an interconnector) is very hard to define. Another way to consider this benefit is that an interconnector can offset the need for new large (CCGT[8] or OCGT[9]) generation capacity in market for a period of time – this could, all other things being equal, lead to lower capacity market clearing prices (in this case, existing or smaller new-build plants would set the price in the capacity auctions, which have far lower capital requirements – as observed in the auctions conducted from 2014 to 2017), thereby reducing costs for consumers.
  - Access to lower cost ancillary services, balancing services and other network operation costs (through **lower pass-through of costs from the network operator**). However, where ancillary service provision costs increase either through increased requirements from the network operator or because ancillary services are being supplied elsewhere, it could form a net cost to consumers.
  - Bringing enhanced **competition and liquidity** for the connected markets, (thereby bringing improvements to consumers via increased efficiency of operation of the underlying electricity market).

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8 CCGT: Combined-cycle gas turbine

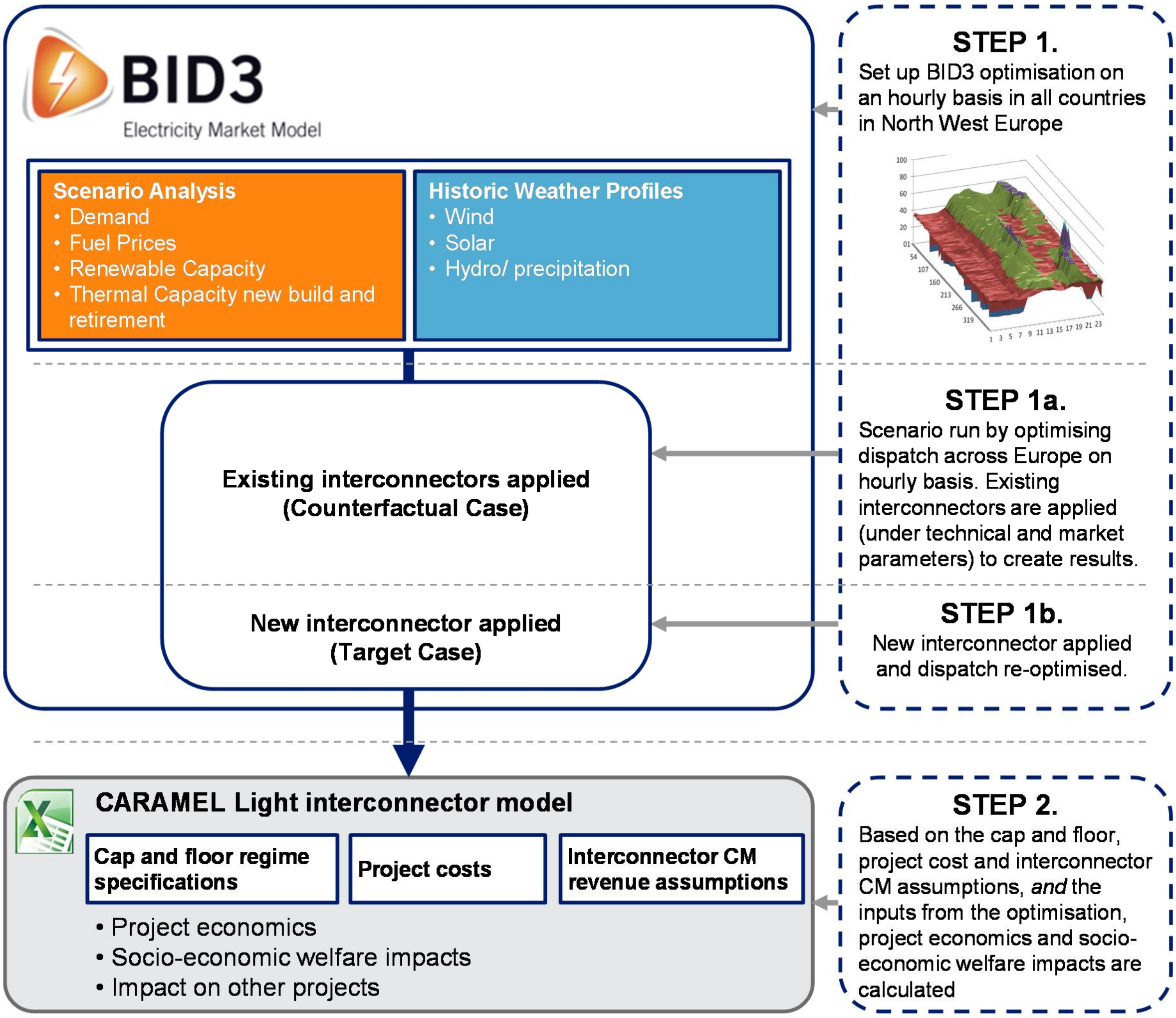
9 OCGT: Open-cycle gas turbine

  - **Additional environmental benefits** from enhancing the ability of a system to integrate renewable generation and provide additional carbon savings (where the value to consumers is over and above that recognised in market prices).
- Additional producer welfare changes:
  - The ability of interconnectors to enable sharing of generation capacity across market borders can **off-set the need for new capacity** in one market. It should be noted, however, that this would, in most cases, create the need for new capacity build in the other or both markets.
  - **Capture of arbitrage revenues** if and where the interconnector capacity is offered for sale in explicit capacity auctions – in effect receiving some of the value of the interconnector. As we have assumed that interconnector owners capture the full value of arbitrage revenue this would simply act as a transfer of welfare from interconnector owners to producers.
  - Changes in payments for **ancillary and balancing services** either through access to additional markets for those services or through displacement of that provider of ancillary services by other sources through the interconnector.
  - Reduction in producer revenues from the **capacity mechanism** either through direct displacement in the auction by the interconnector (where interconnectors are eligible to participate) or indirectly via a reduced capacity market clearing price – i.e. the producer still receives some payment under the capacity mechanism but the interconnector bidding into the market has reduced the clearing price, thereby those payments are lower.
- Additional interconnector owners welfare changes:
  - Revenues from additional rescheduling of interconnectors in **intra-day time-frames** (i.e. between day-ahead market coupling gate closure and intra-day market gate closure) – the market design and the mechanism by which interconnectors could capture that revenue are still highly uncertain.
  - Revenues from providing **TSO to TSO, ancillary and balancing services** between markets (and other post gate-closure services). These would be applicable to the interconnector to the extent that the value is captured by the interconnector and not to the producer (in the interconnected country) who provides the additional services.

2.3 Modelling approach overview

The modelling approach employed for conducting the CBA is based on a combination of Pöyry's pan-European electricity market modelling and an economic interconnector assessment model developed for Ofgem. Figure 6 below shows the main steps in our modelling approach.

Figure 6 – Modelling approach overview



We use our pan-European electricity model BID3 to generate projections of plant dispatch, interconnector flow and electricity prices on an hourly basis from 2022 to 2040 (Step 1 in Figure 6). These projections are the result of a mathematical optimisation process (i.e. minimising the cost of generation in Europe), based on detailed inputs, including every single medium to large generation unit and interconnector as well as detailed fuel price and demand projections. The results from this optimisation feed into the interconnector assessment model.

Pöyry has adapted the flexible Excel based model ***CARAMEL***, developed for the assessment of interconnectors in the first cap and floor window, to perform the economic cost benefit analysis for new interconnector projects. This model, ***CARAMEL Light,*** enables the analysis of new and existing interconnector projects, and the assessment of their impact on different market participants (Step 2 in Figure 6). The model is designed to answer the question:

"Everything else being equal, how does a new interconnector impact the welfare of consumers, producers and interconnector owners in GB and a connected country?"

A more detailed description of the modelling approach is contained in Annex A.

2.4 Cost Benefit Analysis approach

For every project to be assessed as part of the CBA, two different runs need to be done: the **target case** run (on the basis of the actual desired interconnector build schedule), and the **counterfactual** run (with every factor held constant from the target case run, but without the assessment target). These runs should always be defined together and should only differ in that only the interconnector project to be assessed is missing from the counterfactual run. The welfare impact of the interconnector project is then the difference in welfare, in each relevant category, between the target case run and counterfactual run.

The construction of an interconnector will influence the prices in the two countries which it connects. For this reason, the addition of an interconnector into a market will influence any other interconnectors that are connected to or will connect to that market. An important uncertainty of interconnector welfare for a given interconnector is therefore the build profile of additional interconnection in one or other of the markets.

In this assessment we are primarily concerned with the three projects which applied for Ofgem's cap and floor regime, and an additional exempt project (Aquind[10]) expected to commission with a similar time frame. It is impractical to model all possible permutations of projects commissioning over time, as the number of these permutations is very large.

We have therefore taken two different 'build profile' cases which aim at spanning a range of value for the future interconnectors:

- FA case: value as the **f**irst (and only) **a**dditional interconnector; and
- MA case: value as the **ma**rginal interconnector.

This approach is comparable to ENTSO-E's suggested PINT (Put IN one at the Time) and TOOT (Take Out One at the Time) methodologies, as suggested in their CBA guidelines[11].

These assessment methodologies are described in 2.4.1 and 2.4.2 below.

2.4.1 FA assessment case: value as the first additional (FA) interconnector

This assessment case examines the value of each interconnector in turn as if it is the only new interconnector to be built in 2022. It is assumed that no new interconnection is built after 2022 in any scenario. This case is shown conceptually in Figure 7 below. For the avoidance of doubt, it is assumed in all cases that all Window 1 projects (and Eleclink) are in operation by 2022, unless otherwise defined by the scenario or sensitivity.

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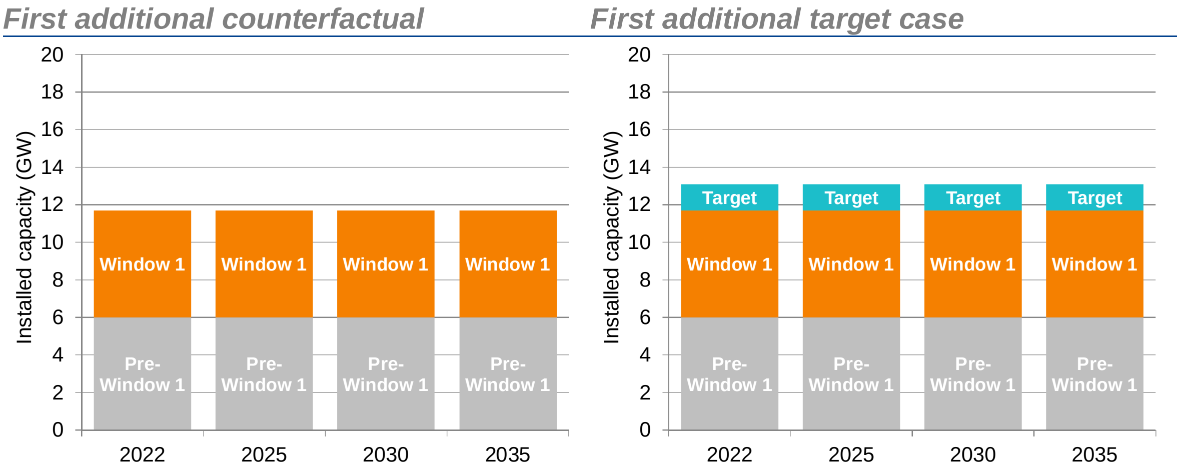
10 According to National Grid's Interconnector register from 18 November 2016, the Aquind project is expected to commission in December 2021 with an import and export capacity of 2,000MW. It has been reflected using these parameters in the modelling for this study. For the avoidance of doubt, the Aquind project is only included in the Marginal (MA) cases, as described in Section 2.4.2.

11 'ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects', February 2015

Figure 7 – FA assessment case: value as a first additional interconnector



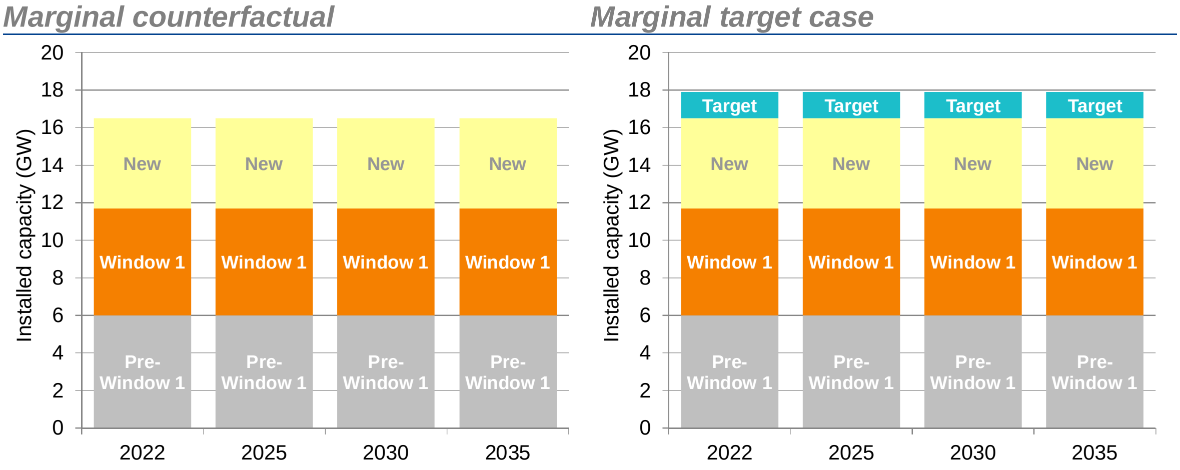
The aim of this stage of the analysis is to indicate a theoretical upper bound of value of the interconnector in a given market environment as additional interconnection will tend to, with very few exceptions, decrease the value of other interconnection in a given market[12]. Furthermore, by examining the value across three market scenarios designed to span a range of underlying value for interconnectors we aim to obtain the 'range of maximum values' in different market conditions (corresponding to the Base Case and High and Low interconnector value scenarios).

2.4.2 MA assessment case: Value as the marginal (MA) interconnector

This assessment case examines the value of each interconnector in turn as if it is one of four additional interconnectors (three application projects and the exempt project) to be built in 2022. It is assumed that no new interconnection is built after 2022 in any scenario. This case is shown conceptually in Figure 8. For the avoidance of doubt, it is assumed in all cases that all Window 1 projects are in operation by 2022, unless otherwise defined by the scenario or sensitivity.

12 Additional interconnection between two markets (say GB and France) would always lower the value of other competing interconnectors between those the same two markets. It will also usually, but not always, lower the value of other GB interconnectors to continental Europe (say Belgium) as French prices are generally closer to those in Belgium than those in GB. It may however increase the value of GB interconnectors to Ireland (as Irish prices are generally more similar to GB than French prices).

Figure 8 – Marginal assessment case: Value as a marginal interconnector



The aim of the marginal interconnector assessment approach is to indicate a theoretical lower bound of value of the interconnector in a given market environment. As with the FA case, by examining the value across three market scenarios designed to span a range of underlying value for interconnectors we actually obtain the range of minimum values in different market conditions (corresponding to the Base Case and High and Low interconnector value scenarios).

The results for all projects using these assessment cases are described in Section 4 below. Throughout the analysis we label the first additional build profile runs as FA and the marginal additional build profile runs as MA.

2.5 Modelling the cap and floor regime

In this study, all interconnectors are modelled separately and, if applicable, their cap and floor regime is applied, leading to cap or floor payments to and from GB consumers. The projects that are assumed to be regulated by this regime are:

- NEMO (1,000MW interconnector to Belgium), from 2020;
- all Window 1 projects (North Sea Link, Viking Link, IFA2, FAB Link, Greenlink), from 2020; and
- all applicable Window 2 projects from 2022.

The cap and floor are applicable to the portion of the interconnector revenue, arbitrage revenue and capacity payments, that accrues to the GB share of the cable (in all scenarios and sensitivities for this study, this share is 50%). The payment flows between the interconnector project and consumers in Great Britain are determined as follows:

- If the interconnector revenue accruing to the GB share of the cable exceeds the cap for the project in any year, the excess revenue is paid by the interconnector to GB consumers.
- If the interconnector revenue accruing to the GB share of the cable falls short of the floor for the project in any year, the missing revenue is paid by GB consumers to the interconnector.

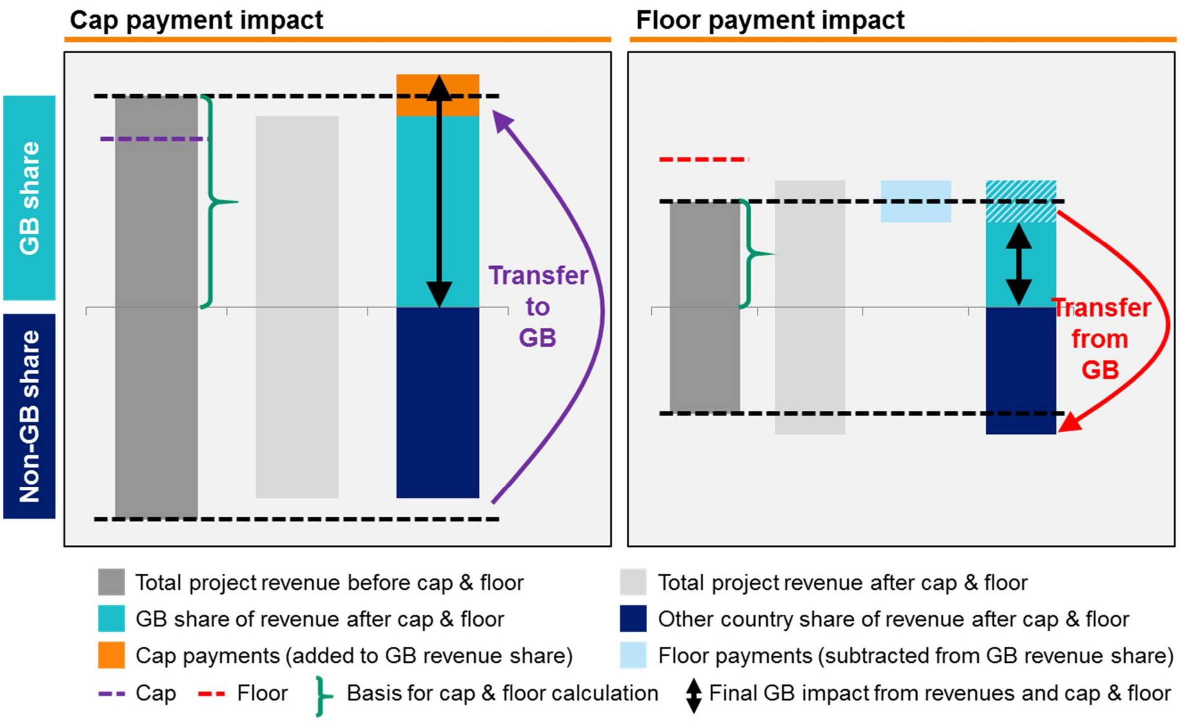
An implication of this calculation is the fact that any cap payments transfer value from the connected country to Great Britain, while floor payments transfer money from GB to the connected country.

This is due to the following mechanism:

- Cap and floor are applied to the GB share of project revenue only (as indicated by the green brace).
- If a project exceeds the cap, the excess revenue is paid to GB consumers from the total project revenue, which reduces revenue on both sides of the link. Therefore, value is transferred from the connected country to Great Britain. Should the value of cap payments fall this results in a transfer of value back to the connected country.
- If project revenues fall short of the floor, the difference is paid from GB consumers to the project, which increases revenue on both sides of the link. However, as floor payments are coming from GB consumers, value is transferred from Great Britain to the connected country. Should the value of floor payments fall this results in a transfer of value back to GB.

Both of these effects are illustrated in Figure 9.

Figure 9 – Impact of cap and floor payments on GB net welfare based on 50:50 split of interconnector revenues between GB and connected country



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3. MARKET DEVELOPMENT SCENARIOS

3.1 Scenario development overview

3.1.1 Development Approach

Three internally consistent market scenarios (Base Case, High interconnector value and Low interconnector value) have been developed for use in this project. The scenarios are aimed at assessing a reasonable range of outcomes for the overall economic benefit of new interconnection by examining a range of important scenario drivers. Due to the nature of the work it is also important that the sources of the scenarios are:

- based on a well-documented set of assumptions;
- widely recognised; and
- available to be utilised for a public purpose.

Based on the above considerations we have examined four primary sources for the scenarios:

- ENTSO-E visions developed for the TYNDP 2016;
- National Grid Future Energy Scenarios work (released in July 2016)[13];
- DECC Energy and Emissions Projections (November 2015 Update)[14]; and
- Pöyry Q2 2016 pan-European Quarterly Update (as and where additional assumptions are required, particularly for non-GB electricity markets).

To ensure the robustness of the CBA, we have constructed a wide range of scenario outcomes for interconnectors around a Base Case. To this end, we have used information sources which:

- represent a moderate view (in the Base Case) of future drivers to form a reasonable baseline against which interconnector projects can be valued; and
- provide reasonable upside and downside options for drivers of interconnector value, reflecting a realistic range for results of the CBA analysis.

3.1.2 Major value drivers for electricity interconnection

From the perspective of interconnector value in a commercial and socio-economic context, the pivotal metric of interest is the price difference between two countries rather than the absolute price itself. The drivers are therefore evaluated around how they will create price differences between potentially connected countries in different timescales.

In that regard the crucial price and value drivers that we have considered are shown in Figure 10 below.

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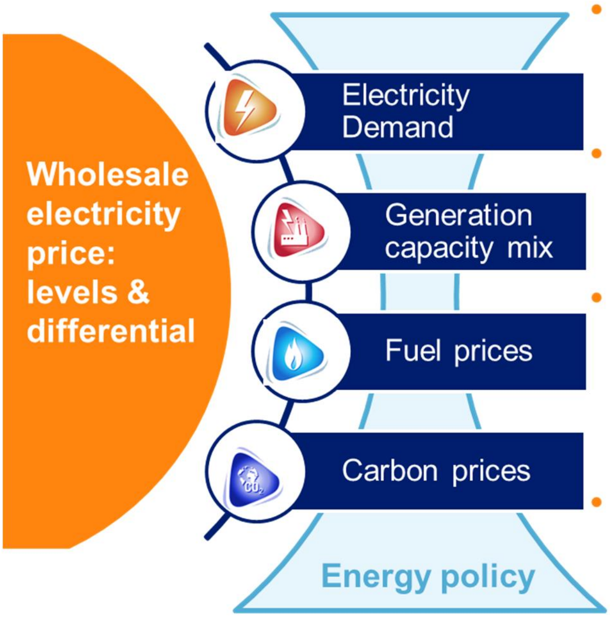
13 http://www2.nationalgrid.com/uk/industry-information/future-of-energy/future-energy-scenarios/

14 https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2015

Figure 10 – Drivers of interconnector value



- Electricity demand and capacity entry / retirement always need to be viewed in conjunction. Higher capacity margins (capacity exceeding demand) generally lead to lower prices within the country.
- The generation mix, together with fuel and carbon prices, determines the power supply curve – this will develop over time particularly with current plans for renewable expansion
- Fuel prices both directly and indirectly (e.g. through indexation or substitution effects) influence each other and the wholesale electricity price. Higher fuel prices generally lead to higher power prices (and indeed higher absolute price differences between countries)
- Carbon price and related policy instruments influence the attractiveness of fossil fuelled generation, and, vice-versa, renewables. Higher carbon prices generally lead to higher power prices in whatever region faces that price.

Alongside the individual market drivers of wholesale prices, the underlying value will also be heavily influenced by energy policy in respective countries. In addition to the below, the existing volume of interconnection itself will also be a major driver of value for new interconnection. A consistent scenario for interconnector value should therefore consider all aspects.

When examining the primary scenario sources, none of the scenarios described represented a complete consistent Base Case, downside and upside that could be taken forward as a reliable range for this work. In that regard we have constructed specific scenarios for this work that are broadly consistent with our internal view of market drivers, but are largely based on published data – the storylines underlying these scenarios and the critical assumptions are presented in section 3.2 below.

3.2 Scenario assumptions

3.2.1 Description of scenarios

Table 2 summarises the main characteristics for each of the three main scenarios, described below:

- The **Base Case** represents a future with moderate economic growth in both GB and Europe but a continuation of energy efficiency and gradual electrification of heat and transport sectors leads to stagnating demand over time in GB. Coal plants decommission as planned and new build thermal capacity mainly constitutes a mix of CCGT and OCGT plants, with some gradual nuclear new build in the 2020s and 2030s. The renewables build-up profile is moderate and GB reaches its 2020 target of 30% electricity generation from renewables on time. Europe is on track to reach its targets for 80-95% reduction in greenhouse gas emissions (compared to 1990 levels) somewhat later than 2050. Electricity storage and DSR capacity deployment is moderate. Across Europe, fuel prices increase in the early years before rising more gradually in the 2020s and remaining flat thereafter. The fuel prices used in this scenario are based on the DECC Reference Scenario while the thermal and renewable capacities for GB come from National Grid's FES 2016 'Slow Progression' and No Progression cases respectively. In other European countries, we base the demand and capacity projections on the Constrained Progress scenario of the final TYNDP 2016 Scenario Development Report. Carbon prices and storage and DRS assumptions are based on Pöyry's Q1 2016 Central scenario.

This scenario aims to represent an internally consistent moderate view of future drivers and a reasonable baseline against which interconnector projects can be valued.

- The **High interconnector value (High) scenario** is driven by high GDP growth across Europe which leads, along with accelerated electrification of heat and transport, to growing electricity demand. The growth rate of renewables and other low carbon technologies (nuclear and CCS[15]) is relatively high in GB and Europe. The GB target for electricity generation from renewables is met before 2020 and the European 2050 carbon targets are on track to be met. Electricity storage and DSR[16] capacity deployment is aggressive. Fuel and carbon prices are very high throughout Europe, linked to strong policy action and high levels of GDP growth. The fuel prices used in this scenario come from DECC's High scenario. In GB and the rest of Europe, demand and capacity projections are based on ENTSO-E's 'National Green Transition' vision (TYNDP 2016 Scenario Development Report). Carbon prices and storage and DRS assumptions are based on Pöyry's Q1 2016 High scenario.

  The drivers are combined such that they lead to relatively large hourly price differentials between countries whilst still being internally consistent in terms of long-run global drivers and sustainability of the extent to which absolute commodity price differentials between markets may rise in the future. **As such the scenario is designed to represent a plausible extreme high view of future value drivers that can represent an upside case for the commercial and economic value of interconnector projects in GB.**

- The **Low interconnector value (Low) scenario** represents a future of stagnating GB and wider European economies, which leads to falling electricity demand and a general lack of progression in the electricity market. The GB target regarding electricity generation from renewables is reached in 2020 but renewables development slows dramatically from then onwards, since the decarbonisation agenda has low priority. In Europe, renewables deployment is also very limited; thereby current target levels are not reached. There is very little need for new thermal capacity and the need for electricity storage and DSR capacity in the system is low. The fuel prices used in this scenario come from DECC's Low scenario. The demand and capacity mix assumptions both in GB and the rest of Europe are based on the 'Slowest Progress' scenario of the final TYNDP 2016 Scenario Development Report. Carbon prices and storage and DRS assumptions are based on Pöyry's Q1 2016 Low scenario. For GB, CPS is assumed to have been abandoned by 2022.

  Drivers are combined such that they lead to small hourly price differentials between countries whilst still being internally consistent in terms of long-run global drivers and

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[15] CCS: Carbon capture and storage

[16] DSR: Demand-side response, and other energy demand management types, including measures known as demand-side management (DSM)

the extent to which commodity price differentials between markets may fall in the future. **As such the scenario is designed as a plausible extreme low view of future value drivers to represent a downside case for the commercial and economic value of interconnectors in GB.**

In all our scenarios capacity payment mechanisms proceed as planned in GB, Ireland and France, having a dampening effect on wholesale electricity market prices – see Annex D for more details.

Table 2 – Overview of scenario assumptions

Driver	Base Case	High IC value scenario	Low IC value scenario
GB Demand	• EVs and electrification of heat increase demand until 2040 [avg. 0.7% p.a.] • Based on NG's 'Slow Progression' scenario	• High GDP, EVs & heat electrification increase demand [avg. 4.5% p.a.] • Based on Vision 3 (V3) TYNDP 2016	• Stagnating GDP leading to continued falling demand [avg. -2.4% p.a.] • Based on lowest TYNDP 2016 vision (V2)
GB thermal Capacity	• Mainly gas, some new nuclear • Based on NG's 'Slow Progression' scenario	• Large-scale build of new nuclear, CCS and CCGT • Based on V3 TYNDP 2016	• Gas only, capacity only required for replacement • Based on lowest TYNDP 2016 vision (V1)
GB Renewables Capacity	• Moderate growth: 2020 targets hit few years late • 34GW 2022, 43GW 2030 • NG 'No Progression' scenario	• Very fast RES build • 40GW 2022, 67GW 2030 • Based on V3 TYNDP 2016	• 33GW 2020 & 30GW 2030 • Based on lowest TYNDP 2016 vision for GB (V1)
NWE demand & Capacity mix	• Continuation of current policy framework • Based on Vision 2 TYNDP 2016	• Favourable economic conditions, large low carbon roll-out • Based on V3 TYNDP 2016	• Low demand leads to little new capacity • Lowest TYNDP vision for each country (V1 or V2)
Fuel prices	• DECC Reference Prices (similar but higher than Pöyry Central)	• DECC High Prices (similar but lower than Pöyry High)	• DECC Low Prices (similar but higher than Pöyry Low)
Carbon prices	• ETS and CPS following Pöyry Central: Q1 2016 • CPS & EU ETS reach parity at €57/tCO_2 in 2040	• ETS and CPS following Pöyry High: Q1 2016 • CPS always €15-25 above EU ETS price	• CPS is zero until 2040 • ETS following Pöyry Low: Q1 2016 – EU ETS rises to €17/tCO_2 in 2040

More detailed model input assumptions are provided in Annex C.

3.2.2 Assumptions for GB interconnection

In order to allow the comparison of projects across all scenarios and sensitivities, the baseline level of GB interconnection (i.e. the amount of interconnection capacity in place before commissioning of any Window 2 projects) has been kept constant over time and equal across scenarios and sensitivities.

All projects that were included in National Grid's interconnector register in November 2016 and/or were granted a cap and floor regime by Ofgem prior to the second window are assumed to be fully operational before or by 01 January 2022. It is assumed that all existing and new projects will continue to operate until at least 2046 (the end of the modelled period in this study). The full list of GB interconnectors included in this baseline is given in Table 3 below.

Table 3 – List of interconnectors included in baseline

Interconnector	Connected market	Cable size (MW)	Status
IFA	France	2,000	Existing link
Moyle	Irish Single Electricity Market	450	Existing link
Britned	Netherlands	1,000	Existing link
East West	Irish SEM	500	Existing link
Nemo[1]	Belgium	1,000	Under construction
North Sea Link[1]	Norway	1,400	Under construction
IFA 2[1]	France	1,000	Planning
Viking Link[1]	Denmark	1,400	Planning
FAB Link[1]	France	1,400	Planning
Greenlink[1]	Irish SEM	500	Planning
ElecLink	France	1,000	Under construction

Source: National Grid Interconnector register, 18 November 2016; and Ofgem
[1] Cap and floor projects

3.2.3 Internal consistency of scenarios

Each or our three scenarios starts with a set of assumptions based on a consistent storyline of GDP growth, energy demand and commodity prices. The underlying energy policy drivers, for example of renewable energy growth, are also considered to be consistent with the underlying global growth scenarios. In addition to the underlying consistency of the storyline we have also examined the consistency of the scenarios using our standard scenario checking processes.

As part of our standard scenario development process we apply a security of supply standard as a check on the internal consistency of new build assumptions in our scenarios (the other being around the economic viability of generic new build projects).

The specific security standard we examine is the capacity margin (i.e. spare capacity over demand) in a 1-in-20 weather year (i.e. accounting for a temperature driven demand profile plus hourly wind and solar yield and inflow of hydro plant)[17]. Capacity margins in the Base Case and the High are within feasible bounds based on our standard scenarios (i.e. at or close to a 0% margin in a 1-in-20 weather year, including the loss of the single largest unit in the market). In the Low scenario capacity margins are generally slightly above those required by our standard security of supply analysis. The generally falling demand in this scenario leads to a persistent state of over-capacity across North West Europe, which is consistent with a downside case for interconnector value.

With regard to the thermal plant mix in Great Britain we assess that the best available non-CfD supported new entry is gas-fired in all scenarios to 2030. The mix of CCGT and OCGT/peaking capacity is defined by National Grid and Pöyry assumptions and is generally consistent with that seen in our standard scenario analysis and a high-level

17 We regard this standard as consistent with National Grid's own definition of their security of supply standard under the capacity mechanism arrangements of a LOLE of not more than 3 of hours per annum.

economic viability test has been applied to achieve a balance between return rates of different asset types.

3.3 Price projections per scenarios

3.3.1 Wholesale electricity prices

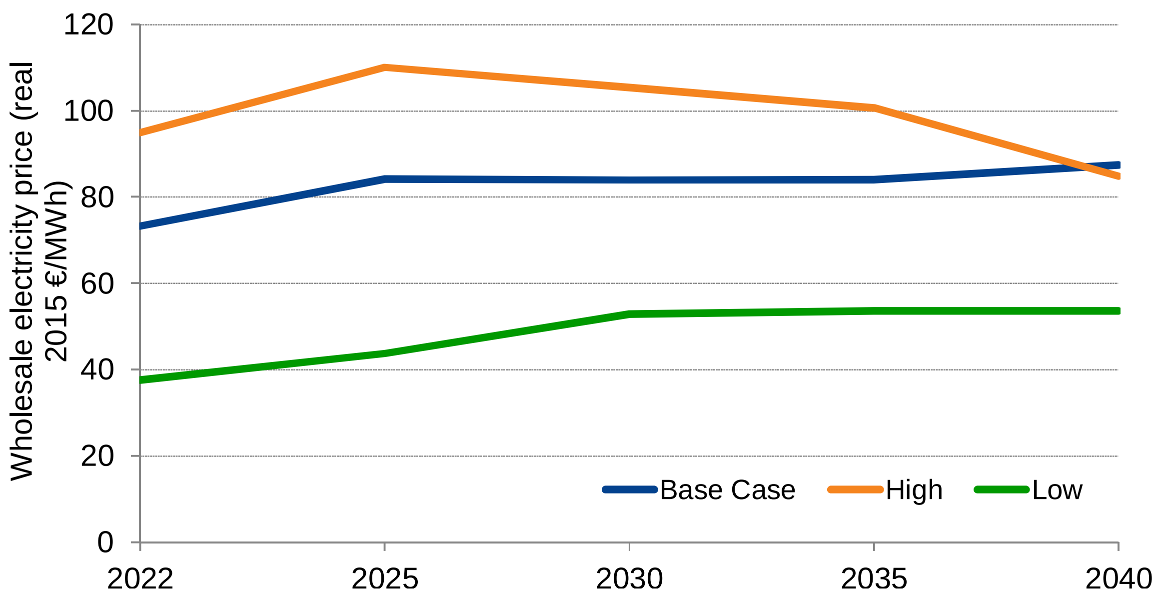
In this section we outline the resulting wholesale price projections generated by BID3 for GB and the other countries included in the modelling study. All assumptions come from the scenarios outlined in section 3.2 and discussed in more detail in Annex C. All scenarios also include the impact of capacity mechanisms on wholesale prices.

Wholesale electricity prices in GB

Figure 11 shows the annual time weighted average wholesale electricity prices in our Low, Base Case and High scenarios:

- In the Base Case, wholesale prices in 2022 (the first year of operation of Window 2 interconnectors) are around €73/MWh, increasing slowly thereafter to reach €84/MWh in 2030. Factors behind the rising prices in the Base Case are increasing fuel and carbon prices, counteracted by relatively slow demand growth and growth in renewables penetration.
- In the High interconnector value scenario prices rapidly increase in line with underlying demand, fuel and carbon prices to reach €110/MWh in 2025. Beyond 2025 prices drop to ~€85/MWh in 2040. This is a result of strong renewables' growth which causes a large number of very low price periods.
- In the Low interconnector value scenario prices fall to €38/MWh in 2022 in GB, before rising slowly in line with underlying EU ETS carbon prices (CPS is assumed to have fallen away). Renewables capacity remains unchanged beyond 2030 and the very low demand growth in this scenario means that little new build is required keeping prices close to €54/MWh until 2040.

Figure 11 – GB power prices: Base Case, High IC value and Low IC value

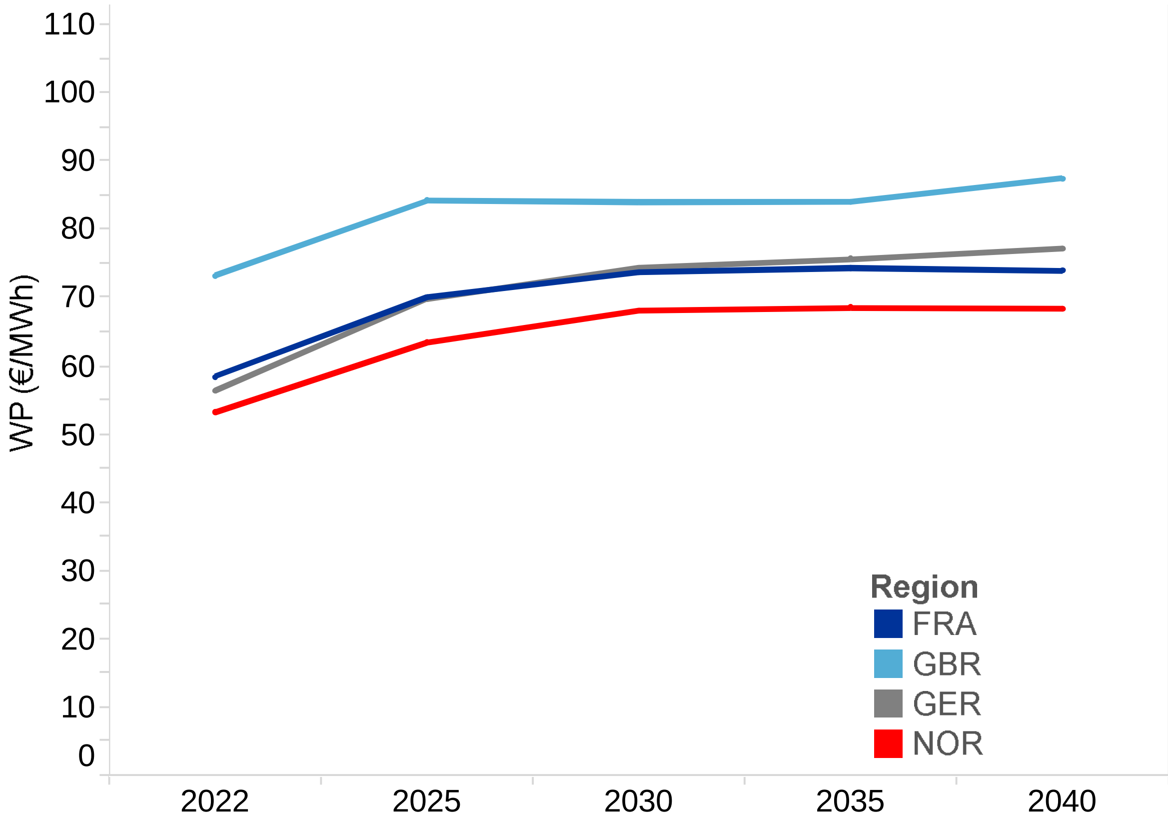


Base Case European wholesale power prices

The annual prices in the Base Case for GB and the modelled interconnected countries are shown in Figure 12 below:

- Electricity prices in GB increase until 2025, largely due to rising fuel and carbon prices. Carbon prices are a particularly large component of costs and prices in the UK due to the requirements on generators to pay both the cost of carbon credits under the EU Emissions Trading Scheme (EU ETS) and the GB specific Carbon Price Support (CPS) levy. Slow demand growth and high renewables expansion combine with slower carbon price growth (as the Carbon Price Floor is projected to remain flat at the 2020 target levels of £35.3/tCO_2 in this scenario) to lead to slower wholesale price rises after 2025, compared to the other modelled countries.
- French prices, German prices and Norwegian prices start much lower than those in GB due to lower carbon prices, absence of BSUoS[18], and generation mix differences. Prices in other countries stay below the level seen in GB throughout for other countries over the modelled period.

Figure 12 – Wholesale power prices by country in the Base Case



Note: FRA: France, GBR: Great Britain, GER: Germany, NOR: Norway.

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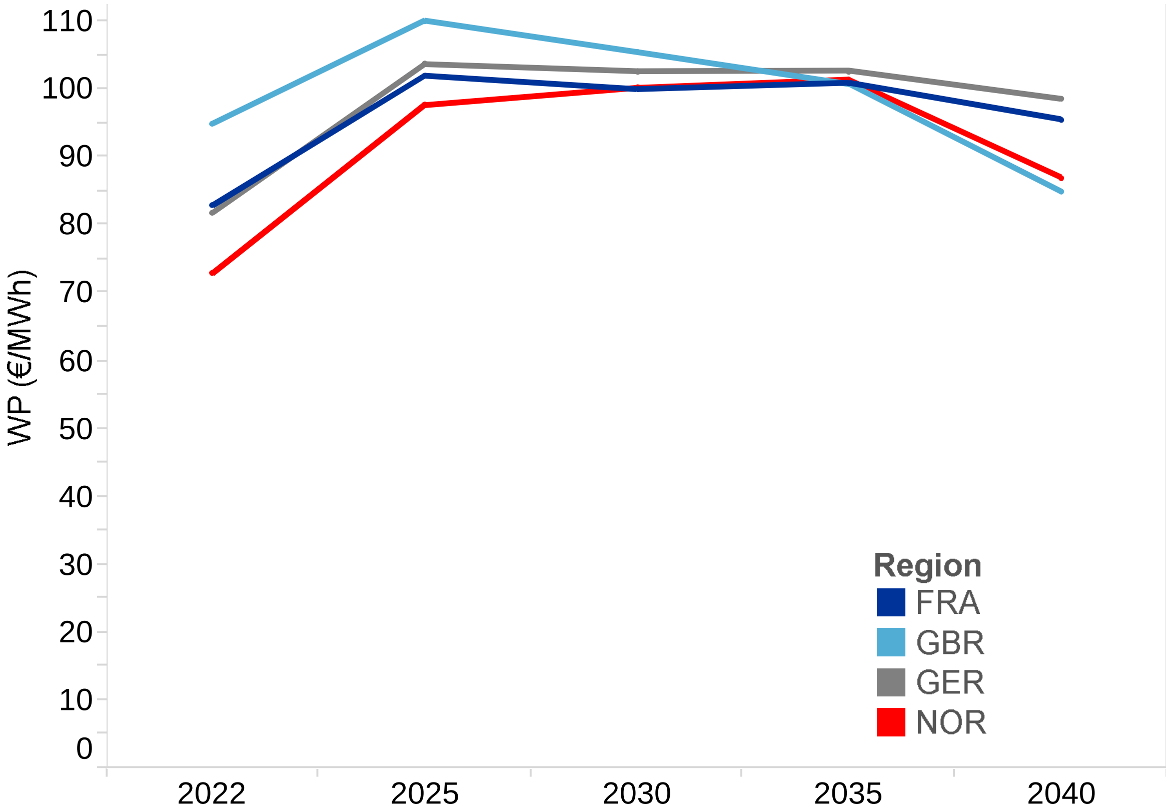
18 Balancing Services Use of System (BSUoS) charges recover the costs incurred by National Grid in balancing the system in its role as System Operator. They are applied to GB generators but not interconnectors, creating wholesale price differentials over and above the economic fundamentals, to increase the interconnectors' opportunities for arbitrage between GB and other markets.

High scenario European wholesale power prices

Resulting modelled annual prices in the High scenario are shown in Figure 13:

- In the High scenario, electricity prices in GB are €21-26/MWh above prices for GB in our Base Case until 2030. Prices in GB start decreasing from 2030 as fuel prices stay reasonably constant from that point onwards and rising carbon prices are counteracted by the rapidly increasing roll-out of low-marginal cost low-carbon technologies.
- Prices in Continental Europe rise rapidly between 2022 and 2025. The rising prices in this scenario result from a combination of high demand growth and a rapid rise in fuel prices EU ETS carbon prices. The fast penetration of renewable capacity in both France and Germany leads to relatively flat prices until 2040. Norway is dominated by hydro until 2040 and large amounts of onshore wind (rather than thermal capacity) are added, resulting in prices dropping between 2035 and 2040.

Figure 13 – Wholesale power prices by country in the High IC value scenario



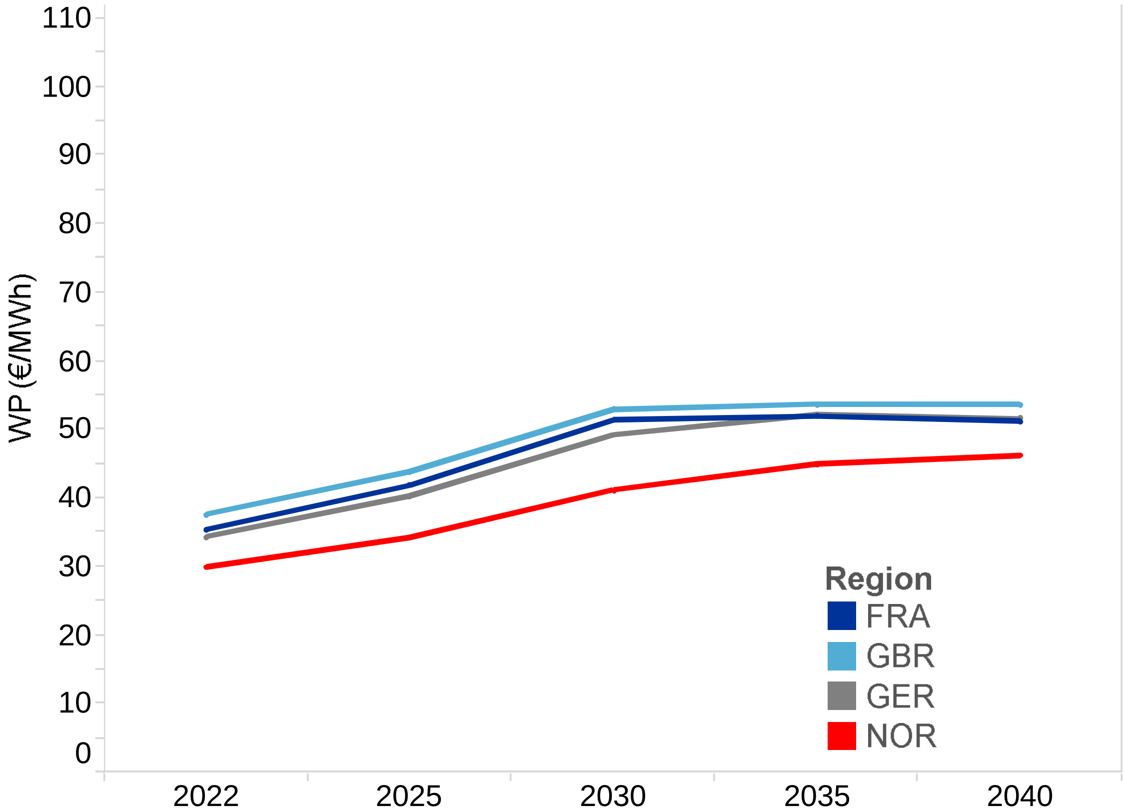
Note: FRA: France, GBR: Great Britain, GER: Germany, NOR: Norway.

Low scenario European wholesale power prices

Electricity prices in the Low scenario are lower than in the Base Case in all countries, driven by decreasing demand and lower fuel and carbon prices. The difference in prices between GB and continental Europe is also generally much lower in this scenario. Lower overall costs, fuel or carbon related, lead to a flatter supply curve and consequently less difference in the absolute price of electricity between countries. Annual wholesale power prices for the Low scenario are shown in Figure 14:

- GB prices are low initially at €37/MWh in 2022 before rising gradually again to reach €54/MWh by 2035. The absence of CPS results to GB prices and French and German prices almost converging.
- German and French prices start slightly lower than those in GB in 2022 due to higher supply margins and move in parallel with GB prices over time due to common carbon prices and similar fuel prices.
- The maximum difference in annual average prices between GB and Norway is approximately €9/MWh on average. This difference persists due to the continued difference in sources of supply in those countries.

Figure 14 – Wholesale power prices by country in the Low IC value scenario



Note: FRA: France, GBR: Great Britain, GER: Germany, NOR: Norway.

3.3.2 *Capacity market prices*

We incorporate capacity markets into our electricity market modelling in all scenarios. In general this leads to downward pressure on prices compared to a world or market where a capacity mechanism does not exist. A discussion of our approach to modelling capacity mechanisms in GB and other European countries is contained in 0.

This study assumes that the modelled interconnectors are eligible to receive capacity payments in GB, France and Ireland. In order to determine the revenue that these interconnectors can capture from capacity markets, two assumptions need to be taken, one for the capacity market price (a €/kW value), and one for the de-rating of the link.

The de-rating factor – which represents the likelihood of the interconnector importing into a particular market during periods of system stress – and the method for its determination is presented in 0.

As this study only takes into account spot years (2022, 2025, 2030, 2035 and 2040), it is limited in determining necessary capacity market prices applicable for the interconnectors (unlike new generators that receive a guaranteed 15-year capacity contract, interconnectors are only eligible for 1 year contracts in the GB capacity market). Therefore, we have taken a simplified approach (for both the GB and the French capacity markets) as follows:

- Each scenario was matched with a standard Pöyry scenario (Base Case with Central scenario, High with High and Low with Low).
- For each scenario, the average clearing price over the modelled period (2022 to 2040) has been averaged and then rounded to the next €5/kW.

The resulting applicable capacity clearing prices are presented in Table 4.

Table 4 – Capacity market prices applied in this study

	Base Case price	High scenario price	Low scenario price
Great Britain	€35/kW	€45/kW	€15/kW
France	€65/kW	€100/kW	€40/kW
Ireland	€35/kW	€75/kW	€20/kW

Note: Calculated based on standard Pöyry scenarios

3.4 Modelled sensitivities

In addition to the three main scenarios we have also conducted sensitivity analysis on a number of important assumptions. These sensitivities are designed to test the robustness of the CBA results to changing single specific assumptions. The modelled sensitivities are as follows:

- **Policy normalisation ('Policy sensitivity')** – for this sensitivity we have assumed that CPS and EU ETS carbon price differential falls to zero by 2022, and that BSUoS is no longer charged on generators in Great Britain[19]. All other assumptions remain the same as in the Base Case.
- **Window 1 delay** – for this sensitivity we have assumed that the Window 1 projects (NSN, Viking Link, IFA2, FAB Link and Greenlink) face a delay in their progress. We have assumed that only the 50% of the capacity of the Window 1 projects is built by 2022 and the full capacity comes online over time until 2025[20].
- **Window 2 delay** – for this sensitivity we have assumed that the Window 2 projects are delayed until 2025.

19 The charge, which applies to generators but not interconnectors, leads to a price difference between GB and any connecting country even when very similar plants are on the margin in both countries. When removed, interconnector would be expected to import less into GB and export more to the connected country.

20 This percentage is applied to the capacity of each Window 1 project. In 2023, 67% are available, rising to 83% in 2024 and 100% in 2025.

- **Connection firmness** – for this sensitivity we have assumed that the NorthConnect and NeuConnect projects are connected under a non-firm arrangement for the first two years of operation and therefore are subject to outages over the summer period. This has been reflected (as a worst-case sensitivity) by reducing cable availability accordingly over that period.

Note that we have also conducted a number of other sensitivities on individual interconnectors as part of the CBA but these are not specific market modelling sensitivities and have not been analysed for all interconnectors. These will be discussed as part of the interconnector benefit assessment.

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4. INTERCONNECTOR COST BENEFIT ANALYSIS

4.1 CBA Introduction

4.1.1 Introduction and approach

In order to assess the impact of an interconnector on the wider society, we have conducted a Cost Benefit Analysis (CBA), comparing the net present value (using a 3.5% discount rate[21] over a 25 year project life) of social welfare in the scenario without the assessed interconnector (the 'counterfactual') and with the assessed interconnector (the 'target case'). To show the impact of the particular interconnector being examined, all other factors are held constant between runs (e.g. other interconnector build, generation capacities and fuel prices).

One presumed driver of interconnector value is the pre-existence and future development of other interconnectors to GB. In order to take account of this effect, we have assessed the interconnectors using two different methodologies: 'first additional' (FA) and 'marginal' (MA). These methodologies are discussed in more detail in Section 2.3 above.

'First additional' assessment approach (FA)

- The FA CBA approach examines the value of each interconnector in turn as if it is the only new interconnector to be built in 2022. No other interconnection is assumed to come online after that point in any scenario.
- The aim of this stage of the analysis is to illustrate the potential upper bound of value of the interconnector in a given market environment, assuming that additional interconnectors will, in general, reduce the value of other interconnectors.
- By examining the value across three market scenarios designed to span a range of underlying value for interconnectors we actually obtain the range of maximum values in different market conditions (corresponding to the High, Base Case and Low scenarios).

'Marginal' assessment approach (MA)

- The MA CBA approach examines the value of each interconnector in turn as if it is the last of four additional interconnectors (three submissions plus Aquind) to be built in 2022. No other interconnection is assumed to come online after that point in any scenario.
- The aim of this stage of the analysis is to illustrate the lower bound of value of the interconnector in a given market environment assuming that additional interconnectors will, in general, reduce the value of other interconnectors.
- By examining the value across three market scenarios designed to span a range of underlying value for interconnectors we actually obtain the range of minimum values in different market conditions (corresponding to the High, Base Case and Low scenarios).

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21 The 3.5% rate has been chosen according to the guidelines to discounting in HMRC's green book (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/220541/green_book_complete.pdf). All social welfare impacts are discounted using this rate, regardless of stakeholder (consumers, generators, interconnector owners) and country.

4.1.2 Projects included in the CBA modelling

We have assessed a total of three different interconnector projects, based on the three submissions received by Ofgem by October 2016. These are summarised in Table 5 below. While we have used the connection size and other input data (including developer capital and operational cost estimates) directly from the submission documents, to avoid bias in the results we have normalised the following assumptions:

- the interconnector being examined will commission on the 01 January 2022[22]; and
- all interconnector welfare is split 50:50 between the GB and the connecting country, regardless of flow.

These interconnectors are discussed in turn in Section 4.2 to Section 4.4, in the order specified in Table 5. We will first present the overview and main conclusions for every project, before expanding into more detail on interconnector flows and revenues and the cap and floor impact of the interconnector projects. For each project we have identified the welfare assuming that the cap and floor mechanism is in operation. The cap and floor levels for all nine (Nemo, Window 1 and Window 2) relevant projects were provided by Ofgem and were based on costs provided by developers in submission documents.[23]

Table 5 – Summary of characteristics of Window 2 projects

Project	Connected country	Project size (MW)	Assumed commissioning date
NorthConnect	Norway	1,400MW	01 January 2022
NeuConnect	Germany	1,400MW	01 January 2022
Gridlink	France	1,400MW	01 January 2022

Source: Developer submissions for respective projects, normalised commissioning dates

In addition, to the Window 2 projects presented in the table, we have assumed that Aquind, a 2,000MW fully merchant (exempt) interconnector project with France, will commission at the same time as these projects in all of the MA cases.

4.1.3 Socio-economic welfare metrics

In the socio-economic welfare analysis as part of this CBA, we have examined:

- **GB consumer, producer and interconnector owner welfare impact** (as defined in Section 2.2);
- **GB net welfare impact** (the sum of the above); and

22 This normalisation has been done to compare all interconnectors on a like-for-like basis. Uncertainties in the development process mean that a start date (i.e. within year) cannot be accurately predicted for any of the proposed interconnector projects and so a common start date is considered prudent in a comparative CBA.

23 In each of the diagrams showing revenues and cap & floor levels, the values indicated are given on a total project basis (i.e. total project revenues vs. total levels of cap & floor). To calculate welfare, however, only the GB share of revenues (50%) is taken into account as cap & floor levels have been calculated on the GB share of the project (50%).

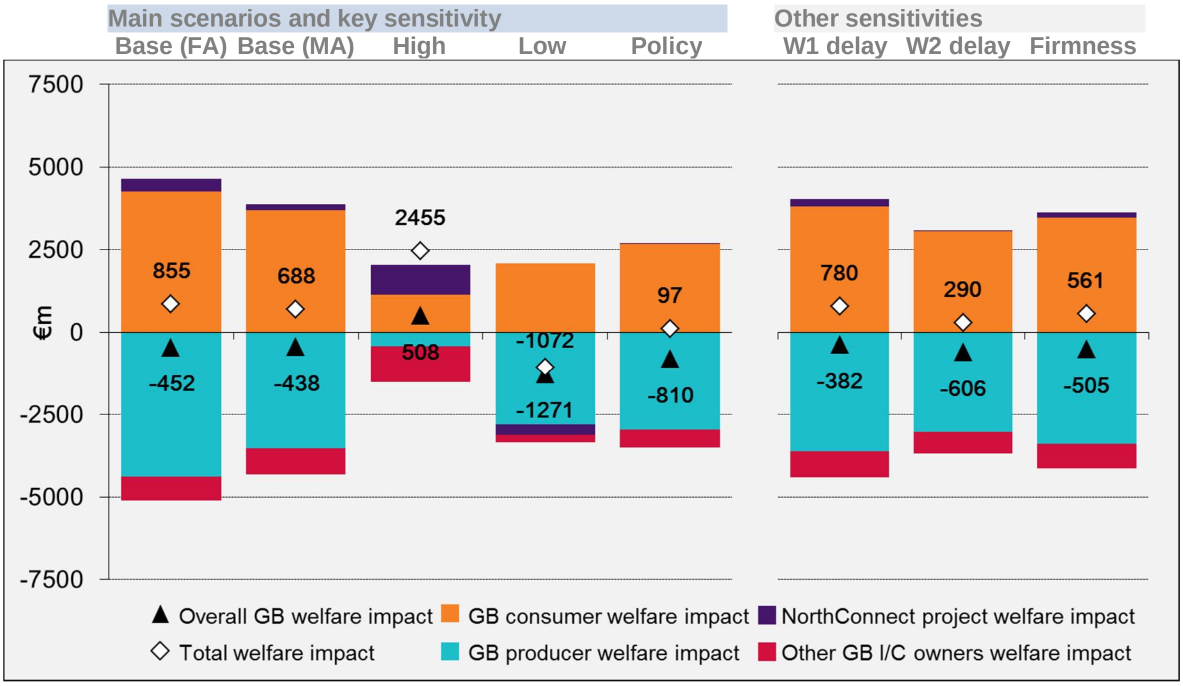
- **total net welfare impact** (sum of GB net welfare impact and the equivalent metric for the country connected by the interconnector).

4.2 NorthConnect cost benefit analysis

4.2.1 NorthConnect – overview and main conclusions

The NorthConnect project has been modelled as a 1,400MW interconnector between Great Britain and Norway, commissioning in 2022.

Figure 15 – NorthConnect welfare impact on socio-economic welfare



Note: For scenarios where only one case is shown in the chart, the MA case is presented.

The main conclusions from our CBA modelling are:

- **NorthConnect has a significantly positive impact on GB consumer welfare in all scenarios and sensitivities**

  The consumer benefit is higher in the Base Case than in the High scenario, as a high renewables share in GB in the High scenario leads to more exports to Norway late in the modelled period.

- **Net impact on GB is negative in most cases, due to significant negative impact on GB producer margins and other interconnector congestion revenues**

  NorthConnect's ability to import inexpensive electricity from Norway competes both with domestic generation and other interconnectors. Some of this negative impact is also included in the consumer welfare impact, when other cap & floor projects require more floor payments due to the introduction of NorthConnect.

- **Total net welfare across GB and Norway significantly positive in most cases**

  The impact is positive in the Base Case and across all sensitivities modelled. The High scenario shows a strong positive total net welfare and the Low scenario a significant negative. In all scenarios and sensitivities modelled, the impact on Norwegian net welfare is always positive.

- **Economic case of the project is robust to other Window 2 interconnectors being built**

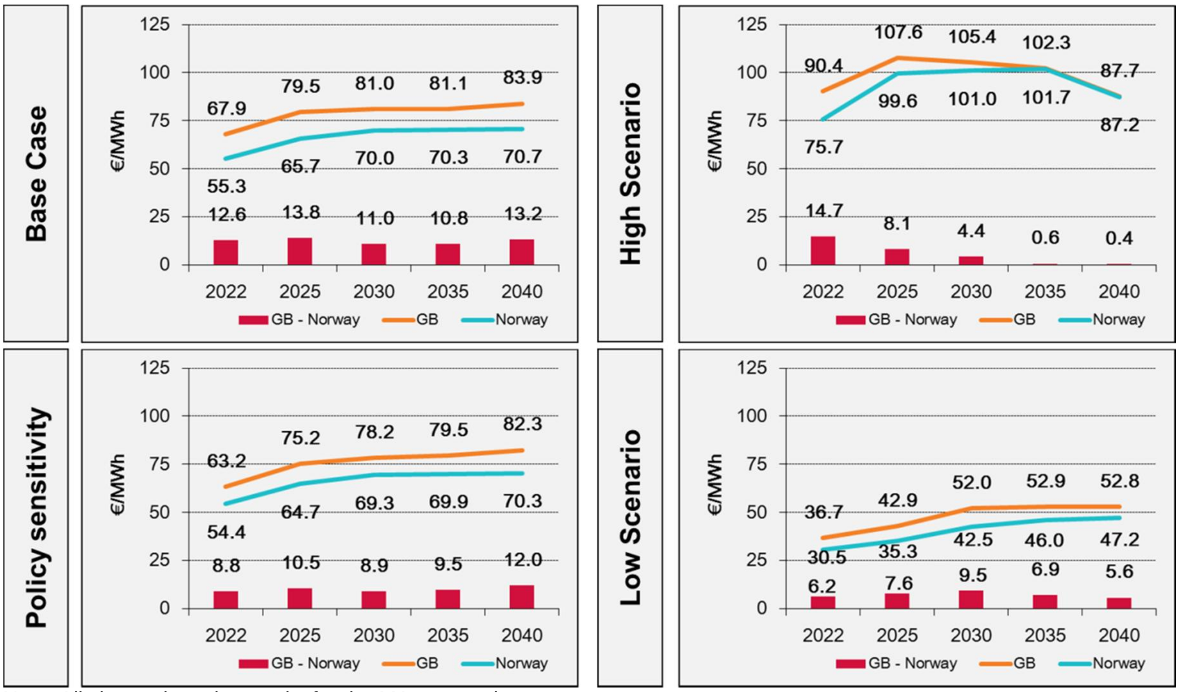
  While the consumer welfare impact is significantly lower in the MA case (although still highly positive), the net impact of NorthConnect on GB is very similar in both assessment approaches (the difference being €10m).

4.2.2 NorthConnect – price differentials and flows

The main factor underlying the economic and commercial case for the NorthConnect project is the large price differentials between Great Britain and Norway. The Norwegian electricity system is almost entirely reliant on hydro power, which leads to low power prices and a less volatile profile of prices over a day. However, due to the unpredictability of hydro inflow, there is a seasonal pattern in Norwegian prices – prices are generally higher in autumn and winter compared to the rest of the year.

Figure 16 shows the annual average wholesale electricity prices and price differentials between Great Britain and Norway in the main scenarios and the Policy normalisation sensitivity. In the Base Case, Low scenario and the Policy normalisation sensitivity, price differentials are largely constant over the modelled period. In the High scenario, continuing deployment of renewable capacity in Great Britain leads to almost equal average prices between the two countries by 2035.

Figure 16 – Price differentials between Great Britain and Norway

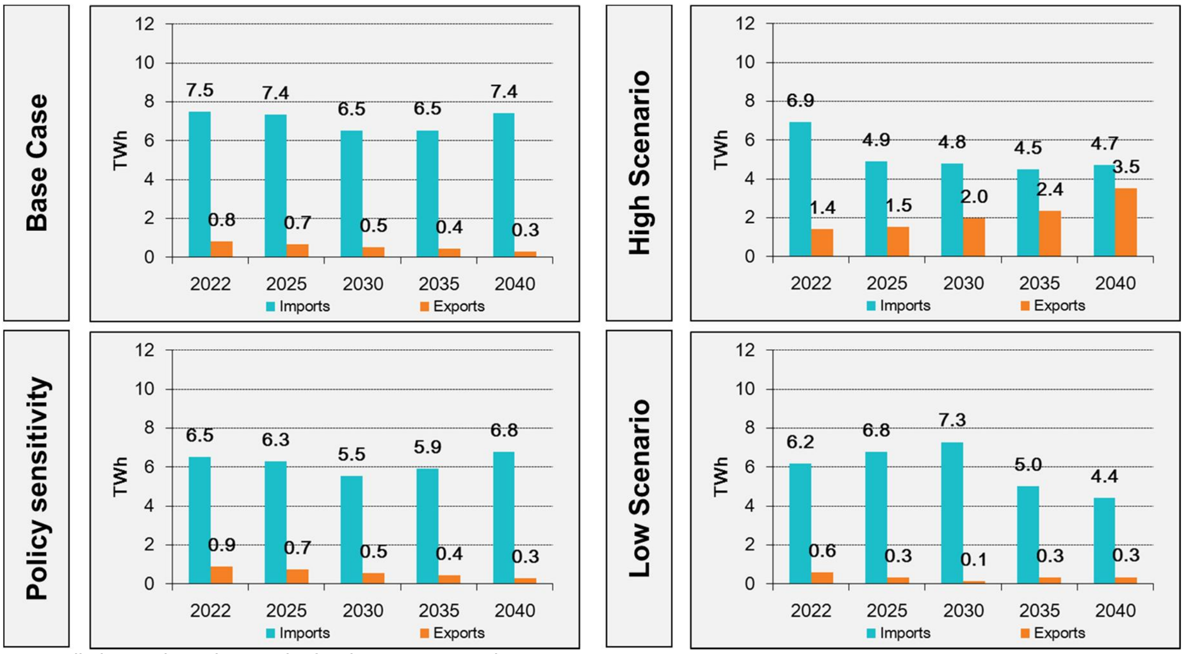


Note: All charts show the results for the MA approach.

The flows of the interconnector – which are closely linked to the price differentials – are presented in Figure 17. Flows are occurring mainly in the direction of Great Britain, due to the persisting higher prices compared to Norway. The only exception to this is the High scenario, where renewables growth in Great Britain leads to more exports over time. The overall utilisation of the cable is relatively low compared to other interconnectors, at 49% (Low scenario) to 60% (Base Case), which is due to the high loss factor (7.5%) and the competition with another Norwegian interconnector, NSL.

Imports from Norway are lower in the Policy normalisation sensitivity compared to the Base Case, as the price differentials are, on average, lower due to the absence of CPS and BSUoS in Great Britain.

Figure 17 – Flows on NorthConnect

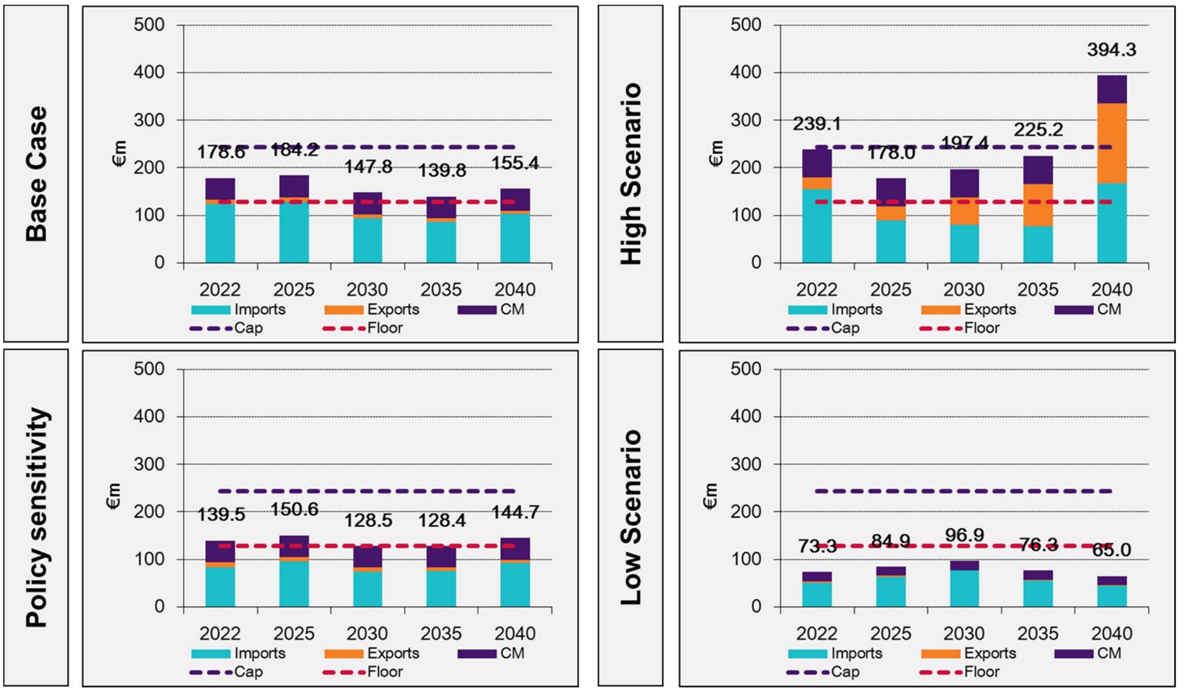


Note: All charts show the results for the MA approach.

4.2.3 NorthConnect – revenues and cap and floor impact

Figure 18 shows the project's revenues in the main scenarios and the Policy sensitivity.

Figure 18 – Revenues for NorthConnect



Note: Cap and floor compared to total project revenue. In practice, and in the calculations for the socio-economic welfare in this report, the cap and floor is calculated for and applied to the GB share of the project only. All charts show MA results.

The main conclusions from analysing NorthConnect's revenues in comparison to its cap & floor are as follows:

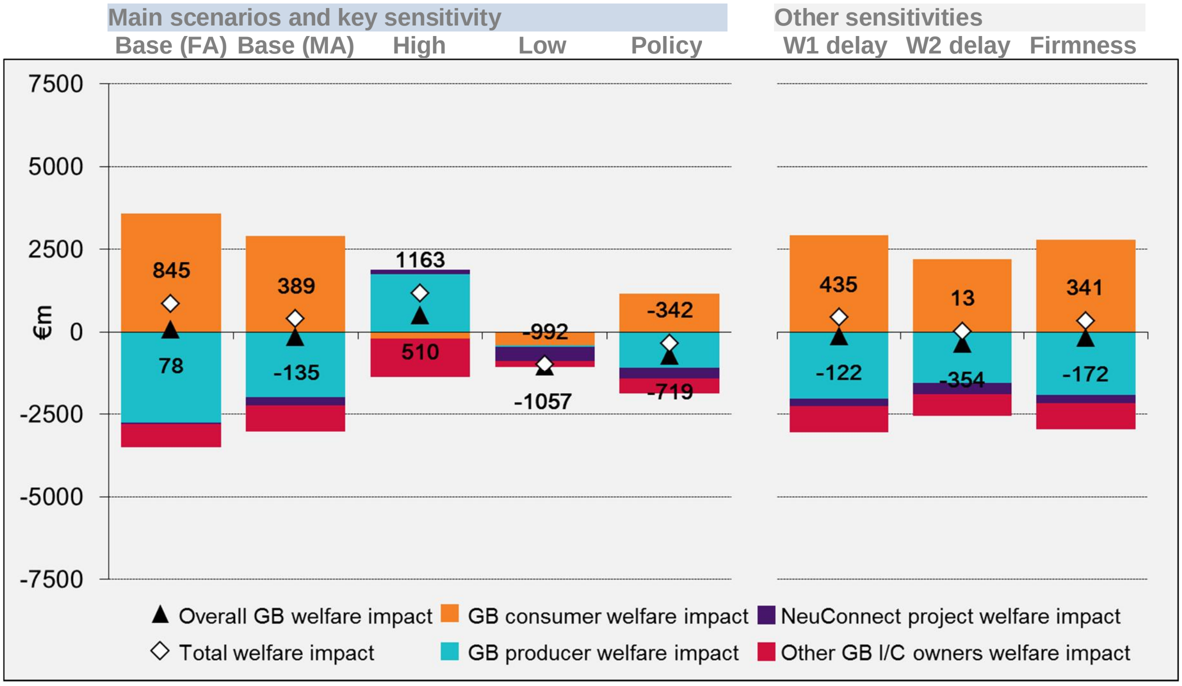
- The majority of revenue is captured on flows in the direction of Norway to GB.
- Only the High scenario includes significant revenues on flows from GB to Norway, which is due to the higher renewables share in GB in that scenario.
- No cap or floor payments are made in the Base Case, but there are significant cap payments in the High scenario and floor payments in the Low scenario.
- Capacity payments constitute a significant share of overall revenues in all but the Low scenario. In the Base Case and the Policy normalisation sensitivity, capacity payments are necessary to reach the revenue floor in most years.

4.3 NeuConnect cost benefit analysis

4.3.1 NeuConnect – overview and main conclusions

The NeuConnect project has been modelled as a 1,400MW interconnector between Great Britain and Germany, commissioning in 2022.

Figure 19 – NeuConnect welfare impact on socio-economic welfare



Note: For scenarios where only one case is shown in the chart, the MA case is presented.

The main conclusions from our CBA modelling of the NeuConnect project are:

- **NeuConnect has a significantly positive impact on GB consumers in the Base Case and all sensitivities, but not in the High and Low scenarios**

  In the High scenario, a high renewables share in Great Britain leads to significant exports and increased prices when the interconnector is built. In the Low scenario, the lack of revenues leads to substantial floor payments being made to the project and therefore a negative impact on consumers.

- **Net impact on GB is positive in FA Base Case, but negative in most other cases, due to negative impact on GB producers and other interconnectors**

  NeuConnect, as an interconnector to a very well interconnected continental Europe, competes with interconnectors to France, Belgium, Netherlands, Ireland and Norway. While the price differential between Germany and Great Britain is not significantly larger than that between France and Great Britain, NeuConnect's longer distance leads to higher costs and a higher loss factor than interconnectors with France.

- **Impact on Germany is positive in all scenarios**

- **Significant impact of additional interconnectors on NeuConnect's case**

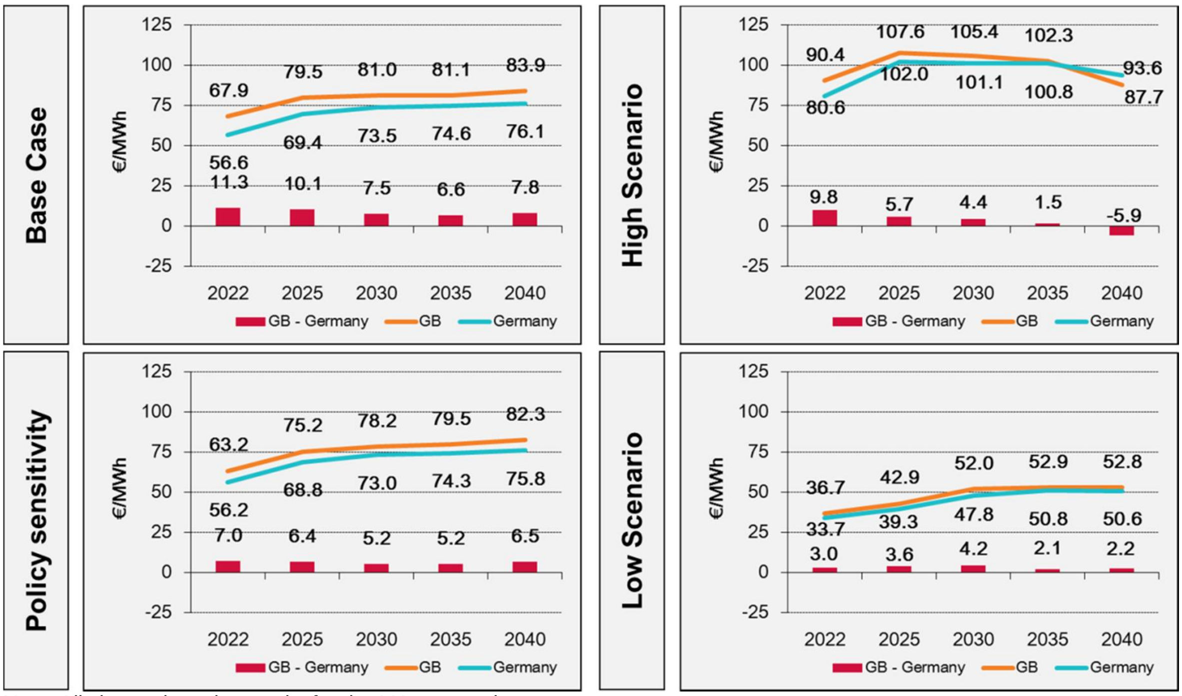
  The MA cases show a significantly lower GB and overall benefit, which is mainly due to the competition from additional GB-France interconnector projects.

4.3.2 NeuConnect – price differentials and flows

The case for NeuConnect is built on fundamental differences between the electricity markets of Germany and Great Britain. While renewable capacity is relatively limited in Britain, Germany has experienced a strong growth of solar PV and wind capacities which have led to low prices in many periods.

Figure 16 shows the annual average wholesale electricity prices and price differentials between Great Britain and Germany in the main scenarios and the Policy normalisation sensitivity. In the Base Case, Low scenario and the Policy normalisation sensitivity, price differentials are slightly decreasing over the modelled period. In the High scenario, continuing deployment of renewable capacity in Great Britain leads to a decrease and eventually a reversal of the average price differential by 2040.

Figure 20 – Price differentials between Great Britain and Germany



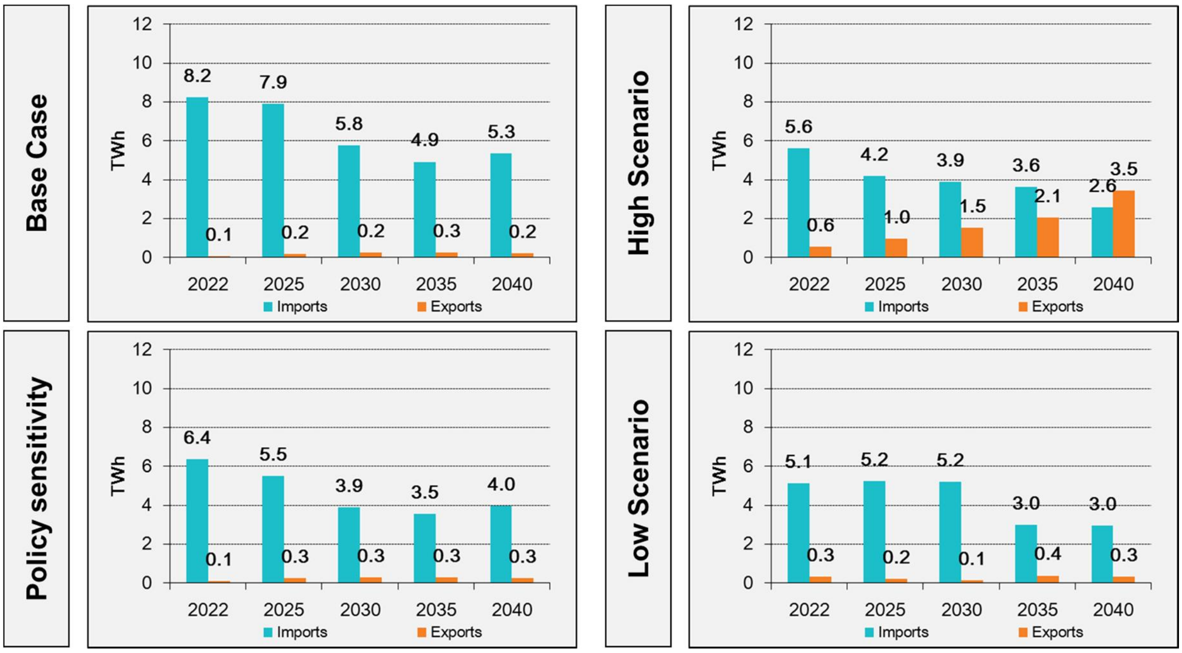
Note: All charts show the results for the MA approach.

The flows of the interconnector – which are closely linked to the price differentials – are presented in Figure 17. Flows are mainly occurring in the direction of Great Britain, due to the persisting higher prices compared to Germany. This is not the case in the High scenario, where increased GB wind capacity leads to an increase in low price periods and more exports over the interconnector. The overall utilisation of the cable is relatively low, between 35% (Low scenario) and 51% (Base Case), which is due to the higher loss factor (5.0%) compared to competing French, Belgian and Dutch interconnectors[24].

Imports from Germany are lower in the Policy normalisation sensitivity and the Low scenario, as the price differentials are, on average, lower due to the absence of the CPS (and, in the Policy normalisation sensitivity, the BSUoS) in Great Britain.

24 Loss factors on interconnectors, i.e. the electricity lost in transmitting power from one market to the other, create a 'dead-band' of price differences that need to exist in order for the interconnector to profit from flow. If price differentials are lower than this dead-band in any period, the interconnector would not flow in this period. The higher this loss factor is, the less an interconnector will flow, all other things being equal.

Figure 21 – Flows on NeuConnect

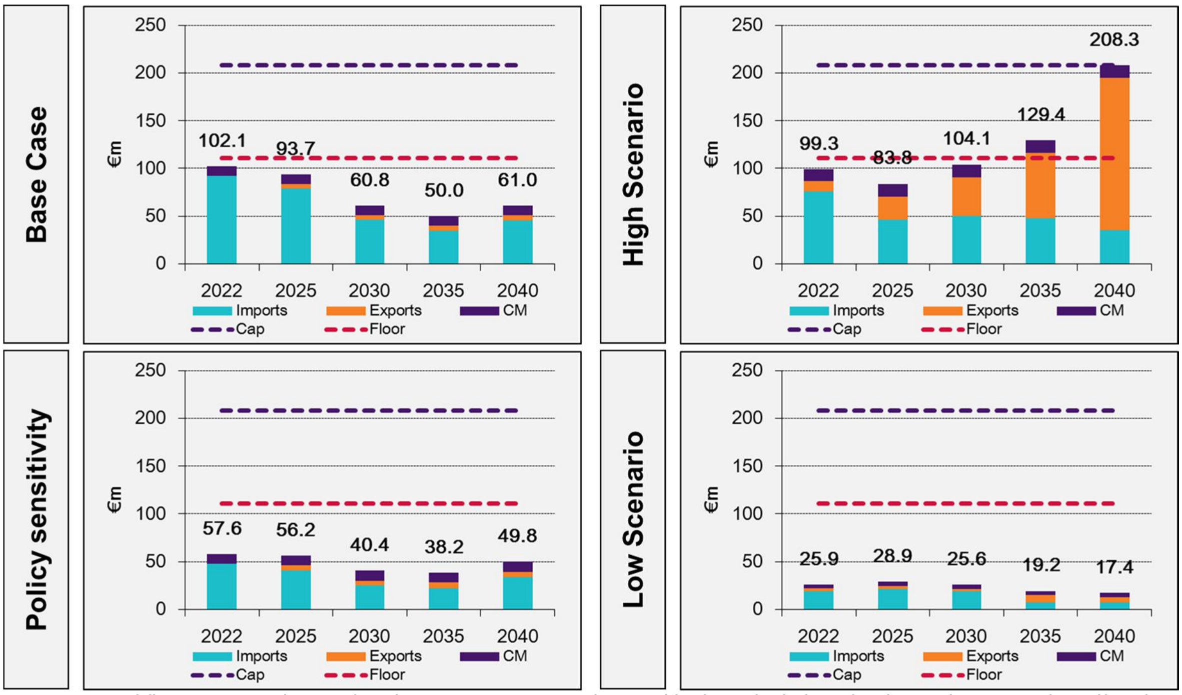


Note: All charts show the results for the MA approach.

4.3.3 NeuConnect – revenues and cap and floor impact

Figure 18 shows the project's revenues in the main scenarios and the Policy sensitivity.

Figure 22 – Revenues for NeuConnect



Note: Cap and floor compared to total project revenue. In practice, and in the calculations for the socio-economic welfare in this report, the cap and floor is calculated for and applied to the GB share of the project only. All charts show MA results.

The main conclusions from analysing NeuConnect's revenues in comparison to its cap & floor are as follows:

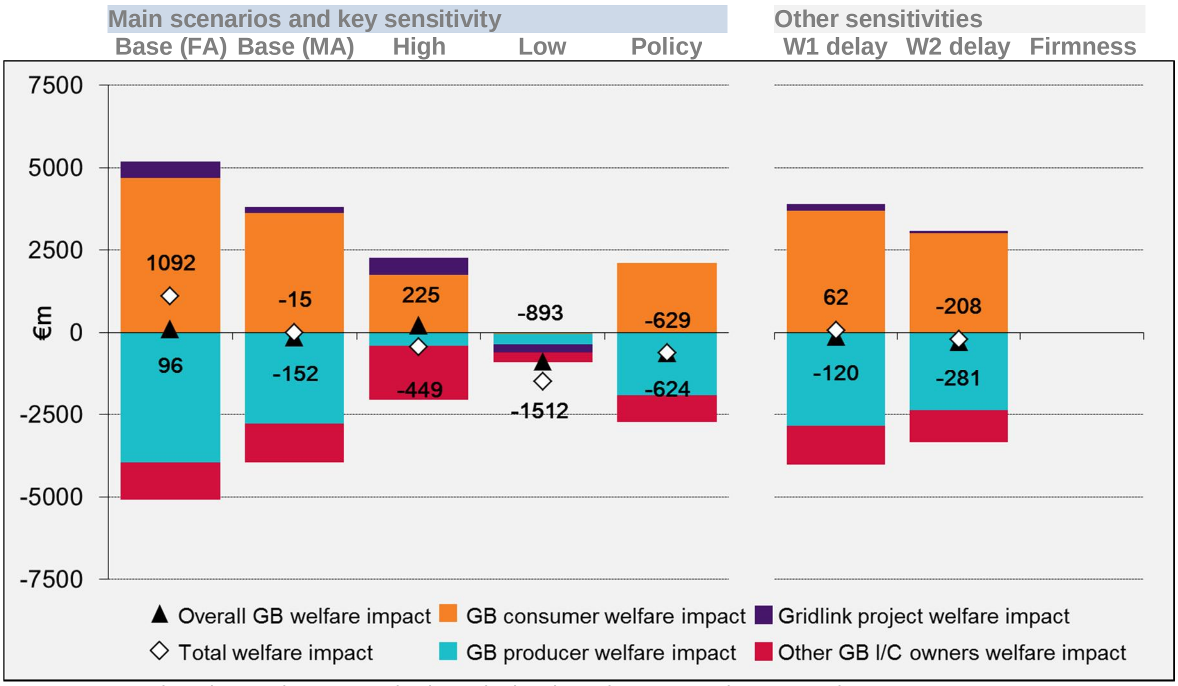
- Only the High scenario includes significant flows from Great Britain to Germany, which is due to the higher renewables share in GB in the scenario.
- The project requires floor payments in every scenario. Revenues reach the level of the floor only in the later years of the High scenario (in 2040, High scenario revenues are close to the cap level).
- Capacity payments do not constitute a significant share of overall revenues as the interconnector is heavily de-rated in the capacity market.

4.4 Gridlink cost benefit analysis

4.4.1 Gridlink – overview and main conclusions

The Gridlink project has been modelled as a 1,400MW interconnector between Great Britain and France, commissioning in 2022.

Figure 23 – Gridlink welfare impact on socio-economic welfare



Note: For scenarios where only one case is shown in the chart, the MA case is presented.

The main conclusions from our CBA modelling of the Gridlink project are:

- **Gridlink has a significantly positive impact on GB consumers in the Base and High scenarios and most sensitivities**

  The consumer benefit is higher in the Base Case than in the High scenario, as a high renewables share in Great Britain in the High scenario leads to more exports to France late in the modelled period. In the Low scenario, no benefit arises for GB consumers, as the lack of revenues leads to substantial floor payments being made.

- **Net impact on GB is positive in Base Case (FA), negative in the Base Case MA cases and negative for all sensitivities**

Gridlink's low cost and loss factor constitute a competitive advantage for the project compared to longer distance projects. However, the large volume of competing French projects means only a small positive impact on Great Britain in the FA results for the Base Case, and a negative impact in the MA case.

- **Significant impact of additional interconnectors on Gridlink's case**

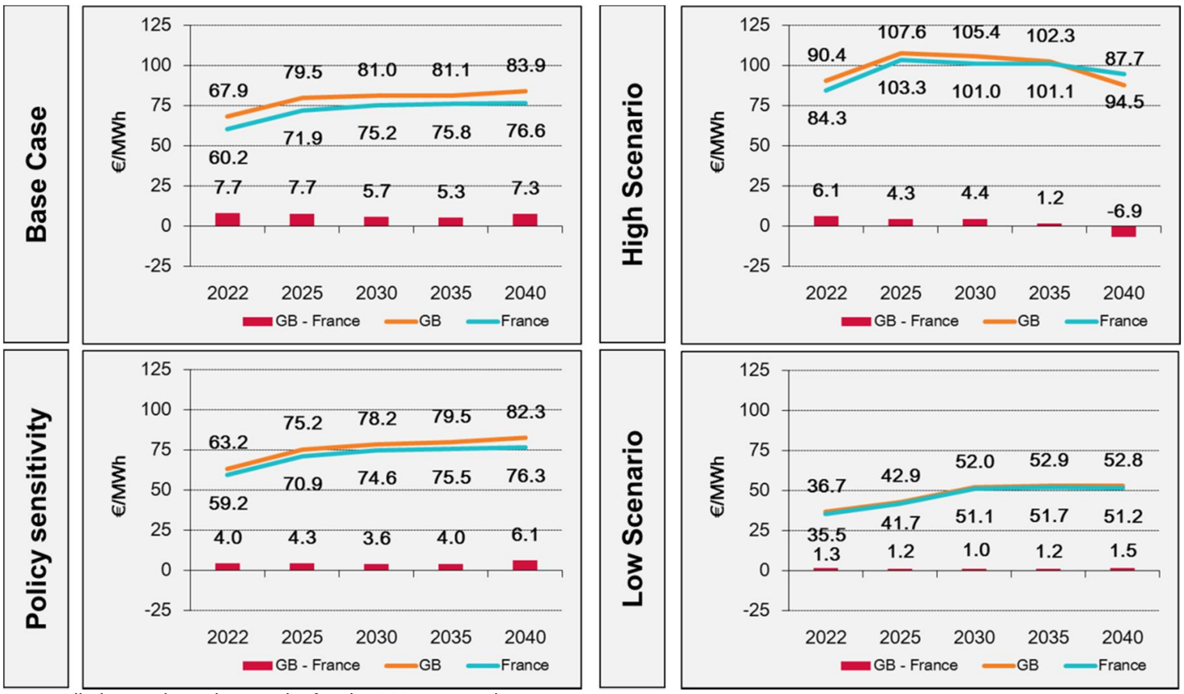
  The MA cases show a significantly lower GB and overall benefit, which is mainly due to the competition from additional GB-France and GB-Germany interconnector projects.

4.4.2 Gridlink – price differentials and flows

The economic and commercial cases for Gridlink are built on the fundamental differences between the electricity markets of Great Britain and France. These differences are related to policy (e.g. carbon tax in Great Britain), capacity mix (e.g. large nuclear fleet in France, higher renewables share in France), and even time difference (GMT vs. CET).

Figure 16 shows the annual average wholesale electricity prices and price differentials between Great Britain and France in the main scenarios and the Policy normalisation sensitivity. In the Base Case, Low scenario and the Policy normalisation sensitivity, price differentials are relatively stable over the modelled period. In the High scenario, continuing deployment of renewable capacity in Great Britain leads to a decrease and eventually a reversal of the average price differential by 2040.

Figure 24 – Price differentials between Great Britain and France

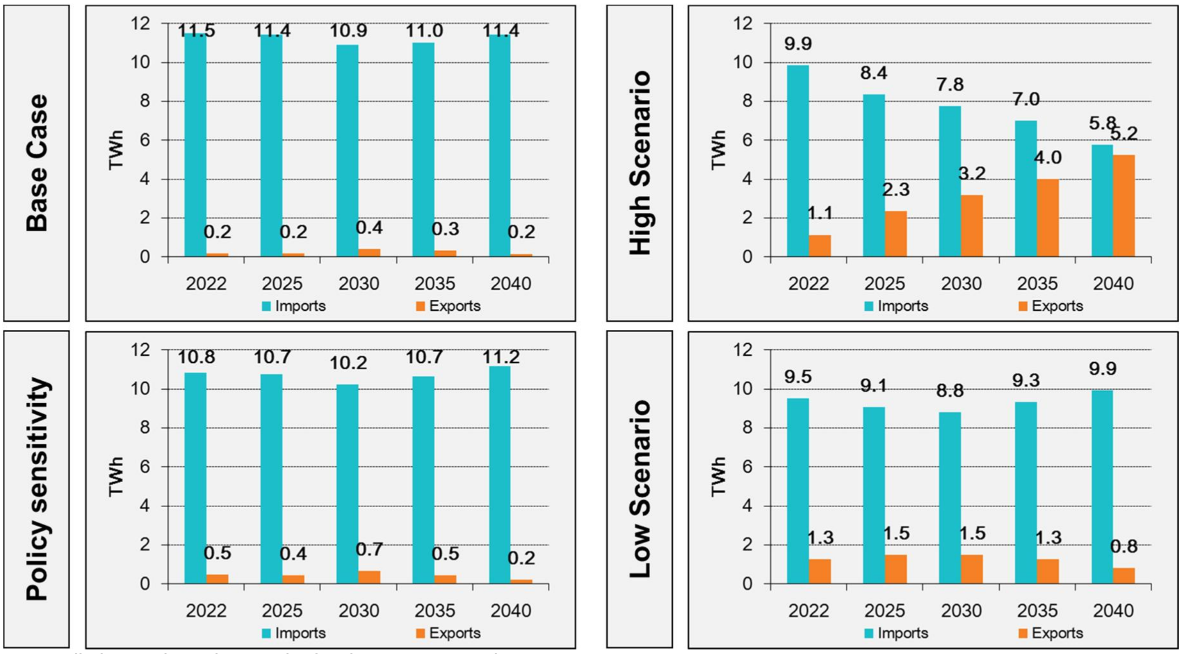


Note: All charts show the results for the MA approach.

The flows of the interconnector – which are closely linked to the price differentials – are presented in Figure 17. Flows are mainly occurring in the direction of Great Britain, due to the persisting higher price compared to France. This is not the case in the High scenario, where increased GB wind capacity leads to an increase in low price periods and more exports over the interconnector. The overall utilisation of the cable is very high, between 89% (Low scenario) and 96% (Base Case).

Imports from France are lower in the Low scenario, compared to the Base Case and Policy normalisation sensitivity, while exports to France are increased. As CPS and BSUoS are removed, price differentials reverse more frequently. However, the value captured from flows in both directions is very low.

Figure 25 – Flows on Gridlink

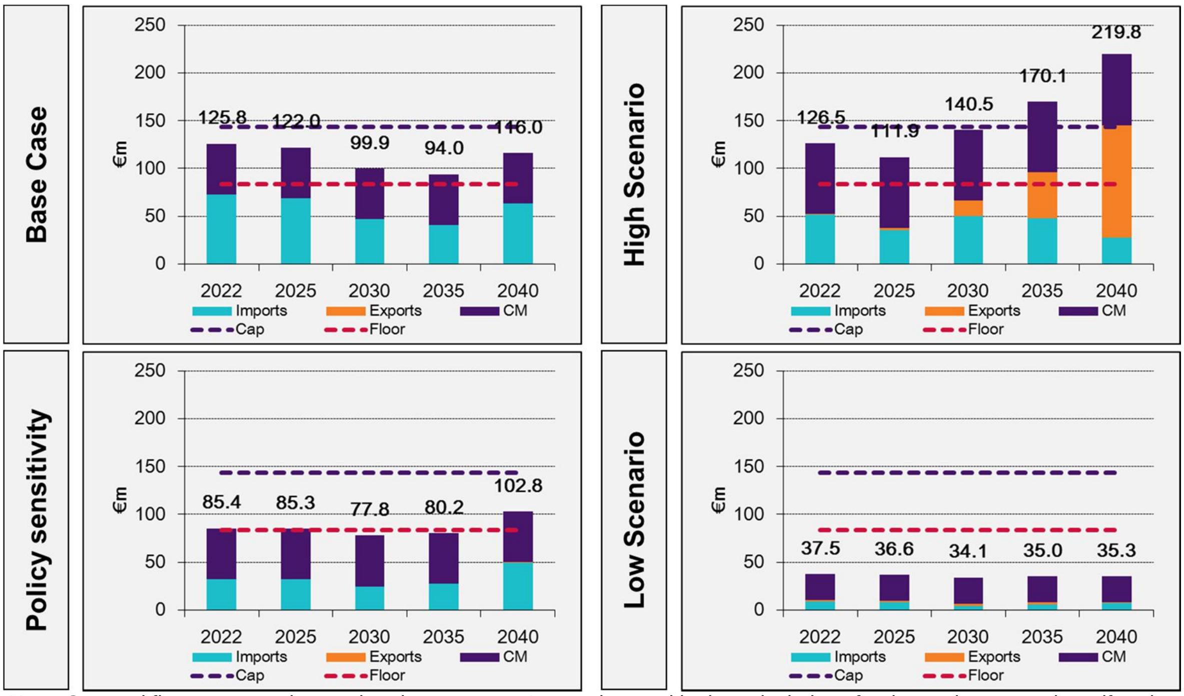


Note: All charts show the results for the MA approach.

4.4.3 Gridlink – revenues and cap and floor impact

Figure 18 shows the project's revenues in the main scenarios and the Policy sensitivity.

Figure 26 – Revenues for Gridlink



Note: Cap and floor compared to total project revenue. In practice, and in the calculations for the socio-economic welfare in this report, the cap and floor is calculated for and applied to the GB share of the project only. All charts show MA results.

The main conclusions from analysing Gridlink's revenues in comparison to its cap & floor are as follows:

- Only the High scenario includes significant revenues on flows from Great Britain to France, which is due to the higher renewables share in GB in that scenario.
- No cap or floor payments are made in the Base Case, but there are significant cap payments in the High scenario in the 2030s. In the Policy normalisation sensitivity, some floor payments are required in the middle of the modelled period. Floor payments are required in all years in the Low scenario.
- Capacity payments constitute a significant share of overall revenues in all scenarios as the project has a high de-rating factor. In the Base Case and Policy normalisation sensitivity, capacity payments are necessary to reach the revenue floor in all years.

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5. SUMMARY OF RESULTS AND MAIN CONCLUSIONS

In order to summarise the analysis and compare the performance of the three interconnectors, we have considered the following welfare impact benchmarks:

- GB consumer welfare impact;
- GB net welfare impact (including GB consumers, producers/generators and GB owned share of interconnectors); and
- total (regional) net welfare impact (consumers, producers and interconnector owners in GB and country connected by the respective interconnector).

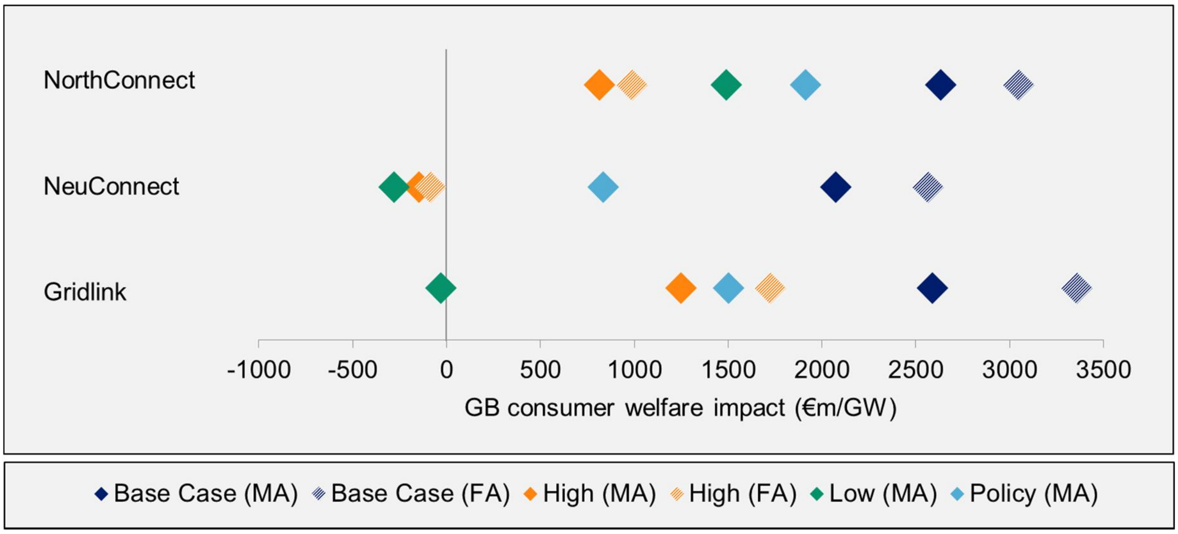
The following sections show results for the MA cases of the scenarios and the Policy sensitivity. For Base Case and High, the FA cases are also included for comparison.

5.1 Impact on GB consumer welfare

Figure 27 shows the project comparison for the impact on GB consumer welfare on a capacity normalised basis (i.e. €m per GW of interconnection capacity installed).

- All three projects provide a large benefit to net GB consumer welfare in the Base Case. The results for NorthConnect and Gridlink are close in the MA case, while NeuConnect's are around €500m lower. This is mostly due to lower flows on this interconnector, as it has a higher loss factor than competing links.
- For all projects, the Base Case represents the best case for GB consumers, as the High shows large GB exports in the later years due to higher renewable deployment.
- NorthConnect is positive for GB consumers in all scenarios and the Policy sensitivity.
- No project shows a significantly negative impact on GB consumers in any scenario, when balanced against the scale of benefits in other scenarios.
- The results for the Policy normalisation sensitivity are in between the Base Case and the Low scenario for all projects as expected.

Figure 27 – GB consumer welfare impact: project comparison (€m/GW)



Source: Pöyry Management Consulting modelling for Ofgem

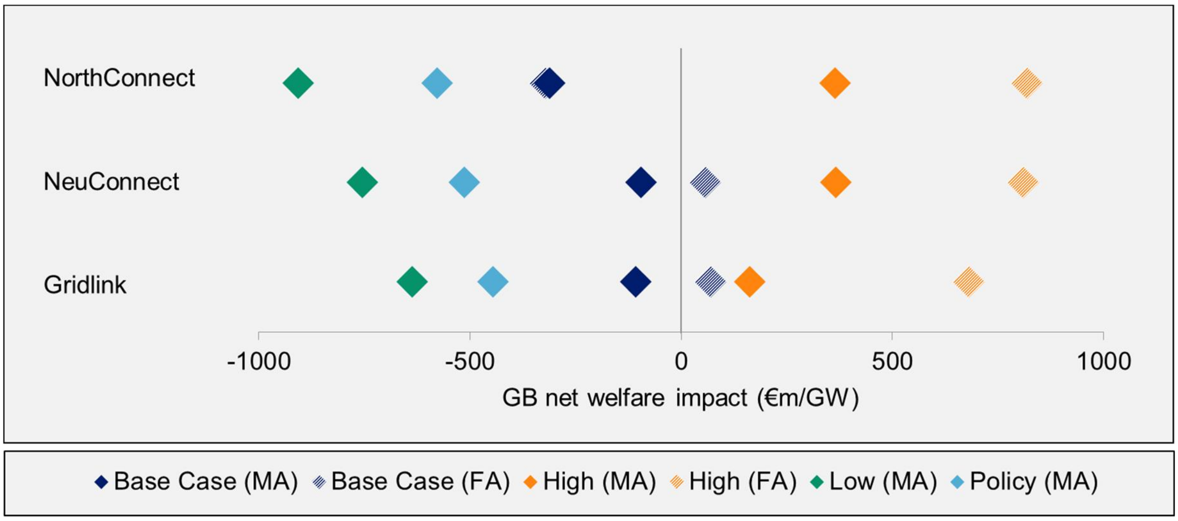
5.2 Impact on GB net welfare

Figure 28 shows the project comparison for the impact on total GB welfare on a capacity normalised basis (i.e. €m/ GW). Total GB welfare is made up of GB consumers, GB producers and the GB share of interconnector welfare, including the respective Window 2 projects.

Comparing the interconnector performance on their impact on GB consumer welfare, the following observations can be made:

- NeuConnect and Gridlink both show a positive, albeit small, benefit for GB net welfare in the Base Case (FA) scenario. None of the projects shows a benefit to GB welfare in the Base Case (MA approach), showing the significant welfare impact of installing all assessed interconnectors.
- The High scenario shows significant upside for all projects, results range in between €390m and €780m.
- The scenario risk appears to be largely symmetrical for all projects.
- The results for the Policy normalisation sensitivity are in between the Base Case and the Low scenario for all projects as expected.

Figure 28 – GB net welfare impact: project comparison (€m/GW)



Source: Pöyry Management Consulting modelling for Ofgem

5.3 Impact on total net welfare

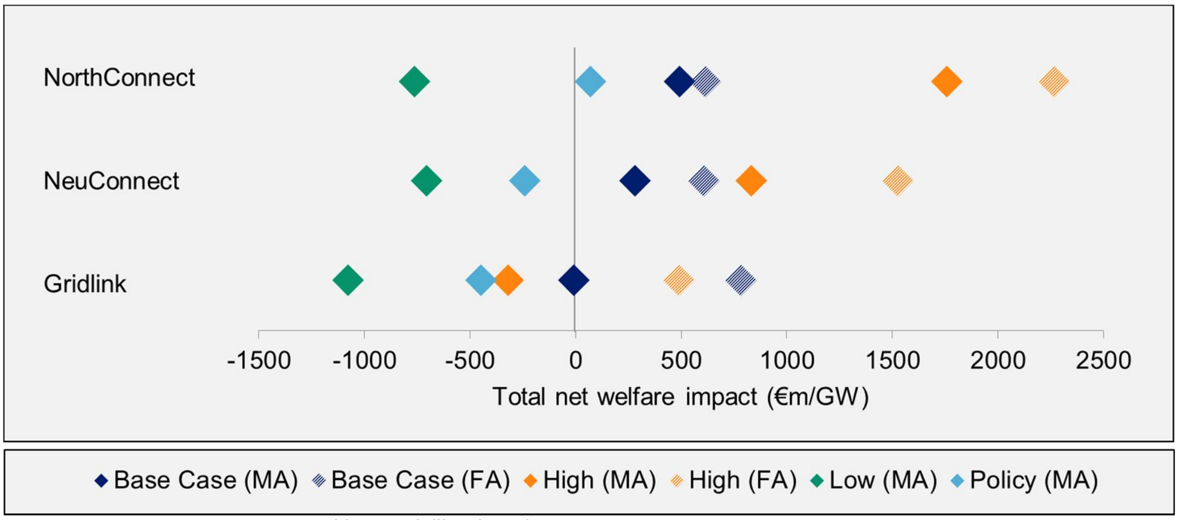
Figure 29 shows the project comparison for the impact on total GB welfare on a capacity normalised basis (i.e. €m/GW). Total GB welfare is made up of GB and connected country consumers, producers and interconnectors, including the respective Window 2 project.

Comparing the interconnector performance on their impact on GB consumer welfare, the following observations can be made:

- All three projects have a positive (or at least neutral) impact on total net welfare in the Base Case for both FA and MA scenarios.

- NorthConnect provides the largest net benefit to Norway and Great Britain combined in the Base Case (MA), High scenario and the Policy normalisation sensitivity.
- Gridlink's impact on total net welfare is worse than its competitors' in most scenarios, due to the large existing and expected additional interconnection capacity between Great Britain and France. It performs best in the Base (FA) scenario showing the significant impact of new interconnection on welfare outcomes in this scenario.
- The total net welfare impact is positive for all projects in the Base Case and High scenario (with the exception of Gridlink in the MA case for the High scenario) and negative for all projects in the Low scenario. NorthConnect is the only project to have a positive total socio-economic welfare impact in the Policy normalisation sensitivity (MA) case.
- Scenario risk is balanced in for all projects, as upside and downside are symmetrical around the Base Case.

Figure 29 – Total net welfare impact: project comparison (€m/GW)



Source: Pöyry Management Consulting modelling for Ofgem

5.4 Main conclusions

Notwithstanding the above discussion of the detailed results of our CBA, our main conclusions from this assessment are as follows:

- All projects assessed in this study are based on a similar premise: connecting Great Britain to countries with lower average wholesale prices, indicative of less expensive sources of electricity generation. In the vast majority of assessed scenarios and sensitivities, all projects provide large benefits for consumers as they lead to lower wholesale electricity prices in GB.
- The High scenario represents a downside for GB consumer welfare for all projects. This is due to the strong increase in GB renewables capacity towards the end of the modelled period which leads to frequent low price periods in Britain. Other things being equal, the resulting exports increase wholesale electricity prices in GB and reduce consumer welfare.
- All projects show a large imbalance of flows in most scenarios towards imports to GB, however:

  - In the High scenario, exports from GB steadily increase on all assessed projects, due to the continued strong renewables development in GB. For NeuConnect, this means that exports exceed imports by the late 2030s.
  - NorthConnect and NeuConnect show a relatively low cable utilisation. Their long distance and consequently relatively high loss factors[25] mean that these projects require large price differentials to make flows economic.
- While all projects are based on a similar premise, there are some important differences in the detailed characteristics, leading to differences in results:
  - NorthConnect has the longest distance and therefore higher costs and loss factors, but connects to the market with the largest average price differential.
  - NeuConnect has a similar distance, costs and loss factor, but connects to a market with a much lower average price differential.
  - Gridlink connects to the market with the lowest average price differential, but has much lower costs and loss factor due to the significantly shorter distance.
- It is noteworthy that the comparative positions of the projects change based on which metric is looked at:
  - From considering the GB consumer welfare, NorthConnect and Gridlink perform stronger. The downside risk is most severe for NeuConnect and Gridlink.
  - NeuConnect and Gridlink provide the largest benefit and highest upside for GB net welfare but all projects are negative in most cases in this metric.
  - Comparing the results from the total net welfare impacts (i.e. net welfare impact in Great Britain and the respective connected country), NorthConnect has the highest benefit in the Base Case and provides the largest upside. Gridlink's impact is only slightly positive in the Base Case (MA) and the project exhibits the largest downside of any project in this metric. NeuConnect has is in between the other two projects for the Base Case and High scenarios, but has the least negative downside in the Low scenario.
- Capacity market revenues represent a significant share of overall revenues for NorthConnect and Gridlink. For both projects, capacity market revenues are required to reach the floor in the Base Case and the Policy normalisation sensitivity. As NeuConnect is assumed to have a much more punitive de-rating factor, capacity market revenues are less substantial for this project.
- All interconnectors are impacted by the cap and floor regime in at least some of the future market scenarios:
  - No significant cap and floor payments are expected in the Base Case and Policy normalisation sensitivity for NorthConnect and Gridlink.
  - In the High scenario, NorthConnect and Gridlink make cap payments from the mid-2030s onwards, which represents a net welfare benefit for GB consumers.
  - NeuConnect requires floor payments in all scenarios in most years. In the High scenario, revenues rise above the floor in the 2030s and are close to the cap from 2040 onwards.

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25 Shorter cables, for example connecting Great Britain to Ireland, France, Belgium or the Netherlands, typically have low loss factors (i.e. the amount of energy lost in transmission). Longer cables have far higher loss factors and therefore need a higher price spread to overcome this volume loss.

ANNEX A – DETAILED MODELLING APPROACH

A.1 Interaction between BID3 and CARAMEL Light

The interaction of our BID3 and CARAMEL Light models is explained in Section 2.3 above. The modelling has broadly been conducted in two stages:

1. In step one our BID3 model is used to produce hourly prices and dispatch for all power plants and interconnectors across the modelled region, in both the case without the interconnector project (counterfactual case) and with the interconnector project (target case) in question.
2. In step two those two cases are imported into the CARAMEL Light model, which then compares the socio-economic welfare and calculates the all other CBA parameters, such as revenues and cap and floor payments.

This modelling process, and its potential strengths and weaknesses, are explained in this Annex below.

A.2 BID3 Market Modelling Approach

The underlying hourly wholesale market price modelling has been done using our BID3 market model. The BID model creates the price and dispatch results that feed into the CARAMEL Light model. A more detailed description of BID3 is provided in Annex B.

As an example Figure 30 and Figure 31 below show the €/MWh prices in GB and France for the Base Case model runs under different granularity time periods in 2025:

- Figure 30 shows the annual average price in 2025 alongside the monthly average prices with the monthly difference (GB less France) shown by the grey solid line; and
- Figure 31 shows the hourly price and price differential in Week 1 of January 2025.

Despite GB prices being significantly higher than those in Norway in both the annual and in all monthly prices, in examining hourly prices, significant hour by hour cross-over between GB and Norwegian prices are observed. While French prices are much closer to GB prices on average, there is significantly less cross-over between the two markets.

In the annual and monthly averages, the difference between Great Britain and Norway are much greater than those between Great Britain and France. However, looking at the first week of 2025 as an example, in most hourly periods the price differences are relatively similar, while a large part of the value on the Norwegian-GB interconnectors is being captured in peak GB periods.

Figure 30 – Annual and monthly avg. prices in GB, FR and NO: Base Case, 2025

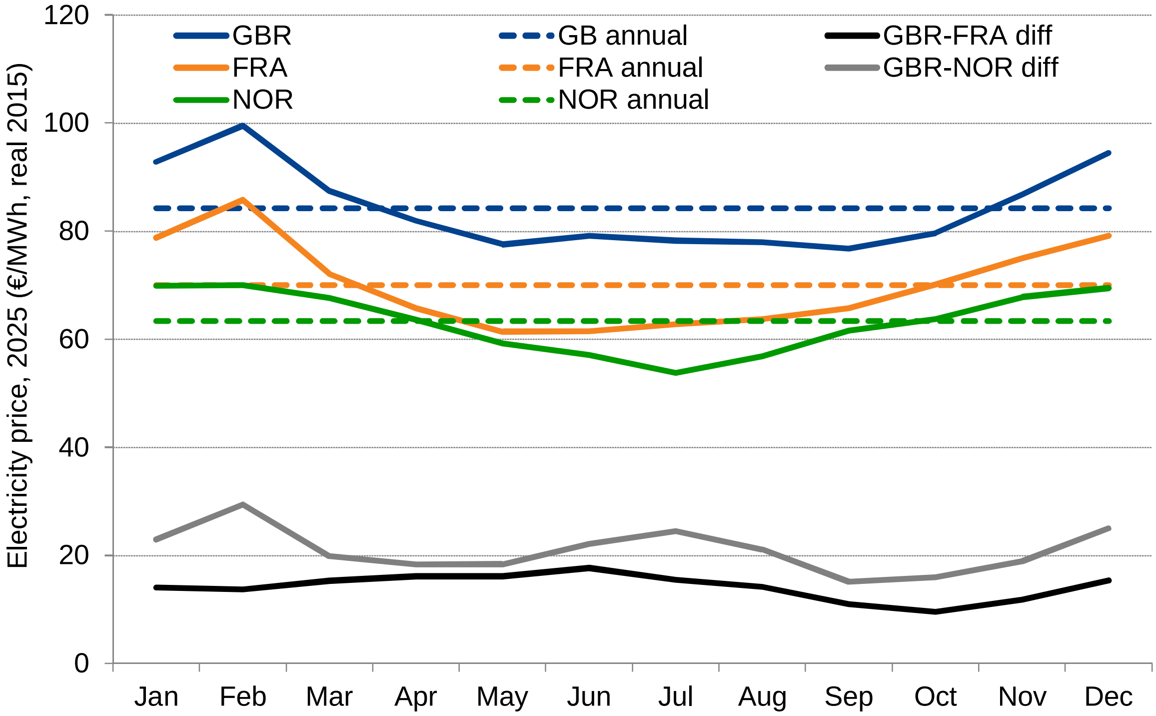
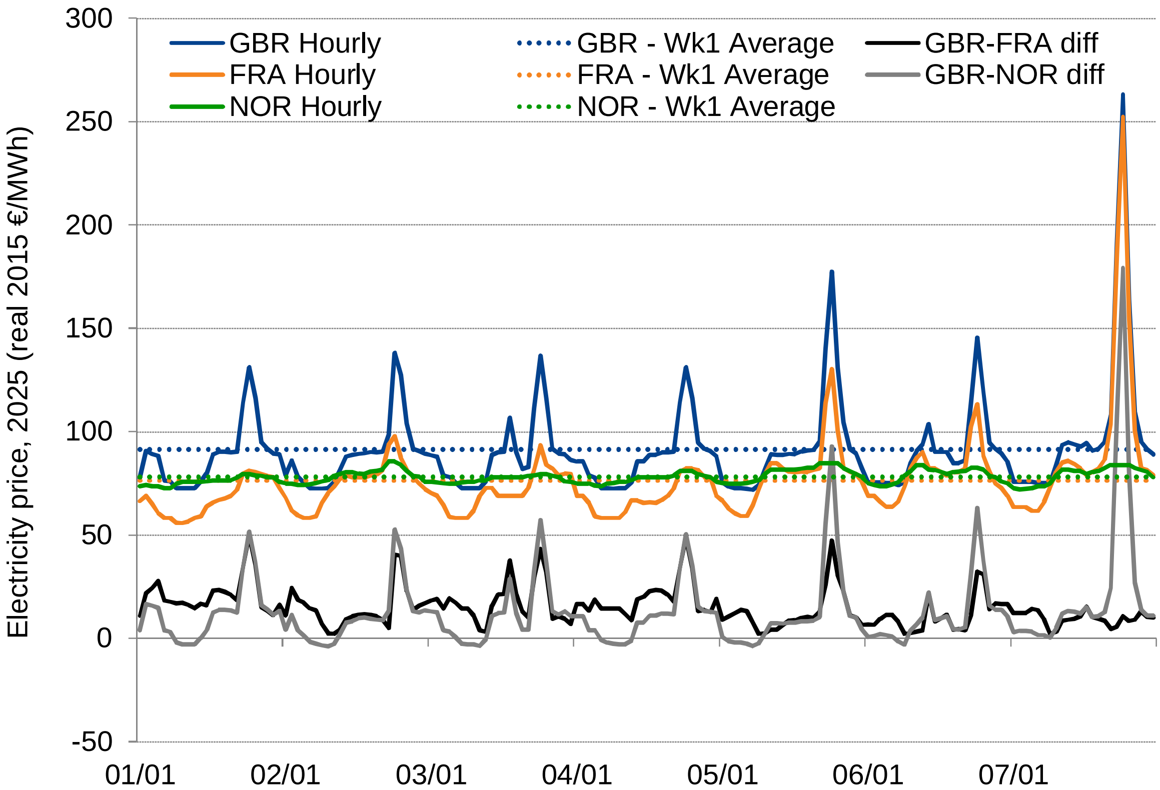


Figure 31 – Hourly prices in GB, FR and NO: Base Case, Week 1 January 2025



For the specific modelling in this project the BID3 model has been run both with and without the target interconnector projects for each of the main scenarios.

We have developed a series of bespoke market scenarios for the project with the aim of spanning a range of interconnector welfare impacts and interconnector values. These scenarios are described in more detail in Section 3.

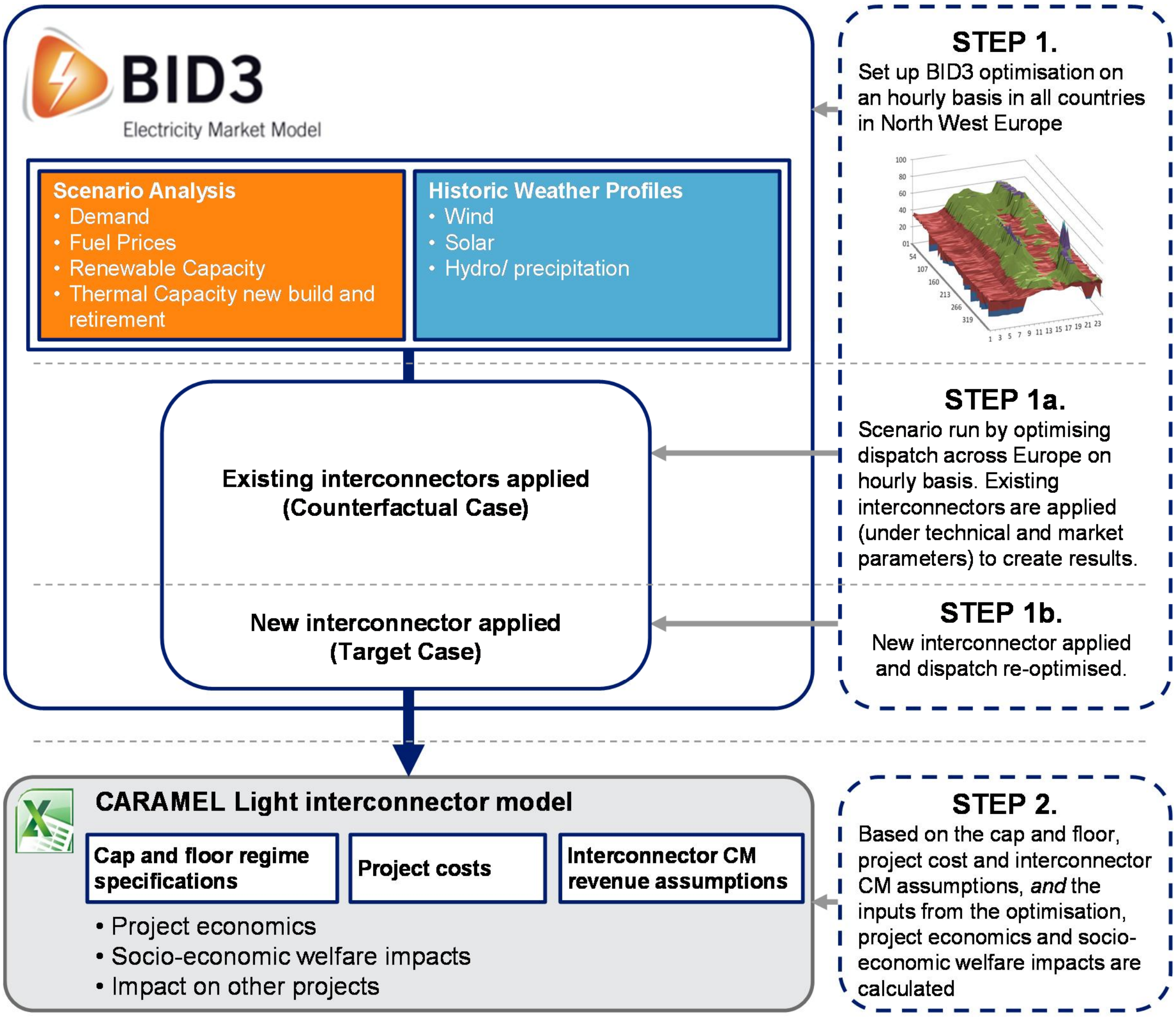
A.3 Description of CARAMEL Light Model

For the assessment of interconnector projects in 2014, Pöyry created an assessment model, CARAMEL, that is capable of using hourly price projections from an optimisation model (BID3) and price elasticity information, to re-optimise flows across GB links and therefore estimate the impact of new links on stakeholders in GB and connected countries. This allowed Ofgem to use the model in a very flexible way at the expense of some granularity on results, particularly for stakeholders outside GB.

The transformed interconnection landscape, as described in Section 1.2, has led to additional complexity in modelling interconnectors connecting to GB. In Window 1, new projects faced only limited competition, connecting GB to markets with very different characteristics. By 2022, markets are expected to have moved closer together, and GB is expecting a much higher level of interconnection in 2022, even before new (Window 2) projects.

This added complexity has led to a re-configuration of the modelling approach for the CBA. Instead of using CARAMEL to re-dispatch flows on the basis of additional interconnection, we run BID3 with and without the new projects and use CARAMEL to calculate the impact of the projects on socio-economic welfare, as shown in Figure 32.

Figure 32 – Modelling approach overview



Using results from two runs of the BID3 model (target case, where the project exists, and counterfactual case, where the project does not exist – all other inputs remain the same across both runs), CARAMEL calculates the economic impact on consumers, producers (generators) and interconnectors based prices and flows by comparing results from BID3 for:

- **Consumer welfare:** Calculated as the sum of hourly movements in wholesale prices multiplied by hourly demand – this implicitly assumes that all such savings accrue to consumers – in our model, this is calculated on an hourly basis by multiplying the demand with the difference between the value of lost load (VoLL) and the resulting price in the country:

  $$Demand\ \times \left(\left(VoLL\ - Post\text{-}flow\ price\right) - \left(VoLL\ - Pre\text{-}flow\ price\right)\right);$$

- **Producer welfare:** Calculated as the change in revenue for generation less the costs of generation, calculated on an hourly basis by BID3 (based on the optimised dispatch schedule determined by the model); and

- **Interconnector welfare:** Calculated as the arbitrage revenue of the new interconnector less the changes in arbitrage revenue on other interconnectors connected to the same market (assuming revenues being split 50:50 across each interconnector). In BID3, this revenue (or congestion rent) is calculated by the revenues of selling power in one country minus the cost of buying power in another, including losses on the cable.

The model also automatically calculates the impact of low carbon support payments (if applied in the form of a CfD), capacity market revenues (if applied), and cap and floor arrangements on each stakeholder group (see Section 2.2.4).

Additionally, CARAMEL Light can be used to report other value metrics which do not form an integral part of the CBA:

- **Carbon emissions in GB:** Where an interconnector causes flows from a country with low marginal carbon intensity of generation to one with a higher marginal carbon intensity of generation we would see carbon savings arising from that flow (this saving/cost implicitly forms part of the producer surplus calculation).
- **Impact on different types of generation in GB:** When flows to and from the GB market occur it will not impact all generators equally. As flows change the marginal producer will change, causing increases or decreases in generation from different plant types (e.g. gas, nuclear or wind). Additionally, the model reports the impact of the interconnector on the load factor of a generic CCGT commissioning around 2025.
- **Weather-related revenue variation:** All scenarios in this study have actually been run 20 times for each modelled future year, using historical wind, solar, rainfall and temperature data to simulate the effect of weather on prices, dispatch and flows. These 20 runs are then averaged to give the final results for the analysis. CARAMEL also allows the user to see how much the revenue of the interconnector can vary between weather patterns.

A.4 Strengths and limitations of the modelling approach

The underlying use of the pan-European BID3 model to produce prices, dispatch and flow projections to 2040 is a central strength of the chosen modelling approach. Utilising a simultaneously optimised pan-European model is a necessary starting point for any cross-border trade analysis as using multiple single country models can quickly introduce internal inconsistencies in market modelling. A pan-European market also as the advantage of accounting for the impact of decisions and developments of large but not directly connected countries on smaller surrounding markets.

BID3 uses robust optimisation techniques which are adopted as standard by numerous consultancies, transmission system operators, governments and utilities for use when projecting long-term electricity market prices, modelling optimal and economically efficient behaviour and minimising the cost of delivery of energy. The approach has been used for asset valuations of both interconnectors and other electricity market assets for many years. Finally it is well aligned with the modelling approach taken by all the cap and floor submissions.

Splitting the modelling procedure into the optimisation process (BID3) and the post-processing of socio-economic and commercial results (CARAMEL) allows Ofgem to retain the model for future use and analysis as well as update/edit aspects of the model and assumptions without the need for additional consultancy support. While the new version of CARAMEL does not allow Ofgem to independently create new interconnector build scenarios, it still offers the flexibility of changing several assumptions, such as project costs, cap and floor levels, project ownership shares, capacity market clearing prices and de-rating factors, exchange rates, and renewable support schemes.

As with every modelling approach, there are some noteworthy limitations:

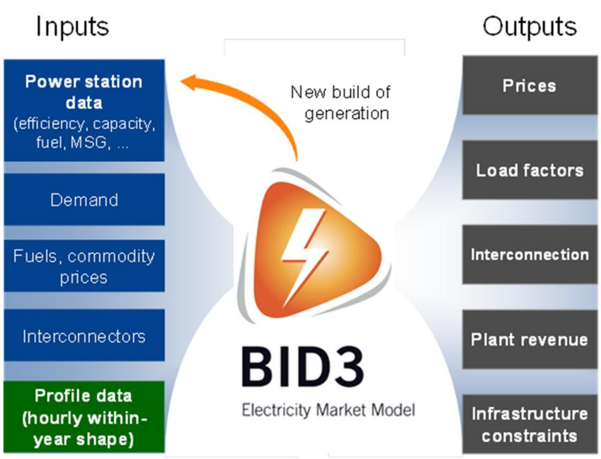
- We have focused on the main elements of interconnector welfare and deriving a consistent approach to the analysis of all interconnectors simultaneously. We have not therefore addressed in detail some of the additional costs and benefits outlined in section 2.2.5 including aspects such as grid reinforcements costs. To the extent that these materially impact the welfare impacts of the interconnectors and/or the costs may fall differentially between interconnectors, further analysis of these cost elements would be beneficial.
- In any scenario approach to modelling a large number of assumptions are required which in turn influence the model results. Furthermore any deterministic scenario will never be a correct representation of the future, and any model is a necessary simplification of real world events. In order to mitigate the weaknesses inherent in this form of scenario modelling we have provided a range of scenarios that are specifically aimed at spanning a reasonable range of values. We have also conducted sensitivity analysis on the results to test the robustness of the analysis to major assumptions.
- The underlying price projection modelling approach aims at creating realistic hourly prices at the day-ahead stage based on historic weather and demand profiles. While we have run every scenario with 20 different weather patterns, the final results and conclusions are based on the average of these scenario runs. Although this gives a good representation of the expected performance of the interconnector on average over the lifetime of the asset – this performance could be significantly higher or significantly lower in some years, depending on the out-turn weather conditions.

ANNEX B – BID3 POWER MARKET MODEL

B.1 Overview

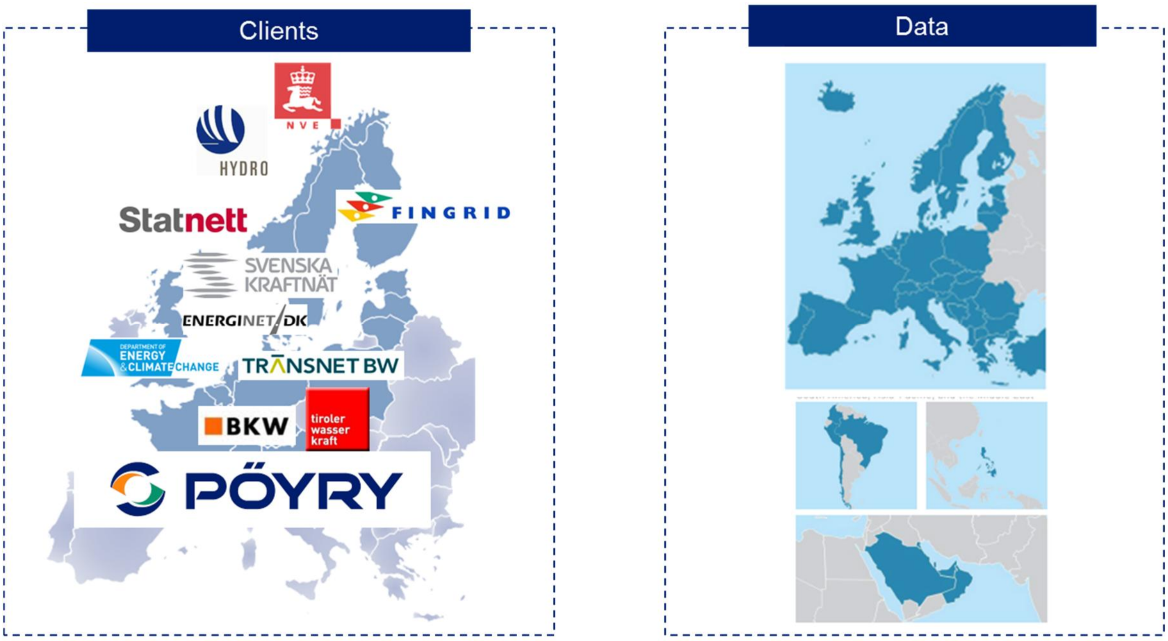
BID3 is Pöyry's power market model, used to model the dispatch of all generation on the European network. It simulates all 8,760 hours per year, with multiple historical weather patterns, generating hourly wholesale prices for each country for each future year and dispatch patterns and revenues for each plant in Europe.

Figure 33– Overview of BID3



BID3 has an extensive client base, as shown below. In addition, Pöyry provides data for BID3 for all European countries.

Figure 34 – BID3 clients and data



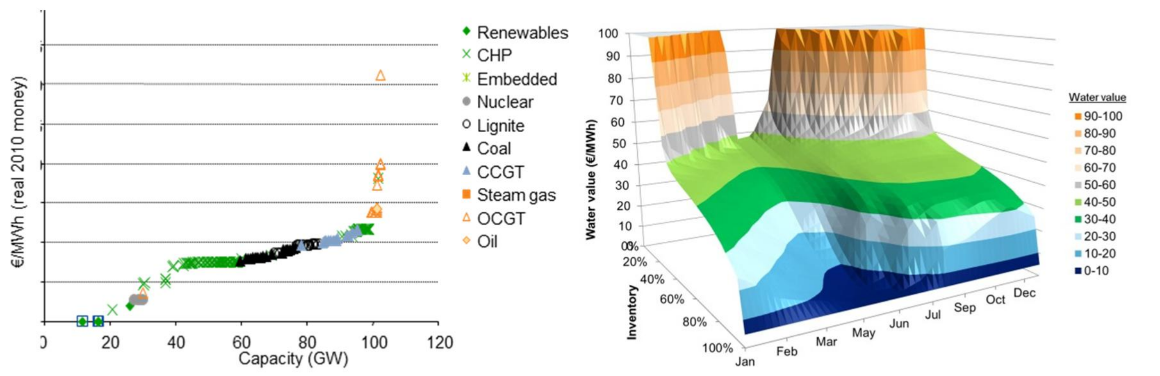
B.2 Modelling methodology

BID3 is an economic dispatch model based around optimisation. The model balances demand and supply on an hourly basis by minimising the variable cost of electricity generation. The result of this optimisation is an hourly dispatch schedule for all power plants and interconnectors on the system. At the high level, this is equivalent to modelling the market by the intersection between a supply curve and a demand curve for each hour.

B.2.1 Producing the system schedule

- **Dispatch of thermal plant.** All plants are assumed to bid cost reflectively and plants are dispatched on a merit order basis – i.e. plants with lower short-run variable costs are dispatched ahead of plant with higher short-run variable costs. This reflects a fully competitive market and leads to a least-cost solution. Costs associated with starts and part-loading are included in the optimisation. The model can also take account of all the major plant dynamics, including minimum stable generation, minimum on-times and minimum off-times. Figure 35 below shows an example of a merit order curve for thermal plant.
- **Dispatch of hydro plant.** Reservoir hydro plants can be dispatched in two ways:
  - A perfect foresight methodology, where each reservoir has a one year of foresight of its natural inflow and the seasonal power price level, and is able to fix the seasonality of its operation in an optimal way.
  - The water value method, where the option value of stored water is calculated using Stochastic Dynamic Programming. This results in a water value curve where the option value of a stored MWh is a function of the filling level of the reservoir, the filling level of competing reservoirs, and the time of year. Figure 35 below shows an example water value curve.
- **Variable renewable generation.** Hourly generation of variable renewable sources is modelled based on detailed wind speed and solar radiation data which can be constrained, if required, due to operational constraints of other plants or the system.
- **Interconnector flows.** Interconnectors are optimally utilised – this is equivalent to a market coupling arrangement.
- **Demand side response and storage.** Operation of demand side and storage is modelled in a sophisticated way, allowing simulation of flexible load such as electric vehicles and heat while respecting demand side and storage constraints.

Figure 35 – Thermal plant merit-order and water value curve



B.2.2 Power price

The model produces a power price for each hour and for each zone (which may be smaller than one country, for example the different price-zones within Norway). The hourly power price is composed of two components:

- **Short-run marginal cost (SRMC).** The SRMC is the extra cost of one additional unit of power consumption. It is also the minimum price at which all operating plant are recovering their variable costs. Since the optimisation includes start-up and part-load costs all plant will fully cover their variable costs, including fuel, start-up, and part-loading costs.
- **Scarcity rent.** A scarcity rent is included in the market price – we assume power prices are able to rise above the short-run marginal cost at times when the capacity margin is tight. In each hour the scarcity rent is determined by the capacity margin in each market. It is needed to ensure that the plants required to maintain system security are able to recover all of their fixed and capital costs from the market.

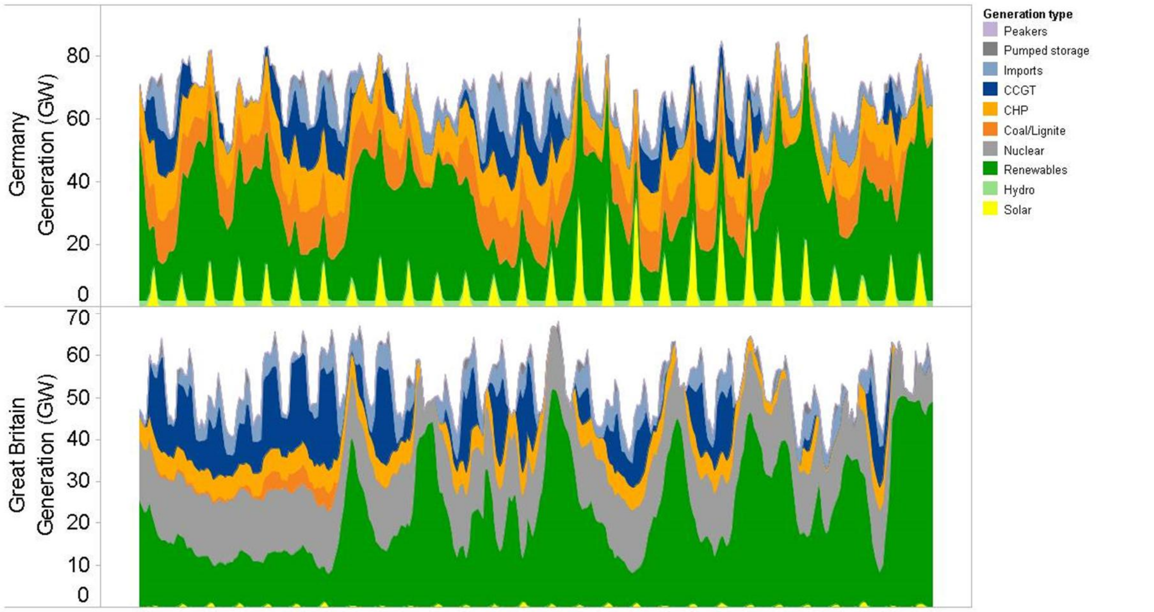
B.3 Input data

Pöyry's power market modelling is based on Pöyry's plant-by-plant database of the European power market. The database is updated each quarter by Pöyry's country experts as part of our *Energy Market Quarterly Analysis*. As part of the same process we review our interconnection data, fuel prices, and demand projections.

- **Demand.** Annual demand projections are based on TSO forecasts and our own analysis. For the within year profile of demand we use historical demand profiles – for each future year that is modelled we use demand profiles from a range of historical years.
- **Intermittent generation.** We use historical wind speed data and solar radiation data as raw inputs. We use consistent historical weather and demand profiles (i.e. both from the same historical year) which means we capture any correlations between weather and demand, and can also example a variety of conditions – for example a particularly windy year, or a cold, high demand, low wind period.

  For wind data, we use hourly wind speeds at grid points on a 20km grid across Europe, at hub height. Hourly wind speed is converted to hourly wind generation based on wind capacity locations and using appropriate aggregated power curves. Detailed hourly solar data, sampled at a 5km resolution is converted to solar generation profiles based on capacity distributions across each country. An example of the resulting profiles and generation mix is shown in Figure 36.
- **Fuel prices.** Pöyry has a full suite of energy market models covering coal, gas, oil, carbon, and biomass. These are used in conjunction with BID3 to produce input fuel prices consistent with the scenarios developed.

Figure 36 – Illustrative snapshot of future generation for a one month period



B.4 Model results

BID3 provides a comprehensive range of results, from detailed hourly system dispatch and pricing information, to high level metrics such as total system cost and economic surplus. A selection of model results is shown below in Figure 37.

Figure 37 – BID3 dashboards output examples (1/2)

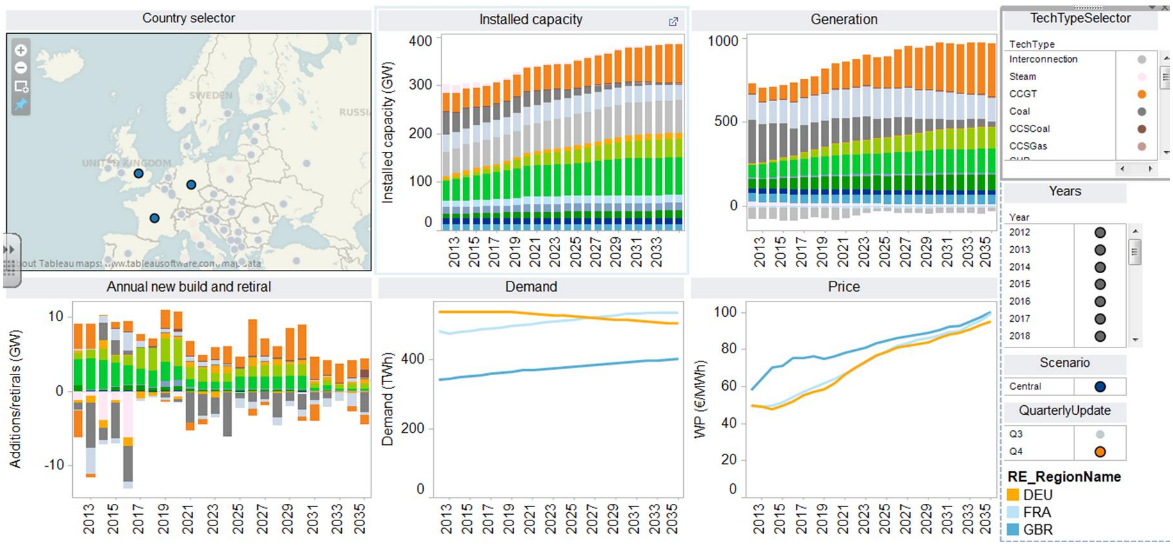


Figure 38 – BID3 dashboards output examples (2/2)

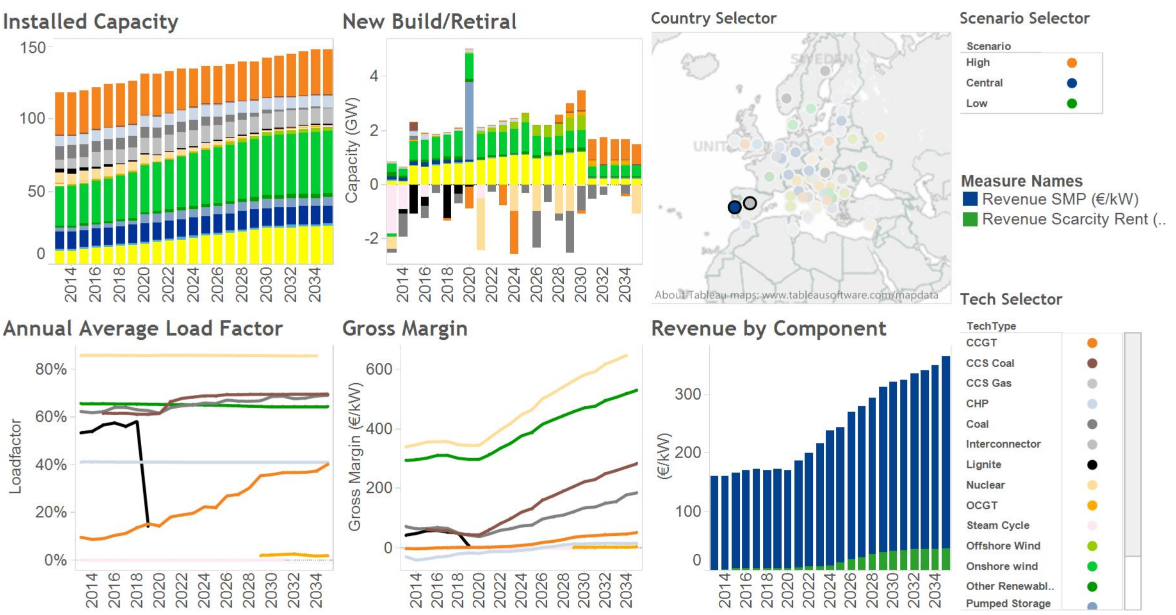
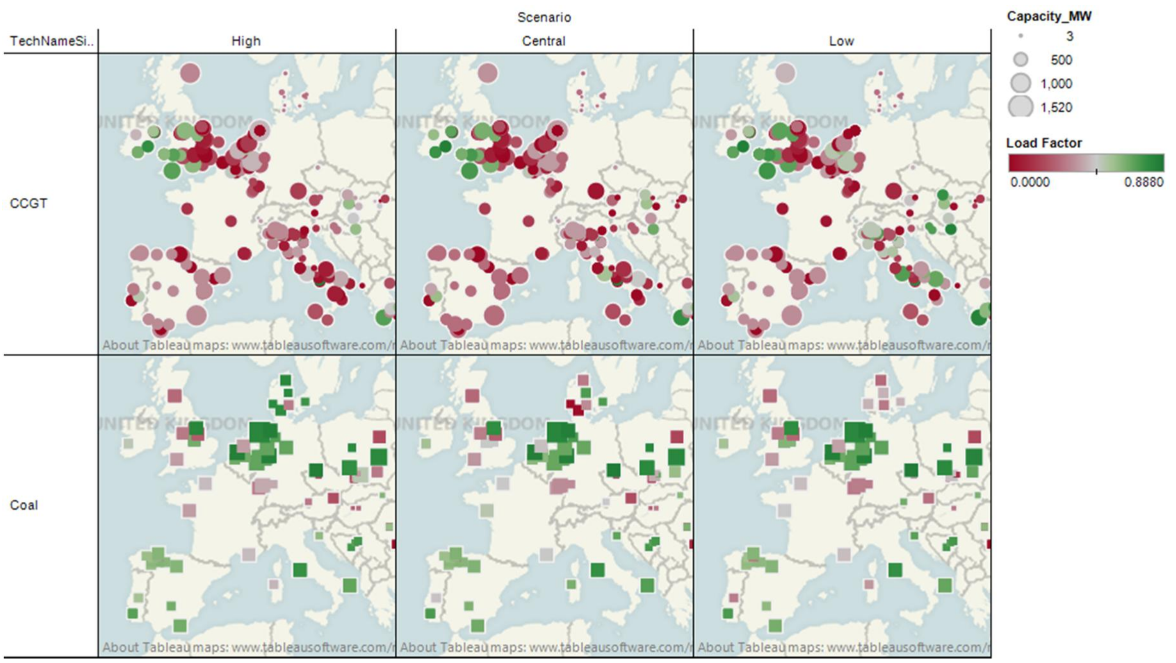


Figure 39 – Geographical representation of results and mapping functionality



For more information about BID3, please visit: www.poyry.com/BID3 or email to BID3@poyry.com.

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ANNEX C – DETAILED MODEL INPUTS

The scenarios have been designed in line the overall aims and principles as laid out in Section 3. Detailed model scenario inputs are shown below.

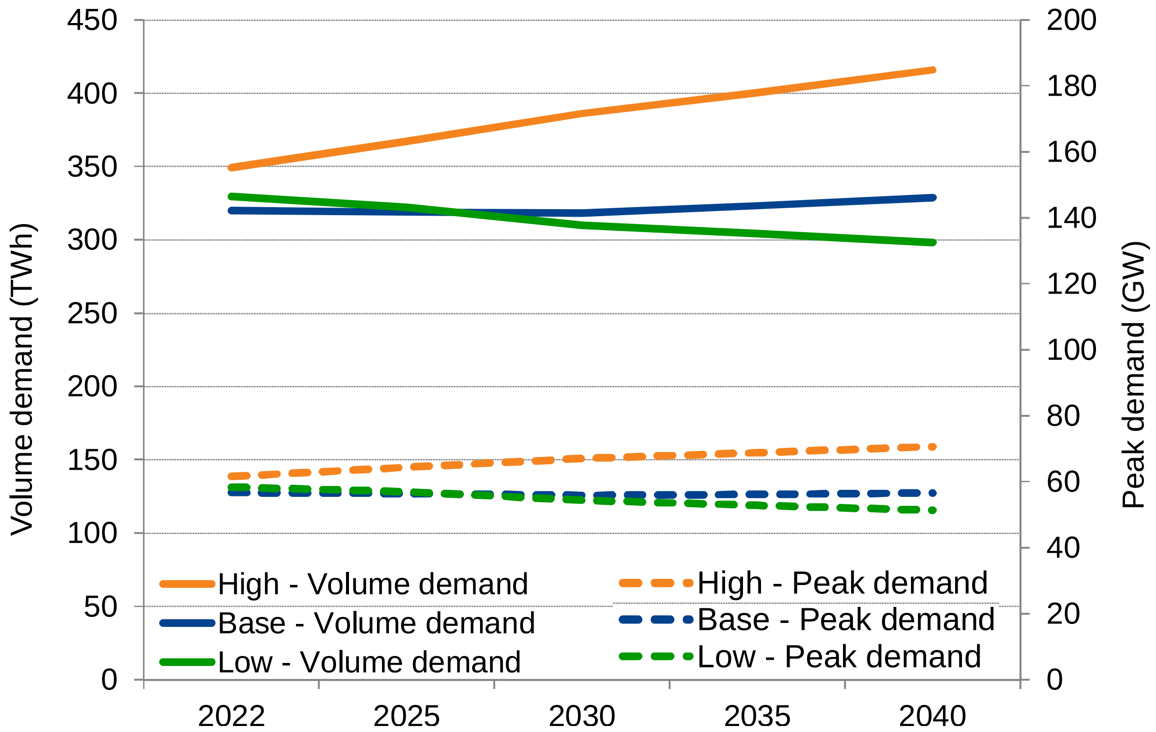
C.1 Demand assumptions

Three demand scenarios have been developed to span a range of future annual and peak demand. Important drivers of future demand growth are GDP and the potential electrification of the heat and transport sectors. This growth can be offset by energy efficiency measures which tend to lower both the total (TWh) and peak (GW) demand. The basis for the demand projections in the three scenarios is as follows:

- In the Base Case, demand development is based National Grid's 'Slow Progression' scenario. While GDP is growing slowly, increased levels of energy efficiency lead to stagnating demand until 2030. After that, electrification of heat and transport leads to a slight increase in demand in this scenario.
- In the High scenario, the more favourable economic conditions along with the electrification of heating and transport lead to growing electricity demand. The demand assumptions are based on the 'National Green Transition' scenario of the final TYNDP 2016 Scenario Development Report.
- In the Low scenario, unfavourable economic conditions and modest GDP growth lead to decreasing demand. The basis for this scenario is the 'Slowest Progress' scenario of the final TYNDP 2016 Scenario Development Report.

The demand assumptions used in the main scenarios are shown in Figure 40.

Figure 40 – Projections of total and peak demand for Great Britain (TWh)



C.2 Capacity mix assumptions

In all scenarios we assume that new plant will come on-line as required, to ensure a reasonable level of security of supply. Generally, we have assumed a level of generic new capacity (not based on specific known projects[26]) to ensure that the capacity margin remains adequate at times when the system is tightest[27]; we model this against historical hourly patterns of weather and demand.

Capacity mix in the Base Case

For the purposes of this study, we have developed the Base Case in such a way so that the installed thermal capacity is consistent with National Grid's 'Slow Progression' scenario, but with lower renewables deployment consistent with National Grid's 'No Progression' scenario. The 'No Progression' scenario assumes onshore wind decommissioning in the 2030s.

In the Base Case, coal plants close by 2021 and no new coal build is assumed. In addition to renewables, gas forms the majority of new build with moderate levels of new nuclear developed in the 2020s and 2030s.

In the rest of North West Europe (NWE), capacity assumptions are based on ENTSO-E's 'Constrained Progress', reflecting a continuation of growth in renewables combined with a slow increase in demand. Specifically:

- Coal plants retire in Ireland (to some extent replaced by CCGT) sees a major expansion in wind capacity.
- Germany and Belgium retire their nuclear capacities by 2023 and 2029 respectively in line with current plans, while nuclear continues to dominate the French market.
- Germany in particular sees a continued increase in the level of installed renewable capacity.
- Norway expands its wind capacity but maintaining a strong focus on hydro power.
- France sees an expansion of solar, offshore wind and onshore wind capacity while nuclear capacity remains dominant even though it declines between 2020 and 2040.

Figure 41 and Figure 42 below show the installed capacity mix assumptions for Great Britain and the rest of the core modelled region in the Base Case (Belgium, Northern Ireland, Republic of Ireland, France, Netherlands, Germany, Denmark and Norway).

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26 We use the term 'generic' for plant which are not yet financially committed (or 'named') but we assume will come online in later years to maintain the capacity margin.

27 A sufficient capacity margin is maintained so that loss of load expectation is acceptable.

Figure 41 – Installed capacity in the Base Case in Great Britain (GW)

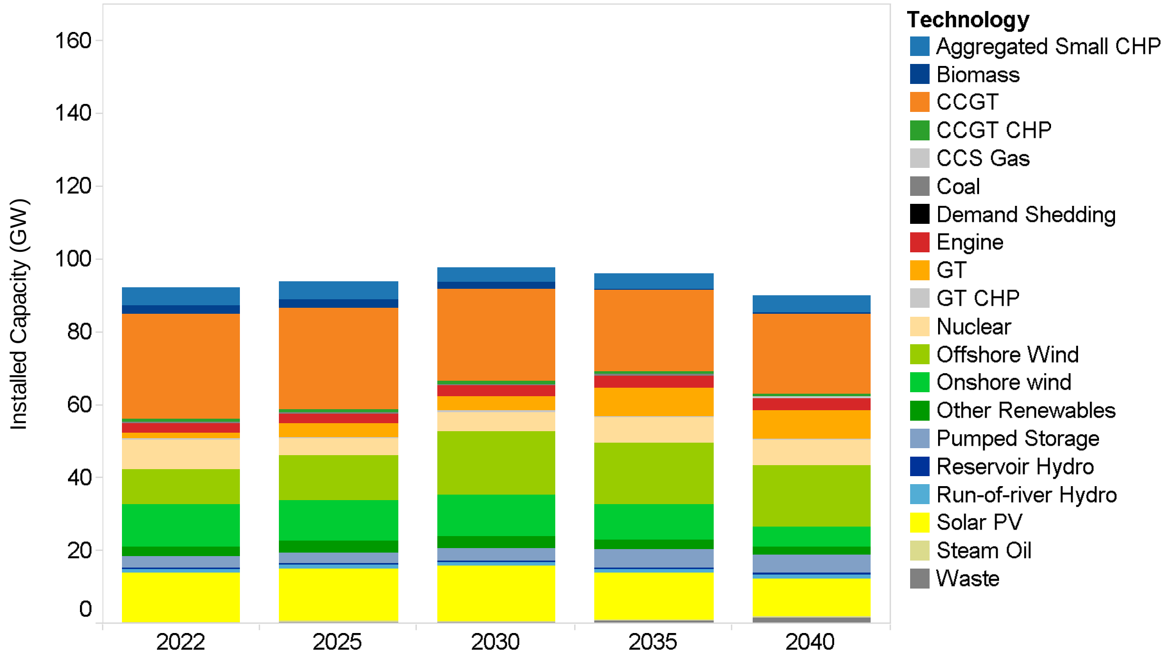
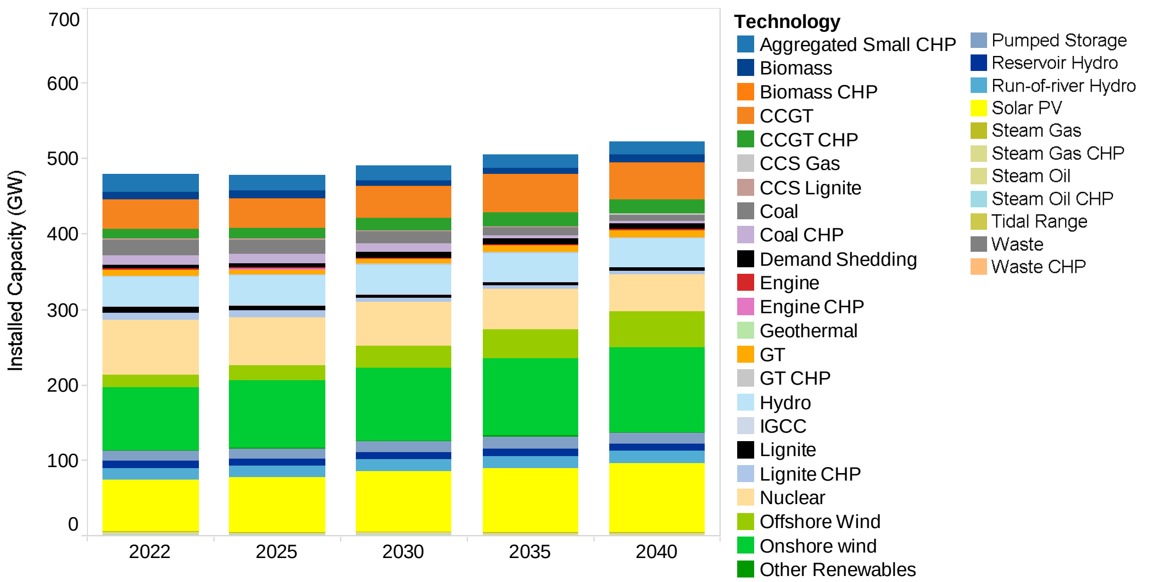


Figure 42 – Installed capacity in the Base Case in rest of North West Europe (GW)



Capacity mix in the High scenario

The High scenario capacity evolution for GB is based on the 'National Green Transition' scenario of the final TYNDP 2016 Scenario Development Report which shows high demand growth, strong growth in installed capacity and accelerated renewable expansion. Retiring coal plants are partially replaced by gas plants and nuclear (after 2020) with strong renewable growth in onshore wind, offshore wind and solar.

The majority of NWE countries also see a strong growth in renewables and demand requiring the development of significant volumes of new capacity:

- Ireland shows onshore wind and solar growth and replaces retiring coal with CCGTs after 2030.
- Belgian nuclear plants close by 2029 and the capacity of offshore and onshore wind increases significantly between 2022 and 2040.
- In the Netherlands, coal runs until 2040 and sees a strong renewables growth.
- While France is still dominated by nuclear, Germany closes its nuclear plants by 2022 and sees a very strong growth of renewables.
- Denmark sees a strong growth in wind capacity and retires coal CHPs by 2030 while Norway builds some wind capacity and stays focused on hydro.

Figure 43 and Figure 44 below show installed capacity mix assumptions for Great Britain and the rest of the core modelled region in the High scenario (Belgium, Northern Ireland, Republic of Ireland, France, Netherlands, Germany, Denmark and Norway).

Figure 43 – Installed capacity in the High scenario in Great Britain (GW)

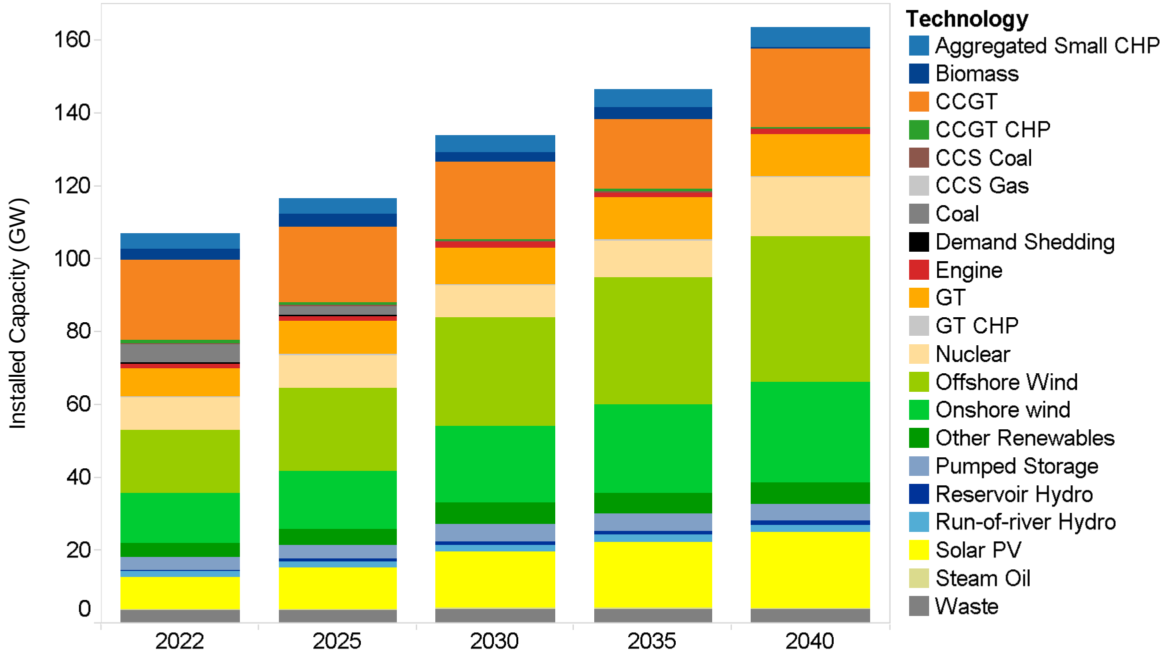
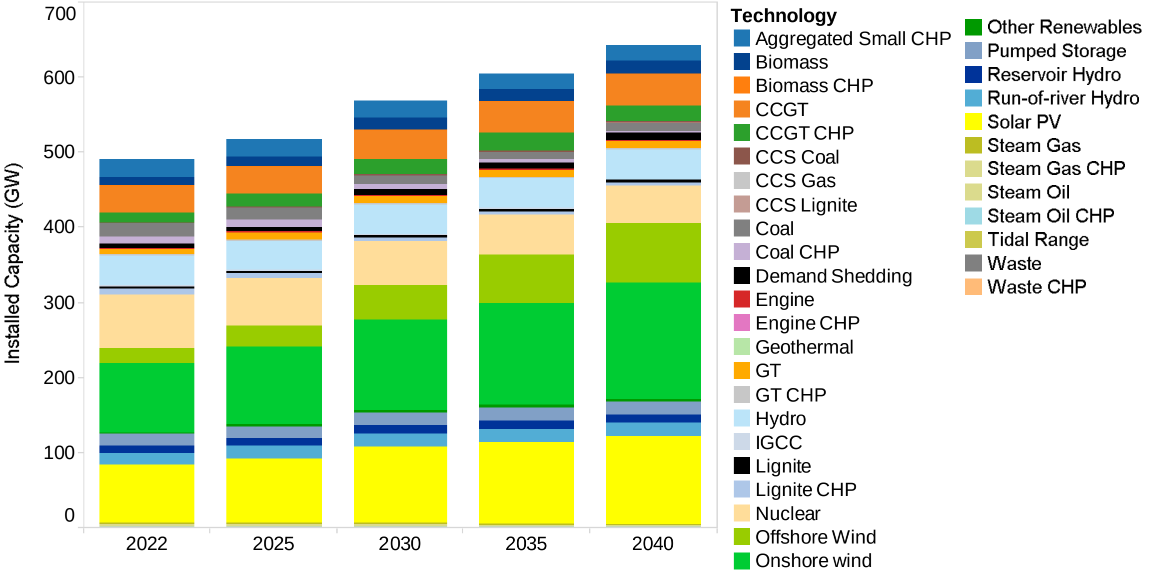


Figure 44 – Installed capacity in the High scenario in rest of NWE (GW)



Capacity mix in the Low scenario

The Low scenario capacity mix for GB is based on the 'Slowest Progress' scenario of the final TYNDP 2016 Scenario Development Report. Coal plants and nuclear plants in Great Britain gradually retire by 2035 and 2040 respectively while the rapidly falling demand growth leads to little requirement for new baseload capacity to 2030 which is mainly covered by OCGTs. Beyond 2030 we assume that 6GW of new CCGTs and 2GW of new Nuclear enter the market however the renewable growth stalls.

The majority of the NWE countries progress in line with the GB market with only a small growth in renewables with stagnating or decreasing demand – this means that the overall installed capacity in this scenario is much lower than in the High and Base scenarios:

- Renewable expansion stalls after 2020 with minor exceptions.
- In Ireland, coal plants retire in the early 2020s while in France they retire gradually until the late-2030s.
- France is dominated by nuclear but share is decreasing, while CCGT is expanding.
- The Netherlands see a weak increase in gas capacity along with a gradual expansion of renewables to 2040. A similar story is seen in Germany where retiring coal and nuclear plants do require some replacement by new gas-fired capacity.
- Denmark's small requirements for new capacity are covered by an increase of offshore wind.
- Norway continues to rely on hydropower.

The figures below show are installed capacity mix assumptions for Great Britain and the rest of the modelled region in the Low scenario (Belgium, Northern Ireland, Republic of Ireland, France, Netherlands, Germany, Denmark and Norway).

Figure 45 – Installed capacity in the Low scenario in Great Britain (GW)

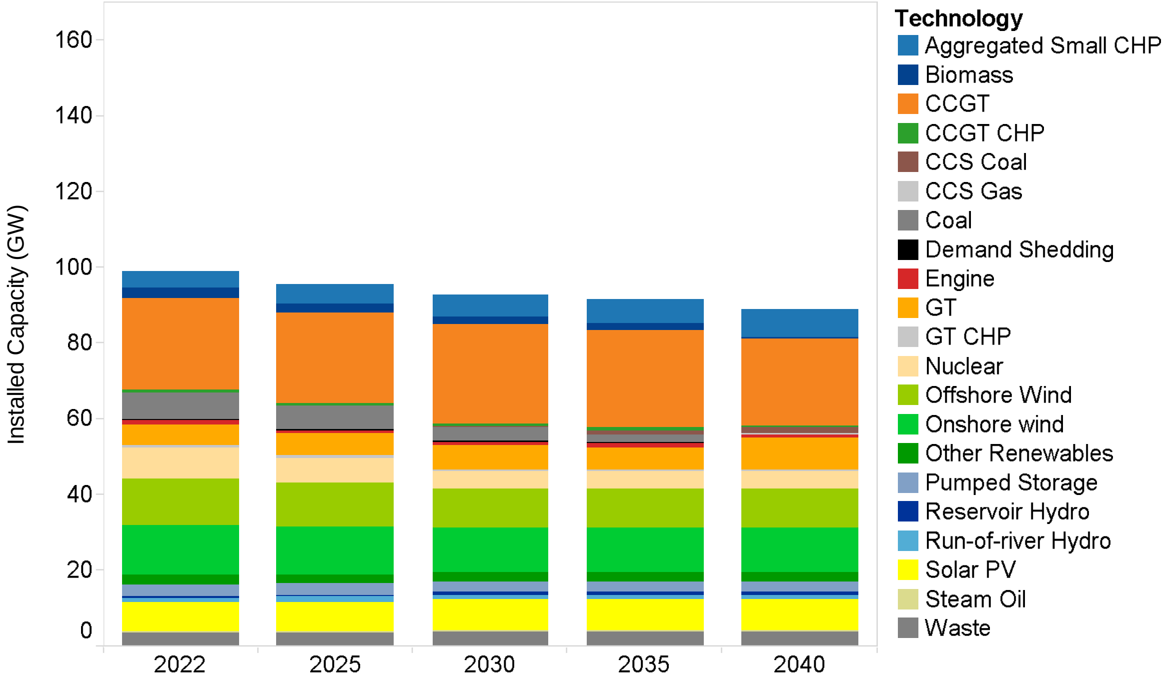
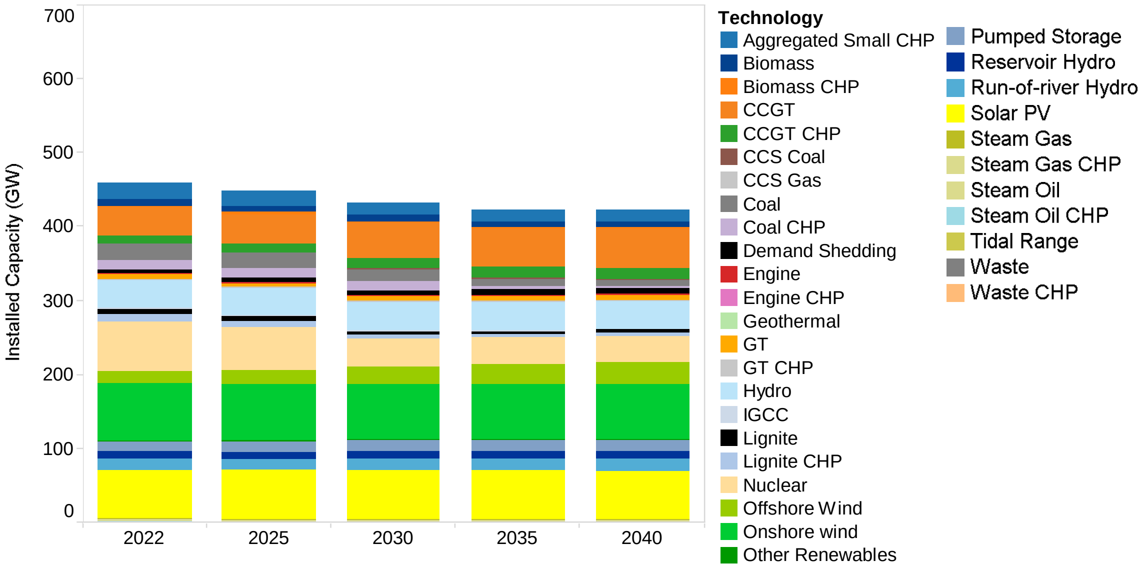


Figure 46 – Installed capacity in the Low scenario in rest of NWE (GW)



C.3 GB renewable support schemes

C.3.1 Introduction to GB renewable support schemes and representation in modelling

There are currently two renewable support schemes in place in Great Britain: the Renewables Obligation Certificate (RO) and the Feed-in Tariff with Contracts for Difference (CfD).

The RO, currently the main support scheme for large scale renewable electricity in the UK, is due to be closed to all new projects from April 2017 as a result of the introduction of the CfD scheme.

For the purpose of assessing interconnectors, the CfD scheme is of interest. Interconnectors create value in GB by influencing the wholesale electricity price. However, as CfD projects are guaranteed their strike price in most circumstances, consumers are required to top up lost revenue for these projects when imports decrease prices. Therefore, not all of the interconnector's price impact feeds through to consumers.

For the RO scheme, no such adjustment is necessary, as projects under this scheme receive ROCs on top of their market revenues but are still exposed to market prices.

In the modelling study conducted for this report, it was assumed that the effect of an interconnector on wholesale prices in Great Britain would be fully attributable to consumers. However, as far as this price effect had an impact on the revenues of CfD generators, the difference in revenue was transferred back to consumers (so that consumers had to pay more towards CfD generators when the interconnector had a negative price impact and vice versa).

C.3.2 The Renewables Obligation Certificate (ROC)

The RO is currently the main support scheme for large scale renewable electricity in the UK[28]. It is a green certificate scheme providing support on top of any revenues gained from the sale of wholesale electricity. It has been in existence since April 2002 and lasts until 31 March 2037. Since its introduction it has been adapted significantly with a movement to technology differentiated support through 'banding' and a movement to more stable certificate prices through the introduction of the 'headroom' mechanism.

C.3.3 The Feed-in Tariff with Contracts for Difference (FiT CfD)

The Energy Act 2013 introduced a new renewables support mechanism, the Feed-in Tariffs with Contracts for Difference scheme. The Feed-in Tariff with Contracts for Difference (FiT CfD) is initially operating alongside the Renewables Obligation (RO) and will replace the RO once this closes to all new generation in 2017.

FiT CfDs are intended to provide greater certainty and stability of revenues to electricity generators by reducing their exposure to volatile wholesale prices, whilst protecting consumers from paying for higher support costs when electricity prices are high.

The first FiT CfD allocation round commenced in October 2014 with the first FiT CfDs awarded in February 2015. A generator which is party to a FiT CfD is paid the difference between the 'strike price', a price for electricity reflecting the cost of investing in a particular low carbon technology, and the 'reference price', a measure of the market price for electricity in the market. Payments will be made on metered output (adjusted for transmission losses), with payments to a generator capped at their respective strike price to avoid the risk of increasingly negative prices[29]. The contracted plant must still generate revenue from the wholesale market for its output. The overall amount of support available

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28 This is due to be closed to all new projects from April 2017 as a result of the introduction of the Contracts for Difference scheme.

29 CfD contracts awarded in future allocation rounds will contain terms which prohibit support during periods when the market reference price is negative for six hours or longer.

through FiT CfDs is limited, due to the UK Government's need to manage the overall level of support paid by consumers under the Levy Control Framework (LCF).

Given the current Government's commitment to end new subsidies for onshore wind it is doubtful that onshore wind will be able to participate in future FiT CfD allocation rounds. The likelihood of the frequency and scope of future CfD allocation rounds will also depend upon the availability of budget under the LCF as discussed below.

For further allocation rounds, projected spending under the LCF would need to fall below the current projection of £8.7bn (real 2011/12 money) and would only appear probable if LCF spending projections for 2020/21 fall below the £7.6bn LCF cap.

There is a significant risk that the LCF projections will not fall below the £7.6bn spending cap. The potential changes are:

- The **CfD projections** have the potential to fall due to projects allocated funding failing to commission or reducing installed capacity[30], assuming BEIS's projections are consistent with a zero or very low attrition rate.
- **Wholesale electricity prices** are likely to continue to change over the period to 2020. Given the future volatility of wholesale electricity prices, how these change and/or BEIS's treatment of them could be a critical element of whether there is a future CfD round for projects commissioning prior to 2020.
- Under the **ssFiT**[31]**,** the cap on the costs of supporting new installations of around £100million means this cost projection should be relatively stable.
- **Future policy changes** could also impact on budgets under the LCF. For example:
  - A move to a single inflation index of CPI to deflate costs to 2011/12 prices under the LCF could increase projected costs.
  - It is not clear what impact the Hinckley Point C CfD will have on the LCF, whether costs set aside for this project would be separate or part of a future LCF cap. If part of a future LCF cap it could have implications, for example, changes in wholesale electricity prices would have an even greater impact on the amount remaining under the cap for future CfD allocation rounds[32].
  - It is not clear what the assessment criteria would be for a trade-off between Swansea Bay Tidal Lagoon (Swansea Bay), a proposed 320MW tidal lagoon project and a further CfD allocation round. This project does not fit within the standard procurement procedure through competitive allocation rounds due to challenges in identifying a generic technology cost[33]. Instead, this project is currently negotiating a bilateral CfD, with the proviso that it can only gain a CfD if there is budget available under the CfD.
  - If the LCF cap is exceeded due to wholesale electricity price changes alone it is not clear how his would be treated. BEIS and HM Treasury could agree that this

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30 Projects currently have the ability to reduce capacity by up to 25% by the milestone delivery date.

31 ssFiT: Small scale Feed-in-Tariffs for installations smaller than 5MW.

32 Projects are able to have an impact on allocation round decisions before commissioning as they could cause a breach to a future years' budget meaning even if money is available in earlier years it cannot be released due to the later projected breach.

33 Swansea Bay Tidal Lagoon: potential support for the project through the CfD mechanism, DECC, January 2015.

is a temporary effect and so allow for changes in these costs within the headroom mechanism or there is also the option to introduce this flexibility more formally into the LCF cap.

– LCF budgets for the period after 2020/21 are still to be determined and announced. They may also have an impact on the current LCF as the higher the post 2020 budgets (net of any nuclear allocated costs), the greater the potential that overspend could be considered temporary.

We believe that new renewables capacity (offshore wind, onshore wind and solar) beyond 2022 will require CfD in order to be built. Figures Figure 47, Figure 48 and Figure 49 present the capacity currently covered by CfD and our assumptions on the new entry capacity that will require CfD in the future.

Figure 47 – Renewables capacity covered by CfD in the Base Case

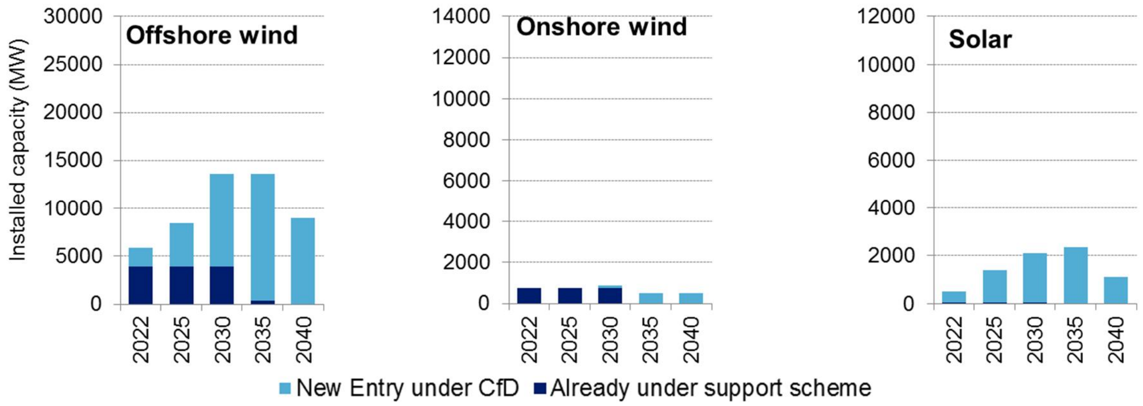


Figure 48 – Renewables capacity covered by CfD in the High scenario

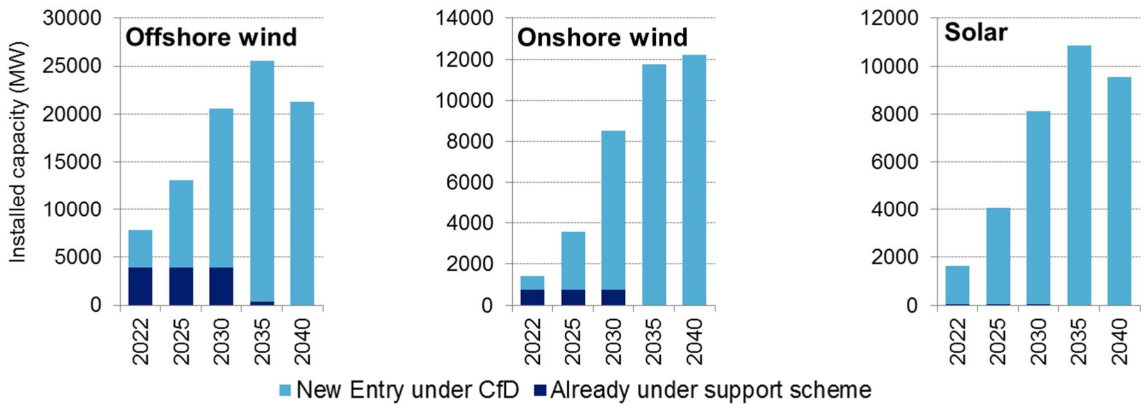
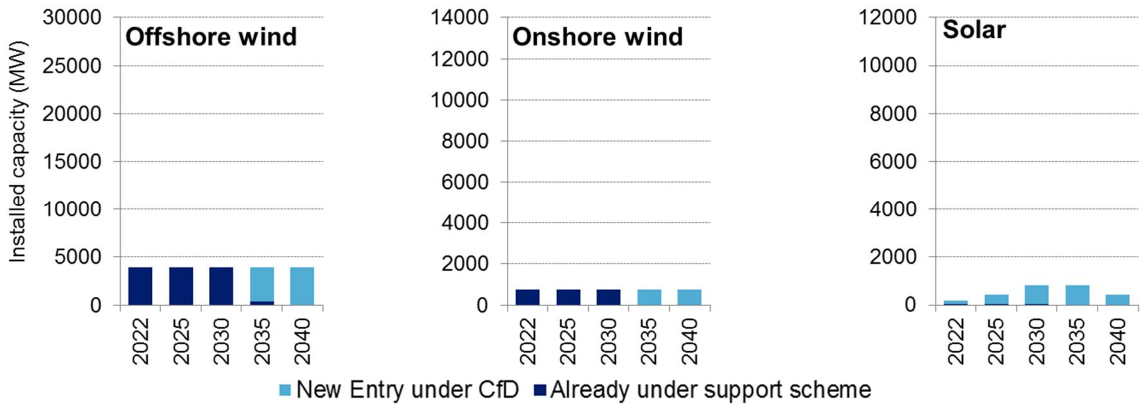


Figure 49 – Renewables capacity covered by CfD in the Low scenario



C.4 GB interconnection capacity

In order to allow the comparison of projects across all scenarios and sensitivities, the baseline level of GB interconnection (i.e. the amount of interconnection capacity in place before commissioning of any Window 2 projects) has been kept constant over time and equal across scenarios and sensitivities.

All projects that were included in National Grid's interconnector register in November 2016 and/or were granted a cap and floor regime by Ofgem prior to the second window are assumed to be fully operational before or by 01 January 2022. It is assumed that all existing and new projects will continue to operate until at least 2046 (the end of the modelled period in this study). The full list of GB interconnectors included in this baseline is given in Table 3 below.

Table 6 – List of interconnectors included in baseline

Interconnector	*Connected market*	*Cable size (MW)*	*Status*
IFA	France	2,000	Existing link
Moyle	Irish Single Electricity Market	450	Existing link
Britned	Netherlands	1,000	Existing link
East West	Irish SEM	500	Existing link
Nemo[1]	Belgium	1,000	Under construction
North Sea Link[1]	Norway	1,400	Under construction
IFA 2[1]	France	1,000	Planning
Viking Link[1]	Denmark	1,400	Planning
FAB Link[1]	France	1,400	Planning
Greenlink[1]	Irish SEM	500	Planning
ElecLink	France	1,000	Under construction

Source: National Grid Interconnector register, 18 November 2016; and Ofgem
[1] Cap and floor projects

C.5 Fuel prices assumptions

Fuel prices both directly and indirectly (e.g. through indexation or substitution effects) influence each other and the wholesale electricity price. Higher fuel prices generally lead to higher power prices and higher absolute price differentials between markets, increasing the value of interconnection.

For the purpose of this study, the fuel prices in GB for each scenario were selected from DECC's November 2015 Energy and Emissions Projections. The scenario selected for the Base Case is DECC's Reference Scenario for fossil fuel prices. The scenarios selected for the High and Low scenarios are DECC's High and Low Price scenarios, respectively.

In each case we have used the DECC fuel prices as a base and built consistent fuel prices for the rest of North West Europe. Where DECC publish an international price directly – as in the case for Crude Oil and ARA Coal– we have used this price directly. For gas prices we have assumed that the price differential between GB and other countries is in line with the relevant scenario from our standard Q1 2016 projections.

Figure 50 – Crude oil prices in Base Case, High and Low scenarios ($/bbl)

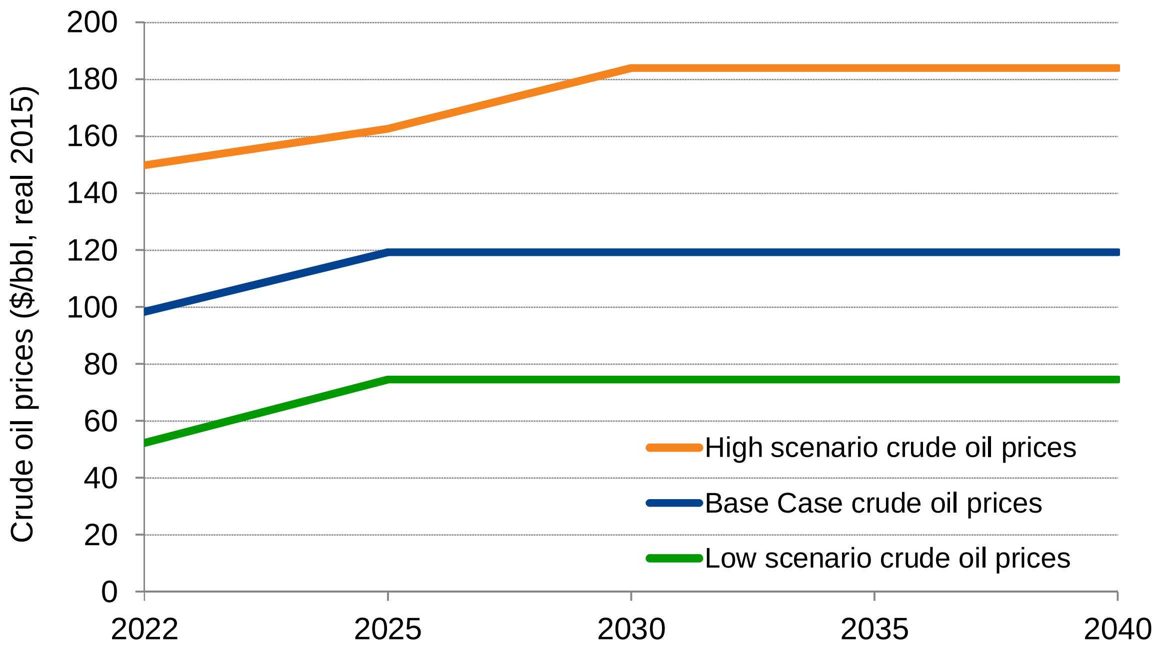


Figure 51 – ARA coal prices in Base Case, High and Low scenarios ($/tonne)

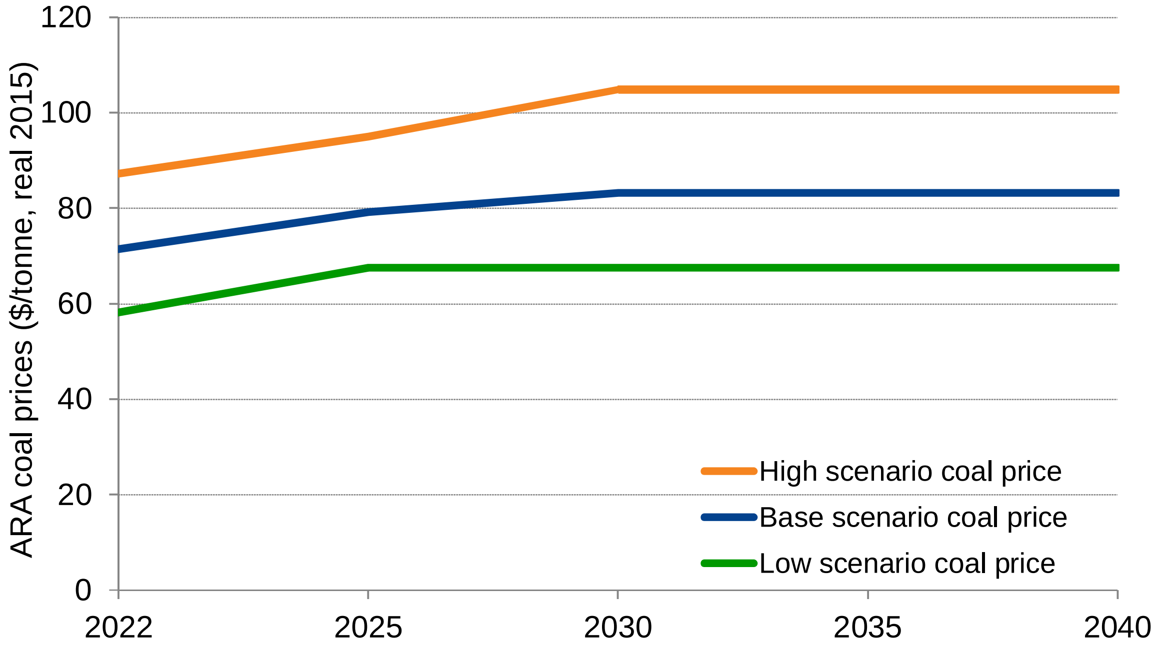
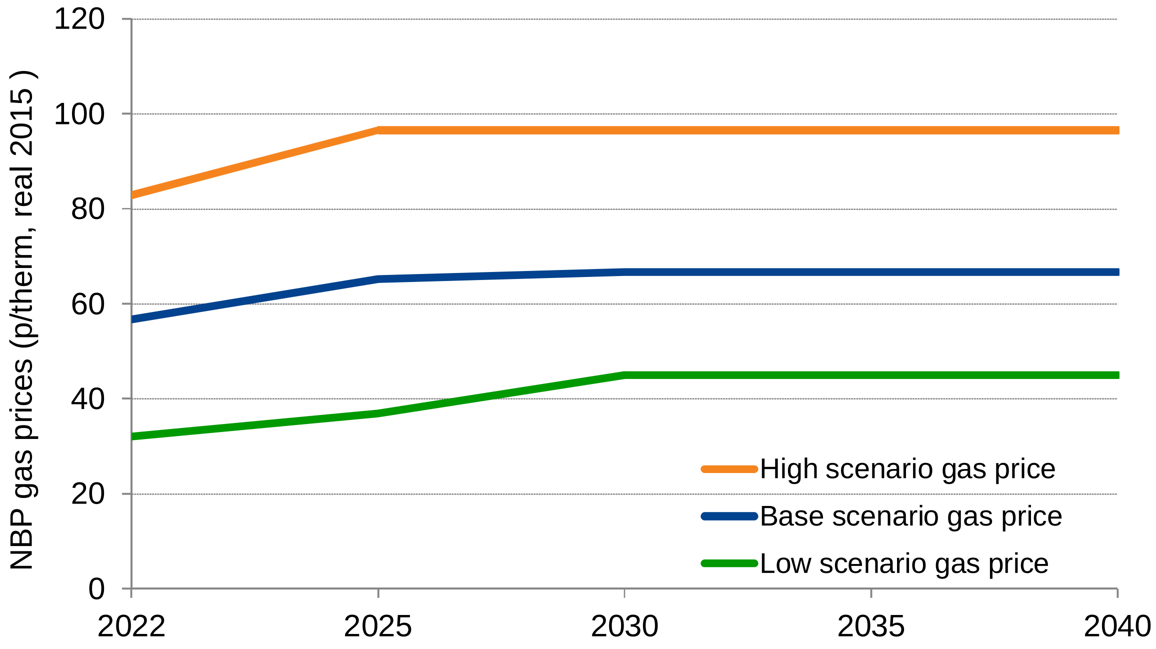


Figure 52 – NBP gas prices in Base Case, High and Low scenarios (p/therm)



C.6 The value of carbon

EU Emissions Trading Scheme

The EU ETS is a cap and trade scheme that covers CO2 emissions from large stationary installations and aviation. These installations are required to submit sufficient carbon allowances, known as EU Allowances (EUAs), to cover their emissions during the previous calendar year. At the heart of the scheme is the ability of companies to trade these EUAs. Companies for whom it is relatively costly to reduce emissions can purchase allowances from companies that can achieve emissions reductions at little or no cost. Through this mechanism, emissions reductions can in theory be achieved at least cost to Europe overall.

Operators are required to submit a verified report of their previous calendar year's emissions by the end of March each year and the allowances are deducted from their accounts at the end of April. Allowances that are not surrendered can be banked and used in subsequent years.

Phase I of the scheme started in 2005 and lasted for three years. This was designed to be a learning phase for market participants. Phase II ran from 2008 to 2012 and corresponded with the first compliance period of the Kyoto Protocol. In both of these phases, the majority of EUAs were allocated for free in an attempt to make the scheme more appealing. Caps on emissions were set by national governments with a high degree of autonomy and consequently many countries 'over-allocated' such that companies received more allowances than they required. In addition to EUAs, credits from the Kyoto flexible mechanisms – Clean Development Mechanism (CDM) and Joint Implementation (JI) – could be used by companies to meet their emissions targets during Phase II.

Phase III of the EU ETS runs from 2013-2020 and incorporates a number of important changes:

- **A tighter EU wide cap:** A single EU wide cap for Phase III replaced individual Member State NAPs.
- **An increase in scope:** The scope was extended to cover both new sectors and gases.
- **Increased level of auctioning:** The majority of electricity generators face full auctioning of allowances from 2013 onwards, and industries which are not at risk of carbon leakage will need to buy an increasing amount of allowances at auction over the course of Phase III.
- **Use of benchmarking for sectors with carbon leakage risk:** For those industries deemed to be at risk of carbon leakage, in the majority of cases, free allowances will be allocated to the level of a product specific benchmark for each relevant product.
- **Restricted use of carbon credits:** Operators will be able to use credits from CDM and JI projects for up to 50% of the EU wide reductions over the period 2008 to 2020.
- **Sale of allowances to support new low carbon technologies (NER 300 Fund):** Revenue from the sale of 300m allowances from the New Entrant Reserve (NER) will be used to support CCS and renewable energy technologies that are not yet commercially viable. The sale of the allowances finished in April 2014, and so far the European Commission has awarded €2.2 billion to 41 innovative renewable projects and one CCS project.

The value placed on the emission of carbon in the power sector is a major driver of forward looking projections of power prices. For an interconnector project any differential in the carbon value between interconnected regions is likely to be a major driver of value for the project.

For the purposes of this study, we have used Pöyry's own modelling of carbon prices in GB and Europe in all modelled scenarios and sensitivities.

EU ETS carbon allowances

Pöyry's carbon model is used to derive projections of European Union Allowance (EUA) CO_2 credit prices that are consistent with the fuel prices, capacity, generation and electricity demand projections in each of our electricity price scenarios. Table 7 summarises the target levels of emission reduction from the EU ETS sectors applied in our scenarios.

Table 7 – EU ETS targets, relative to 2005 emissions

	High	Central (Base Case)	Low
2020	-21%	-21%	-21%
2030	-47%	-43%	-38%
2050	-90%	-80%	-70%

The emissions cap in our Central scenario is consistent with the current 2020 and 2030 targets for the EU ETS sectors. Beyond 2030 we assume it continues to tighten and is consistent with an 80% emission reduction by 2050, in line with the lower end of the EU's objective of reducing greenhouse gas emissions by 80-95% by 2050[34]. Our High and Low scenarios test plausible ranges around this level. The cap assumption in the Low is consistent with a steady trajectory to a 70% reduction in 2050. Our High scenario cap delivers a more stretching emission reduction of 47% in 2030 and 90% in 2050.

Figure 53 presents our latest projections of the value of carbon allowances. The prices in our three scenarios can be summarised as follows:

- In the **High** scenario, prices increase strongly from current levels driven by strong demand growth and a swiftly tightening emissions cap.
- The **Central** scenario (used for the Base Case) is characterised by medium levels of demand, medium commodity prices and an emissions cap that is consistent with currently announced targets. The cap in our Central scenario is consistent with the current 2020 and 2030 targets for the EU ETS sectors. Beyond 2030 we assume it continues to tighten and is consistent with an 80% emission reduction by 2050, in line with the lower end of the EU's objective of reducing greenhouse gas emissions by 80-95% by 2050.
- In the **Low** scenario, prices remain at low levels. Prices do not recover at all until the 2020s and then only move above €10/tCO2 in the 2030s. The Low scenario is characterised by a loose cap, low demand for abatement and a large surplus of allowances.

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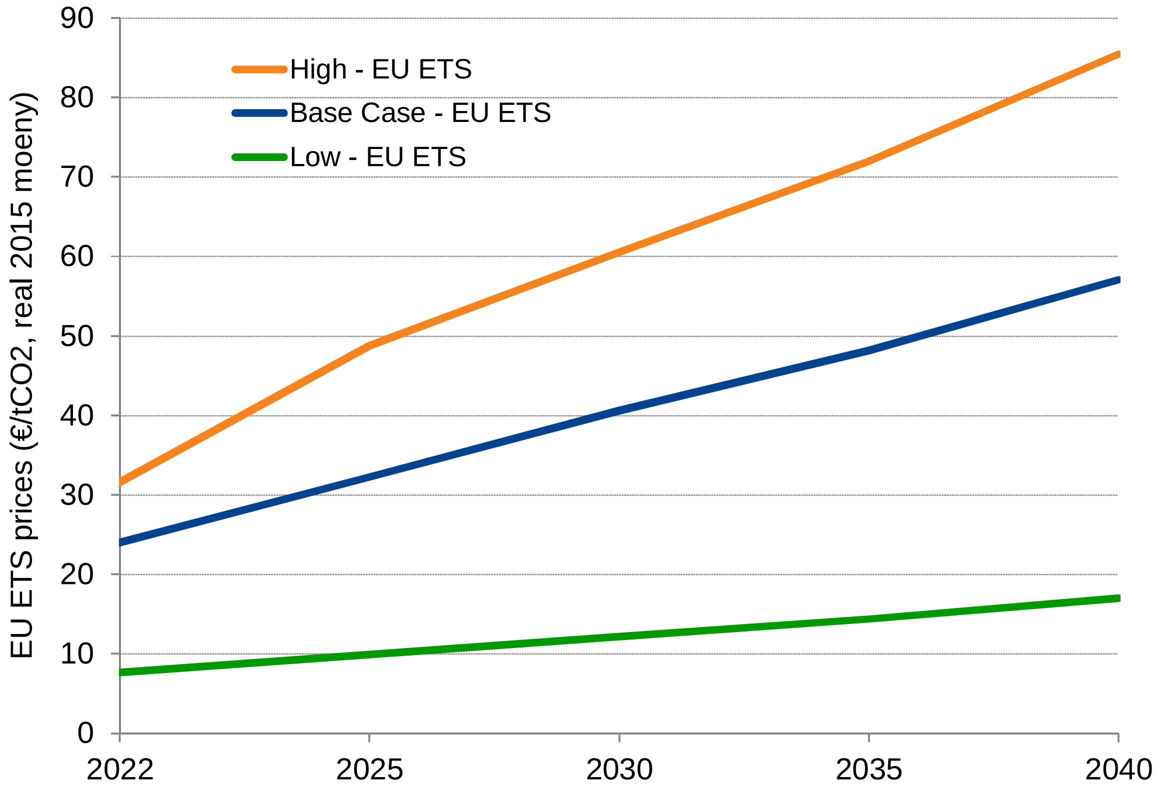
[34] A Roadmap for moving to a competitive low carbon economy in 2050, European Commission, 8th March 2011

Figure 53 – EU ETS prices in Central, High and Low scenarios (€/tCO_2)



UK Carbon Price Floor

Under the UK carbon price support scheme, generators pay for their emissions within the EU ETS, but they also pay an additional top-up tax (the 'Carbon Price Support' or CPS) to ensure that the effective CO_2 price reaches a certain floor level. The Government's target carbon price floor level is £30/tCO_2 in 2020 and £70/tCO_2 by 2030 (both in real 2009 money).

The CPS for each year is set two years in advance, and is applied to the supply of fossil fuels via the Climate Change Levy (CCL). The historical CPS rates were set at £4.94/tCO_2; £9.55/tCO_2; and £18.08/tCO_2 for financial years 2013/14, 2014/15 and 2015/16, respectively.

Due to concerns about the impact on the competitiveness of the UK economy and affordability, in the Budget 2014 the UK Government capped the level of the CPS for financial years 2016/17 to 2019/20 at £18.00/tCO_2 (nominal money). The effect of the cap on the CPS is to introduce a difference between the effective carbon price faced by UK generators and the carbon price floor trajectory in the years when the cap is binding (i.e. when the EU ETS price is more than £18.00/tCO_2 nominal below the carbon price floor).

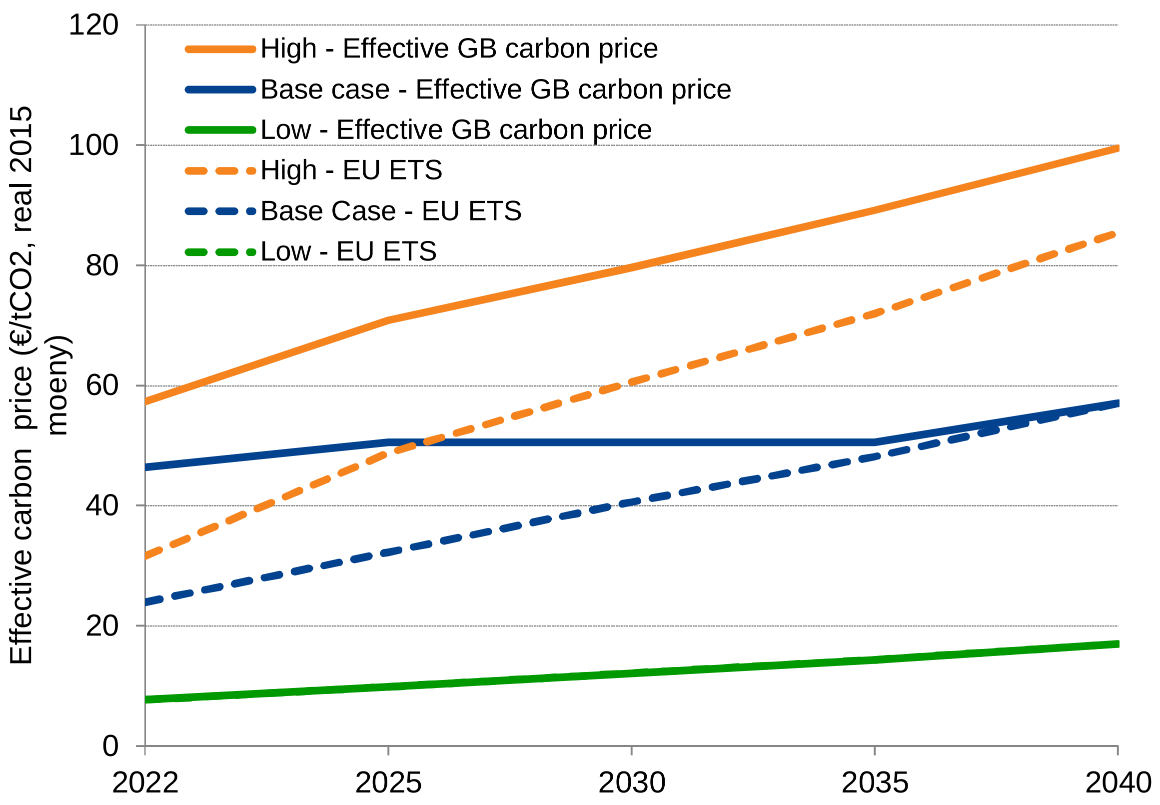
We have implemented the CPS cap for 2017/18 to 2019/2020 in all scenarios for Great Britain, and also assumed in all scenarios that the cap continues indefinitely into the future.

Beyond financial year 2016/17, we model the carbon price in Great Britain as follows:

- In our High scenario, the CPS cap results in an effective carbon price that is equal or lower than the floor (held at the Government's proposed trajectory to 2030 and constant thereafter), but higher than the EU ETS price, in all years from 2017 to 2040. In 2040 the effective carbon price reaches £69.5/tCO_2.
- In our Central scenario (used for the Base Case), the cap on the CPS results in an effective carbon price that is lower than the floor, but higher than the EU ETS price, between 2017 and 2023. After 2023, the cap on the CPS is no longer binding and the effective carbon price faced by generators is the higher of the carbon price floor and the EU ETS. In terms of the floor, we assume the Government's proposed trajectory to 2020, after which the carbon price floor remains flat to 2040 at the 2020 target level of £35.3/tCO_2; the further rise in the Government price floor trajectory between 2020 and 2030 is not followed. We believe that it would be untenable for the carbon price in the UK to reach the Government's proposed level of £82.2/tCO_2 in 2030 when the rest of Europe pays around £28/tCO_2, particularly when, in this scenario, such a high price is not required to meet the cap on carbon emissions in the EU ETS.
- In the Low scenario, we assume that the CPS is abandoned by the government by 2022, and therefore all GB generators face the same carbon price as continental European generators.

Where the floor price for carbon price support is higher than the EU ETS it will form the effective carbon price in GB resulting in a carbon price differential between GB and non-GB generators as shown in Figure 54.

Figure 54 – Carbon prices (€/tCO_2)



C.7 Selected Supply Curves for GB

Resulting example January supply curves for the Base Case in GB in 2025 and 2040 are presented in Figure 55 and Figure 56 respectively.

Figure 55 – GB Supply Curve: Base Case 2025 January Example Hour

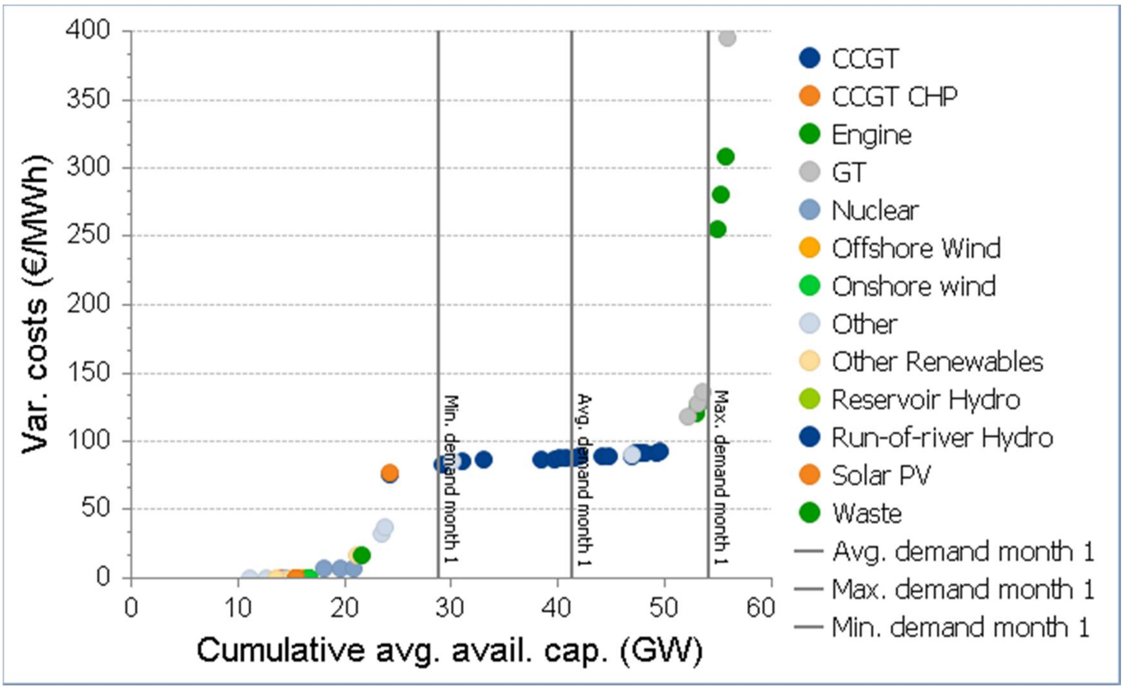
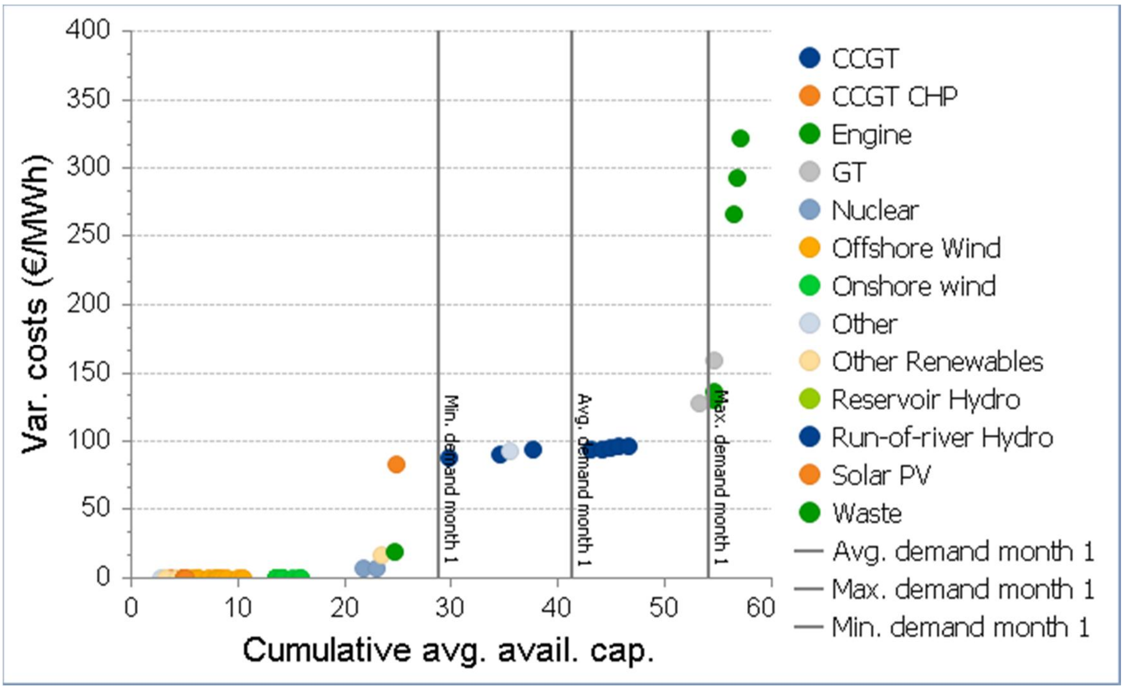


Figure 56 – GB Supply Curve: Base Case 2040 January Example Hour



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ANNEX D – CAPACITY MARKETS AND THE CAPACITY VALUE OF INTERCONNECTION

D.1 Background to capacity markets

The introduction of capacity mechanisms may lead interconnectors to earn lower revenues from the energy market (as opposed to the capacity market) than they would in an energy only market (i.e. if there was only the energy market and no capacity market). This is due to the dampening effect of capacity mechanisms on prices:

- Firstly, the additional stream of revenue from capacity payments should allow generators to bid lower and closer to SRMC, acting to lower the wholesale electricity price – in effect money moves from the energy market to the capacity market.
- Secondly, a capacity mechanism often requires that an organisation (typically the government, regulator or system operator) specifies the system security standard. Given the direct accountability of the organisation setting the system security standard, but the absence of direct costs, we would anticipate that the security standard would be higher (i.e. less likelihood of lost load) than in a market without a capacity mechanism – leading to a greater amount of capacity than would be the case under an energy-only market.

Where capacity markets or other remuneration mechanisms are planned, we have accounted for these in our wholesale market projections via the capacity margins and wholesale prices that we have modelled.

This Annex describes the theoretical value interconnectors may capture from participating in capacity markets, our approach to modelling of the GB capacity market; our modelling of other NWE capacity markets and mechanisms; and the impact of including capacity market participation in the interconnector cost benefit analysis.

D.2 Commercial value of interconnector participation in capacity markets

Where this impacts wholesale prices lower price differentials between markets, this may result in lower congestion rents. However, interconnectors may be able to earn additional revenue from direct participation in capacity mechanisms.

The value of participation in a capacity mechanism to an interconnector project is uncertain. It is dependent on three main aspects which vary by country and over time:

1. the underlying capacity mechanism design, most specifically the eligibility of interconnectors to receive capacity payments;
2. the nature of flows across the interconnector, specifically in relation to the market stress events for which capacity is required to be available; and
3. the specific capacity needs of the system into which it is connected (which in turn drives the price of capacity in the market).

D.3 Socio-economic value of interconnector participation in capacity markets

Other things being equal, participation in a capacity mechanism improves the interconnector business case and makes it less likely to hit any revenue floor levels imposed in the cap and floor regime. However, if interconnectors merely displace other capacity without changing the clearing price, this is in principle largely a transfer of welfare (from producers to interconnector owners) and as such should not significantly impact the overall net welfare case of the interconnector.

This welfare transfer depends on the assumed effect an interconnector would have on the outcome of a capacity auction. Several outcomes could be considered:

- **Lower clearing price:** The interconnector displaces higher bids in the auction, which will therefore clear lower than in a case where the interconnector was not present.

  In this case, GB consumers would benefit from having to pay less towards the capacity mechanism, while GB producers would be negatively affected, as less capacity has cleared and the payment will be lower.

- **Same clearing price:** The interconnector displaces higher bids in the auction. However, in this case it is assumed that generation capacity will bid up so that the existing clearing price is the same as it would have been without the interconnector.

  *In this case (**which has been assumed in this study**), GB consumers would not be affected by the change. GB producers lose the exact amount the interconnector receives.*

- **Higher clearing price:** The interconnector displaces higher bids in the auction. However, in this case it is assumed that generation capacity will bid up in the auction so that the total generator capacity market revenue is the same as it would have been without the interconnector.

  In this case, GB consumers would pay more towards the capacity mechanism, while producers would not face any net capacity market effect.

In theory, all of these outcomes appear equally likely, so that it appears prudent to choose the ‘same clearing price’ assumption as a basis for the assessment in this study.

It should be noted that in any of these cases, welfare is transferred from GB to the other country. This is due to the fact that any capacity payments made to the interconnector need to come either from GB consumers or GB producers, while the interconnector itself is split between GB and the connected country. In the same way, welfare is transferred to GB if an interconnector receives payments in another market (such as France or Ireland).

D.4 Country specific mechanisms

D.4.1 GB capacity market

The aim of the GB Capacity Market is to deliver generation adequacy. It offers capacity providers a capacity payment revenue stream, in return for which they commit to deliver energy in periods of system stress or face exposure to penalties if they fail to deliver.

Capacity contracts are allocated to providers through auctions intended to secure a capacity requirement needed to meet a 3-hour loss of load expectation reliability standard. The auction clearing price forms the basis of the capacity payment to successful auction participants.

In its Response to the Consultation on Capacity Market Supplementary Design Proposals published in January 2015, the Department of Energy and Climate Change (DECC, now Department for Business, Energy & Industrial Strategy – BEIS) confirmed that interconnectors (but not interconnected capacity) will be eligible to participate in the auctions for delivery year 2019/20 onwards, and that their contribution to security of supply will be assessed using an administratively set de-rating factor for each link.

In February 2015, DECC confirmed that the de-rating factors will be set based on a hybrid method, using a historic data to set a conservative availability limit (subject to there not being any publically known security of supply concerns in interconnected markets for the delivery year in question). The de-rating factors for the 2015 Y+4 auction were published by the Secretary of State for Energy and Climate Change in June 2015 and were revised for the 2016 Y+4 auction in July 2016. The latest de-rating factors and the resulting eligible capacities are summarised in Table 8.

Table 8 – Interconnector de-rating for 2016 capacity auction

Interconnector	Interconnected country	Capacity (MW)	Derating factor (%)	Eligible capacity (GW)
IFA	France	1988	60%	1193
ElecLink	France	1000	65%	650
Britned	Netherlands	1000	74%	740
NEMO	Belgium	1000	77%	770
Moyle	Northern Ireland	295	26%	77
EWIC	Ireland	500	26%	130
NSL	Norway	1400	78%	1092
Total				**4652**

We summarise the main features of the Capacity Market in Table 9. These are as they were for the first Capacity Market auction in December 2014, except where changes have since been publically announced.

Table 9 – Design and implementation features of the GB Capacity Market

Auction design	▪ Pay-as-clear descending clock auction ▪ Administratively set availabilities based on technology type ▪ A linear demand curve based on procuring: the target capacity at a price equal to Net CONE; the target capacity + 1.5GW at £0/kW/year; and the target capacity – 1.5GW at a price equal to overall auction price cap ▪ Net Cost of New Entry (CONE) of £49/kW/year ▪ Auction price cap of £75/kW/year for price makers (overall auction price cap) ▪ Auction price cap of £25/kW/year for price takers ▪ Up to 15-year contracts for new plants ▪ Up to 3-year contracts for existing plants undergoing major refurbishment ▪ 1-year contract for other existing plant
Security standard	▪ Security standard to be a Loss of Load Expectation (LOLE) of 3 hours per annum
Scope of Capacity Market	▪ Fossil-fuelled thermal capacity included ▪ CHP included ▪ Demand Side Response (DSR), Electricity Demand Reduction (EDR) and electricity storage included ▪ Plants commencing construction after May 2012 can be treated as new capacity ▪ RO, CfD, FiT, RHI, NER300, CCS Commercialisation supported capacity excluded ▪ Interconnectors included (from 2015 auction)

Penalties	▪ Penalties to be based on failure to deliver energy at times of real system stress ▪ Obligation to provide capacity profiled to demand on the system at the time ▪ Total penalties that can be incurred capped at 200% of monthly income and 100% of annual income ▪ Real system stress periods to be based on load-shedding or brown-outs due to SO instructions to DSOs ▪ Level of penalty for failing to deliver during a system stress settlement period to be 1/24th of the clearing price, multiplied by the capacity shortfall relative to the obligation in that settlement period
Timetable	▪ Four year lead time between auction and delivery of capacity ▪ Third Y+4 auction to be held in 2016, for delivery of capacity in 2020/2021

D.4.2 Capacity Market in France

Electricity demand in France is highly sensitive to temperature due to the significant use of electric heating. This sensitivity is in the order of magnitude of an additional 2.4GW of generating capacity required per Celsius degree below the seasonal normal temperature in winter. To deal with this critical peak issue, a capacity obligation (introduced via the NOME law) will become effective from winter 2016/17 onwards.

In order to deal with this issue, a capacity obligation mechanism will be introduced in France in 2017 to ensure system security and deal with the temperature sensitivity of French demand (around an additional 2.5GW per Celsius degree below seasonal normal temperature). The aim is to ensure that suppliers, through the buying of capacity certificates from generators and demand side operators, have enough certificates to cover their respective portfolio's demand during peak time. Generators and demand side operators will therefore receive two revenue streams: the wholesale electricity price and the capacity price received for relevant capacity certificates.

A cap (P_{admin}) on the capacity price was set at €40/kW of available capacity by a French Decree[35]. This current cap level is expected to be reviewed by the French regulator (CRE) after the first year (2017). CRE has also mentioned the cap on the capacity price should be closer to the cost of new entry of a peaker but the initial years of the scheme are unlikely to be an issue as the French electricity system is not deemed to be facing a capacity shortage[36]. Our capacity price projections do not exceed the current cap in the short-term as no new entry is required but then rise to levels sufficient to support entry of new capacity when needed to meet each year's capacity obligation level. There is some uncertainty regarding the start date of the capacity obligation mechanism due to the European Commission investigation. It is therefore likely for the scheme to be delayed and we have assumed a start date in 2018 in the Central and Low scenarios whilst keeping it in 2017 in the High scenario.

Prices for capacity certificates are highly uncertain at present due to uncertainty in both market operation and future capacity requirements in France.

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35 The cap on the capacity price was set by the French Government (rather than by the regulator – CRE – as planned in article 23 of the 14 December 2012 Decree) in order to finalise the rules and get the capacity obligation mechanism running.

36 CRE, 'Délibération de la Commission de régulation de l'énergie du 6 mai 2015 portant décision sur la règle de calcul du prix administré prévu par les règles du mécanisme de capacité', 6 May 2015.

Current indications are that interconnectors will not be able to directly participate in the mechanism, but will rather be used by capacity in other countries to participate in the French capacity market, based on the expected availability of the interconnectors. Therefore, interconnectors will indirectly receive revenues from the mechanism.

D.4.3 Strategic reserve in Germany

Germany has opted not to introduce a capacity market and will put in place a capacity reserve (strategic reserve) instead.

The introduction of a capacity reserve with a capacity of approximately 4.4GW serves as an additional safeguard. This ring-fenced reserve capacity will be competitively procured by the Transmission System Operators and used exclusively by them. The reserve is activated only after market closure and according to the BMWi should have no influence on the price formation in the wholesale market. This capacity reserve would consist of power plants that do not compete on the market, but as a last resort for when supply and demand cannot be balanced. In addition to the specification of this reserve in the Green Paper and Power Market paper, the White Paper specified that 2.7GW of old lignite power plants will be moved into this reserve, for a duration of four years. During this period, these plants are not able to operate in the wholesale market, and after this period, the plants are decommissioned.

The effects of this reserve on wholesale prices is uncertain, however, since capacity will be ring-fenced from the market rather than dispatched in peak periods as part of the day-ahead schedule, wholesale peak prices in peak periods (e.g. winter evenings) could be higher in Germany than they are in markets where a capacity market exists.

D.4.4 Capacity mechanisms in other European countries

Other capacity mechanisms are in existence or being considered across Europe, most notably:

- in Ireland, the current capacity mechanism will be replaced by a quantity based mechanism based on Reliability Options issued by a central party;
- Belgium operates a strategic reserve scheme; and
- in Italy, a Reliability Payment with a one-way Contract for Difference (CfD), with a security standard (as yet undefined), is being discussed.

Where such capacity mechanisms are planned, we have accounted for these in our wholesale market projections via the capacity margins and wholesale prices that we have modelled.

D.5 Capacity value of interconnectors

Each GB capacity auction operates on a pay-as-cleared basis, with all successful bidders receiving the same clearing price on a £/kW$_{available}$ basis. The available capacity that is eligible to receive the clearing price is based on a capacity de-rating factor which differs between technologies – and, in the case of interconnectors, between units.

The capacity value of interconnectors is expressed by its de-rating factor, where a higher factor represents a judgement of more reliable capacity provision. There are different approaches one can use to determine that de-rating factor. We present here the method we have used to calculate the factors alongside an alternative method, in order to emphasize the differences different calculations methods can create.

Method 1: Flows during tight system periods

In this method, which is similar to the approach Pöyry used in a study commissioned by DECC (2015), we calculate the de-rating factor as the probability of the interconnector importing during tight system periods, which is defined as the 5th percentile of tightest capacity margins across all modelled weather patterns.

The de-rating factor for every modelled year is the average flow from each neighbouring country to GB during periods of system stress (which can on occasion also be negative), as a percentage of the capacity of the cable into GB.

The results of the de-rating analysis using this method are summarised in Table 10.

Table 10 – Modelled interconnector de-rating factors under Method 1

	2022	2025	2030	2035	2040	**Average**
GBR - FRA	57%	58%	55%	64%	62%	**59%**
GBR - GER	40%	19%	13%	17%	16%	**21%**
GBR - NOR	94%	95%	94%	94%	94%	**94%**
FRA - GBR	53%	52%	46%	57%	55%	**53%**

Method 2: Stress event correlation

In this method, we calculate the de-rating factor as the probability of a stress event in GB not coinciding with a stress event in the neighbouring country. In this analysis, we assume that a stress event is defined as the 10 lowest capacity margin periods of every modelled year.

We summarise the results of the de-rating factor analysis in Table 11.

Table 11 – Modelled interconnector de-rating factors under Method 2

	2022	2025	2030	2035	2040	**Average**
GBR - FRA	17%	30%	27%	23%	18%	**23%**
GBR - GER	19%	16%	18%	31%	25%	**22%**
GBR - NOR	92%	92%	69%	66%	73%	**78%**
FRA - GBR	17%	30%	27%	23%	18%	**23%**

ANNEX E – ADDITIONAL SENSITIVITY – GB CAPACITY REDUCTION

E.1 Introduction

This annex is to provide Ofgem with the results of an extra sensitivity on the modelling for the Window 2 interconnector CBA. Ofgem has asked Pöyry to provide results for a re-modelling of dispatch in the Base Case with changes to CCGT capacities in Great Britain.

This was required to alleviate concerns that consumer benefits or GB net benefits stated in the original analysis could be eroded if generators were to avoid investing in thermal generation in Great Britain when further interconnector capacity is delivered.

E.2 Approach to sensitivity modelling

The main difference between the original Base Case and the extra sensitivity is as follows:

- The generation capacity in the Base Case is assumed fixed, but output levels (and hence load factors and profits) change, whereas in the Capacity Reduction sensitivity, generation capacity is allowed to change if the shift in underlying profitability makes new investment uneconomic or closure economic.
- The extent of capacity reduction is determined by maintenance of an assumed system security of supply level. The Base Case would therefore have delivered a higher overall level of security of supply, though we note that any additional value from this to consumers was not quantified in the original CBA.

For each interconnector, the amount of capacity removed in the Capacity reduction sensitivity has to be determined separately, as the capacity contribution during system tightness depends on the market connected to. We have used BID3 iteratively to assess security of supply (based on minimum available capacity margins in any year) in both the FA and MA cases and determined the following capacities to be removed to attain the same security of supply in the cases with and without the interconnector:

- For NorthConnect, we have removed 1,000MW of CCGT capacity from 2022 in both the MA and the FA cases.
- For NeuConnect, we have removed 200MW of CCGT capacity from 2022 in both the MA and the FA cases.
- For Gridlink, we have removed 200MW of CCGT capacity from 2022 in both the MA and the FA cases.

These differences arise because of the different contribution of interconnectors to security of supply in both countries. This is similar but not equal to the de-rating calculation for interconnectors in capacity markets.

We have assumed that capacity clearing prices are the same as they are in the Base Case. The rationale for this is that while some capacity (1,000MW or 200MW, respectively) will not be commissioned, Great Britain will still procure the same amount of capacity from the capacity market and while there is less capacity, some new build is still occurring in the same technology (CCGT), which requires the same clearing price.

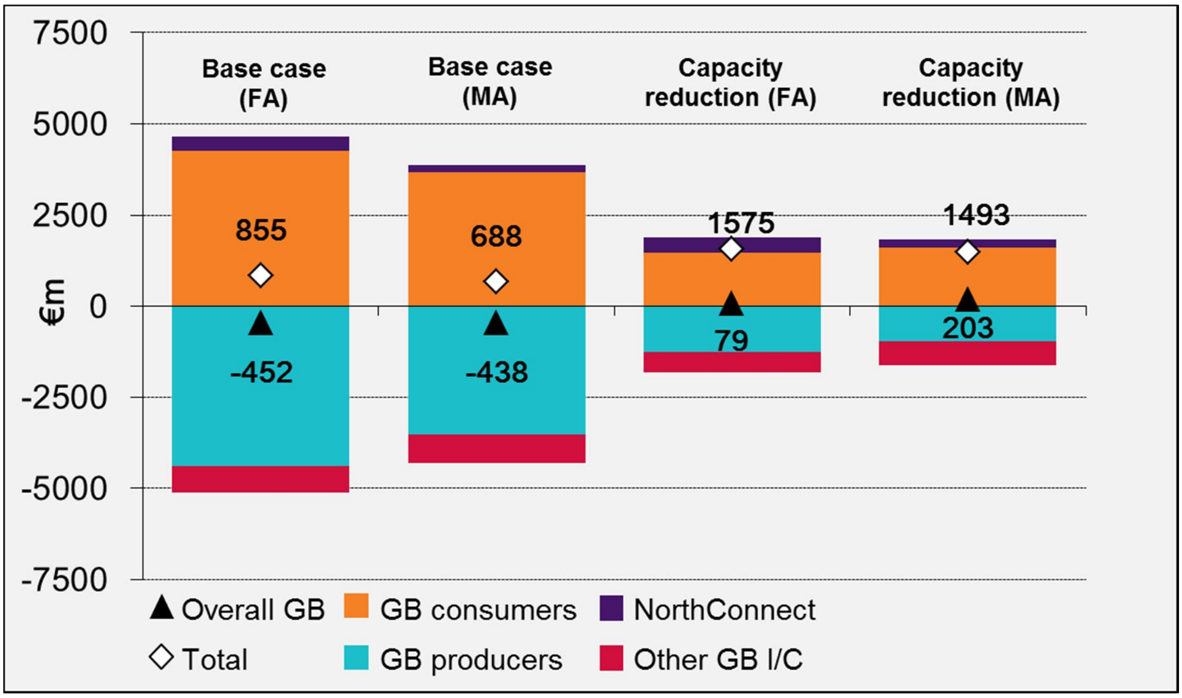
It is worth noting that while this sensitivity addresses the reaction of GB generators to an interconnector being commissioned from a capacity perspective, the same is not being considered on the other side of the interconnector, where generators may wish to increase their capacity due to potentially higher export opportunities. In such a case, additional benefits for GB consumers would be expected.

E.3 NorthConnect cost benefit analysis

E.3.1 NorthConnect – overview and main conclusions

The NorthConnect project has been modelled as a 1,400MW interconnector between Great Britain and Norway, commissioning in 2022 and it has replaced a new-entry CCGT of 1,000MW that was commissioned in 2022.

Figure 57 – NorthConnect impact on socio-economic welfare



The main conclusions from modelling the Capacity reduction sensitivity are:

- **NorthConnect's impact on GB consumers is much lower than in Base Case but still remains significant**

  The absence of a new 1,000MW CCGT cancels out some of the price decrease brought about by the interconnector. However, prices are still lower compared to the case that includes the CCGT but excludes the interconnector (counterfactual case).

- **GB overall welfare improves materially and goes from negative to positive because the reduction in producer surplus is much less pronounced**

  The less negative impact on producers is more than balancing the drop in consumer welfare, as producers avoid investment capex from not investing in 1,000MW of extra CCGT capacity.

- **GB overall welfare is positive in the sensitivity due to substantially less negative impact on producers**

The less negative impact on producers is more than balancing the drop in consumer welfare, as producers avoid investment capex from not investing in 1,000MW of extra CCGT capacity.

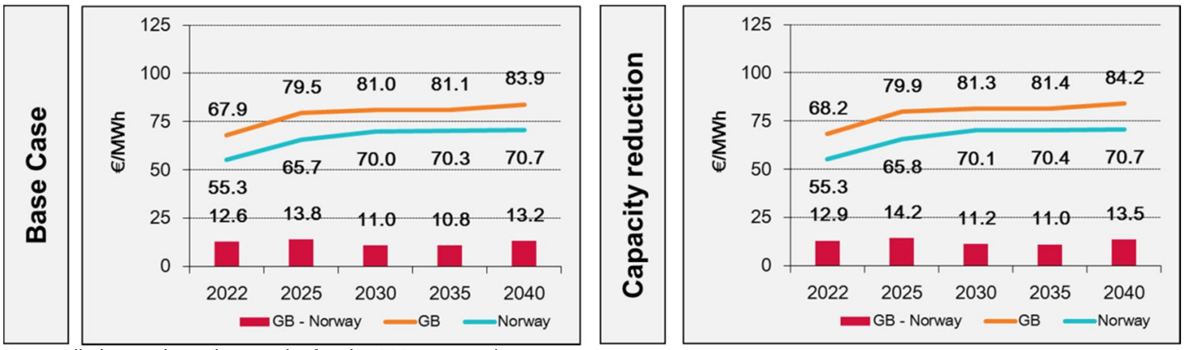
- **Positive impact in Norway is increased compared to Base Case**

  The more positive impact on producers is more than balancing the increased negative consumer welfare, as slightly higher exports marginally improve Norwegian stakeholder welfare.

E.3.2 NorthConnect – price differentials and flows

Figure 16 compares the annual average wholesale electricity prices and price differentials between Great Britain and Norway between the Base Case and the Capacity reduction sensitivity. The annual average wholesale prices in Great Britain have increased while the prices in Norway remained unchanged leading the higher price differentials of ~2% on average.

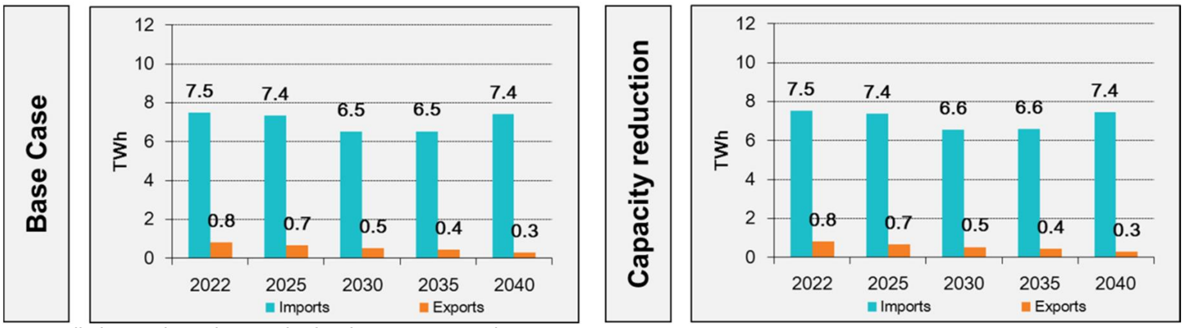
Figure 58 – Wholesale prices and differentials between Great Britain and Norway



Note: All charts show the results for the MA approach.

The flows of the interconnector are presented in Figure 17. NorthConnect's flows are the same as in Base Case and are mainly in the direction of Norway to Great Britain. The utilisation remains stable (62% compared to 61% in the Base Case) due to the high loss factor and competition with NSL.

Figure 59 – Flows on NorthConnect

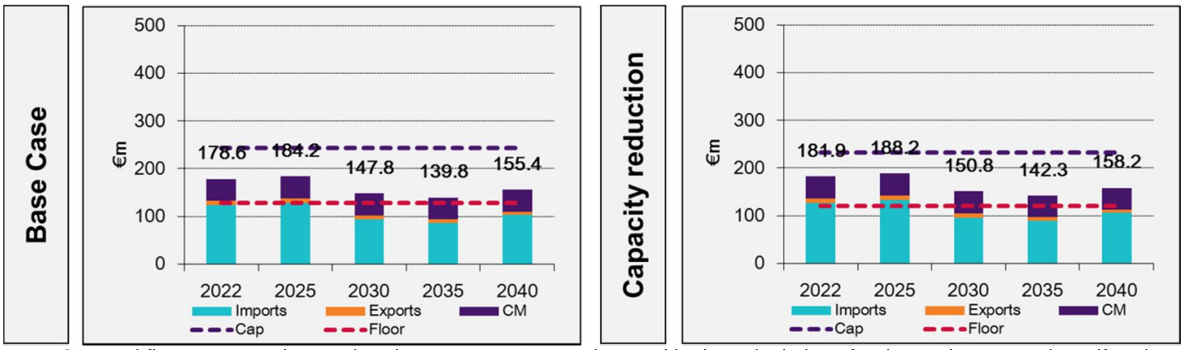


Note: All charts show the results for the MA approach.

E.3.3 NorthConnect – revenues and cap and floor impact

Figure 18 shows the project's revenues in the Base Case and the Capacity reduction sensitivity.

Figure 60 – Revenues for NorthConnect



Note: Cap and floor compared to total project revenue. In practice, and in the calculations for the socio-economic welfare in this report, the cap and floor is calculated for and applied to the GB share of the project only.

The main conclusions from comparing the Base Case and Capacity reduction sensitivity regarding interconnector revenues are as follows:

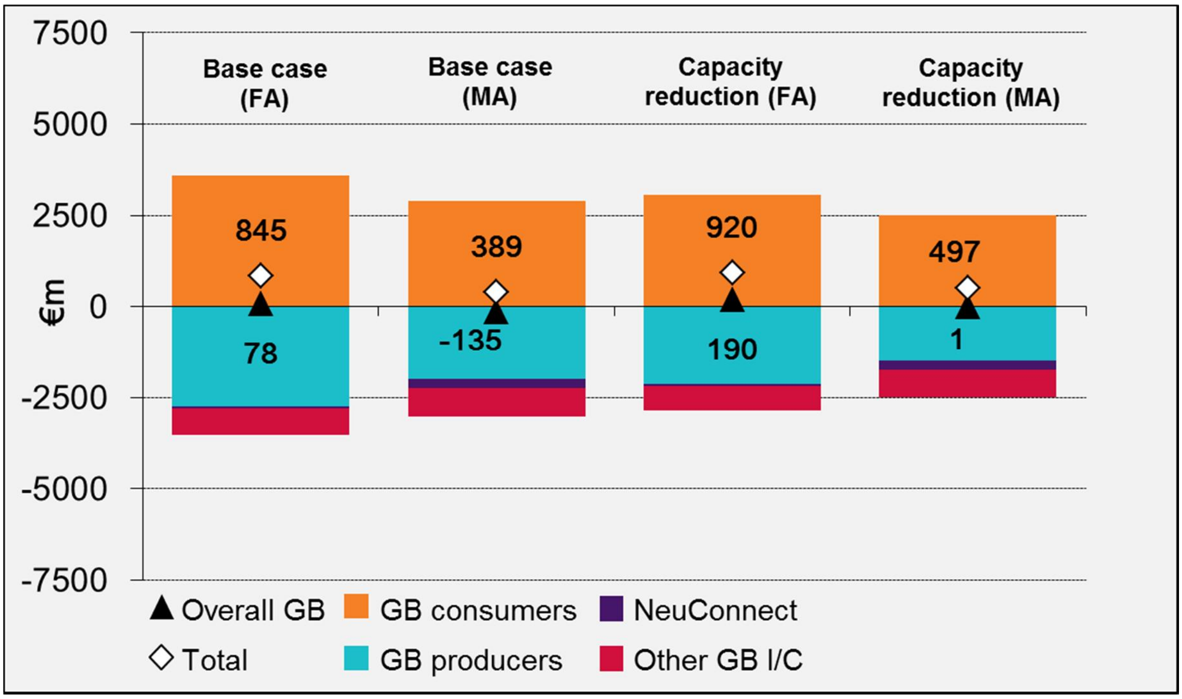
- The flows between Norway and GB remain unchanged and NorthConnect's revenues increase slightly as a result of the larger price differential.
- As in the Base Case, no cap or floor payments are made.
- Capacity payments remain unchanged from the Base Case.

E.4 NeuConnect cost benefit analysis

E.4.1 NeuConnect – overview and main conclusions

The NeuConnect project has been modelled as a 1,400MW interconnector between GB and Germany, commissioning in 2022 and it has replaced new-entry CCGT capacity of 200MW that was commissioned in 2022. The impact of this capacity reduction is much less significant than the one observed in the NorthConnect sensitivity.

Figure 61 – NeuConnect impact on socio-economic welfare



The main conclusions from modelling the Capacity reduction sensitivity are:

- **NeuConnect's impact on GB consumers is slightly lower than in Base Case**

  The absence of new 200MW CCGT capacity leads to slightly higher prices on average. However, the consumer welfare impact remains highly positive, as prices are still significantly lower compared to the case that includes the CCGT but excludes the interconnector (counterfactual case).

- **GB overall welfare is now positive in both the FA and the MA case due to a significantly less negative impact on producers**

  The less negative impact on producers is more than balancing the drop in consumer welfare, as producers avoid investment capex from not investing in 200MW of extra CCGT capacity.

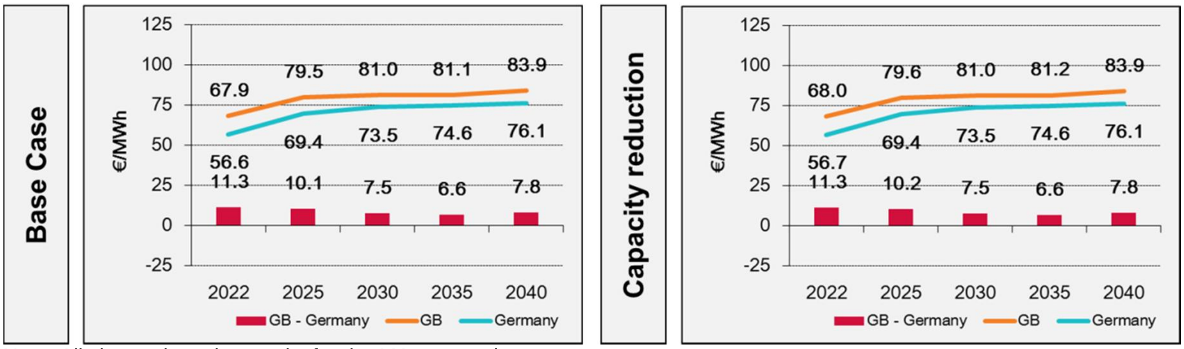
- **Positive impact in Germany is reduced compared to Base Case**

  Even though the positive producer welfare impact increases, the consumer welfare impact decrease is more significant. The increased positive impact on German producers is outweighed by the more negative consumer welfare impact which is a result of average prices changing slightly (<€0.1/MWh) but to such an extent to cause such a drop in consumer welfare.

E.4.2 NeuConnect – price differentials and flows

Figure 16 compares the annual average wholesale electricity prices and price differentials between Great Britain and Germany between the Base Case and the Capacity reduction sensitivity. Prices in Germany have remained almost unchanged and the drop of CCGT capacity by 200MW does not increase the prices in Great Britain substantially. Therefore the price differential stays at almost the same level as in the Base Case.

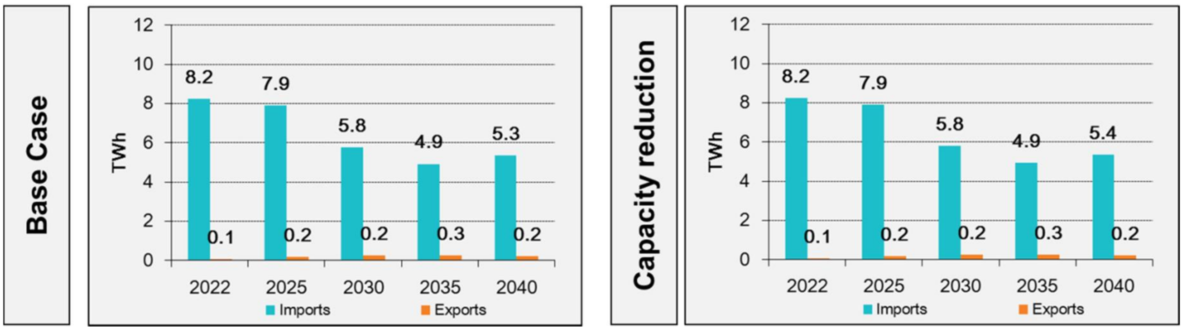
Figure 62 – Wholesale prices and differentials between Great Britain and Germany



Note: All charts show the results for the MA approach.

The flows of the interconnector are presented in Figure 17. NeuConnect's flows remain effectively unchanged and are mainly in the direction of Germany to Great Britain. The utilisation remains relatively low (at 51% as in the Base Case) due to the high loss factor and competition with French, Belgian and Dutch interconnectors.

Figure 63 – Flows on NeuConnect

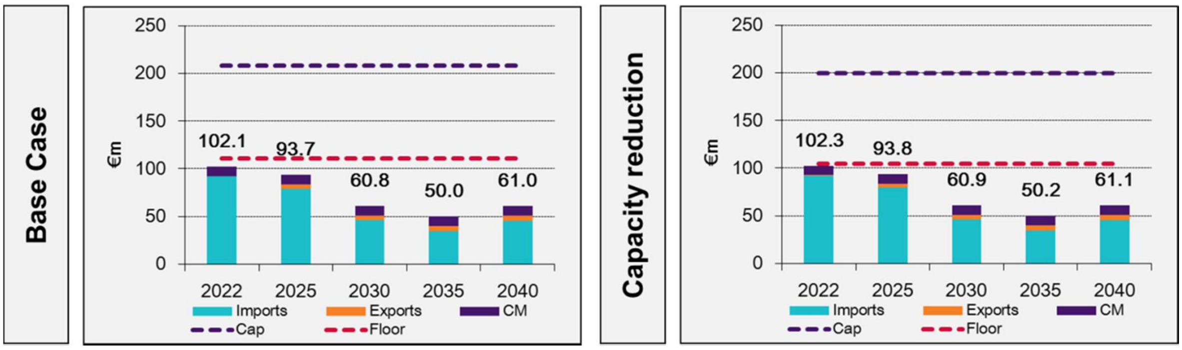


Note: All charts show the results for the MA approach.

E.4.3 NeuConnect – revenues and cap and floor impact

Figure 18 shows the project's revenues in the Base Case and the Capacity reduction sensitivity.

Figure 64 – Revenues for NeuConnect



Note: Cap and floor compared to total project revenue. In practice, and in the calculations for the socio-economic welfare in this report, the cap and floor is calculated for and applied to the GB share of the project only.

The main conclusions from comparing the Base Case and Capacity reduction sensitivity regarding interconnector revenues are as follows:

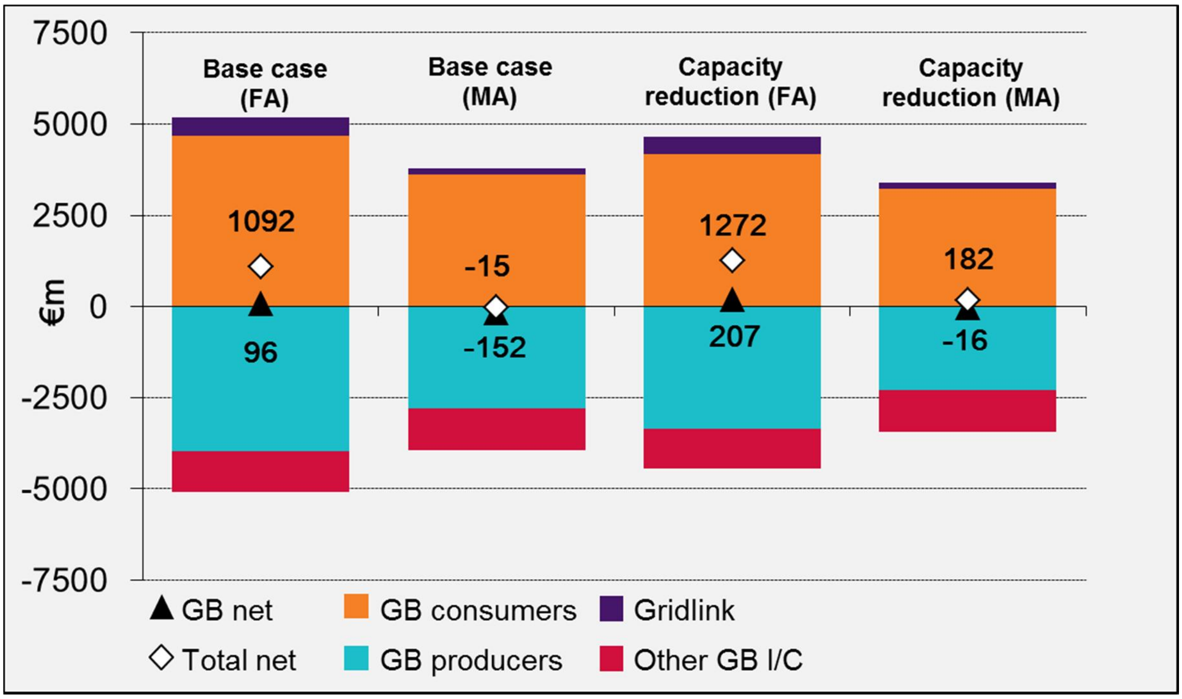
- NeuConnect's revenues remain virtually unchanged, as the removal of 200MW of CCGT capacity does not cause a substantial increase in price differentials and no significant change in flows on NeuConnect.
- As in the Base Case, the project requires floor payments in every year.
- Capacity payments remain unchanged from the Base Case.

E.5 Gridlink cost benefit analysis

E.5.1 Gridlink – overview and main conclusions

The Gridlink project has been modelled as a 1,400MW interconnector between Great Britain and France, commissioning in 2022 and it has replaced new-entry CCGT capacity of 200MW that was commissioned in 2022. The impact of this capacity reduction is much less profound than the one observed in the NorthConnect sensitivity.

Figure 65 – Gridlink impact on socio-economic welfare



The main conclusions from modelling the Capacity reduction sensitivity are:

- **Gridlink's impact on GB consumers is slightly lower than in Base Case**

  The absence of new 200MW CCGT capacity leads to slightly higher prices on average. However, the consumer welfare impact remains highly positive, as prices are still significantly lower compared to the case that includes the CCGT but excludes the interconnector (counterfactual case).

- **GB overall welfare remains slightly negative in the MA case though overall GB welfare has improved**

  Even though the less negative impact on producers is more significant than the drop in consumer welfare, it is not enough to turn the GB overall welfare positive.

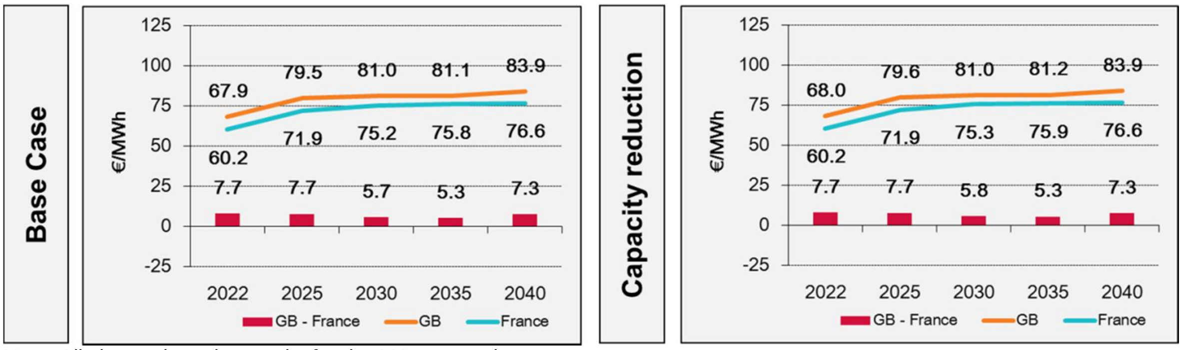
- **Positive impact in France is increased compared to Base Case**

  The increased positive impact on producers is more than balancing the increased negative consumer welfare, as slightly higher exports marginally improve French stakeholder welfare.

E.5.2 Gridlink – price differentials and flows

Figure 16 compares the annual average wholesale electricity prices and price differentials between Great Britain and France between the Base Case and the Capacity reduction sensitivity. Prices in France have remained unchanged and the drop of CCGT capacity by 200MW does not increase the prices in Great Britain substantially. Therefore the price differential stays at almost the same level as in the Base Case.

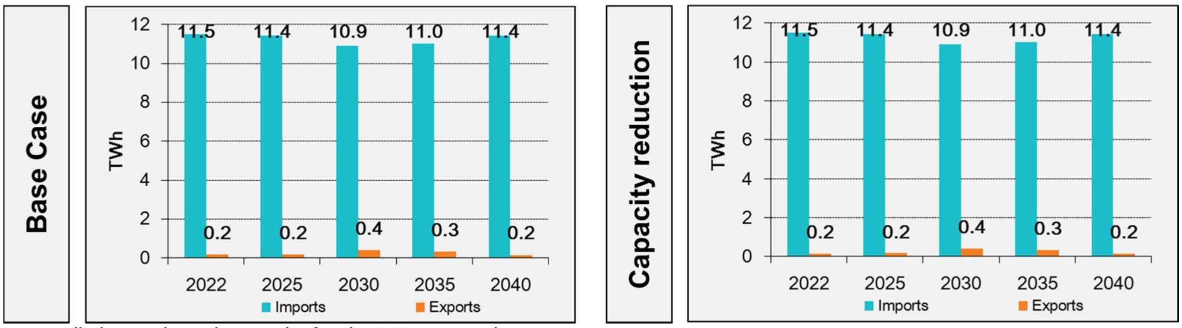
Figure 66 – Wholesale prices and differentials between Great Britain and France



Note: All charts show the results for the MA approach.

The flows of the interconnector are presented in Figure 17. Flows between GB and France remain unchanged and are mainly in the direction of France to Great Britain. The utilisation remains relatively high (96%).

Figure 67 – Flows on Gridlink

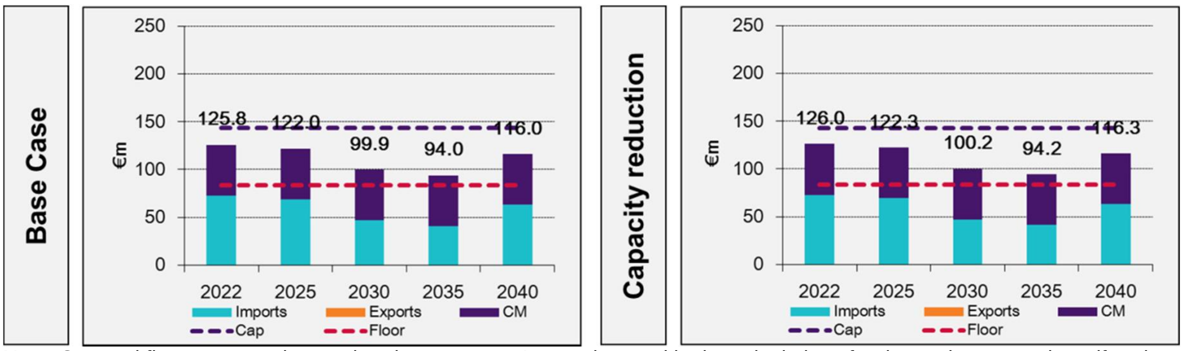


Note: All charts show the results for the MA approach.

E.5.3 Gridlink – revenues and cap and floor impact

Figure 18 shows the project's revenues in the Base Case and the Capacity reduction sensitivity.

Figure 68 – Revenues for Gridlink



Note: Cap and floor compared to total project revenue. In practice, and in the calculations for the socio-economic welfare in this report, the cap and floor is calculated for and applied to the GB share of the project only.

The main conclusions from comparing the Base Case and Capacity reduction sensitivity regarding interconnector revenues are as follows:

- Gridlink's revenues remain virtually unchanged, as the removal of 200MW of CCGT capacity does not cause a substantial increase in price differentials and no significant change in flows on the interconnector.
- As in the Base Case, no cap or floor payments are made.
- Capacity payments remain unchanged from the Base Case.

E.6 Main conclusions from Capacity reduction sensitivity modelling

The main conclusions from comparing the Capacity reduction sensitivity results to the results from the Base Case are as follows:

- The observed results in GB consumer welfare, GB producer welfare and total welfare are largely a consequence of changes in prices since removing new CCGT capacity leads to very small changes in flows.
  - Large capacity removals, as in the case of NorthConnect, did not lead to material change of flows or their direction.
  - Removing 200MW of CCGT capacity in the cases of NeuConnect and Gridlink did not result in a change of the direction and volume of flows.
  - Even if more capacity were to be removed in the cases of NeuConnect and Gridlink, these patterns are expected to be similar.
- Results from the Capacity reduction sensitivity show that GB consumer welfare and even more so GB net welfare are robust to a change in assessment approach.
- The impact from all of the three projects on GB consumer welfare remains significantly positive in the Capacity reduction sensitivity, although the removal of new CCGT capacity leads to a less positive impact on GB consumers.
- GB net welfare increases for all projects to such extent that both NorthConnect and NeuConnect turn positive in the MA case. Gridlink remains slightly negative in the MA case.
- In addition to the welfare increase in Great Britain, the impact on the other countries improves for all projects in the Capacity reduction sensitivity in both the FA and the MA cases:
  - Increased producer welfare impacts, compared to the Base Case, outweigh reduced consumer welfare impacts.
  - In NeuConnect's case, however, the producer welfare gain in Germany cannot offset the decrease of consumer welfare.
- In comparison to the Base Case, capacity factors and direction of flows remain virtually unchanged between GB and the other country.
- Revenues of interconnectors slightly increase in all cases as a result of somewhat higher prices in GB due to the reduced domestic generation capacity. Therefore, the conclusions regarding cap and floor payments remain unchanged from the Base Case.

ANNEX F – QUALITY ASSURANCE STATEMENT

Our approach to quality assurance aims to ensure that our analysis is at all times fit-for-purpose, executed with a minimum of errors, and at all times presented alongside the residual uncertainties, risks and any limitations of the analysis.

Our Quality Assurance Plan has three main components:

- collaboration with Ofgem throughout the project;
- our internal Quality Assurance processes; and
- the provision of a Quality Assurance Statement by the project Quality Assurer.

Collaboration with Ofgem

Throughout the project, we have ensured that the aims of the project are achieved with the highest possible level of quality assurance and the client's satisfactions met through regular contact, given the time and budget available.

Our internal quality assurance processes

Pöyry operates an internal quality management system designed to ensure that all our projects are completed to the high standard expected by our clients. Our internal quality assurance processes have included the following specific processes:

- allocation of our most expert consulting staff both at the analytical level and in the management and leadership of the project;
- a rigorous system of version control for modelling iterations and document production;
- analyst verification (i.e. error checking) of the model inputs, transformations and outputs using error checking scripts within the model, and sense checking (supervised by the project manager);
- modelling validation (ensuring the modelling approach is fit-for-purpose) by the project manager; and
- overall quality assurance provided by the Quality Assurer, who sits outside the project team day to day but provides internal challenge at each stage of the project in order to satisfy himself that the quality of the analysis is appropriate, thus enabling him to sign the Quality Assurance Statement that we provide for this project.

Quality Assurance Statement

This document has been signed off by the Quality Assurer, Dr Gareth Davies, as indicated by the quality and document control section at the end of this report.

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QUALITY AND DOCUMENT CONTROL

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