NEAR-TERM INTERCONNECTOR COST-BENEFIT ANALYSIS: INDEPENDENT REPORT

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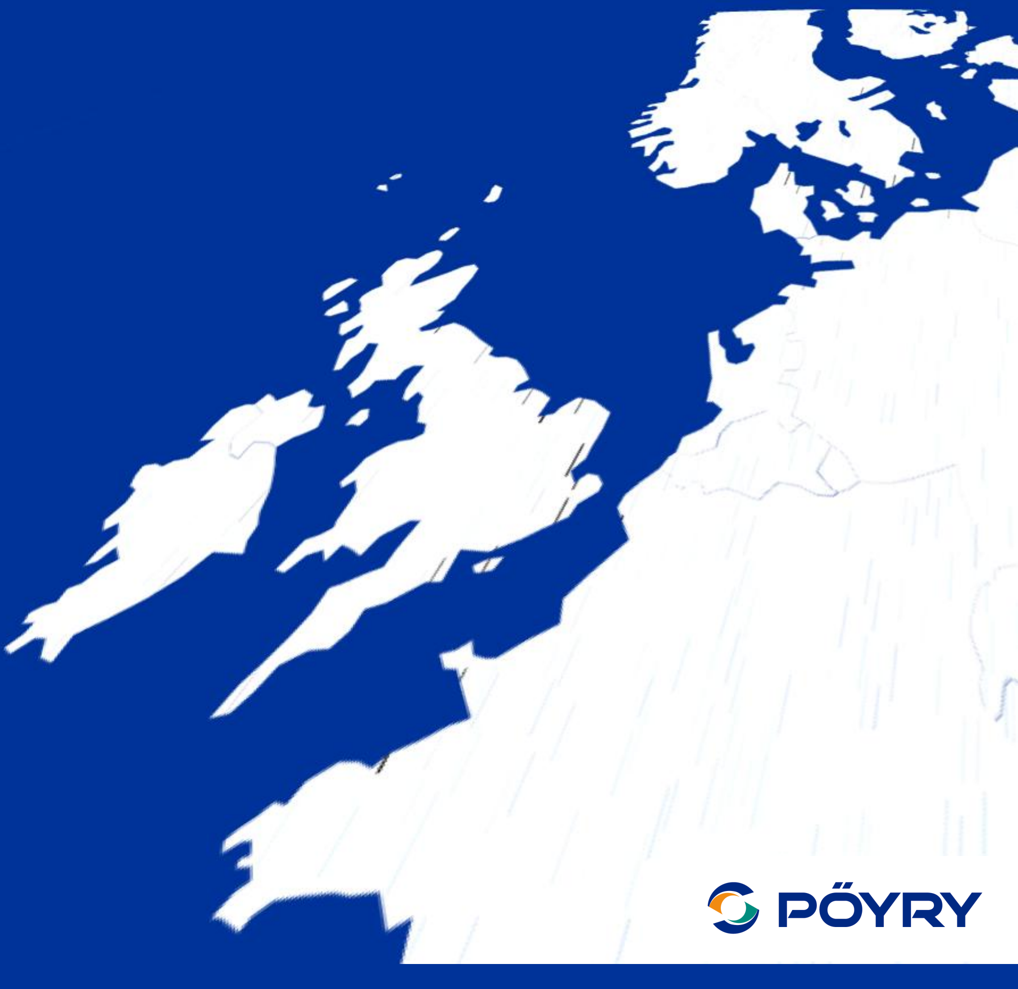
A Pöyry report for Ofgem

December 2014



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Pöyry Management Consulting provides leading-edge consulting and advisory services covering the whole value chain in energy, forest and other process industries. Our energy practice is the leading provider of strategic, commercial, regulatory and policy advice to Europe's energy markets. Our energy team of 200 specialists, located across 12 European offices in 10 countries, offers unparalleled expertise in the rapidly changing energy sector.

EXECUTIVE SUMMARY

Project background

Ofgem has commissioned Pöyry Management Consulting (UK) Ltd. (Pöyry) to support the decision making process regarding the recently introduced cap and floor regulatory framework for near-term electricity interconnector cables into GB.

Interconnectors derive their revenue from hourly price differences between the two interconnected electricity markets. The cap and floor framework will provide revenue protection up to the level of the floor, in exchange for any revenues above the cap for interconnectors that are successful in their application to the regime. Where revenue earned by interconnector owners exceeds the cap level there is a money transfer to consumers (via network tariffs). Where revenue earned is below the floor there will be a transfer from consumers to interconnector owners.

Five eligible applications were received as part of the first application window:

- NSN – a proposed 1,400MW link between GB and Norway;
- Viking Link – a proposed 1,000MW link a proposed between GB and Denmark;
- IFA2 – a proposed 1,000MW link a proposed between GB and France;
- FAB Link – a proposed 1,400MW link a proposed between GB and France; and
- Greenlink – a proposed 500MW link between GB and the Single Electricity Market in Ireland.

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;
- what the economic impact of these projects could be; including the impact on wholesale electricity prices, consumer surplus, producer surplus, security of supply and carbon emissions; and
- how these interconnector projects impact on each other.

In order to enable Ofgem to develop understanding of interconnector economics and investigate their economic impact, we have developed a spreadsheet model (CARAMEL) for Ofgem to take ownership of and use as the basis for this cost benefit analysis (CBA).

Methodology Overview

Market development scenarios

From the perspective of interconnector value, the fundamental value driver is the price difference between two countries. 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:

- **Base Case:** moderate economic growth and a continuation of energy efficiency in GB leading to slightly decreasing demand with moderate levels of renewables new build. Base Case fuel prices are based on DECC's Reference Scenario. This scenario aims to represent a moderate view of key drivers of price differentials and a reasonable baseline against which interconnector projects can be valued.

- **High interconnector value (High) scenario:** high GDP growth and growing electricity demand, combined with strong growth in all low carbon technologies (renewables, nuclear and CCS). Carbon prices and fuel prices (based on DECC High scenario) are also very high throughout Europe. Drivers are combined such that they lead to large 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 as a plausible representation of an extreme upside case for the commercial and economic value of interconnectors in GB.
- **Low interconnector value (Low) scenario:** stagnating economies lead to **falling electricity demand** and a general lack of progression in the electricity market. **Renewables development stops in 2020,** with very little need for new capacity and very low fuel prices (DECC Low scenario). Drivers are combined such that they lead to small price differentials between countries whilst still being internally consistent in terms of long-run global drivers and the extent to which commodity price differentials between markets may fall in the future. As such the scenario is designed as a plausible representation of an extreme downside case for the commercial and economic value of interconnectors in GB.

The key drivers for the scenarios and are summarised in Table 1. We have assumed that capacity mechanisms in GB, Ireland and France are operational in all scenarios.

Table 1 – Summary of key drivers across market scenarios

Driver	Base Case	High IC value scenario	Low IC value scenario
GB Demand	• Moderate GDP growth leads to slowly falling demand [-0.4% p.a.] • Based on NG's 'Slow Progression' scenario	• High GDP growth creates high demand [+0.9% p.a.] • Based on DECC's High scenario	• Stagnating GDP leading to continued falling demand [-1.2% p.a.] • Based on Base Case -0.75% growth
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 DECC's High scenario	• Gas only, capacity only required for replacement • Based on NG's 'No Progression' scenario
GB Renewables Capacity	• Moderate growth: 2020 targets hit few years late • 26GW 2020, 37GW 2030 • NG 'No Progression' scenario	• Very fast RES build • 40GW 2020, 60GW 2030 • Based on DECC's High Scenario	• Renewables capacities 'No Progression' to 2020, **but** fixed from 2020 onwards • 26 GW in 2020 & 2030
NWE demand & Capacity mix	• Moderate GDP growth and mixed capacity build • Pöyry Central scenario from Q3 2014	• Strong GDP growth and large low carbon roll-out • Pöyry High scenario from Q3 2014	• Weak GDP and demand growth: little new capacity • Pöyry Low scenario from Q3 2014
Fuel prices	• DECC Central Prices (similar but higher than Pöyry Central)	• DECC High Prices (similar but higher than Pöyry High)	• DECC Low Prices (similar but higher than Pöyry Low)
Carbon prices	• ETS and CPS following Pöyry Central: Q3 2014 • CPS & EU ETS reach parity @€55/tCO_2 in 2040	• ETS and CPS following Pöyry High: Q3 2014 • CPS always €10-20 above EU ETS price	• CPS falls to zero by 2020 • ETS following Pöyry Low: Q3 2014 – EU ETS rises to €20/tCO_2 in 2040

The key sources for assumptions as shown in the table are, for GB, National Grid Future Energy Scenarios work (released in July 2014) and the September 2013 Update of DECC Energy and Emissions Projections. For demand and capacity in other European countries we have based our assumptions on Pöyry's Q3 2014 pan-European Quarterly Update of prices.

We have also examined a series of sensitivities on a project specific basis to test the key drivers of welfare and value for that interconnector. The impact of potential direct capacity mechanism revenues on interconnectors is not included in the main CBA scenarios but is included as part of this sensitivity analysis.

Cost Benefit Analysis methodology

To assess the impact of an interconnector on the wider society, we have conducted a Cost Benefit Analysis (CBA) in our different market scenarios, comparing social welfare in scenario with and without the assessed interconnector (the latter being the 'counterfactual'). To show the impact of the particular interconnector being examined, all other factors are held constant between runs (e.g. build of other interconnectors, costs for other projects). All interconnectors have been assessed assuming that they would be operating under the cap and floor regulatory framework.

One additional driver of interconnector value is the extent to which other interconnection is developed in GB. In order to take account of uncertainties in the future 'build profile' of interconnectors, we have conducted the CBA using two different approaches: 'first additional' (FA) and 'marginal' (MA).

FA CBA approach

For this approach we examine the value of each interconnector in turn as if it is **the only new interconnector** to be built in 2020. Other interconnection is assumed to come online in this scenario but gradually over time.

The key 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 this value. 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).

MA CBA approach

In contrast to the above, for this approach we examine the value of each interconnector in turn as if it **commissioning at the same time as four other additional interconnectors** in 2020. In the MA approach we assume all five projects that applied for C&F are brought forward to 2020, deviating from the assumption in the FA approach that this interconnection expansion comes online over time. The combined interconnection in the FA case and MA case is equal from 2035 onwards; it is the path of build to 2035 that differs.

The key aim of this stage of the analysis is to illustrate the lower bound of value of the interconnector in a given scenario assuming that additional interconnectors will, in general, reduce this value. By again examining the value across the three market scenarios we obtain the range of minimum values in different market conditions (corresponding to the High, Base Case and Low scenarios).

Key CBA metrics

The fundamental sources of economic value for an interconnector derive from an increase in the economic efficiency of electricity markets through the building of interconnection. The change in the social welfare is split into the impact on three categories of stakeholder – consumers, producers (generators) and interconnector owners. The Net Present Value (NPV) of these categories of costs and benefits are calculated using the CARAMEL model provided to Ofgem as part of this work and form the basis of the CBA:

- Consumer surplus in the electricity market in a given country is represented by the total electricity demand in a country multiplied by the difference between the price charged for electricity and the value of lost load (VoLL). Net consumer welfare change therefore 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.
- Producer surplus in the electricity market in a given country is the difference between the price received for each unit of electricity produced and the marginal cost of producing that unit of electricity (i.e. the gross margin of electricity production). Net producer welfare change therefore 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.
- 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 (flow multiplied by price differential between markets) which are assumed to be captured by the interconnector owner;
  - 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;
  - 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 show 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.

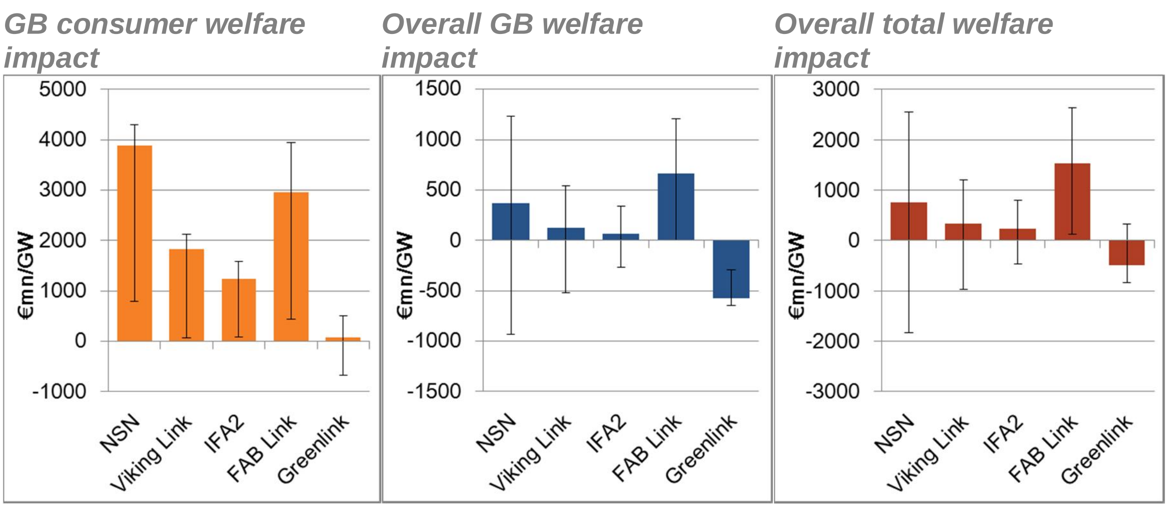
Figure 1 shows the resulting project comparison expressed as the impact of the interconnector on the NPV (at a 3.5% discount rate, over a 25 year project life) for three measures of net social welfare change:

- GB consumer welfare (GB consumers only);
- Overall GB Welfare (GB consumers, GB producers and GB interconnectors); and
- Overall total welfare (consumers, producers and interconnectors in GB and connected country).

These are expressed on a normalised basis i.e. on a per GW of interconnection capacity installed. The solid bars show the welfare impact in the Base Case under the MA CBA approach (i.e. they show the lower bound of value) – where significant differences arise between the MA and FA results these are identified in the text. The top and bottom of the error bars show the range of outcomes across our High and Low market scenarios (also under the MA CBA approach).

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 – Project comparison (€m/GW): All scenarios (Marginal Analysis)



Source: Pöyry Management Consulting modelling for Ofgem

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

- In the Base Case, NSN and FAB Link provide the highest projected benefit to GB consumer welfare (of €3bn-€4bn), the highest projected benefit to net GB welfare (of €400m-€600m), and the highest projected benefit to total welfare (of €800-1500m).
- Viking Link and IFA2 also show a strong benefit under the Base Case to GB consumers of (€1bn-€2bn) in NPV terms, and a small net benefit to overall GB welfare and overall total welfare.
- NSN, Viking Link, IFA2 and FAB Link **all** show a positive impact on GB consumer welfare even in the Low scenario (once any potential floor payments are accounted

for). However, the High scenario results also show that they all have only limited additional upside value to consumers over and above the Base Case.

- FAB Link's significant additional benefit to GB consumers over IFA2 (the other French connected interconnector) is based, at least in part on its low cost estimates, low cap levels and resulting large projected cap payments.
- NSN, Viking Link and IFA2 show a symmetrical Low/High overall GB welfare and overall total welfare impact – there are downside risks that the interconnector will be a net social welfare dis-benefit to GB but these appear to be broadly balanced against potential upside benefits in a high scenario. NSN and Viking Link show a large range in benefit around the Base Case (±€2.5bn and ±€0.5, respectively), principally due to their high cost compared to other interconnector projects.
- Greenlink shows a very small positive impact on GB consumers in the Base Case, and a strong dis-benefit to overall GB welfare in all scenarios. The key welfare beneficiary of the Greenlink interconnector across all scenarios is Ireland. However, under our Base Case CBA the positive impact on welfare in Ireland does not offset the welfare losses in GB therefore leading to a negative net total welfare. The High and Low scenarios are broadly symmetrical around the Base Case for Greenlink across all measures. As would be expected given the business case, the overall project welfare case appears to be highly dependent on the level of new renewables build in GB and Ireland.

Final Conclusions

- NSN, Viking Link, IFA2 and FAB Link are all based on a similar business case and operating model. They connect the GB market to markets with a significantly lower expected average price level leading to large net imports of electricity into GB. Greenlink is based on a different model, whereby value is primarily derived from connecting two markets with increasing volumes of intermittent low carbon generation and thereby increasingly volatile prices.
- GB consumer welfare benefits are generally much higher than the Overall GB welfare impact. Apart from Greenlink, the interconnectors examined all showed large net flows of electricity into the GB market, lowering GB prices – this leads to increased GB consumer surplus, but these welfare benefits are offset by lower GB producer surplus. Overall interconnector social welfare is generally neutral in the Base Case after the operation of the cap and floor has been accounted for.
- While business cases and operating models are similar, key differentials in the social welfare impact between NSN, Viking Link, IFA2 and FAB Link are driven by:
  - The capacity of the interconnector with larger interconnectors having higher costs but higher potential revenues;
  - The length of the interconnector which in turn drives costs – NSN and Viking Link are significantly longer and therefore more costly than IFA 2 and FAB Link;
  - The scale of the average price differences between the markets and the extent to which this varies by hour with Norway and Denmark showing the highest levels of price difference in the Base Case.
- 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 envisaged in the Base Case for NSN, Viking Link or IFA 2.

  - FAB Link sees reasonable levels of payments to consumers over the cap (€450-550mn in NPV terms) in the Base Case, representing a welfare benefit for GB consumers;
  - Greenlink sees revenues under the floor level in the Base Case (assuming no capacity mechanism payments) leading to payments from consumers to Greenlink (~€20mn in NPV terms) thereby lowering GB consumer welfare.
  - All projects apart from FAB Link receive floor payments from consumers in the Low scenario as revenues are below the floor in certain years. However, all projects also make cap payments to consumers under the High scenario as revenues are above the cap in certain years. This variability in potential revenues across market scenarios is a key feature for future interconnectors.
- Sensitivity analysis on capacity market participation by interconnectors shows that:
  - Capacity market participation represents an upside for the interconnector business case and decreases the likelihood of projects requiring floor payments. Where revenues are pushed above the floor level or when revenues are pushed above the cap level it will also represent an upside for GB consumers – in cases where the revenue stays between the cap and floor there is no GB consumer impact.
  - Where IFA2, FAB Link and Greenlink are assumed to participate broadly equally in two capacity markets (one at either end of the link), the impact on overall GB welfare is minor but represents a wealth transfer from producers to interconnector owners (and then, potentially, indirectly to consumers via the cap and floor mechanism).
  - Where the interconnector is only participating in one capacity market, this leads to a net transfer of welfare out of the country offering that capacity market – particularly relevant for interconnection with Norway and Denmark where no capacity market is currently envisaged.
  - For Greenlink in particular, CM participation appears essential to the business case – in the Base Case, Greenlink revenues are consistently below the floor before capacity market revenues but close to or above the cap when including capacity market revenues.
  - For NSN and Viking Link, which are below or close to the floor in certain years in the Base Case, this risk would be much reduced by allowing projects to bid into the GB capacity market.
  - For the French projects (IFA2 and FAB Link) and Greenlink, CM participation in both markets presents a slight upside to overall GB welfare, as capacity market clearing price in the connected market is assumed to be higher than the GB capacity market clearing price.
- It was generally found that the MA and FA approach produced very similar results in terms of overall social welfare. While the volume of ‘competing’ interconnection can be a driver of the business case for an individual interconnector, the similarity of social welfare levels between the two approaches shows that the build profile of the five new interconnectors is a much smaller driver of welfare than the underlying fundamentals across the market scenarios.

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1. INTRODUCTION AND BACKGROUND

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 this regulatory framework, Ofgem assesses the economic needs case of eligible interconnector projects as part of the Initial Project Assessment (IPA) process.

Ofgem has commissioned Pöyry Management Consulting (UK) Ltd. (Pöyry) to conduct a social welfare Cost Benefit Analysis to support the decision making process. To support the assessment of the economic needs cases of these projects, Ofgem commissioned Pöyry to conduct an analysis investigating:

- where project value arises (both costs and revenues), the key drivers and how this is impacted by the cap and floor provisions;
- what the economic impact of these projects could be; including impact on wholesale electricity prices, consumer surplus, producer (generator) surplus and security of supply; and
- how these interconnector projects impact on each other.

This report presents the findings of Pöyry's independent Cost Benefit Analyses (CBAs) of the five interconnectors which have submitted applications under the cap and floor framework.

1.2 Background

Until recently interconnector projects in GB were developed under the merchant-exempt framework, where interconnector revenues are based on arbitrage of prices between markets ('congestion rent'). Under this framework, only a limited number of projects have been realised.

To provide for a regulated route for new interconnection and to encourage investment, Ofgem has developed a 'cap and floor' regime for project NEMO, the proposed interconnector between Belgium and GB. In August 2014, Ofgem decided to roll out the cap and floor to other new near-term electricity interconnectors.

Under this regime, NEMO and other new projects successful in their application would 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.

Projects with a connection date before the end of 2020 that meet proposed criteria are eligible to apply for this scheme in the first application window opened in August 2014. The key criteria for an eligible application are as follows:

- a connection date in 2020;
- a realistic project plan;
- an interconnector licence acquired or in the process of acquiring one; and
- an existing connection agreement.

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.

Five eligible applications were received as part of the first application window:

- NSN – proposed 1400MW link between GB and Norway;
- Viking Link – proposed 1000MW link a proposed between GB and Denmark;
- IFA2 – proposed 1000MW link a proposed between GB and France;
- FAB Link – proposed 1400MW link a proposed between GB and France; and
- Greenlink – proposed 500MW link between GB and the Single Electricity Market in Ireland.

1.3 Conventions

The following conventions are used throughout this report:

- Money is real 2013 money euros unless otherwise specified.
- All years are calendar years.

Where not specifically sourced, figures, tables and diagrams should be attributed to Pöyry.

1.4 Report structure

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

- Chapter 2 presents the methodology and approach taken to analyse the social welfare impacts of proposed new interconnectors;
- Chapter 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;
- Chapter 4 contains the resulting Cost Benefit Analysis for each interconnector; and
- Chapter 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 methodology applied in this CBA;
- Annex B provides an overview of BID3, our pan-European electricity market dispatch and optimisation model;
- Annex C contains additional detail on model inputs; and
- Annex D presents the capacity market modelling and sensitivity results.

2. ANALYSING INTERCONNECTOR BENEFITS: METHODOLOGY AND 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 have developed an economic model for Ofgem, which is used to assess the key 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 Chapter 3. The remainder of this chapter describes the theoretical benefits; provides an overview of our modelling approach and its limitations and; introduces the assessment methodology with which we have assessed interconnector welfare for near-term electricity interconnectors that have applied for the cap and floor regulatory framework.

2.2 Theoretical key costs and benefits of 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 key challenges and complexities for developers relate to predicting and accessing arbitrage revenues between markets which are the key 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.

2.2.1 Theoretical benefits of increased interconnection

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.

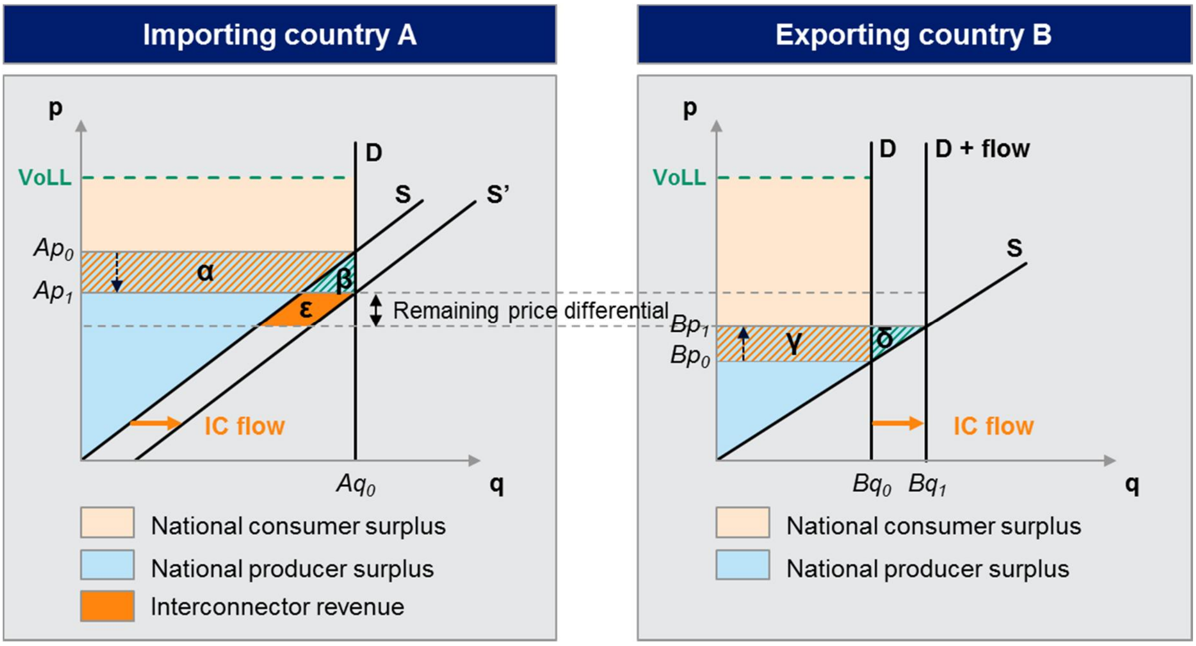
It should be noted that the economic costs and benefits of interconnection can be categorised in different ways and there is no ‘correct’ value split between sub-categories. Some elements are welfare creating and can have benefits on both sides of an interconnector (such as efficiency gains from generating 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).

Consumers, 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 2 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 2.2.2:

- 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 2 – Fundamental economic value of interconnectors



2.2.2 *Key costs/benefits included in the core CBA*

The following costs and benefits have been modelled as part of the core 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 core CBA.

- Net consumer welfare change:
  - Savings [Area α + β in Figure 2] or increases [Area γ in Figure 2] 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 (i.e. from/to GB consumers to/from an interconnector asset where welfare is, in principle, jointly shared between countries).
- 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 2] in gross margin from increased exports and/or higher prices in hours when they generate or a decrease [Area α in Figure 2] from increased imports and lower prices [Area γ + δ in Figure 2].
- 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 2]. We assume in the core 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.

2.2.3 Additional potential costs/benefits not include in core 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 core 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[1] between groups rather than fundamental welfare creation. The overall value of

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[1] Some elements in a CBA can act simply as welfare transfers from one stakeholder group to another – we have considered these in the core CBA where they are of particular import to

these elements is also sometimes several orders of magnitude lower than those analysed in the main CBA modelling.

Where we assess the impact of some of these elements to be significant and quantifiable we have included the effects as part of the CBA sensitivity analysis.

- Additional consumer welfare changes:
  - **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 we do 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 generation capacity in market for a period of time – this could, all other things being equal, lead to lower capacity market clearing prices, thereby reducing costs for consumers.
  - Changes in **Low carbon support payments** – if low carbon producers are able to access higher market prices they would reduce the burden on consumer support under the Contracts for Difference (CfD) or indeed broader 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 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.
  - Changes in **network reinforcement costs** 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.
  - 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).
  - Additional value from consuming more in periods where the price in the market would otherwise have led you (as a half-hourly metered customer) to curtail your consumption **(reduced demand side response).** This element is already captured in our approach as producer surplus (in effect treating price responsive customers as producers in periods they curtail consumption) and would therefore show up only as a transfer element and not as additional total welfare.
  - **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:
  - **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

GB consumer welfare in our analysis (for example in the application of the cap and floor) but otherwise they are generally excluded.

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.

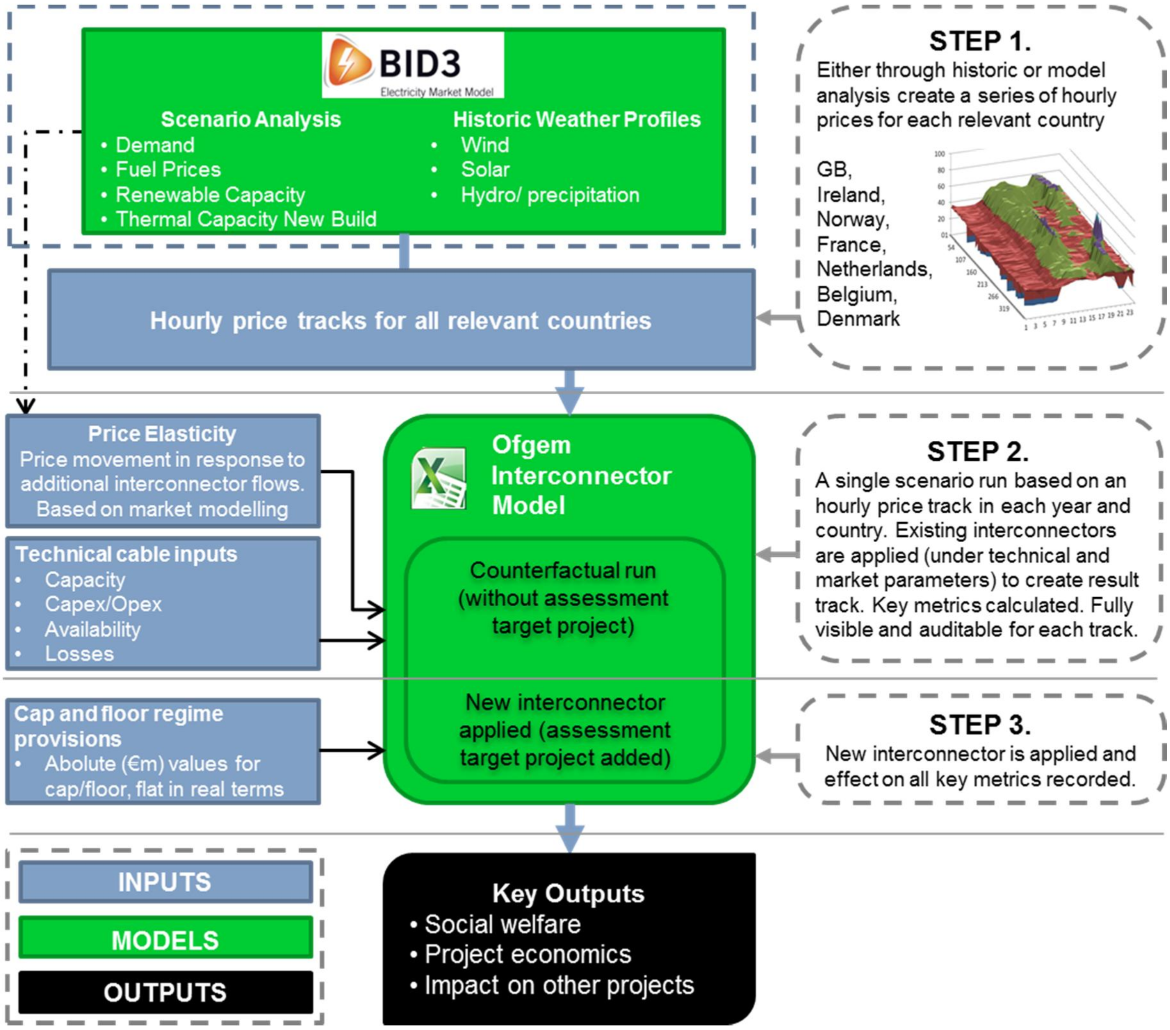
  - Changes in payments for **ancillary and balancing services** either through access to additional markets for those services or through displacement of that provider of ancillary services by other sources through the interconnector.
  - Changes in required **low carbon support payments** – primarily a transfer element between producers and consumers (see above).
  - 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 participation in **capacity payment mechanisms** on either or both sides of the interconnector (where regulations and flow directions in system stress periods allow).
  - 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 methodology overview

The modelling methodology employed for conducting the CBA is based on a combination of Pöyry's pan-European electricity market modelling and an interconnector economic assessment model developed for Ofgem. Figure 3 below shows the main steps in our modelling methodology.

Figure 3 – Modelling Methodology Overview



We use our pan-European electricity model BID3 to generate price projections for every country in Europe on an hourly basis between 2015 and 2040 (Step 1 in Figure 3). 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. These hourly price projections feed into the interconnector scheduling model.

On behalf of Ofgem, Pöyry has also developed a flexible Excel based model (***CARAMEL***) to perform an economic cost benefit analysis for new interconnector projects. The model we have designed enables the analysis of new and existing interconnector projects, and the assessment of their impact on different market participants (Step 2 and Step 3 in Figure 3). The model is therefore 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 methodology is contained in Annex A.

2.3.1 Modelling strengths and weaknesses

To enable the transfer of the model into a flexible Excel format a number of simplifications have been required and these should be borne in mind when reviewing the results of the analysis. The key strengths and weaknesses of the modelling approach are described in more detail in section A.3 with the key elements summarised as follows:

- The underlying use of the pan-European BID3 model as a starting point for the production of hourly price projections to 2040 is a key strength of the chosen modelling approach. Utilising a pan-European model is a necessary starting point for any cross-border trade analysis as single country models can quickly introduce internal inconsistencies in market modelling. A pan-European market also has the advantage of accounting for the impact of decisions and developments of large but not directly connected countries (such as Germany) on smaller surrounding markets.
- The CARAMEL model co-optimises the scheduling of all interconnectors simultaneously, accounting for elasticity of prices in markets thereby incorporating:
  - the tendency of interconnectors to 'cannibalise their own revenue'; and
  - the tendency of interconnectors to also impact the revenue and welfare of other GB interconnectors (which can either be positive or negative).
- However it should be noted that using a market price elasticity approach in CARAMEL (with elasticity expressed as a % movement in prices for a given change in market demand) as a proxy for the slope of supply curve is a simplification of the actual market supply curve. To the extent that the supply curve cannot be well defined as a curve with a constant percentage change in prices due to demand (e.g. in very high or very low price periods) an approach using an optimisation solution would be beneficial. By comparing the prices and flows in CARAMEL with those that would be derived under an optimisation solution we have minimised differences between these approaches on average, but hourly differentials still remain. Large changes in the assumptions on, for example, the scale of new interconnector build within the Excel model, will tend to reduce the level of consistency with the results that would be obtained with a full run of a pan-European model optimisation model.
- 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 this is appropriate granularity on which to conduct the interconnector analysis it has been necessary, given the long-term nature of the scenario modelling, to assume that each year is average in terms of weather, demand and plant availability.
- We have focused on the key 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 2.2.3 including aspects such as grid reinforcements costs or wind curtailment. 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 costs elements would be beneficial.
- The non-GB interconnector welfare calculations are inherently less robust than the GB market as interconnectors which have no direct relationship with GB are not included in the analysis (as the CARAMEL model focus is GB). Although 'second country' interconnector welfare levels are not reported as separate line items in the CBA they do feed into the overall total welfare calculations.

Finally, in any scenario approach, whether using an LP or Excel based to modelling a large number of assumptions are required which in turn influence the model results. 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 and assessment of the results should be with regard to the range of future outcomes. We have also conducted sensitivity analysis on the results to test the robustness of the analysis to certain key assumptions.

2.4 Cost Benefit Analysis methodology

For every project to be assessed as part of the CBA, two different runs need to be done: the **project assessment** run (on the basis of the actual desired interconnector build schedule), and the **counterfactual** run (with every factor held constant from the project assessment 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 project assessment 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. A key 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 five projects which applied for Ofgem's cap and floor regime. We have therefore taken two different 'build profile' assessment methodologies which aim at spanning a range of value for the future interconnectors:

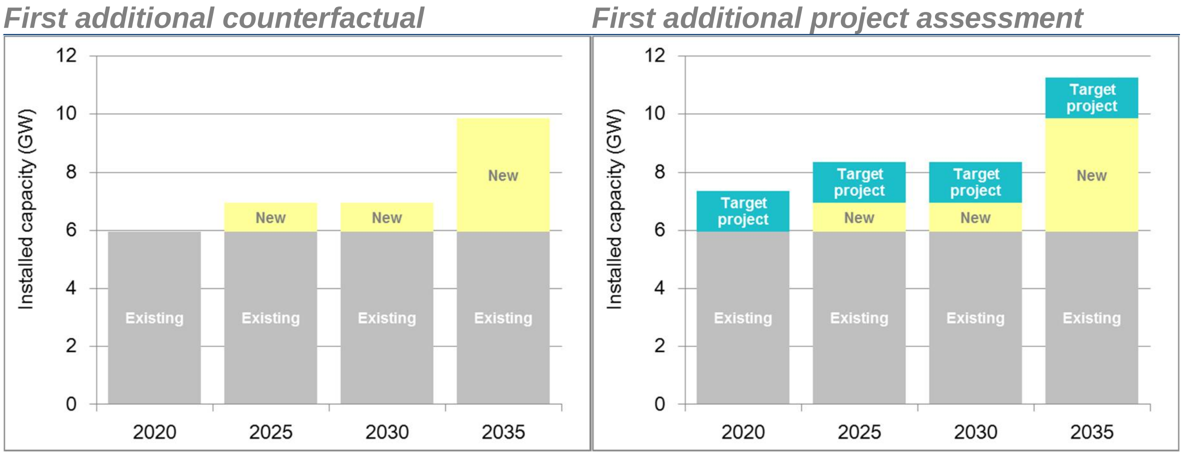
- FA Methodology: value as the **f**irst **a**dditional interconnector; and
- MA methodology: value as the **ma**rginal interconnector.

These assessment methodologies are described in 2.4.1 and 2.4.2 below.

2.4.1 FA Methodology: Value as the first additional (FA) interconnector

The FA assessment methodology examines the value of each interconnector in turn as if it is the only new interconnector to be built in 2020. Other interconnection is assumed to come online in this scenario but gradually over time (in line with the schedules shown in the scenario assumptions, as given by National Grid and DECC, described in Annex C.3). This method is shown conceptually in Figure 4 below.

Figure 4 – Assessment methodology: Value as a first additional interconnector



The key aim of this stage of the analysis is to show the upper bound of value in theory of the interconnector in a given market environment for interconnection as additional interconnection will tend to, although not always, decrease the value of other interconnection in a given market[2]. 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 High, Base Case and Low scenarios).

2.4.2 MA Methodology: Value as the marginal (MA) interconnector

The MA assessment methodology examines the value of each interconnector in turn as if it is the last of five additional interconnectors to be built in 2020. It is assumed that very little new interconnection occurs after 2020 in this build scenario, as all 'planned' projects before ~2035 have been brought forward. In this regard the 'total' volume of interconnection by 2040 in the two methodologies is very similar but it is the different pathways to 2040 that drive different results[3]. This method is shown conceptually in Figure 5.

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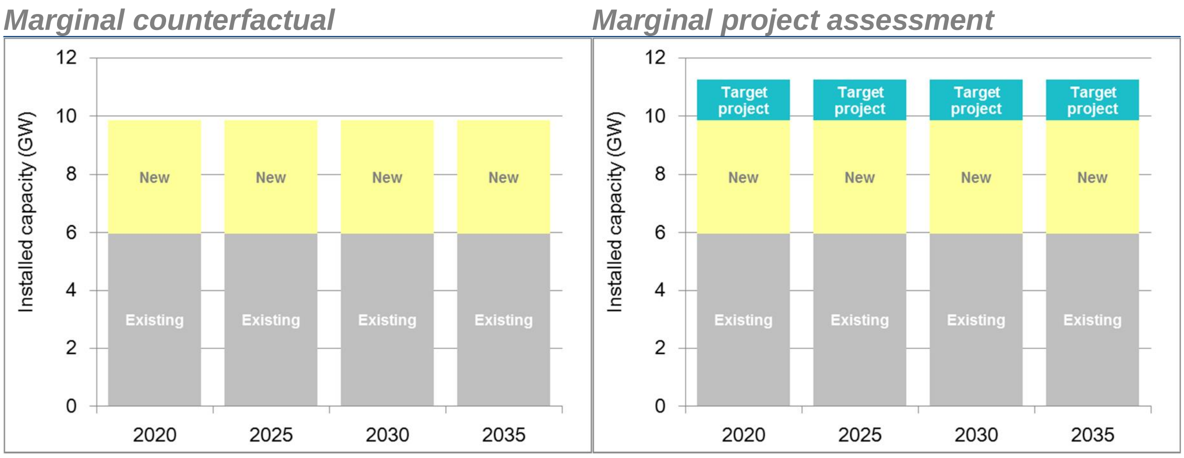
2 Additional interconnection between two markets (say GB and France) would always lower the value of other competing interconnectors between those the same two markets. It will also usually, but not always, lower the value of other GB interconnectors to continental Europe (say Belgium) as French prices 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). This effect can be seen by comparing the FA and MA results for different interconnectors in Chapter 4.

3 As the interconnector that is built first is generally able to deliver social welfare benefits in the absence of other interconnectors

Figure 5 – Assessment methodology: Value as a marginal interconnector



The key aim of the MA methodology, marginal interconnector approach is to show the lower bound of value of the interconnector in a given market environment. As with the FA methodology, 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).

The results for all projects using the 'first additional interconnector' and 'marginal interconnector' methodology are described in Chapter 4 below. Throughout the analysis we label the first additional build profile runs as FA and the marginal additional build profile runs as MA.

3. MARKET DEVELOPMENT SCENARIOS

3.1 Scenario development overview

3.1.1 Development Approach

Three internally consistent market scenarios (Base Case, High and Low) 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 key 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 three primary sources for the scenarios:

- National Grid Future Energy Scenarios work (released in July 2014)[4];
- DECC Energy and Emissions Projections (September 2013 Update)[5]; and
- Pöyry Q3 2014 pan-European Quarterly Update of prices (as and where additional assumptions are required, particularly for non-GB electricity markets);

To make the CBA robust, we constructed a range of scenario outcomes for interconnectors around a Base Case. As a result, we used information sources which:

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

3.1.2 Key value drivers for electricity interconnection

From the perspective of interconnector value, the key 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 countries, on macro- (annual, quarterly, seasonal or monthly) and micro-timescales (day-ahead, intra-day).

In that regard the key price and value drivers that we have considered are shown in Figure 6 below.

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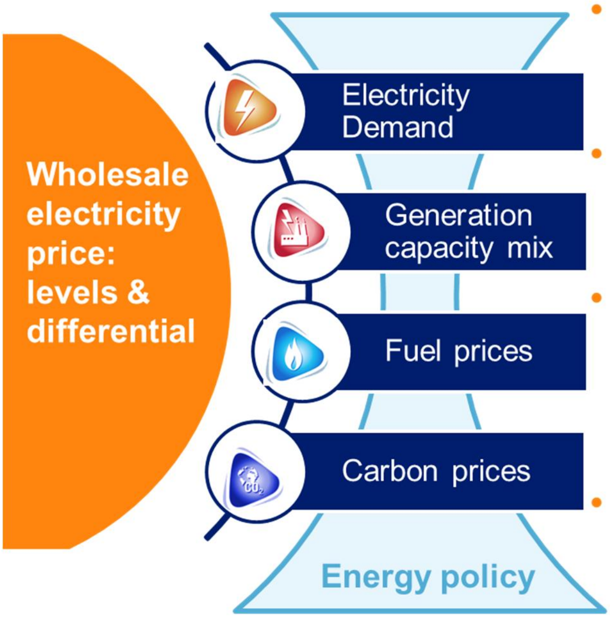
4 http://www2.nationalgrid.com/uk/industry-information/future-of-energy/future-energy-scenarios/

5 https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2013

Figure 6 – 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 key 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 key 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 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 key market drivers – the storylines underlying these scenarios and the key assumptions are presented in section 3.2 below.

3.2 Key scenario assumptions

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

- In the **Base Case** we project moderate economic growth in both GB and Europe but and a continuation of energy efficiency leads to **slightly decreasing demand** over time in GB. Coal plants decommission as planned and **new build thermal capacity mainly constitutes gas plants,** with some gradual nuclear new build in the 2020's and 2030's. The **Renewables build-up profile is moderate** with GB reaching its 2020 targets slightly late (in the early 2020s) alongside some other European countries. Across Europe, **Fuel prices increase in the early years** before flattening out in the 2020's. 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 Slow progression and No Progression cases respectively. In other

European countries we base the demand and capacity projections on Pöyry's Q3 2014 Central scenario.

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

- In the **High interconnector value (High) scenario** we project **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) is relatively **high**. **Fuel and carbon prices** are also very **high** throughout Europe**,** linked to strong policy action and high levels of GDP growth. The fuel prices used in this scenario and the generation capacities in GB come from DECC High scenario. Demand and capacity expansion in other European countries is based on Pöyry's Q3 2014 High scenario.
  - The drivers are combined such that they lead to 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 key drivers that can represent an upside case for the commercial and economic value of interconnector projects in GB.

- In the **Low interconnector value (Low) scenario** we project that the stagnating GB and wider European economies lead to **falling electricity demand** and a general lack of progression in the electricity market. **Renewables development in GB stops in 2020,** thereby never reaching current target levels**,** with very little need for new capacity and very low fuel prices. The fuel prices used in this scenario come from DECC's Low scenario. The new build capacities in GB are based on National Grid's No Progression scenario but beyond 2020 we have held the renewables' capacities constant. Demand and capacity expansion in other European countries is based on Pöyry's Q3 2014 Low scenario.
  - 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 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 key 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 and are introduced in Italy and Germany around 2020, having a dampening effect on European wholesale electricity market prices – see section 3.5 for more details.

Table 2 – Overview of scenario assumptions

Driver	Base Case	High IC value scenario	Low IC value scenario
GB Demand	• Moderate GDP growth leads to slowly falling demand [-0.4% p.a.] • Based on NG's 'Slow Progression' scenario	• High GDP growth creates high demand [+0.9% p.a.] • Based on DECC's High scenario	• Stagnating GDP leading to continued falling demand [-1.2% p.a.] • Based on Base Case -0.75% growth
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 DECC's High scenario	• Gas only, capacity only required for replacement • Based on NG's 'No Progression' scenario
GB Renewables Capacity	• Moderate growth: 2020 targets hit few years late • 26GW 2020, 37GW 2030 • NG 'No Progression' scenario	• Very fast RES build • 40GW 2020, 60GW 2030 • Based on DECC's High Scenario	• Renewables capacities 'No Progression' to 2020, **but** fixed from 2020 onwards • 26 GW in 2020 & 2030
NWE demand & Capacity mix	• Moderate GDP growth and mixed capacity build • Pöyry Central scenario from Q3 2014	• Strong GDP growth and large low carbon roll-out • Pöyry High scenario from Q3 2014	• Weak GDP and demand growth: little new capacity • Pöyry Low scenario from Q3 2014
Fuel prices	• DECC Central Prices (similar but higher than Pöyry Central)	• DECC High Prices (similar but higher than Pöyry High)	• DECC Low Prices (similar but higher than Pöyry Low)
Carbon prices	• ETS and CPS following Pöyry Central: Q3 2014 • CPS & EU ETS reach parity @€55/tCO_2 in 2040	• ETS and CPS following Pöyry High: Q3 2014 • CPS always €10-20 above EU ETS price	• CPS falls to zero by 2020 • ETS following Pöyry Low: Q3 2014 – EU ETS rises to €20/tCO_2 in 2040

Detailed model input assumptions are provided in Annex C.

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 one key 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-5 weather year (i.e. accounting for a temperature driven demand profile plus hourly wind and solar yield)[6]. 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-5 weather year, including the loss of the single largest unit in the market). In the Low scenario capacity margins are generally slightly above (1-2%) those required by our standard security of supply analysis. The generally falling demand in this scenario creates a small persistent over capacity situation (or to put it another way, a higher security standard is maintained) and 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 is defined by National Grid and DECC (depending on the scenario) but is generally consistent with that seen in our standard scenario analysis. All new build capacity in GB passes our standard economic viability test (earning returns consistent with historic hurdle rates for assets with similar risk profiles[7]); in part due to payments under the capacity mechanism in GB.

3.3 Wholesale price projections by scenario

In this section we outline the resulting wholesale price projections generated by the BID3 modelling of wholesale electricity price projections, first for GB and then for the other countries included in the CARAMEL interconnector model. All scenarios and assumptions are based on those outlined in section 3.2 and discussed in more detail in Annex C. All scenarios also include the impact of European capacity mechanisms on wholesale prices as outlined in section 3.5.

Wholesale electricity prices in GB

Figure 7 shows the resulting GB scenario annual time weighted average wholesale electricity prices in our Low, Base Case and High scenarios:

- In the Base Case, 2020 wholesale prices (the first year of operation of new interconnection) are around €78/MWh, increasing slowly thereafter to reach €82/MWh by 2030. Key factors behind the rising prices in the Base Case are increasing fuel and carbon prices, counteracted by relatively slow demand growth and rising renewables build.
- In the High scenario prices rapidly increase from prices today in line with underlying demand growth, fuel and carbon prices to reach €103/MWh by 2020. Beyond 2020 prices continue to rise, reaching ~€110/MWh by 2040.
- In the Low scenario prices fall to €39/MWh in 2020 in GB, before rising slowly in line with underlying EU ETS carbon prices (as the CPS is assumed to have fallen away). The very low demand growth in this scenario means that little new build is required after the growth of renewables to 2020's keeping prices close to €40/MWh to 2040.

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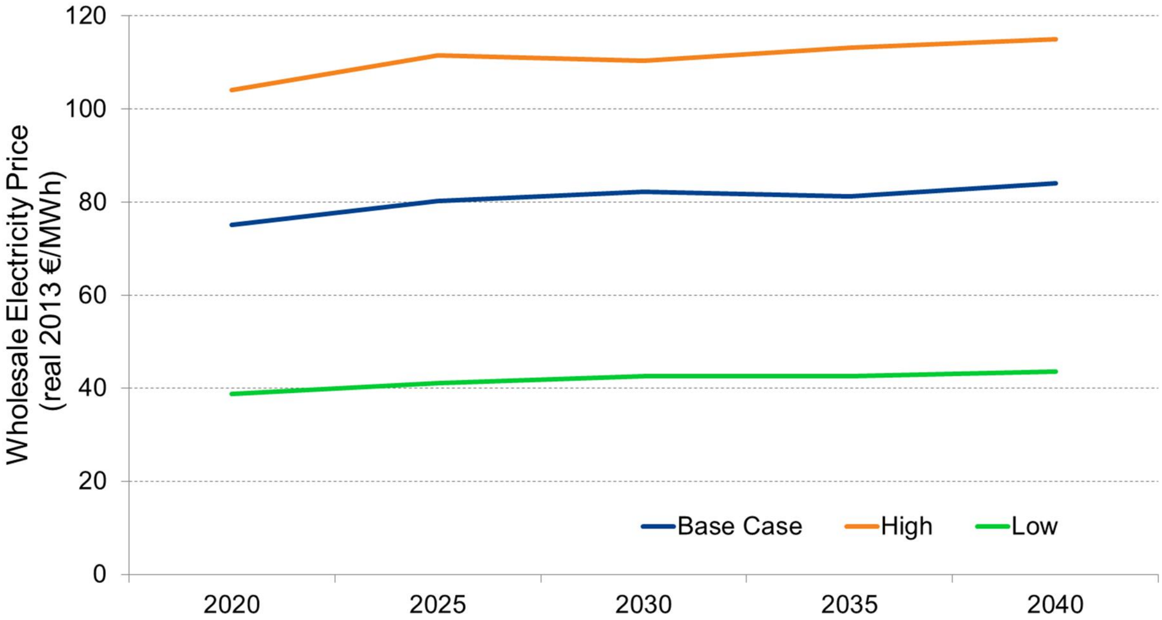
6 We regard this standard as consistent with National Grid's own definition of their security of supply standard under the capacity mechanism arrangements of a LOLE of not more than 3 of hours per annum.

7 These 'target' hurdle rates vary by scenario – they are approximately (i.e. ±2.5% depending on the year of new build) 8.5% in our Base Case, 11.5% in our High scenario and 6.5% in our Low scenario.

Figure 7 – GB power prices: Base Case, High and Low

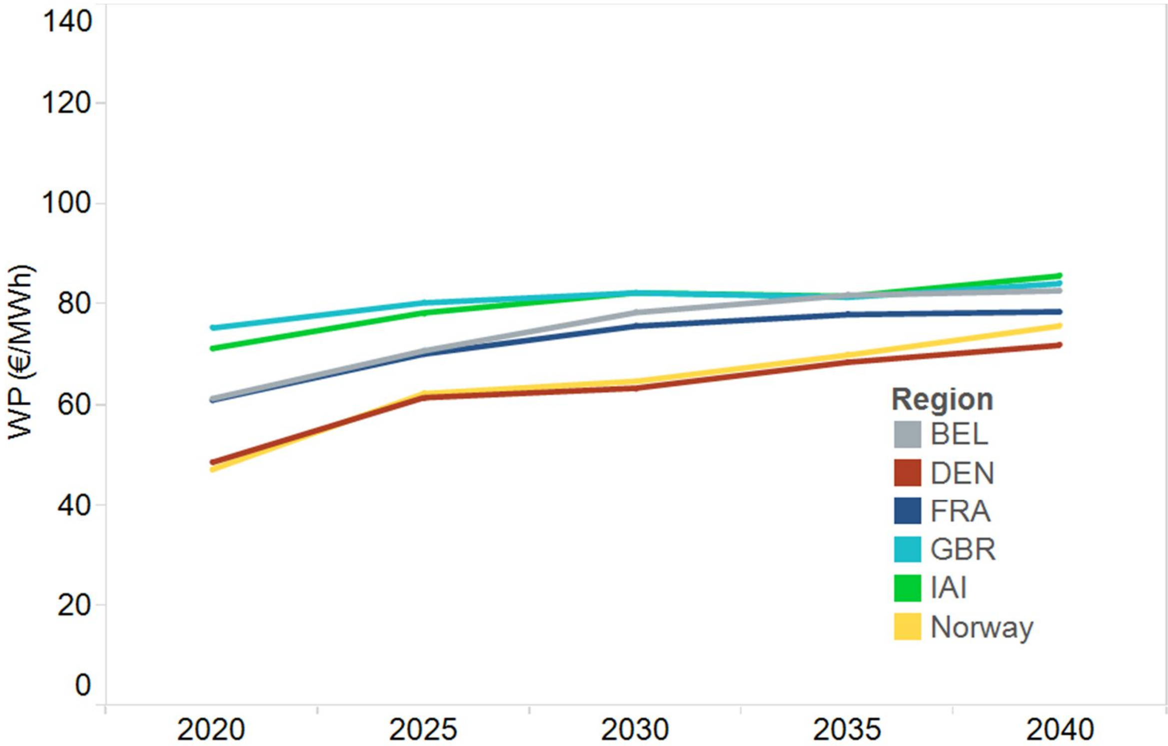


Base Case European wholesale power prices

The annual prices in the Base Case for GB and the key modelled interconnected countries are shown in Figure 8 below:

- Electricity prices in GB increase to a high level by 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 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 CPS is projected to gradually fall away under this scenario) to lead to slower wholesale price rises after 2020, compared to the other modelled countries.
- Continental European and Scandinavian prices start much lower than those in GB due to lower carbon prices and the large over capacity situation that is currently observed in the North West European region. That situation take a significant amount of time to unwind from the system and prices stay below the level seen in GB throughout for all countries with the exception of Belgium (which rises above GB in 2035) and Netherlands (in 2040).
- The Irish price (which has often been higher than GB in recent years) is lower than the GB price to 2025 due to the high level of the CPS in GB (increasing to £18/tCO_2 in 2015) and the requirement for all Irish generators to bid into the market on a pure marginal cost basis. Over time, the Irish price increases to surpass the GB price in 2030, thereafter staying at a similar level to that seen in GB.

Figure 8 – Wholesale power prices by country in the Base Case



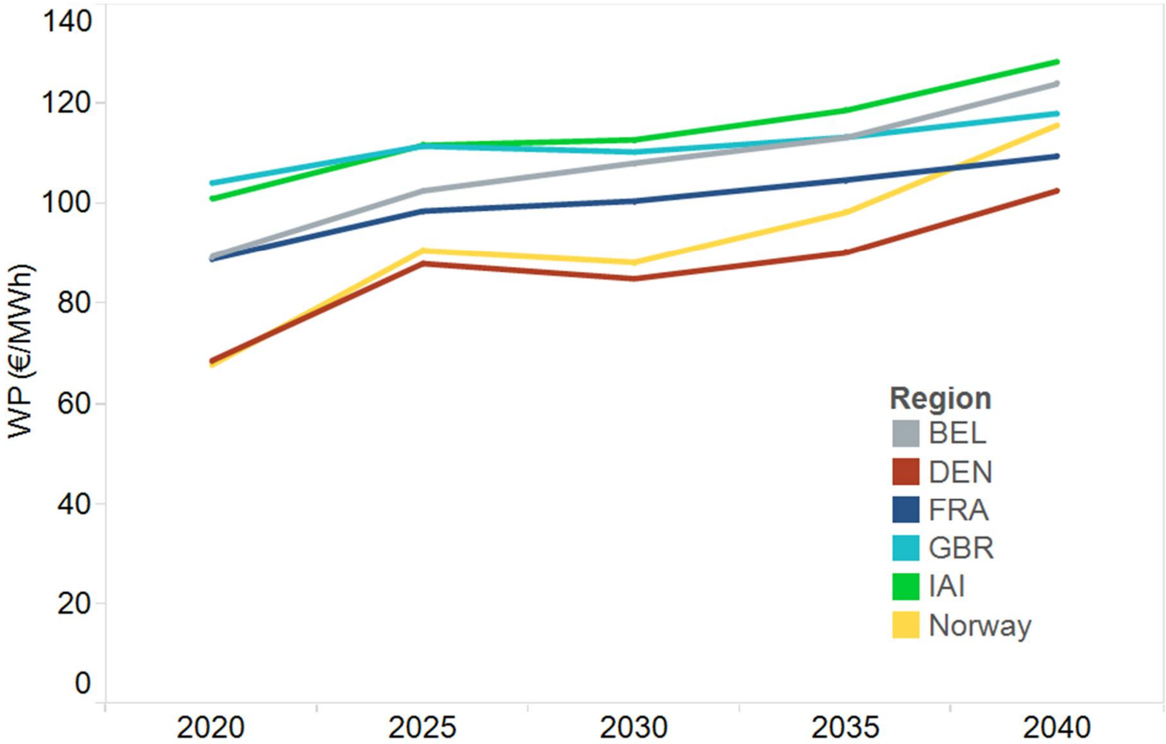
Note: BEL: Belgium, DEN: Denmark, FRA: France, GBR: Great Britain, IAI: Ireland SEM, NET: Netherlands.

High scenario European wholesale power prices

Resulting modelled annual prices in the High scenario are shown in Figure 9:

- In the High scenario, electricity prices in GB are consistently €25-30/MWh above prices for GB in our Base Case. Prices in GB are relatively flat from 2025 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. GB capacity margins are relatively constant throughout this scenario as high demand growth is matched by new entry.
- Prices in Continental Europe rise rapidly over time. The rising prices in this scenario result from a combination of high demand growth (which leads to a rapid reversal of the current over capacity situation) as well as high fuel prices and a rapid rise in EU ETS carbon prices. Although all other modelled countries have lower prices than GB in 2015 at €49-67/MWh, they increase steeply and by 2025 in Ireland and by 2030 in Belgium prices move above those in GB. By 2040 prices in Norway, France and the Netherlands also rise to levels which are in line with GB.

Figure 9 – Wholesale power prices by country in the High scenario



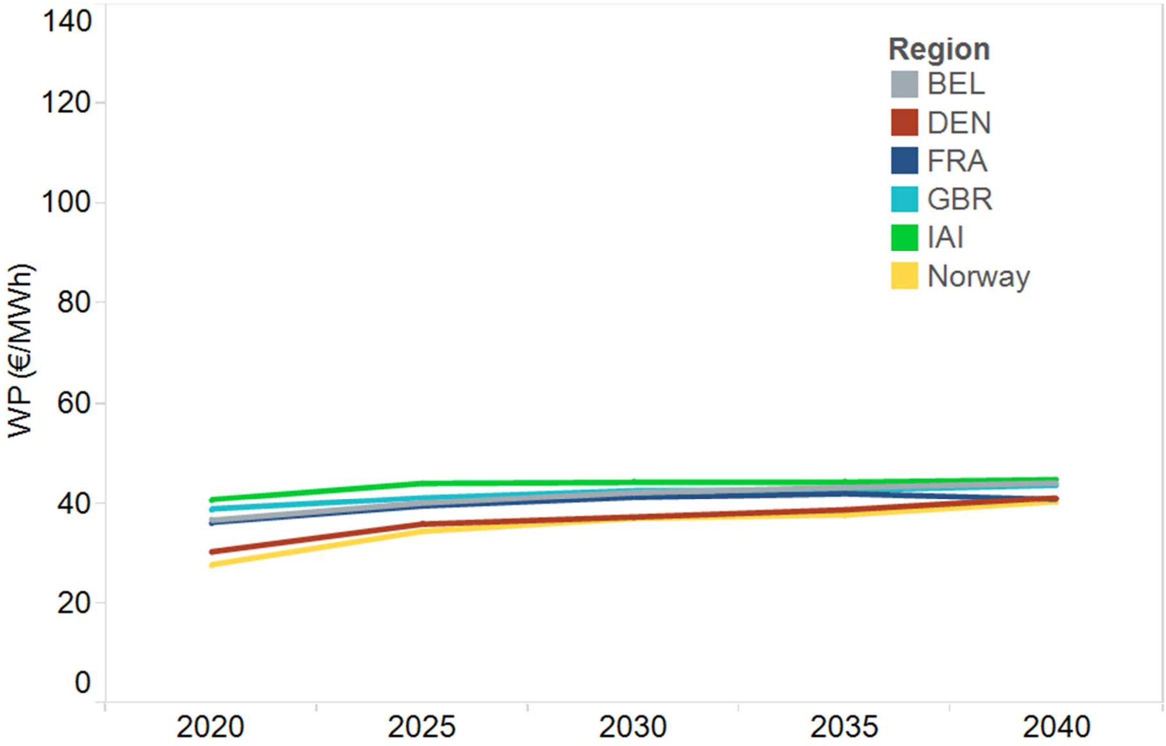
Note: BEL: Belgium, DEN: Denmark, FRA: France, GBR: Great Britain, IAI: Ireland SEM, NET: Netherlands.

Low scenario European wholesale power prices

Electricity prices in the Low scenario are lower than in the Base Case in all countries considered, 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, whether they be 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 10:

- GB prices are low initially at €45/MWh in 2015, fall to €38/MWh by 2020 before rising gradually again to reach €44/MWh by 2035. Irish prices are very close but slightly above those in GB in this scenario due to the slightly higher gas prices in Ireland compared to GB.
- Continental European prices start slightly lower than those in GB in 2020 due to very high supply margins in Europe, but converge towards prices in GB over time, with prices in Belgium and Denmark almost reaching GB prices by 2040.
- The maximum difference in annual average prices between GB and other European countries is with Norway and Denmark, although prices are only €4/MWh less than in GB by 2040. This difference persists due to the continued difference in key sources of supply in those countries (hydro and wind).

Figure 10 – Wholesale power prices by country in the Low scenario



Note: BEL: Belgium, DEN: Denmark, FRA: France, GBR: Great Britain, IAI: Ireland SEM, NET: Netherlands.

3.4 Modelled market sensitivities

In addition to the three core modelled scenarios we have also conducted sensitivity analysis on key inputs. These sensitivities are designed to test the sensitivity of the CBA results to changing single specific assumptions. The key modelled market sensitivities are as follows:

- No CPS sensitivity – for this sensitivity we have assumed that CPS and EU ETS carbon price differential falls to zero by 2020 but that all other assumptions remain the same as in the Base Case.
- Low Gas price – for this sensitivity we have assumed that all assumptions are the same as the Base Case apart from GB and NWE gas prices which fall our Low scenario prices.
- High GB RES – for this sensitivity we have expanded the volume of renewable electricity supply in GB in the Base Case to be in line with National Grid 'Slow Progression' scenario (rather than National Grid 'No Progression'). All other assumptions are kept the same as in the Base Case[8].
- High NWE RES – for this sensitivity we have expanded the volume of renewable electricity supply in NWE (but not GB) in the Base Case to be in line with those assumptions under our High scenario.

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8 Please note that we have ensured that the security of supply standard in the two RES sensitivities (for GB and NWE) is in line with the Base Case by removing some generic new thermal capacity – this avoids an unrealistic over capacity situation developing over time.

- Please note that this sensitivity represents an upside case for most continental European interconnectors but is not considered fundamental to their business case. The CBA results have therefore only been reported for Greenlink as it was a key element of the value proposition for this interconnector.

3.5 Role of capacity markets

We incorporate capacity markets into our core electricity market modelling in all scenarios. In general his leads to downward pressure on prices compared to a world or market where a capacity mechanism does not exist – this impact is outlined in the section below. A discussion of our approach to modelling country-specific capacity mechanisms in GB and other European countries is contained in Annex D.

3.5.1 Theoretical impacts of capacity markets

In electricity markets there are two fundamental ways of remunerating the costs of maintaining existing, or building new capacity: either by paying for the energy delivered (in €/MWh) or by separately paying for capacity provided to the system for security of supply (in €/MW). The energy-only model (where payments are only for energy delivered to the system) has been dominant across much of Europe (with exceptions in Spain, Ireland and Greece), with its popularity stemming from simplicity, and its similarity to other commodity markets.

The rapid and continuous growth of renewable generation, combined with other factors discussed further below, has led to markets in many parts of Europe coming under strain. In particular, the ability of existing thermal plant to recover their annual fixed costs has been made harder as a result of low- or zero-priced renewable generation, which acts to drive down wholesale market prices. This results in reducing the operating hours over which it is economic to operate a thermal plant.

Electricity prices are lower in periods of abundant renewable generation and higher in periods of low renewable generation during which thermal plant price up in an attempt to recover their fixed costs. Critically, this may make it much harder to build new thermal plant, as investors in new power stations face increased uncertainty over the future returns to thermal generation in an energy-only market with volatile electricity prices.

As a result, a number of European governments are implementing or actively considering a substantial change in the structure of their wholesale markets by including capacity mechanisms. Capacity mechanisms are of many forms, but the key element for all of these schemes is a move away from paying for energy-only, to paying for a combination of energy and capacity. A simple regulated capacity payment (in €/MW) has been adopted in Spain for many years. In the UK, the proposed Capacity Market is a capacity auction for the GB electricity market, with capacity paid the clearing price in an annual auction. In France, a Capacity Obligation is being finalised, whilst in Italy a Reliability Payment based around a one-way Contract for Difference (CfD) is under development.

Although the growth in renewables is an important driver, there are a number of other key factors in the increasing popularity of capacity mechanisms.

- Firstly, the on-going overcapacity across many European markets stemming from the economic recession has led to poor returns for many plants, which has led to call for capacity mechanisms in an attempt to subsidise loss-making power stations such that they remain on the system.

- Secondly, particularly in France, peak demand has grown faster than annual demand for a number of years, so a capacity mechanism has been proposed as a way of bringing more demand side response onto the system and to reduce the temperature dependence of demand.
- Thirdly, particularly in Germany, there are concerns over security of supply at a regional level in the near-term.

This shift in the design of wholesale electricity markets from energy-only markets to separate energy market and capacity mechanism will directly affect wholesale electricity prices in residual energy markets. Revenues earned by generators will depend on their ability (and eligibility) to participate in the energy and the capacity mechanism.

In energy-only markets, generators will try to bid above short-run marginal cost (SRMC), whilst competitive pressures act to limit their ability to achieve this. The resulting 'scarcity rent' typically appears when the system is tight, and in the long-term should be sufficient to ensure that existing plant can recover their annual fixed costs, or new build plant can recover their capital costs.

With a capacity mechanism, there are two, interrelated, effects which lead to a downward pressure 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.

For a market wide capacity mechanism, and in the long-run during periods when new capacity is required on the system, based on our internal modelling, we would expect that such a price impact is in the region of €5-€10/MWh on an annual average basis.

There are increasingly solid plans that capacity mechanisms will be adopted in many Continental European countries. In addition to those present in GB, Ireland and France (the interconnected countries), there are relatively advanced plans in both Germany and Italy. Where such capacity markets are planned, we have accounted for these in our wholesale market projections via the capacity margins and wholesale prices that we have modelled.

3.5.2 Interconnector value in a capacity mechanism

The introduction of a capacity mechanism may lead interconnectors to earn lower revenues from the energy market than they would in an energy only market. As the capacity market has a dampening effect on wholesale prices lower hourly price differentials may result leading to lower congestion rents[9]. However, the interconnector

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9 It should be caveated that it is possible that the introduction of a capacity mechanism could lead to higher hourly price differentials in hours where the price in the country introducing the

may be able to earn additional revenue from direct participation in the capacity mechanism itself.

The value of participation in a capacity mechanism to an interconnector project is uncertain. It is dependent on three main aspects which we may expect to 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).

More broadly, we note that, 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, in principle it is largely a transfer of welfare (from producers to interconnector owners[10]) and as such should not significantly impact the overall net welfare case of the interconnector.

Due to the uncertainties surrounding the ability of interconnectors to derive revenue from this (and other) capacity mechanisms we do not include capacity mechanism revenues in our base assessments of interconnector revenues and CBA analysis. Rather we have treated these revenues separately, as an upside and shown separately in the CBA sensitivity analysis.

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mechanism is already lower than the price in the country it is connecting to. This would then lead to an increase in arbitrage revenue for a given interconnector. However, as the impact of the capacity mechanism should be greatest on peak-period prices, we would generally expect the net effect on the arbitrage revenue of most interconnectors to be negative. These lower revenue levels can be offset (to a greater or lesser extent, depending on the rules) by participation in the capacity mechanism itself.

10 This assumes that the impact of the interconnector bidding into the capacity market means that the equivalent volume of alternative capacity is therefore unsuccessful. Assuming that the resulting price in the auction does not change, this simply results in a transfer of wealth from the owner of the alternative capacity to the owner of the interconnector (and thereafter potentially to consumers via the cap and floor mechanism)

4. INTERCONNECTOR COST BENEFIT ANALYSIS

4.1 CBA Introduction

4.1.1 Introduction and approach

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 over a 25 year project life) of social welfare in the scenario without the assessed interconnector (the 'counterfactual') and with the assessed interconnector. To show the impact of the particular interconnector being examined, all other factors are held constant between runs (e.g. other interconnector build, costs for other projects).

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 2020. Other interconnection is assumed to come online but gradually over time (in line with NG's FES).
- Key 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 c**ommissioning at the same time as four other additional interconnectors** in 2020. It is assumed that very little new interconnection occurs after 2020 in this build scenario, as all 'planned' projects before ~2035 have been brought forward.
- Key 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).

4.1.2 Projects included in the CBA modelling

We have assessed a total of five different interconnector projects, based on the five submissions received by Ofgem by September 2014. These are summarised in Table 3 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 2020[11]; and
- all interconnector welfare is split 50:50 between the GB and the connecting country, regardless of flow, in the absence of a firm cost and revenue allocation decision (which we would expect be taken at the point of the final investment decision).

These interconnectors are discussed in turn in section 4.2 to section 4.6, in the order specified in Table 3. We will first present the overview and key conclusions for every project, before expanding into more detail on interconnector flows and revenues and the social welfare impact of the interconnector projects. Finally we will present the key results and messages from the sensitivity analysis run for each of the projects. For each project we have identified the welfare assuming that the cap and floor mechanism is in operation. The cap and floor levels were provided by Ofgem and were based on estimated costs provided by developers in submission documents.[12]

Table 3 – Summary of key interconnector characteristics

Project	*Connected country*	*Project size (MW)*	*Assumed commissioning date*
NSN	Norway	1,400MW	01 January 2020
Viking Link	Denmark	1,000MW	01 January 2020
IFA2	France	1,000MW	01 January 2020
FAB Link	France	1,400MW	01 January 2020
Greenlink	Republic of Ireland	500MW	01 January 2020

Source: Developer submissions for respective projects, normalised commissioning dates

11 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.

12 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 assumed GB share of revenues (50%) is taken into account as cap & floor levels have been calculated on the assumed GB share of the project (50%).

4.2 NSN cost benefit analysis

4.2.1 NSN overview and key conclusions

We have modelled the NSN project as a 1,400MW interconnector between Great Britain and Norway. Figure 11 presents the results for the key metrics used in the assessment.

Figure 11 – NSN welfare impact on GB and total

Source: Pöyry Management Consulting modelling for Ofgem

The key conclusions for NSN from our CBA modelling are[13]:

- **NSN has an overall net benefit on total GB social welfare in Base Case and High scenario, GB consumers benefit in all scenarios**

  In our Base Case, the NSN presents large benefits to GB consumers, a benefit for GB welfare (even when losses to GB producers/generators are accounted for), and a benefit for overall total welfare (with both sides of the interconnector benefiting). GB consumers benefit in all three scenarios, although there are floor payments in the Low scenario.

- **Substantial downside risk because NSN is a large capacity, long distance interconnector which translates to high project costs**

  Due to its length, NSN has high investment costs. It relies on high price differentials between the two markets to recover these costs. While analysis shows that in the Base Case the project does not require significant floor payments, its revenues are

13 As previously mentioned, the 'first additional' and 'marginal' assessment methods produced very similar results for NSN, we will therefore present the 'marginal' results only. The presented conclusions, however, also hold true for the 'first additional' assessment.

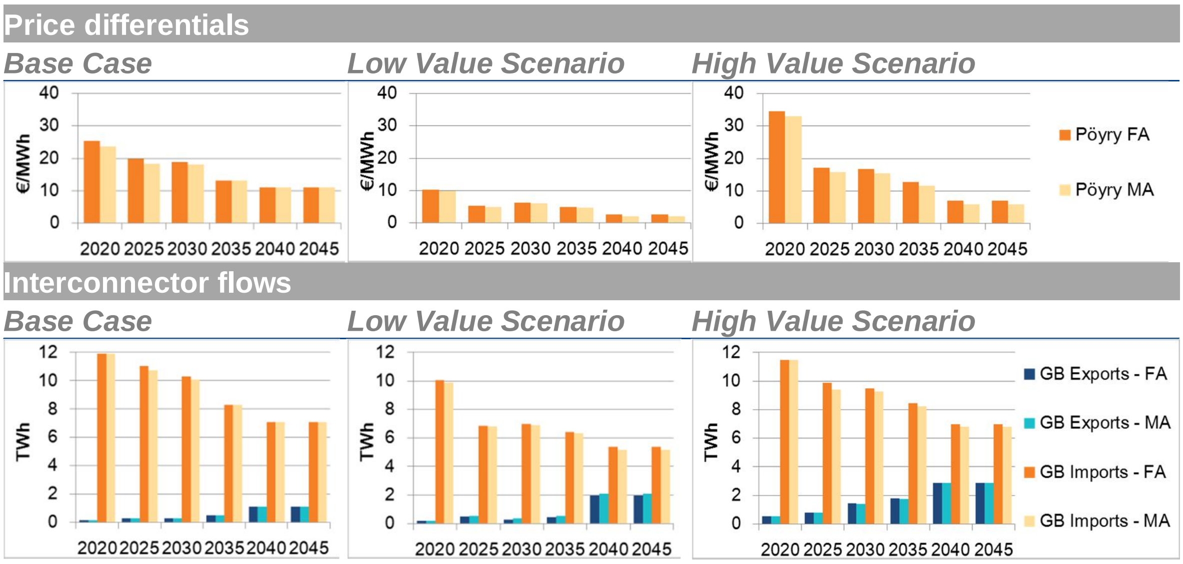
close to the floor. In the Low Value Scenario, the project requires floor payments in all years, in the High scenario, revenues are close to, or above the cap in most years.

- **Economic and business case is not sensitive to other interconnectors build**

  In all three main scenarios, the results for NSN do not differ greatly between the 'first additional' and 'marginal' assessment methods. In other words, both 'first additional' and 'marginal' assessment methods lead to the same conclusion, so the project CBA appears robust to significant interconnection volume added to GB.

4.2.2 Prices, flows and arbitrage revenues for NSN

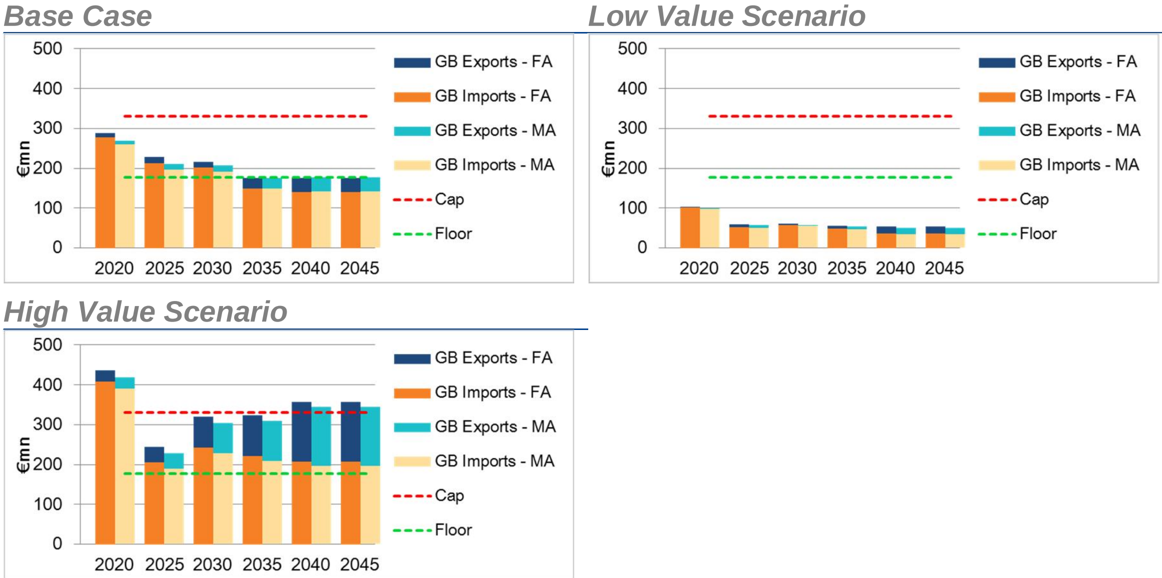
Figure 12 – Price differentials and flows on NSN



Source: Pöyry Management Consulting modelling for Ofgem

As shown in Figure 12, in all three main scenarios, the price in Great Britain is significantly higher than the price in Norway. This leads to large flows in the direction of Norway to GB. In the first years, GB and Norwegian prices are kept apart by structural differences (thermal vs. hydro-dominated markets), the carbon price floor in GB and relatively low volatilities in both countries. Over time, the prices move closer as the carbon price top-up decreases, and more renewable capacity is built in GB. This leads to the share of GB exports increasing from 1% in 2020 to 13% in 2040 in the Base Case. This effect is amplified in the High Scenario, but weaker in the Low Scenario, due to different RES shares.

Figure 13 – Arbitrage revenues for NSN



Source: Pöyry Management Consulting modelling for Ofgem

Arbitrage revenues as shown in Figure 13 initially decrease as the price differential decreases. From 2025 onwards, however, the revenues increase, as new RES generation (wind, solar PV) leads to higher volatility and GB prices falling to low levels in an increased number of periods. While NSN still flows mostly to GB, revenues earned in these low price periods in GB are higher than on flows from Norway to GB.

Under the Base Case, the project is only very slightly affected by the cap and floor arrangements. Generally, project revenues are closer to the floor, but fall below the floor level (€88m/year in the model) by only around €0.1m from 2035 to 2037. In the High scenario, project revenues are closer to the cap, exceeding it in 2020, and from 2040. Under the Low scenario, the project needs floor support in all years.

4.2.3 NSN's impact on social welfare

NSN presents a benefit to GB consumers in all scenarios, as GB prices remain higher than Norwegian. These price differences are driven by different market structures (hydro-dominated Norwegian market vs. thermal-focused GB market). The benefit is highest in the early years, when the price differential is largest. In NPV terms, the benefit to GB consumers is €4.2bn (FA) or €3.9bn (MA) in the Base Case. In the Low scenario, the benefit to GB consumers is lower (around €800mn).

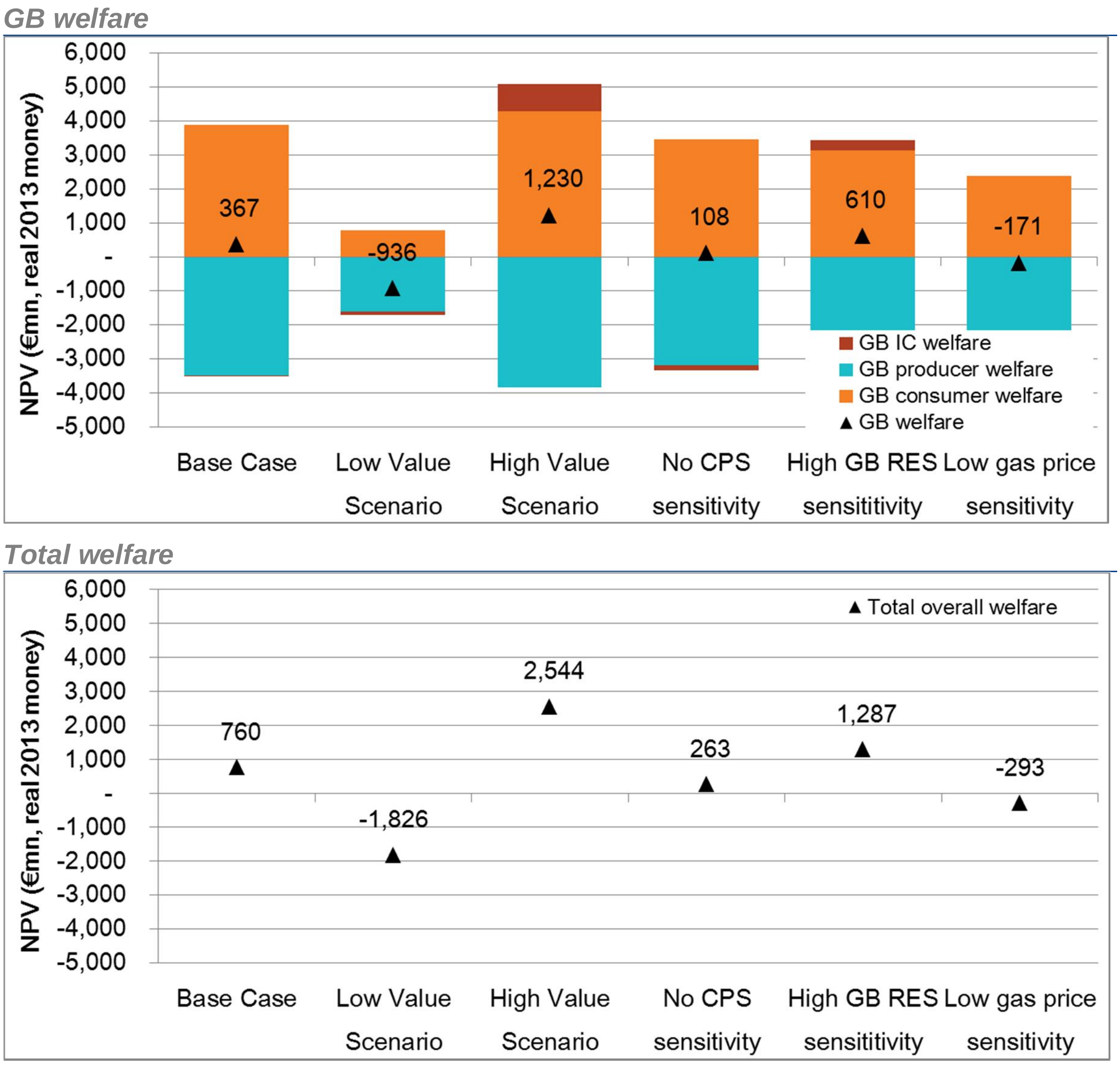
While GB consumers benefit from cheaper electricity prices, producers lose revenues both because of the price effect and because of the substitution effect (i.e. being replaced by generation from Norway). In the Base Case and High scenario, the consumers' gains outweigh the producers' loss, in the Low scenario, the net is negative. This leads to an overall GB welfare benefit of around €360mn in the Base Case, -€940mn in the Low scenario, and €1,200mn in the High scenario (NPV terms), including IC welfare.

For Norway, the overall social welfare effect of NSN is significantly positive in the Base Case (around €800mn, NPV terms), highly positive in the High scenario (~€2,500mn) and very negative in the Low scenario (-€1,800mn). The benefits (and dis-benefits) are split approximately equally between GB and Norway in all three main scenarios.

4.2.4 Sensitivity results for NSN

Figure 14 shows the GB and total welfare impact results for NSN from our MA modelling.

Figure 14 – NSN key results for all sensitivities and scenario (MA)



Source: Pöyry Management Consulting modelling for Ofgem

Key results to highlight from the sensitivity analysis on the NSN project are:

- NSN still shows overall benefit on GB consumers, overall GB and overall total welfare even when removing the CPS (GB carbon price floor) from 2020. While the project performs less well in this sensitivity in all of the aforementioned key metrics, it does not appear that the project welfare case depends on the CPS. However, it does appear to be more sensitive to a sustained low gas price.
- In the High GB RES sensitivity, the price spreads are lower due to lower GB wholesale prices, which decreases NSN's positive impact on GB consumers compared to the Base Case. The overall economic case, however, improves, as there is more flow on the cable and therefore higher project revenues.

- Sensitivity analysis on the capacity mechanism (see Annex D) shows that the welfare case for NSN is impacted if we assume it participates in the mechanism. The revenue from the capacity market is accrued to the interconnector, and therefore split between the two countries. As there is no capacity mechanism in Norway, the GB capacity revenue gets split between the countries leading to a net transfer of welfare out of GB (generally from GB producers to the IC owners). However, the cap and floor mechanism means that GB consumers are benefited by the IC participation in the CM by lower floor payments and/or higher cap payments across the core scenarios.

4.3 Viking Link cost benefit analysis

4.3.1 Viking Link overview and key conclusions

We have modelled the Viking Link project as a 1,000MW interconnector between Great Britain and Denmark. Figure 15 presents the results for the key metrics used in the assessment.

Figure 15 – Viking Link welfare impact on GB and total

Source: Pöyry Management Consulting modelling for Ofgem

The key conclusions for Viking Link from our CBA modelling are[14]:

- **Viking Link has an overall net benefit on GB social welfare and GB consumer welfare in Base Case and High scenario**

  In our Base Case, the Viking Link presents large benefits to GB consumers, a benefit for GB social welfare (even when losses to GB producers are accounted for), and a

14 As previously mentioned, the 'first additional' and 'marginal' assessment methods produced very similar results for Viking Link, we will therefore present the 'marginal' results only. The presented conclusions, however, also hold true for the 'first additional' assessment.

benefit for overall total social welfare (with both sides of the interconnector benefiting). GB consumers benefit in the Base Case and High scenario, but there are substantial floor payments in the Low scenario, resulting in a net consumer welfare benefit of around zero.

- **Substantial downside risk because Viking Link is a large capacity, long distance interconnector which translates to high project costs**

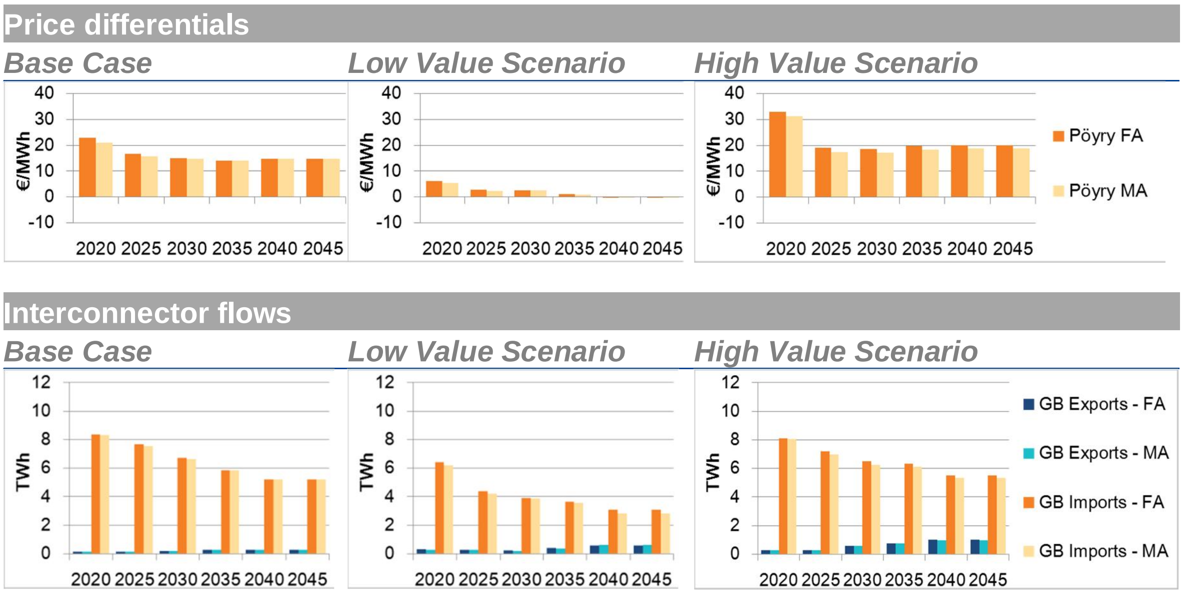
  Viking Link, as a very large project, has high investment costs. It relies on high price differentials between the two markets to recover these costs. While analysis shows that in the Bas e Case the project does not require significant floor payments (€2.2mn on average between 2027 and 2033), its revenues generally are closer to the floor. In the Low Value Scenario, the project requires floor payments in all years, in the High scenario, revenues are close to, or above the cap in most years.

- **Economic and business cases are not particularly sensitive to other interconnectors being build**

  In all three main scenarios, the results for Viking Link do not differ greatly between the 'first additional' and 'marginal' assessment methods. In other words, both 'first additional' and 'marginal' assessment methods lead to the same conclusion, as the project is robust to significant interconnection volume added to GB.

4.3.2 Prices, flows and arbitrage revenues for Viking Link

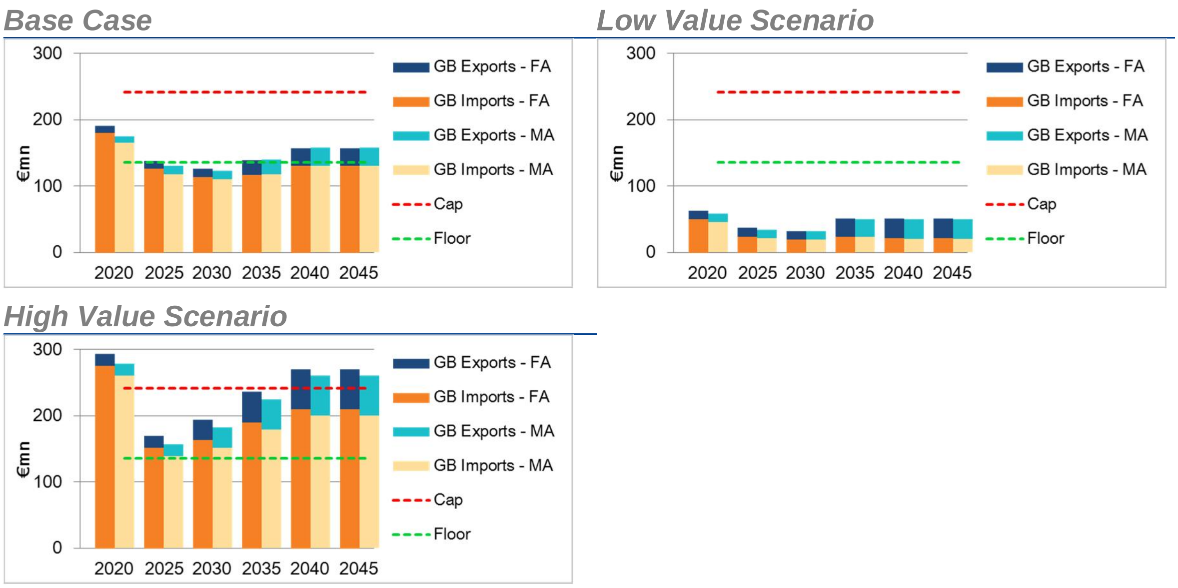
Figure 16 – Price differentials and flows on Viking Link



Source: Pöyry Management Consulting modelling for Ofgem

As shown in Figure 16, the price in Great Britain is significantly higher than the price in Denmark in all three main scenarios. This leads to large exports from Denmark to Great Britain. In the first years, GB and Danish prices are kept apart by structural differences (domestic thermal in GB vs. high wind share and interconnection in Denmark) and the carbon price floor in GB. Until 2030, the prices move closer as the carbon price floor decreases, and more renewable capacity is built in GB leading to an increasing share of GB exports from total flow. However, as the price differential remains substantial, the majority of flows (>90%) are imports into GB. In the High scenario, GB exports reach 15% in 2030, due to lower prices and higher renewables share, while in the Low scenario, prices move closer and eventually reach the same level in 2040, leading to balanced flows on the interconnector.

Figure 17 – Arbitrage revenues for Viking Link



Source: Pöyry Management Consulting modelling for Ofgem

Arbitrage revenues (shown in Figure 17), closely linked to flows, initially decrease as the price differential decreases. From 2025 onwards, however, the revenues increase again, as newly commissioned renewable generation (onshore and offshore wind, solar PV) leads to higher volatility and GB prices falling to very low levels in an increased number of periods. While the interconnector still flows mostly to GB, the revenue earned in these very low price periods in GB is higher on export flows.

Under the Base Case, the project requires floor payments between 2027 and 2033. The NPV of these floor payments is between €11mn (FA) and €25mn (MA). Project revenues are generally closer to the floor. In the High scenario, project revenues are closer to the cap, exceeding it in 2020 and 2021, and from 2040. Under the Low scenario, the project needs floor support in all years.

4.3.3 Viking Link's impact on social welfare

Viking Link presents a benefit to GB consumers in the Base Case and High scenario, as the price in GB remains higher than the price in Denmark. The benefit is highest in the early years, when the price differential is largest, and largely constant from 2025 onwards, in the Base Case. In NPV terms, the benefit to GB consumers is around €2.6bn in the Base Case, and €3.0bn to €3.5bn in the High scenario. In the Low scenario, the benefit to GB consumers is close to zero (as floor payments reach around €750mn in NPV terms).

While GB consumers benefit from cheaper electricity prices, producers lose revenues both because of the price effect and because of the substitution effect (i.e. being replaced by generation from Denmark). In the Base Case and High scenario, the consumer gains outweigh the producer loss, in the Low scenario, the net is negative. This leads to overall

GB welfare of around €180mn in the Base Case, -€700mn in the Low scenario, and €750mn in the High scenario (NPV terms), including interconnector welfare.

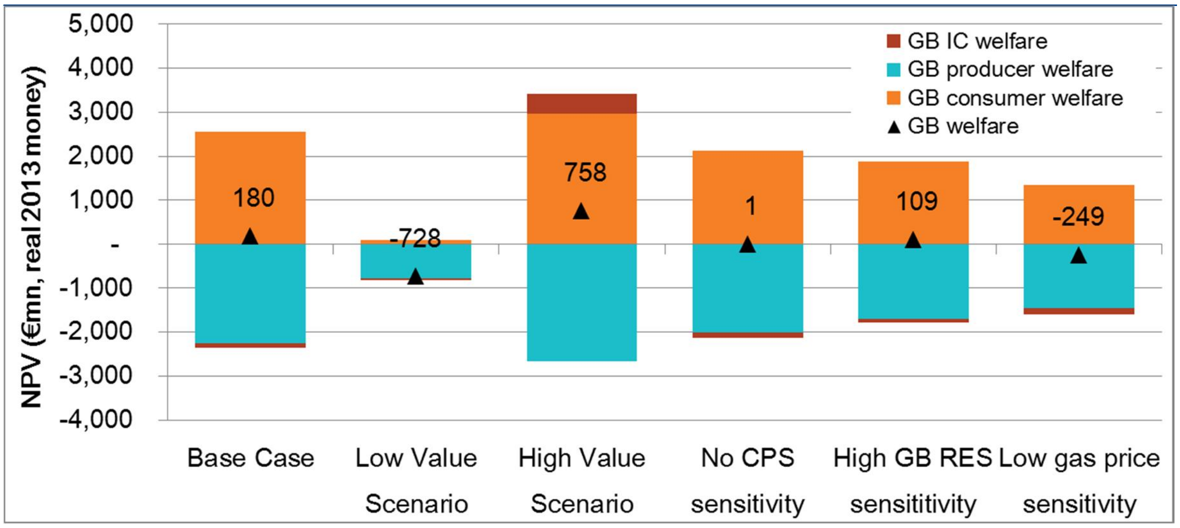
The overall social welfare effect of Viking Link is significantly positive in the Base Case (around €500mn, NPV terms), highly positive in the High scenario (~€1,700mn) and very negative in the Low scenario (-€1,300mn). The benefits (and dis-benefits) are split approximately equally between GB and Denmark in all three main scenarios.

4.3.4 Sensitivity results for Viking Link

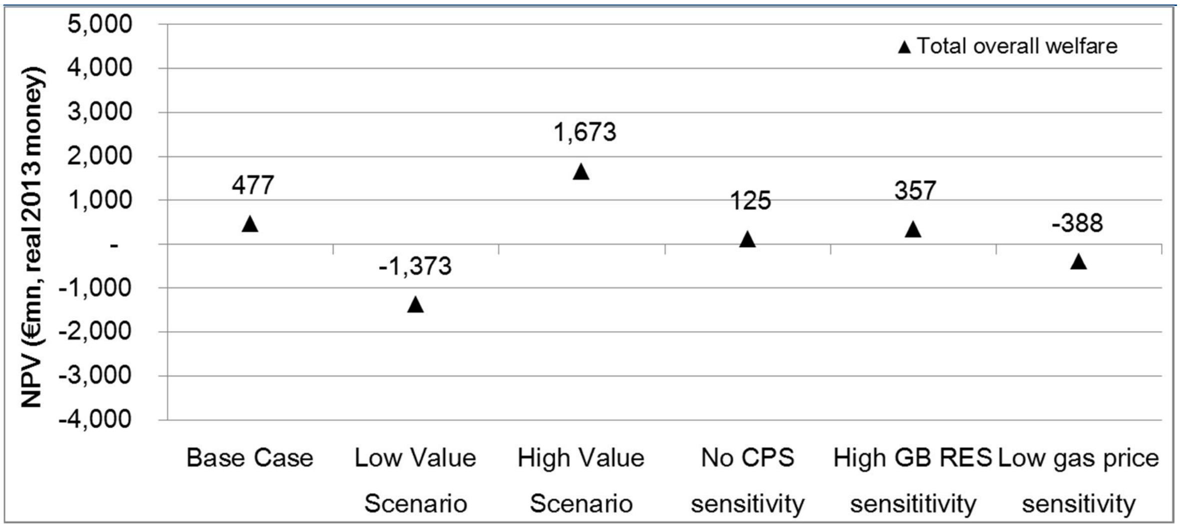
Figure 18 shows the GB and total welfare impact results for Viking Link from our MA modelling.

Figure 18 – Viking Link key results for all sensitivities and scenario (MA)

GB welfare



Total welfare



Source: Pöyry Management Consulting modelling for Ofgem

Key results to highlight from the sensitivity analysis on the Viking Link project are:

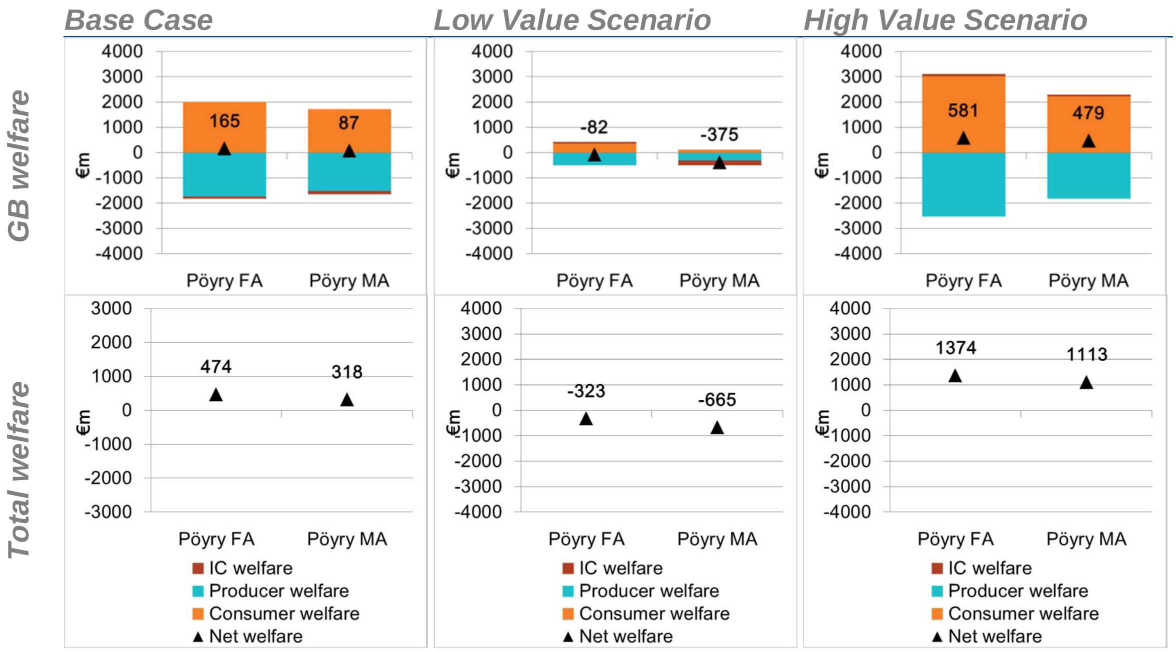
- Viking Link still shows overall benefit on GB consumers, overall GB and overall total welfare even when removing the CPS (GB carbon price floor) from 2020. While the project performs worse in this sensitivity in all of the aforementioned key metrics, it does not appear that the project welfare case depends on the CPS.
- In the High GB RES sensitivity, the average price in GB decreases, which decreases Viking Link's positive impact on GB consumers compared to the Base Case. The overall economic case, however, improves, as there is more flow on the cable and therefore higher project revenues.
- Sensitivity analysis on the capacity mechanism (see Annex D) shows that the welfare case for Viking Link is impacted if we assume it participates in the mechanism. The revenue from the capacity market is accrued to the interconnector, and therefore split between the two countries. As there is no capacity mechanism in Denmark, the GB capacity revenue gets split between the countries leading to a net transfer of welfare out of GB (generally from GB producers to the IC owners). However, the cap and floor mechanism means that GB consumers are benefited by the IC participation in the CM by lower floor payments and or higher cap payments across the core scenarios.

4.4 IFA2 cost benefit analysis

4.4.1 IFA2 overview and key conclusions

We have modelled the IFA2 project as a 1,000MW interconnector between Great Britain and France. Figure 19 presents the results for the key metrics used in the assessment.

Figure 19 – IFA2 welfare impact on GB and total



Source: Pöyry Management Consulting modelling for Ofgem

The key conclusions for IFA2 from our CBA modelling are[15]:

- **IFA2 an overall net benefit to total social welfare in Base Case and High scenario, GB consumers benefit in all scenarios**

  In our Base Case, IFA2 presents large benefits to GB consumers, a benefit for GB social welfare (even when losses to GB producers are accounted for), and a benefit for overall total social welfare (with both sides of the interconnector benefiting). GB consumers benefit in all three scenarios, although there are floor payments in the Low scenario. In the Base Case, IFA2 makes cap payments to GB consumers in 2020 and 2021 ('first additional' assessment only).

- **Overall GB welfare benefit marginal, as producer welfare losses are close to consumer welfare gains. IFA2's effect on France is slightly greater**

  In GB, the overall welfare is positive, although GB consumer gains only marginally offset producer's losses. The overall welfare in France is also positive, in the Base Case (€300mn).

- **Although competing with other GB-France interconnector cables, both existing (IFA) and future (Eleclink, FAB Link), IFA2 is positive in both 'first additional' and 'marginal' Base Case assessments**

  IFA2's GB consumer welfare impact is around 15% higher in the 'first additional' Base Case, but the project remains positive. It is only in the Low scenario, that IFA2's economic case differs significantly between 'first additional' (slightly negative) to 'marginal' (very negative).

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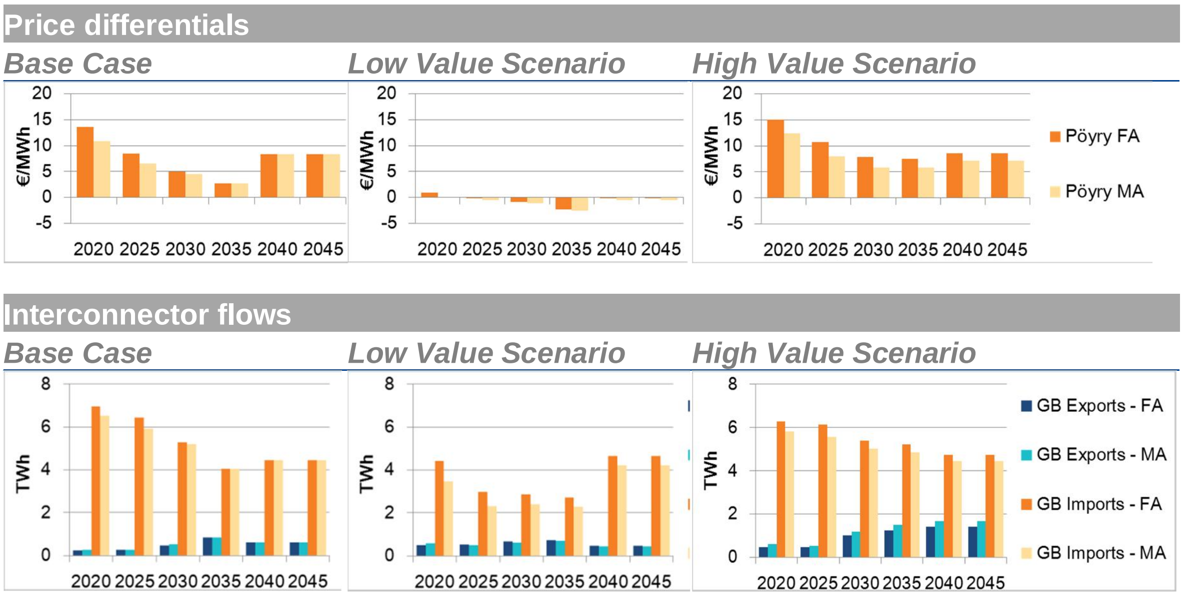
4.4.2 Prices, flows and arbitrage revenues for IFA2

Figure 20 – Price differentials and flows on IFA2

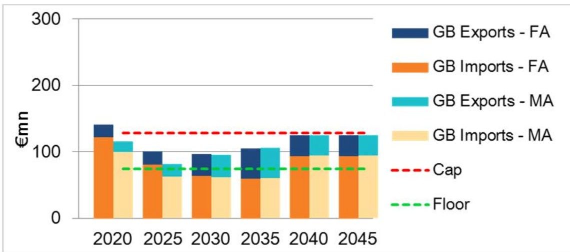


Source: Pöyry Management Consulting modelling for Ofgem

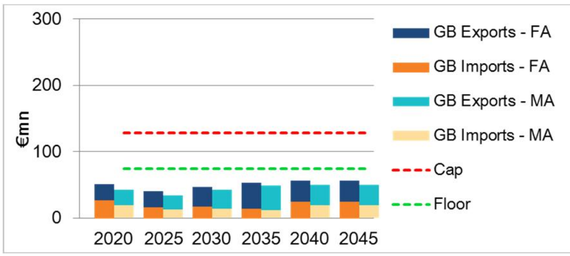
In all three main scenarios, the price in Great Britain in 2020 is higher than the price in France, as shown in Figure 20. Over time, this price difference decreases in the Base Case and in the High scenario, while in the Low scenario, the price in France moves above the British price in the mid-2020s. In the Base Case and High scenario, the cable flows into GB the majority of time. However, in both of these scenarios, export flows increase over time as prices move closer but also, and primarily due to the increased share of renewables in both markets leading to higher volatility.

Figure 21 – Arbitrage revenues for IFA2

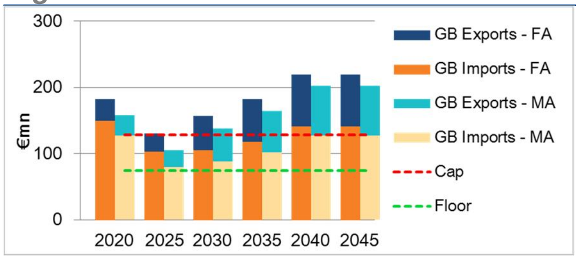
Base Case



Low Value Scenario



High Value Scenario



Source: Pöyry Management Consulting modelling for Ofgem

Arbitrage revenues (shown in Figure 21), closely linked to flows, initially decrease as the price differential decreases. From 2025 onwards, however, the revenues increase again, as newly commissioned renewable generation (onshore and offshore wind, solar PV) leads to higher volatility and GB prices falling to very low levels in an increased number of periods. While the interconnector still flows mostly to GB, the revenue earned in these very low price periods in GB is higher on flows from GB to France.

Under the Base Case, the project is only affected by the cap and floor arrangements in 2020 and 2021, and only in the ‘first additional’ case. Generally, project revenues are around the mid-point between cap and floor. In the High scenario, project revenues exceed the cap in most years. Under the Low scenario, the project needs floor support in all years.

4.4.3 IFA2’s impact on social welfare

IFA2 presents a benefit to GB consumers in the Base Case and High scenario, as the price in GB remains higher than the price in France. This benefit is close to constant over the modelled period. In NPV terms, the benefit to GB consumers is €2.0bn (FA) or €1.7bn (MA) in the Base Case. In the Low scenario, the GB price moves below the French price, this has a negative effect on consumer benefits. While GB consumers still benefit slightly, the NPV is close to zero (between €100mn in ‘marginal’ and €350mn in ‘first additional’ cases).

While GB consumers benefit from cheaper electricity prices, producers lose revenues both because of the price effect and because of the substitution effect (i.e. being replaced by generation from France). In the Base Case and High scenario, the consumer gains outweigh the producer loss, in the Low scenario, the net is negative. This leads to overall GB welfare of around €100-150mn in the Base Case, between -€400mn and -€100mn in the Low scenario, and €500-600mn in the High scenario (NPV terms), including interconnector welfare.

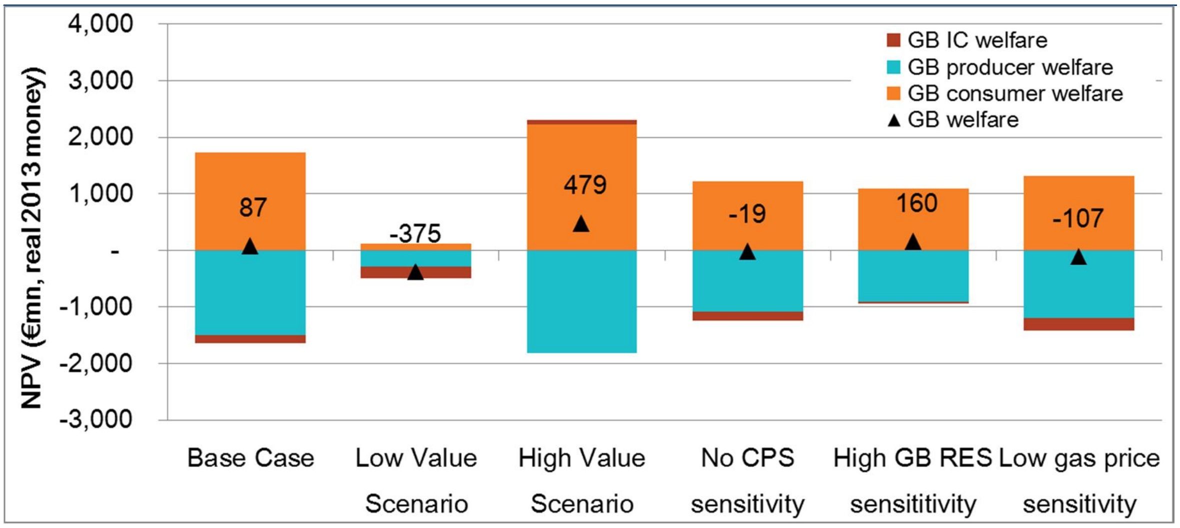
The overall social welfare effect of IFA2 is significantly positive in the Base Case (around €300-500mn, NPV terms), highly positive in the High scenario (€1,100-1,400mn) and significantly negative in the Low scenario (between -€700mn in the MA and -€300mn in the FA analysis). In the Base Case, the net gain for France is higher than the net gain for GB, while in the other two main scenarios, the benefits are split more equally.

4.4.4 Sensitivity results for IFA2

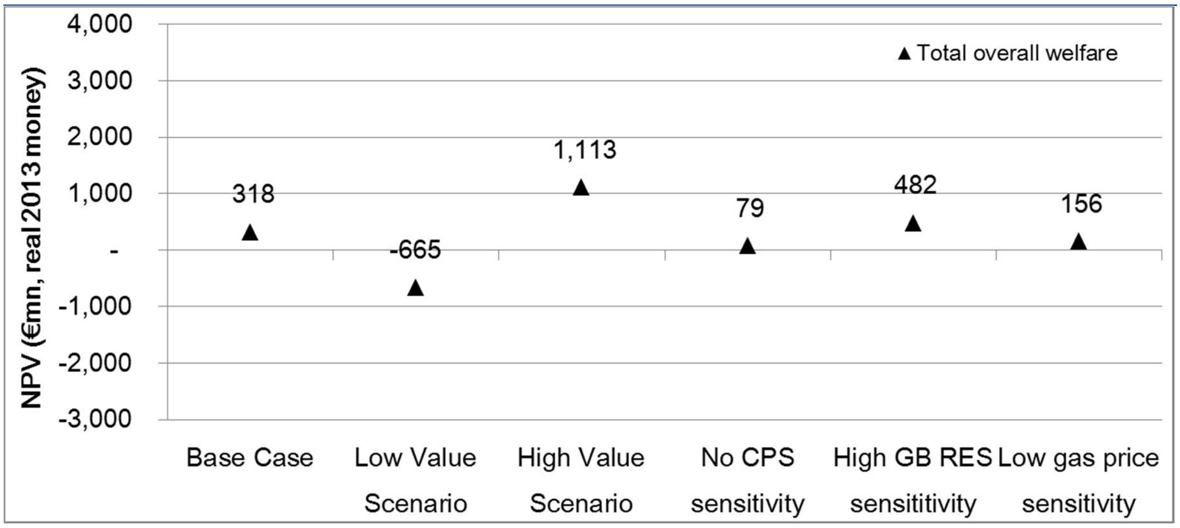
Figure 22 shows the GB and total welfare impact results for IFA2 from our MA modelling.

Figure 22 – IFA2 key results for all sensitivities and scenario (MA)

GB welfare



Total welfare



Source: Pöyry Management Consulting modelling for Ofgem

Key results to highlight from the sensitivity analysis on the IFA2 project are:

- When removing the CPS (GB carbon price floor) from 2020, IFA2's impact on overall GB welfare and overall total welfare decreases to close to zero, while GB consumers still benefit significantly. While it worsens the overall project welfare case, IFA2 does not appear to depend on the CPS to have a positive impact on GB consumers.

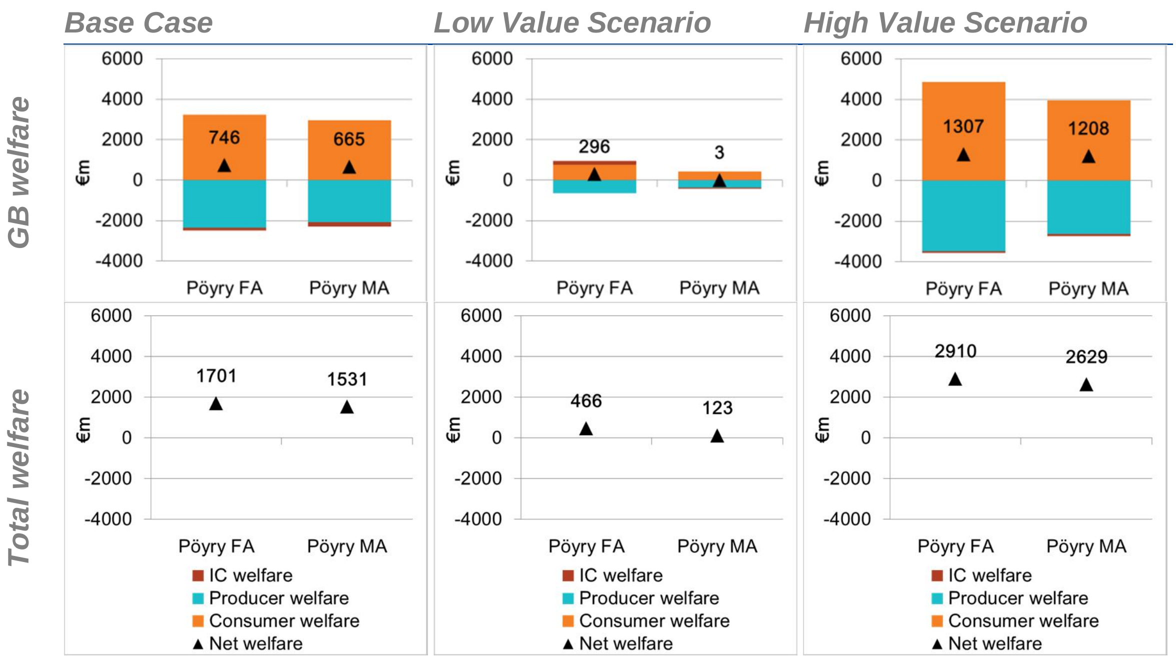
- In the High GB RES sensitivity, the average price in GB decreases, which decreases IFA2's positive impact on GB consumers compared to the Base Case. The overall economic case, however, improves, as there is more flow on the cable and therefore higher project revenues.

4.5 FAB Link cost benefit analysis

4.5.1 FAB Link overview and key conclusions

We have modelled the FAB Link project as a 1,400MW interconnector between Great Britain and France. Figure 23 presents the results for the key metrics used in the assessment.

Figure 23 – FAB Link welfare impact on GB and total



Source: Pöyry Management Consulting modelling for Ofgem

The key conclusions for FAB Link from our CBA modelling are:

- **FAB Link an overall net benefit to GB consumer welfare, total GB welfare and total overall welfare in all three main scenarios**

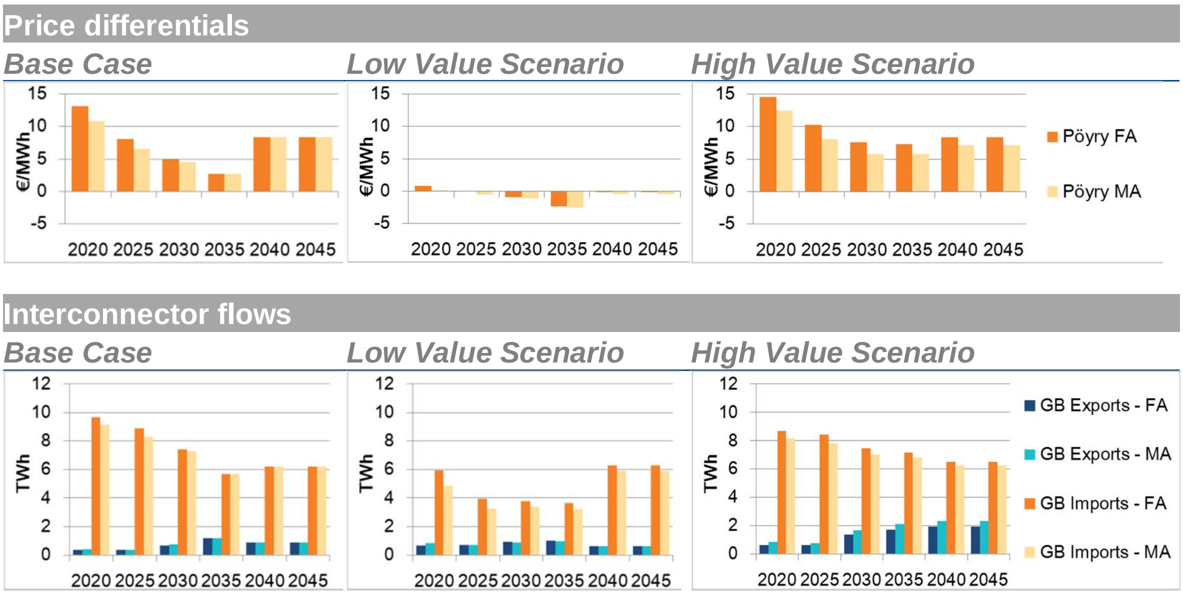
  In our Base Case, FAB Link presents large benefits to GB consumers, a benefit for GB social welfare (even when losses to GB producers are accounted for), and a benefit for overall total social welfare (with both sides of the interconnector benefiting). GB consumers benefit in all three scenarios, as revenues are above the cap in the Base Case and High scenario, and never fall below the floor in the Low scenario. In the Base Case, FAB Link's average annual cap payment is around €30mn.

- **Although competing with other GB-France interconnector cables, both existing (IFA) and future (Eleclink, IFA2), FAB Link is positive in both 'first additional' and 'marginal' assessments**

  FAB Link's GB consumer welfare impact is around 10% higher in the 'first additional' Base Case, but the project remains positive. It is only in the Low scenario, that FAB Link's economic case differs significantly between 'first additional' (slightly positive) to 'marginal' (close to zero). FAB Link's significant additional benefit to GB consumers over IFA2 (the other proposed interconnector to France) is based, at least in part on its larger size, low cost estimates, low cap levels and resulting large projected cap payments.

4.5.2 Prices, flows and arbitrage revenues for FAB Link

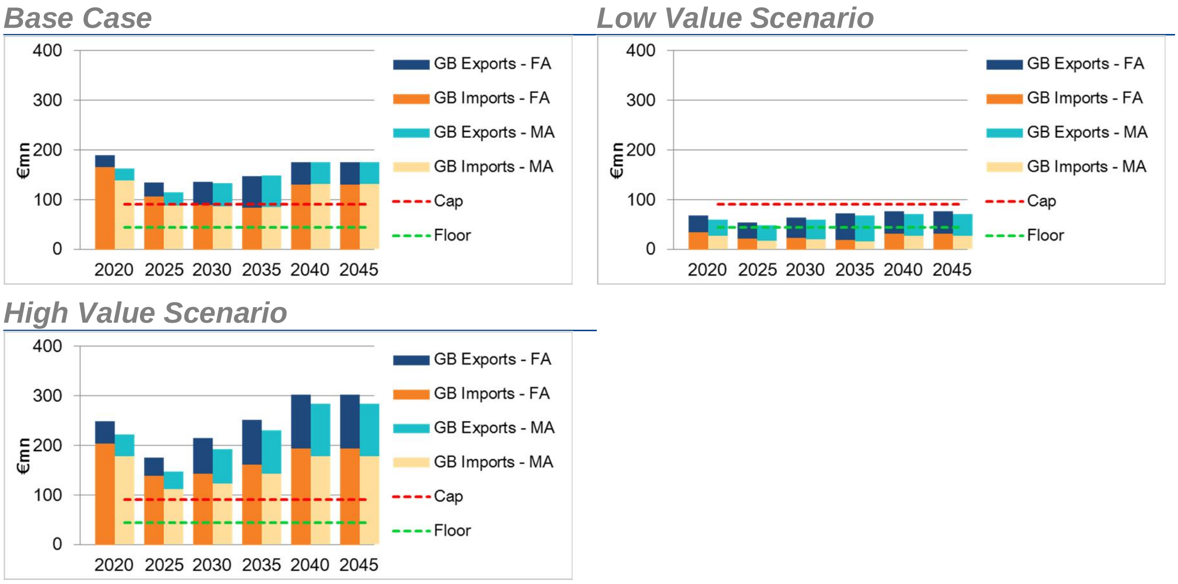
Figure 24 – Price differentials and flows on FAB Link



Source: Pöyry Management Consulting modelling for Ofgem

As shown in Figure 24, the price in Great Britain in 2020 is higher than the price in France in all scenarios. Over time, this price differences decreases in the Base Case and in the High scenario, while in the Low scenario, the price in France moves above the British price in the mid-2020s. In the Base Case and High scenario, the cable flows into GB the majority of time. However, in both these scenarios, exports increase over time as prices move closer but also, and primarily due to the increased share of renewables in both markets leading to higher volatility.

Figure 25 – Arbitrage revenues for FAB Link



Source: Pöyry Management Consulting modelling for Ofgem

Arbitrage revenues (as shown in Figure 25), closely linked to flows, initially decrease as the price differential decreases. From 2025 onwards, however, the revenues increase again, as newly commissioned renewable generation (onshore and offshore wind, solar PV) leads to higher volatility and GB prices falling to very low levels in an increased number of periods. While the interconnector still flows mostly to GB, the revenue earned in these very low price periods in GB is higher on flows from GB to France.

Under the Base Case and High scenario, the project is making cap payments in all years and under both 'first additional' and 'marginal' cases. In the Low scenario, project revenues are around the mid-point between cap and floor, the project does not require floor support in any year.

4.5.3 FAB Link's impact on social welfare

FAB Link presents a benefit to GB consumers in the Base Case and High scenario, as the price in GB remains higher than the price in France. This benefit is highest in the early years of the modelled period, but close to constant over the remainder of the modelled period. In NPV terms, the benefit to GB consumers is €3.2bn (FA) or €3.0bn (MA) in the Base Case. In the Low scenario, the GB price moves below the French price, this has a negative effect on consumer benefits. While GB consumers still benefit slightly, the NPV is much reduced compared to the Base Case (between €400mn in 'marginal' and €750mn in 'first additional' cases).

While GB consumers benefit from cheaper electricity prices, producers lose revenues both because of the price effect and because of the substitution effect (i.e. being replaced by generation from France). In the Base Case and High scenario, the consumer gains outweigh the producer loss, in the Low scenario the net is close to zero. This leads to overall GB welfare of around €650-750mn in the Base Case, around €0mn to €300mn in the Low scenario, and €1,200-1,300mn in the High scenario (NPV terms), including interconnector welfare.

The overall social welfare effect of FAB Link is significantly positive in the Base Case (around €300-500mn, NPV terms), highly positive in the High scenario (€1,500-1,700mn) and only slightly positive in the Low scenario (between €450mn and €750mn). In the Base Case, the net gain for France is higher than the net gain for GB, while in the other two main scenarios, the benefits are split more equally.

4.5.4 Sensitivity results for FAB Link

Figure 26 shows the GB and total welfare impact results for FAB Link from our MA modelling.

Figure 26 – FAB Link key results for all sensitivities and scenario (MA)

Source: Pöyry Management Consulting modelling for Ofgem

Key results to highlight from the sensitivity analysis on the FAB Link project are:

- FAB Link still shows overall benefit on GB consumers, overall GB and overall total welfare even when removing the CPS (GB carbon price floor) from 2020. While the project performs worse in this sensitivity in all of the aforementioned key metrics, it does not appear that the project welfare case depends on the CPS.

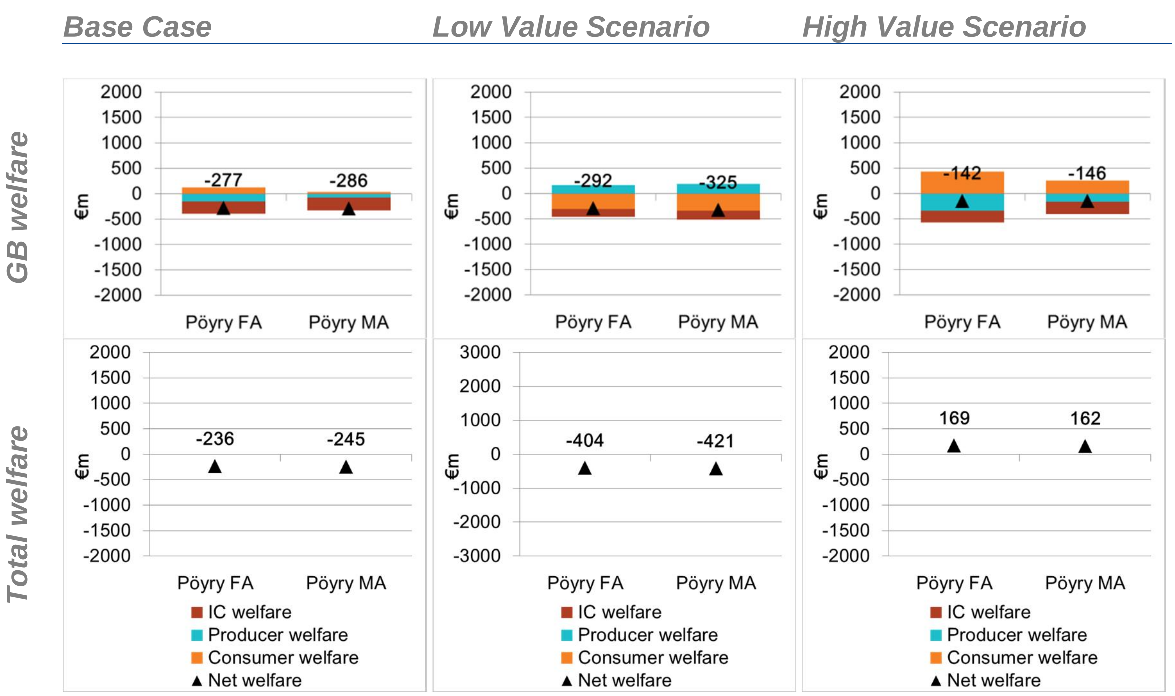
- In the High GB RES sensitivity, the average price in GB decreases, which decreases FAB Link's positive impact on GB consumers compared to the Base Case. The overall economic case, however, improves, as there is more flow on the cable and therefore higher project revenues.

4.6 Greenlink cost benefit analysis

4.6.1 Greenlink overview and key conclusions

We have modelled the Greenlink project as a 500MW interconnector between Great Britain and the Republic of Ireland. Figure 27 presents the results for the key metrics used in the assessment.

Figure 27 – Greenlink welfare impact on GB and total



Source: Pöyry Management Consulting modelling for Ofgem

The key conclusions for Greenlink from our CBA modelling are:

- **Greenlink's impact on overall GB welfare (both consumers and producers) is slightly negative, due to the nature of the markets and the small size of the cable in comparison to market size and the size of other interconnector cables**

  In the Base Case, Greenlink has a marginal, yet slightly positive effect on GB consumers. In the High and Low scenarios, GB consumer welfare is broadly symmetrical around the Base Case, with a ~€300mn downside in the Low, and an upside of €450mn ('first additional') or €250mn ('marginal') in the High scenario. Overall GB welfare is negative in all scenarios, due to a strong cannibalisation effect with the other Irish interconnectors and the general small effect of the 500MW cable on GB welfare.

- **The Greenlink project is a net benefit to Ireland in all but the Low scenario**

  In both the Base Case and the High scenario we see that Ireland benefits on a net basis from the interconnector – around €50m in the Base Case and €300m in the High scenario.

- **Greenlink's business and economic cases are largely dependent on the rate of renewables build in GB and Ireland**

  The project performs significantly better in the scenarios and sensitivities that include a higher share of renewables in the generation mix. In the High scenario (which includes 32.7GW of wind in GB, equal to 25% of installed capacity, and 10.3GW of wind in Ireland, equal to 55% of installed capacity; all in 2030), the overall total welfare gain is around €150mn. In the High GB RES sensitivity (which includes a similar RES share in GB, but Base Case assumptions for Ireland), the overall total welfare gain is around €100mn, with GB consumer welfare largely unaffected.

- **Greenlink connects two markets with new capacity mechanisms – in the absence of very high levels or renewables build, project economics are dependent on its ability to derive revenue from those mechanisms**

  In the Base Case and Low, arbitrage revenues are close to or below the floor level in all years in the absence of capacity payments requiring payments to the interconnector under the floor mechanism. Operation in either or both capacity mechanisms (see section D.3) significantly raises the economic viability of the project, reducing the potential downside burden on GB consumers and introducing the potential of cap payments in the Reference and High scenarios.

4.6.2 Prices, flows and arbitrage revenues for Greenlink

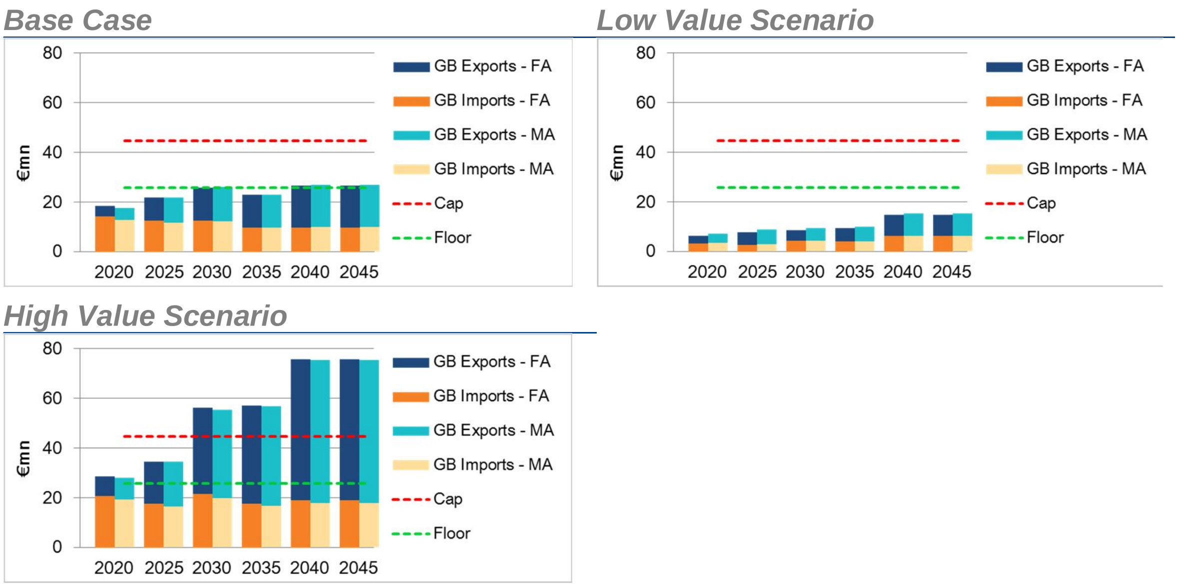
Figure 28 – Price differentials and flows on Greenlink

Source: Pöyry Management Consulting modelling for Ofgem

As shown on Figure 28, in the Base Case and High scenario, the price in Great Britain in 2020 is higher than the price in the Irish Single Electricity Market (SEM). Over time, the

Irish price rises above the British price by the late 2020s. In all scenarios, arbitrage revenues are increasing. In the Base Case and the Low scenario, this is due to both the increasing price differential and the increasing volatility in both markets as more intermittent generation is deployed. In the Low scenario, revenues increase slightly due to increased price differentials. Arbitrage revenues increase together with flows in all scenarios.

Figure 29 – Arbitrage revenues for Greenlink



Source: Pöyry Management Consulting modelling for Ofgem

As shown in Figure 29, under the Base Case, the project requires floor payments in the early years of the assessment in both 'first additional' and 'marginal' cases. In the Low scenario, project revenues are considerably lower and the project requires floor payments in all years. In the High scenario, project revenues rise from around the floor in 2020 to making cap payments from 2028.

4.6.3 Greenlink's impact on social welfare

Greenlink has a very marginal positive impact on GB consumer welfare in the Base Case as well as a slightly negative impact in the Low scenario and a positive impact in the High scenario. In the Base Case, this benefit is highest in the early years, and decreases to zero or slightly negative after 2030, when GB prices are lower than SEM prices. In NPV terms, the benefit to GB consumers is €50mn (FA) or 100mn (MA) in the Base Case. In the Low scenario, the GB price is lower than the SEM price in all years, leading to a negative, and largely constant, effect on GB consumers in all years (NPV around -€300mn). Although the High scenario's price differential to the Base Case's, GB consumer welfare remains positive throughout the modelled period, as more volatility lead to balanced flows and cap payments due to higher revenues.

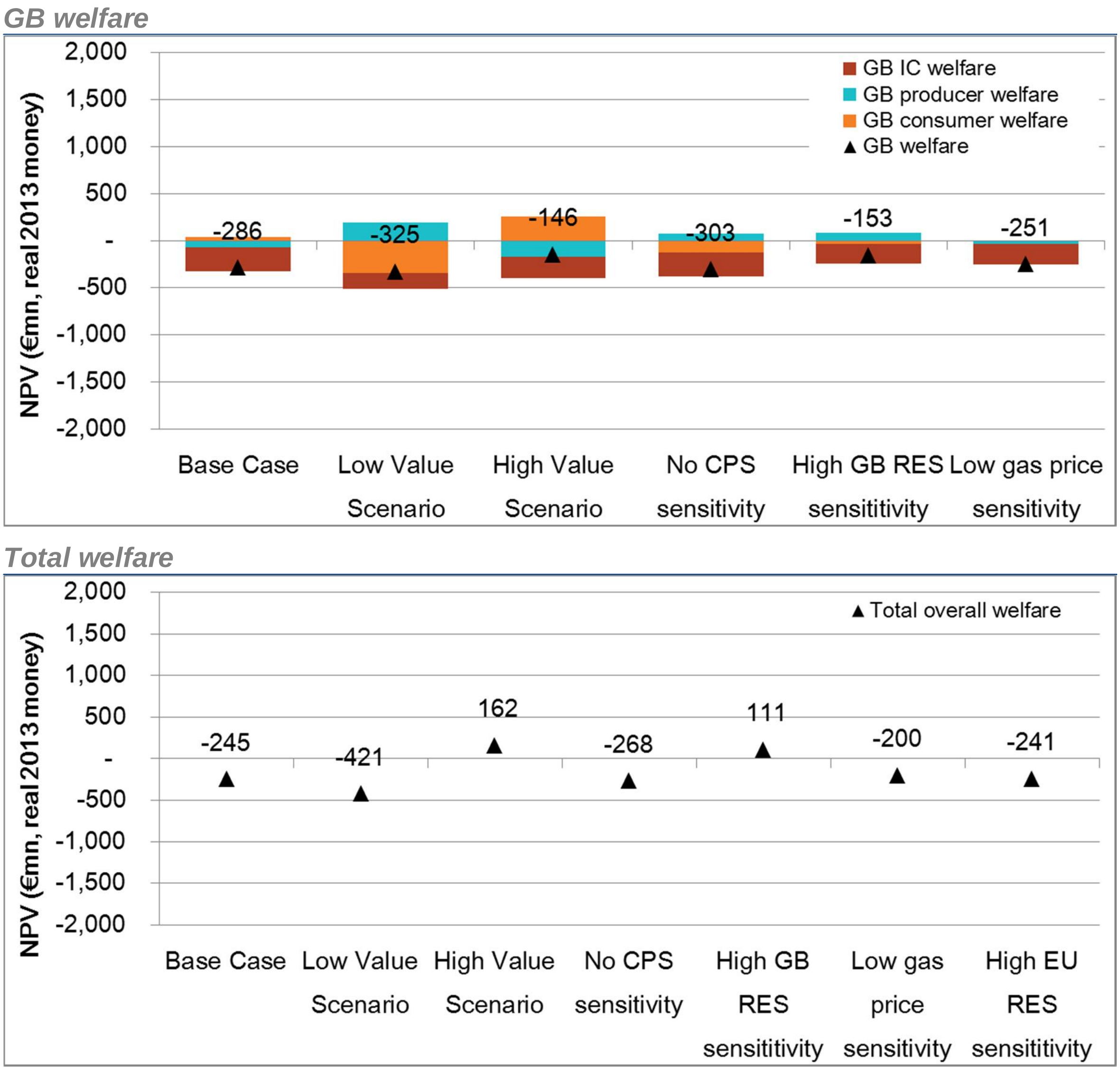
As regards GB producers, the effect on their welfare is equally minor, and balanced by consumer gains in the Base Case and High scenario, while in the Low scenario, the net is around -€150mn. The overall GB welfare in the Base Case and Low scenario is around -€300mn, and -€150mn in the High scenario (NPV terms), including interconnector welfare.

The overall social welfare effect of Greenlink is negative in the Base Case (around -€250mn, NPV terms), slightly positive in the High scenario (around €175mn) and only negative in the Low scenario (around -€400mn). For Ireland, the cable is very positive in the High scenario (€300mn), slightly positive in the Base Case (€50mn) and negative in the Low scenario (-€100).

4.6.4 *Sensitivity results for Greenlink*

Figure 14 shows the GB and total welfare impact results for Greenlink from our MA modelling.

Figure 30 – Greenlink key results for all sensitivities and scenario (MA)



Source: Pöyry Management Consulting modelling for Ofgem

Key results to highlight from the sensitivity analysis on the Greenlink project are:

- As removing the CPS (GB carbon price floor) decreases the GB price compared to the Base Case, flows from GB to Ireland increase, having a negative impact on GB consumers. The overall economic case is largely unaffected.
- The High GB RES sensitivity is a clear upside for the project, and it shows improvement for the interconnector(s), overall GB and overall total welfare. GB consumers are only very slightly affected (GB consumer welfare impact around zero compared to ~€100mn in the Base Case).

5. SUMMARY OF RESULTS AND KEY CONCLUSIONS

All interconnectors examined as part of this CBA assessment show 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 under the floor, the project can still deliver a net gain for GB consumers because of the significant benefit arising from wholesale price effects.

To summarise the analysis and compare the performance of the five interconnectors we have considered the following key welfare benchmarks:

- GB consumer welfare;
- Overall GB welfare (including GB consumers, producers/generators and GB share of interconnector welfare); and
- Overall total welfare (including GB and connected country consumers, producers and interconnectors[16]).

5.1 Impact on GB consumer welfare

Figure 31 shows the project comparison for the impact on GB consumer welfare on a normalised basis (i.e. expressed on a per GW of interconnection capacity installed). The orange bars show the welfare impact in the Base Case, for the marginal and First additional runs. The error bars show the range of outcomes across our High and Low market scenarios.

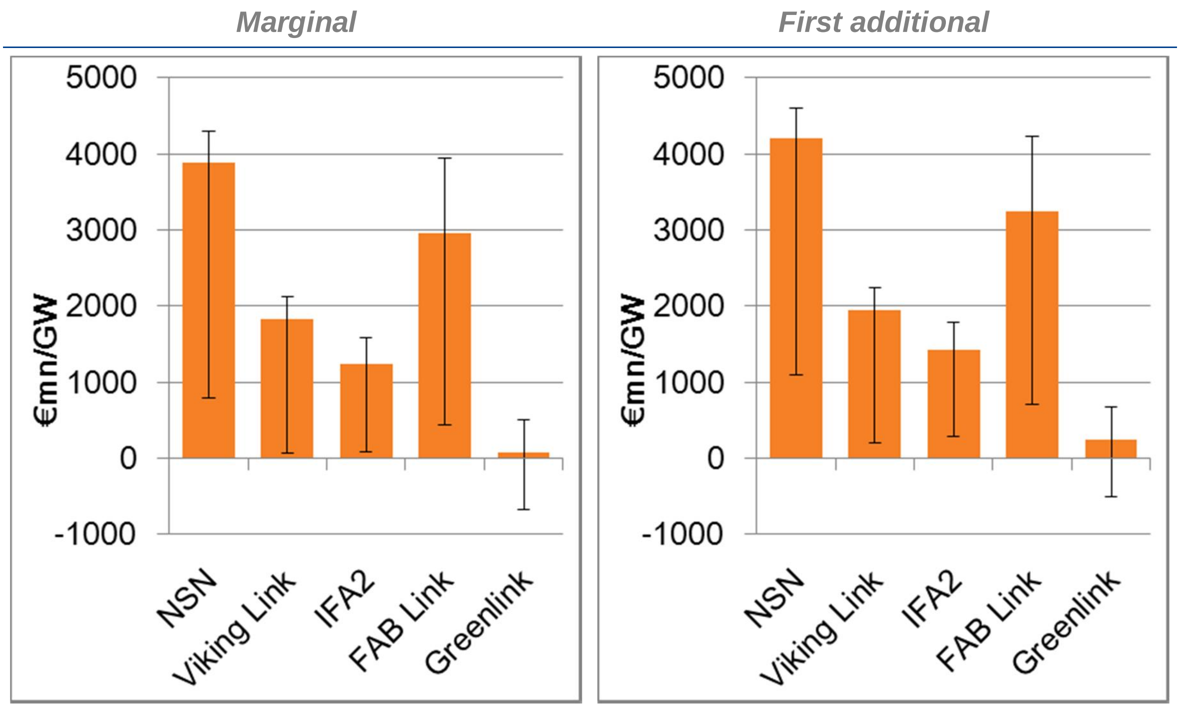
Comparing the interconnector performance on their impact on GB consumer welfare, we see the following:

- NSN and FAB Link provide the highest projected level of benefit to GB consumer welfare in the Base Case (of €3bn-€4bn), with Viking Link and IFA2 also showing a strong benefit to GB consumers of (€1bn-€2bn) in NPV terms. FAB Link's significant additional benefit to GB consumers over IFA2 (the other French connected interconnector) is based, at least in part on its large projected cap payments[17];
- NSN, Viking Link, IFA2 and FAB Link show a positive impact on GB consumer welfare even in the Low scenario (once any potential floor payments are accounted for), but they all have limited additional upside value to consumers above the Base Case;
- Greenlink shows a small positive impact for GB consumers in the Base Case but at much lower levels than the other interconnectors analysed. The High and Low scenarios are broadly symmetrical around the Base Case for Greenlink, with a significant welfare gain in the High scenario but a large welfare loss in the Low scenario. This shows the strong dependency of the Greenlink GB consumer welfare case on the assumed market development scenario.

16 Includes GB share of welfare and the connected country share of welfare for those interconnectors included in the modelling.

17 With the cap/floor level based on the overall cost indicated to Ofgem – where this is low the cap/floor level will also be low meaning that, ceteris paribus, GB consumers will be better off.

Figure 31 – GB consumer welfare: Project comparison (€m/GW)



Source: Pöyry Management Consulting modelling for Ofgem

5.2 Impact on Total GB Welfare

Figure 32 shows the project comparison for the impact on total GB welfare on a normalised basis (i.e. expressed on a per GW of interconnection capacity installed). Total GB welfare is made up of GB consumers, GB producers and the GB share of interconnector welfare.

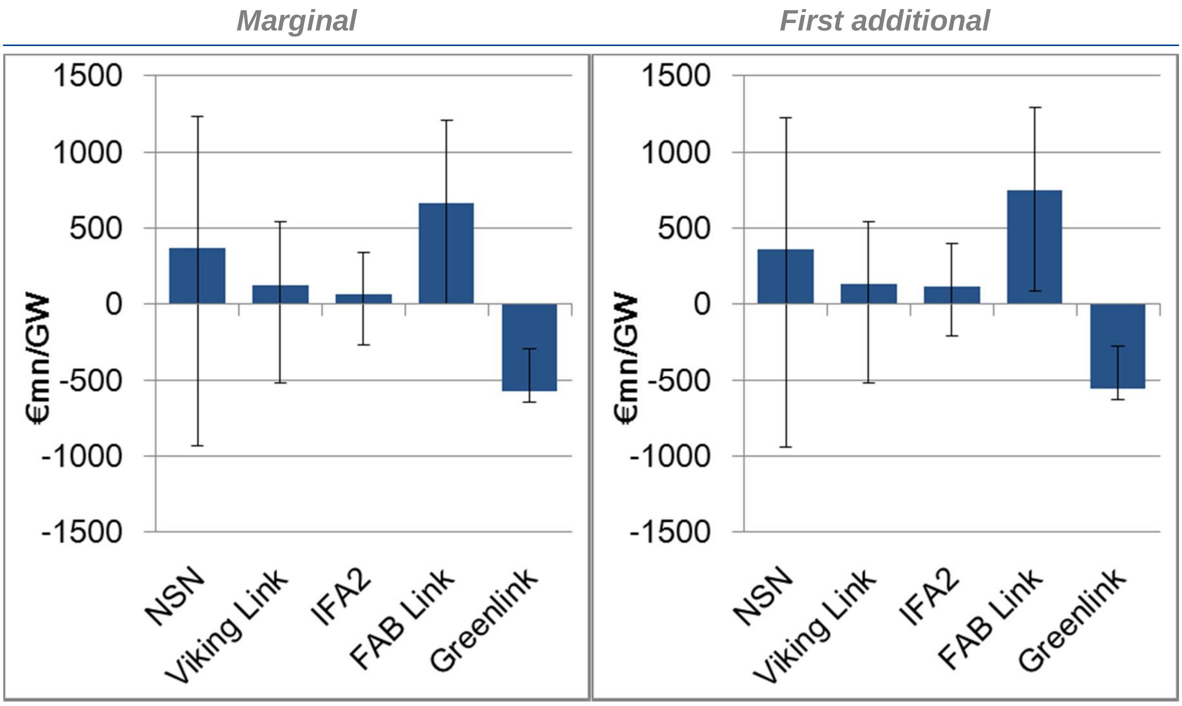
The blue bars show the welfare impact in the Base Case, for the marginal and First additional runs. The error bars show the range of outcomes across our High and Low market scenarios.

Comparing the interconnector performance on their impact on GB total welfare, we see the following:

- FAB Link and NSN provide the highest projected level of benefit to net GB welfare in the Base Case (of €400m-€600m), with Viking Link and IFA2 also showing a small net benefit to GB of in NPV terms;
- FAB Link shows a net benefit to GB welfare in all modelled market scenarios – sensitivity analysis concerning its revenues shows that its clearly superior net welfare benefits over IFA2 arise largely because of the significantly lower cost estimates;
- NSN, Viking Link and IFA2 show a symmetrical High/Low GB net welfare impact in – there are downside risks that the interconnector will not be a net social welfare benefit to GB but these appear to be broadly balanced against potential upside benefits in a high scenario. NSN and Viking Link show a large range in benefit around the Base Case, principally due to their high cost.

- Greenlink shows a strong dis-benefit to net GB welfare all scenarios (although this is somewhat reduced in the High scenario).

Figure 32 – GB Net Welfare: Project comparison (€m/GW)



Source: Pöyry Management Consulting modelling for Ofgem

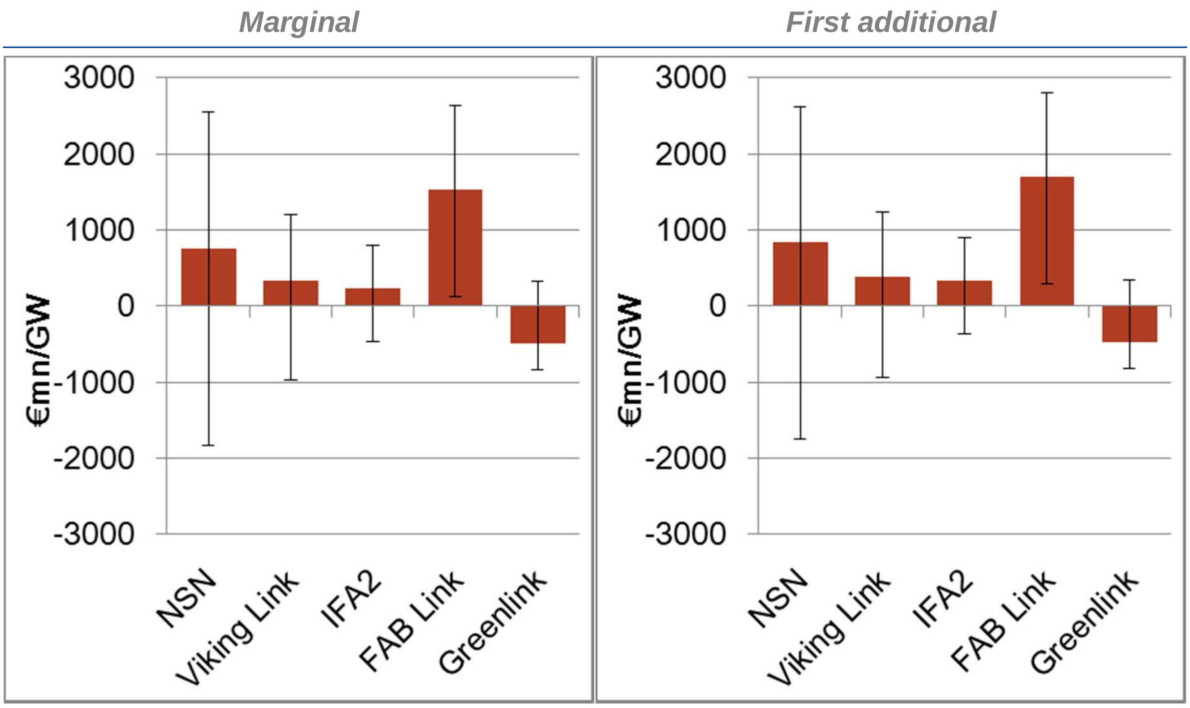
5.3 Impact on Total Welfare

Figure 33 shows the project comparison for the impact on total GB welfare on a normalised basis (i.e. expressed on a per GW of interconnection capacity installed). Total GB welfare is made up of GB and connected country consumers, producers and interconnectors. The red bars show the welfare impact in the Base Case, for the marginal and first additional runs. The error bars show the range of outcomes across our High and Low market scenarios.

Comparing the interconnector performance on their impact on total welfare, we see the following:

- FAB Link provide the highest projected level of benefit to net total welfare in all scenarios and there is no market scenario examined in which it has a negative net welfare benefit.
- NSN, Viking Link and IFA2 also showing a small net total welfare benefit in the Base Case, with symmetrical Low and High scenario results i.e. there are downside risks that the interconnector will not be a net social welfare benefit in total but these appear to be broadly balanced against potential upside benefits.
- Greenlink shows a dis-benefit to overall welfare in the Base Case and Low scenario but a positive contribution in the High scenario. The project welfare case appears to be highly dependent on the level of new renewables build in GB and Ireland.

Figure 33 – Total Net Welfare: Project comparison (€m/GW)



Source: Pöyry Management Consulting modelling for Ofgem

5.4 Key conclusions

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

- NSN, Viking Link, IFA2 and FAB Link are all based on a similar business case and operating model. They connect the GB market to markets with a significantly lower expected average price level leading to large net imports of electricity into GB. Greenlink is based on a different model, whereby value is primarily derived from connecting two markets with increasing volumes of intermittent low carbon generation and thereby increasingly volatile prices.
- GB consumer welfare benefits are generally much higher than the Overall GB welfare impact. Apart from Greenlink, the interconnectors examined all showed large net flows of electricity into the GB market, lowering GB prices – this leads to increased GB consumer surplus, but these welfare benefits are offset by lower GB producer surplus. Overall interconnector social welfare is generally neutral in the Base Case after the operation of the cap and floor has been accounted for.
- While business cases and operating models are similar, key differentials in the social welfare impact between NSN, Viking Link, IFA2 and FAB Link are driven by:
  - The capacity of the interconnector with larger interconnectors having higher costs but higher potential revenues;
  - The length of the interconnector which in turn drives costs – NSN and Viking Link are significantly longer and therefore more costly than IFA 2 and FAB Link;

  - The scale of the average price differences between the markets and the extent to which this varies by hour with Norway and Denmark showing the highest levels of price difference in the Base Case.
- All interconnectors are impacted by the cap and floor regime in some future market scenarios:
  - No significant cap and floor payments are envisaged in the Base Case for NSN, Viking Link or IFA 2.
  - FAB Link sees reasonable levels of payments to consumers over the cap (€450-550mn in NPV terms) in the Base Case, representing a welfare benefit for GB consumers;
  - Greenlink sees revenues under the floor level in the Base Case (assuming no capacity mechanism payments) leading to payments from consumers to Greenlink (~€20mn in NPV terms) thereby lowering GB consumer welfare.
  - All projects apart from FAB Link receive floor payments from consumers in the Low scenario as revenues are below the floor in certain years. However, all projects also make cap payments to consumers under the High scenario as revenues are above the cap in certain years. This variability in potential revenues across market scenarios is a key feature for future interconnectors and the risk/reward balance for consumers of the cap and floor mechanism should be considered.
- Sensitivity analysis on capacity market participation by interconnectors shows that:
  - capacity market participation represents an upside for the interconnector business case and decreases the risk likelihood of projects requiring floor payments. Where revenues are pushed above the floor level or when revenues are pushed above the cap level it will also represent an upside for GB consumers – in cases where the revenue stays between the cap and floor there is no GB consumer impact;
  - where IFA2, FAB Link and Greenlink are assumed to participate broadly equally in two capacity markets (one at either end of the link), the impact on overall GB welfare is minor but represents a wealth transfer from producers to interconnector owners (and then, potentially, indirectly to consumers via the cap and floor mechanism);
  - where the interconnector is only participating in one capacity market, this leads to a net transfer of welfare out of the country offering that capacity market – particularly relevant for interconnection with Norway and Denmark where no capacity market is currently envisaged;
  - For Greenlink in particular, CM participation appears essential to the business case – in the Base Case, Greenlink revenues are consistently below the floor before capacity market revenues but close to or above the cap when including capacity market revenues;
  - For NSN and Viking Link, which are below or close to the floor in certain years in the Base Case, this risk would be much reduced by allowing projects to bid into the GB capacity market; and
  - For the French projects (IFA2 and FAB Link) and Greenlink, CM participation in both markets presents a slight upside to overall GB welfare, as capacity market clearing price in the connected market is assumed to be higher than the GB capacity market clearing price.

- It was generally found that the MA and FA approach produced very similar results in terms of overall social welfare. While the volume of 'competing' interconnection can be a driver of the business case for an individual interconnector, the similarity of social welfare levels between the two approaches show that the build profile of the five new interconnectors is a much smaller driver of welfare than the underlying fundamentals across the market scenarios. .

ANNEX A – DETAILED MODELLING METHODOLOGY

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

1. In stage 1 the hourly granularity price projections for various scenarios are developed in our BID3 model.
2. In stage 2 those power price projections are taken into the CARAMEL which then optimises the flows across interconnectors and calculated the key CBA parameters.

This modelling process, and its potential strengths and weaknesses, is explained in the annex below.

A.1 BID3 Market Modelling Approach

The underlying hourly wholesale market price modelling has been done using our BID3 market model. The BID model creates hourly price tracks that feed into the CARAMEL model for each country examined as part of the CBA assessment. A more detailed description of BID3 is provided in Annex B.

As an example Figure 34 and Figure 35 below show the €/MWh prices in GB and France for the Base Case model runs under different granularity time periods in 2025:

- Figure 34 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 35 shows the hourly price and price differential in Week 1 of January 2025.

It can be seen that, despite GB prices being significantly higher than those in France in both the annual and in all monthly prices, once you examine the hourly prices there is significant hour by hour cross-over between GB and French prices.

Figure 34 – Annual and monthly prices in GB and France: Base Case, 2025

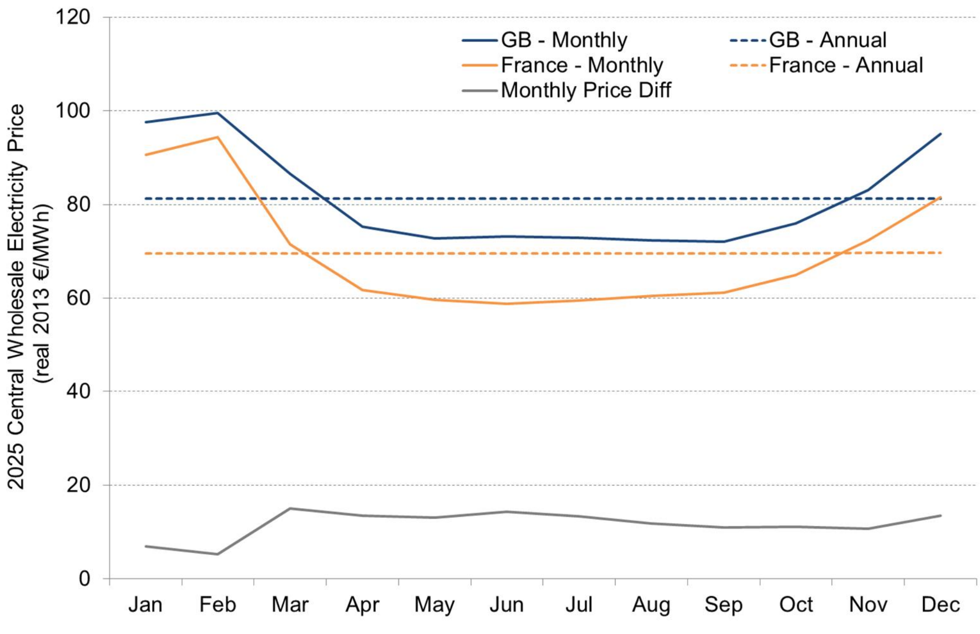
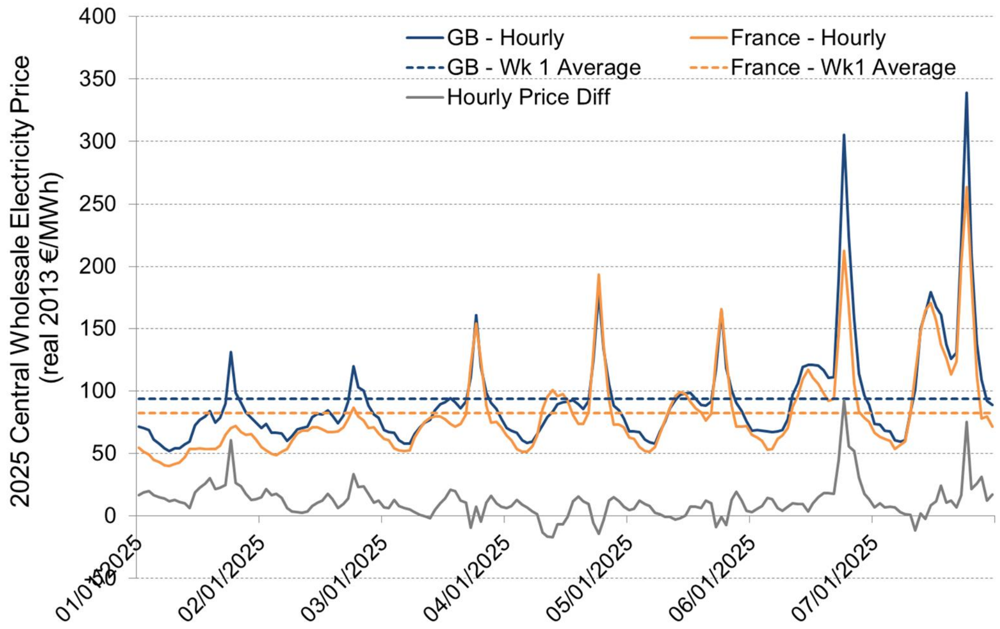


Figure 35 – Hourly prices in GB and France: Base Case, Week 1 January 2025



For the specific modelling in this project the BID3 model has been run both with and without additional interconnection in GB (above and beyond that interconnection capacity currently operational) for each of the core scenario. The 'with additional interconnection' runs and the 'without additional interconnection' runs are used in different ways:

- The runs containing additional new interconnection (in line with NG/DECC assumptions as described) are used:
  - to establish the baseline for new build of capacity in GB and in the rest of NWE ensuring that a reasonable, internally consistent capacity margin (and LOLE) is maintained;
  - to sense check and ensure compatibility between the optimised model prices and those published results from DECC and National Grid; and
  - to sense check and ensure compatibility of prices and interconnector scheduling by the full LP model in comparison to the CARAMEL model.
- The 'without additional interconnection' runs have then been developed by removing all additional interconnector capacity but leaving all other assumptions the same. These runs have then formed the basis of the 'pre-interconnection' price shapes that feed into the CARAMEL model. The CARAMEL model combines these pre-interconnection prices with user driven assumptions on new interconnection build and then schedules each new interconnector on an hourly basis internally.

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 Chapter 3.

A.2 Description of CARAMEL Model

Essentially, CARAMEL is designed to be consistent with welfare projections deriving from BID3's optimal solution to the same question (and other optimal solutions) but to allow increased flexibility in cost/benefit calculations, interconnector build profiles, sensitivity analysis and cap/floor assessments.

The model considers the prices in two countries, and, should there be a new interconnector available, adds flow from the cheaper country to the more expensive country. This flow will then result in a higher price in the exporting country, and lower the price in the importing country based on the underlying elasticity of prices in the model (which in turn is a function of the supply curve). By directly scheduling multiple interconnectors simultaneously as part of the Excel model, generation levels in all countries are re-optimised based on any new interconnection that is assumed to be available. CARAMEL uses a non-linear optimisation approach to schedule the interconnectors in each hour.

Box 1: Example of rescheduling due to additional interconnection:

Without any additional interconnection, the price in GB was €70/MWh in one hour, set by a coal plant. The price in France in the same hour was €40/MWh, set by a CCGT plant.

In this case, an additional interconnector would flow from France to GB, essentially adding supply to GB and increasing demand in France. Therefore, the formerly marginal coal plant in GB would no longer be needed and would shut down. The new price-setting plant could be a more efficient plant and the new price in GB would be €68/MWh. In France, an additional power plant would be needed to compensate for the export. This new power plant could be a less efficient CCGT, leading to a new power price of €41/MWh in France.

Essentially a power plant generating with a cost of €70/MWh has been replaced by a plant generating at a cost of €41/MWh – the market has therefore found a more efficient solution to deliver the required power.

After re-optimising the cost of generation, CARAMEL calculates the economic impact on consumers, producers (generators) and interconnectors based on the new flows and prices:

- **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: $Demand \times (VoLL - Post\ flow\ price)$);
- **Producer welfare:** Calculated as the change in revenue for generation less the costs of generation, as estimated by the underlying market supply curve, calculated by the formula[18] $(Post\ flow\ price - Pre\ flow\ price) \times \left(Demand + \frac{Outflow}{2}\right)$; and

18 The term 'Outflow/2' represents the approximation of the supply curve as a straight line of slope = elasticity. The remainder of the supply curve (i.e. the upper and lower sections not impacted by flow decisions in the market in a given hour) is excluded from the calculation as

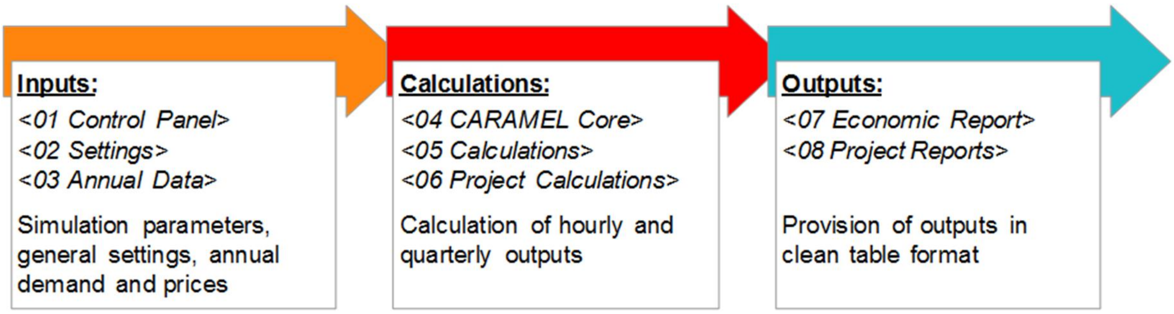
- **Interconnector welfare:** Calculated as the arbitrage revenue of the new interconnector less the changes in arbitrage revenue on other interconnectors connected to the GB market. In the model, this is calculated by the revenues of selling power in one country minus the cost of buying power in another, including losses on the cable:
  $-(Price\ in\ exporting\ country\ \times Outflow) + (Price\ in\ importing\ country\ \times Inflow)\ where\ Inflow = \ Outflow\ - cable\ loss..$

The model also automatically calculates the impact on each stakeholder group of the cap and floor arrangements (see Section 2.2.2). Other revenue elements (such as capacity payments) can be added as required and their welfare impacts incorporated as sensitivity analysis.

Additionally, CARAMEL can be used to obtain a high-level view of other value metrics which do not form a core part of the CBA such as:

- **Carbon emissions:** 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); and
- **The 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, wind etc.). These generation impacts by generation type in GB are estimated in the CARAMEL model.

Figure 36 – Overview of the CARAMEL model



A.3 Strengths and limitations of the modelling methodology

The underlying use of the pan-European BID3 model as a starting point for the production of hourly price projections to 2040 is a key strength of the chosen modelling approach. Utilising a pan-European model is a necessary starting point for any cross-border trade analysis as single country models can quickly introduce internal inconsistencies in market modelling. A pan-European market also has the advantage of accounting for the impact of decisions and developments of large but not directly connected countries (such as Germany) on smaller surrounding markets.

it is not required for a difference analysis of this kind. This equation is therefore only a partial producer surplus designed to represent only the element that changes by flow over ICs.

BID3 uses robust optimisation techniques which are adopted as standard by numerous consultancies, 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 methodology has been used for asset valuations of both interconnectors and other electricity market assets for many years. Finally it is aligned with the modelling approach taken by all the cap and floor submissions.

The CARAMEL model co-optimises the scheduling of all interconnectors simultaneously, accounting for elasticity of prices in markets thereby incorporating:

- the tendency of interconnectors to 'cannibalise their own revenue'; and
- the tendency of interconnectors to also impact the revenue on other GB interconnectors (which can either be positive or negative).

This modelling approach allows good flexibility for editing the assumptions on interconnection quickly and getting results for multiple scenarios while still retaining a high level of consistency with a full LP optimisation approach (such as BID and those used in the submissions). It also 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 reruns of large LP models. The capability of the model to run multiple interconnection build profiles quickly and efficiently has allowed us to take an assessment of the interconnectors using multiple build profiles – this approach is described further in section 2.3.

However, it should be noted that there are some limitations in the approach:

- Large changes in the assumptions on, for example, the scale of new interconnector build within the Excel model, will tend to reduce the level of consistency with the results that would be obtained with a full run of the LP model. We do not expect this inconsistency to be a major issue with the different build profiles run in this project and, to minimise the risk of bias in results, we conducted a sensitivity run of the BID3 model with a high level of new interconnection build in 2020.
- We have focused on the key 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 2.2.3 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 costs elements would be beneficial.
- Using a market price elasticity approach in CARAMEL (with elasticity expressed as a % movement in prices for a given change in market demand) as a proxy for the slope of supply curve is a simplification of the actual market supply curve. By comparing the prices and flows in CARAMEL with the results which would be derived under an LP solution we have minimised differences between these approaches on average, but hourly differentials still remain. To the extent that the supply curve cannot be well defined as a curve with a constant percentage change in prices due to demand (over areas of the supply curve impacted by the flow e.g. in very high or very low price periods) an approach using an LP solution would be beneficial. The impact of this simplification is lowered however by our producer surplus calculation methodology which removes the need to model the part of the supply curve not impacted by interconnector flow in a given hour.
- Wind curtailment is only indicatively modelled in CARAMEL via an implicit assumption that only small absolute price movements occur in low price periods,

despite an increase in output in the given country. This creates implied benefits from curtailment reduction but does not separate it explicitly from other forms of benefit/arbitrage revenue. This split could be better assessed using an LP model approach but, given its dependency on other complex areas such as assumed grid reinforcements and market rules, is very difficult to accurately assess curtailment issues even using an LP approach. For countries and scenarios where wind curtailment is likely to be a significant welfare issue further assessment would be beneficial.

- The non-GB interconnector welfare calculations are inherently less robust than the GB market as interconnectors which have no direct relationship with GB are not included in the analysis (as the CARAMEL model focus is GB). Although these 'second country' interconnector welfare levels are not reported as separate line items in the CBA they do feed into the overall total welfare calculations. A full LP model which took the whole of Europe into account simultaneously would be present a more robust solution but would be significantly less flexible. To the extent that a decision on support was to be based on the overall total welfare impacts, further analysis of these additional interconnectors 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 so any person reviewing these results should bear these limitations in mind. 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 key 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 this is appropriate granularity on which to conduct the interconnector analysis it has been necessary, given the long-term nature of the scenario modelling, to assume that each year is average in terms of weather, demand and plant availability. This removes an underlying source of variability in the modelling. To counteract this effect we have set up the CARAMEL model to be able to conduct sensitivity analysis select using 5 historic 'weather' years including a 1-in-5 cold and 1-in-5 warm year. Although the results are not included in the core scenarios, this sensitivity analysis revealed little difference in overall conclusions from these variations and provides additional comfort around the robustness of the results.

ANNEX B – BID3 POWER MARKET MODEL

B.1 Evolution of Pöyry market models

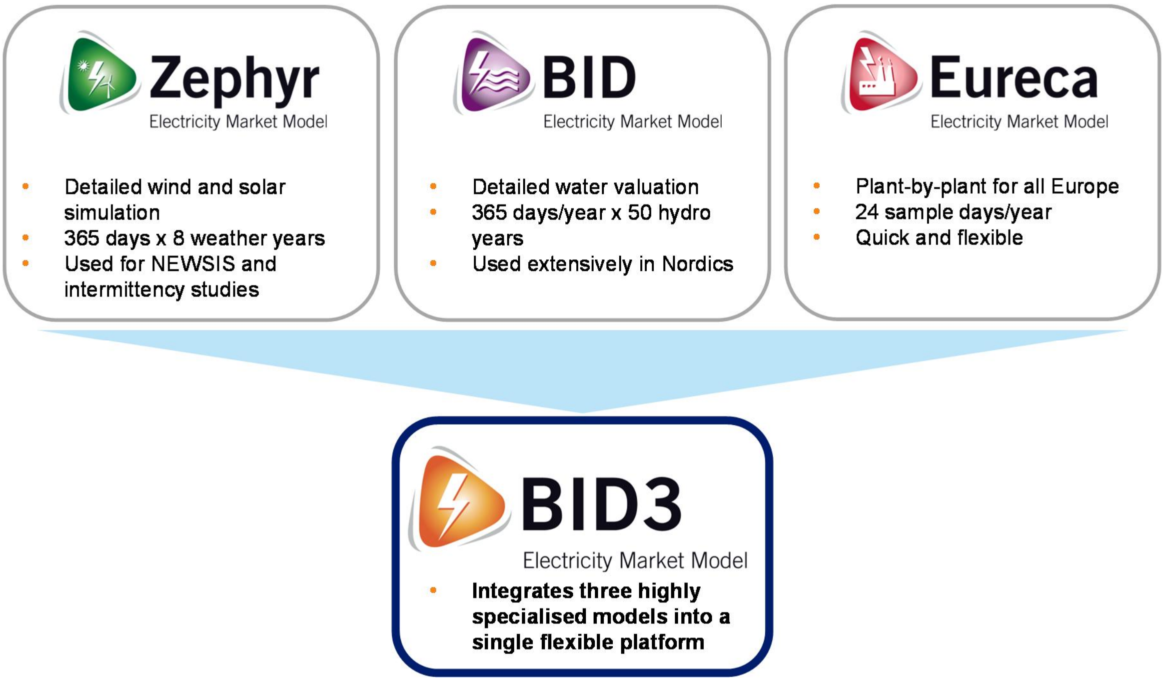
BID3 is Pöyry's power market model, used to model the dispatch of all generation on the European network. We simulate all 8,760 hours per year, with multiple historical weather patterns, generating hourly wholesale prices for each country for each future year and dispatch patterns and revenues for each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

As illustrated in Figure 37 we have developed *BID3* out of our previous power market models: *BID 2.4* which has sophisticated treatment of hydro dispatch, using Stochastic Dynamic Programing to calculate the option value of stored water; and *BID3*, which has underpinned our ground-breaking studies quantifying the impacts of intermittency in European electricity markets and the role flexibility could play in meeting the challenges of intermittent generation. *BID3* is highly flexible to use and incorporates the best aspects of our previous models. Since *BID3* is based upon the same underlying dispatch algorithm as *BID3*, there is no fundamental basis shift in projections when moving between the two.

BID3 is:

- the modelling platform used for Pöyry's *Electricity Market Quarterly Analysis* reports, giving European power price projections used by major banks, utilities, Governments and developers;
- used for bespoke projects for a wide range of clients; and
- available to purchase – deployed in-house by Energinet, Fingrid, Hydro, NVE, Statnett, and Svenska Krafnät.

Figure 37 – Evolution of Pöyry electricity market models



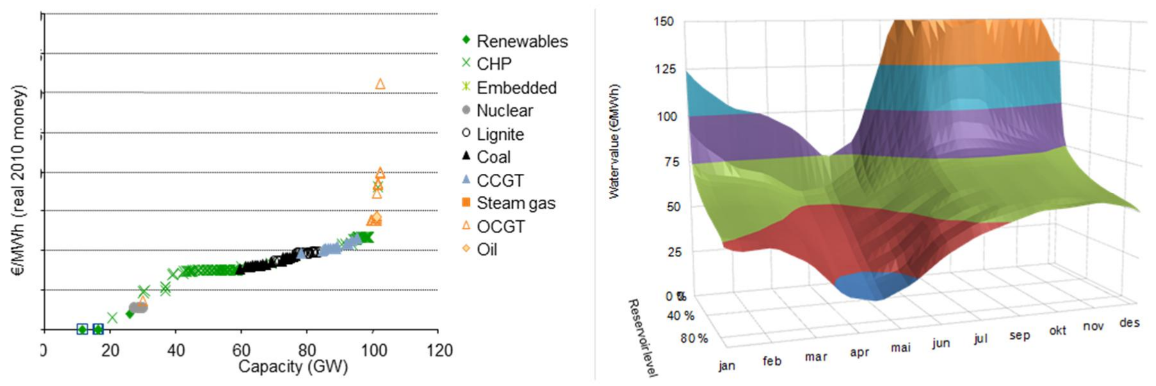
B.2 Modelling methodology

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 plant and interconnectors on the system. At a 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 bases – 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 also takes account of all the major plant dynamics, including minimum stable generation, minimum on-times and minimum off-times. Figure 38 below shows and example merit order curve for thermal plant.
- **Dispatch of hydro plant.** Reservoir hydro plants can be dispatched in two ways:
  - A simple 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 38 below shows an example water value curve, and Section B.5 presents this methodology in more detail.
- **Interconnector flows.** Interconnectors are optimally utilised – this is equivalent to a market coupling arrangement.

Figure 38 – 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:

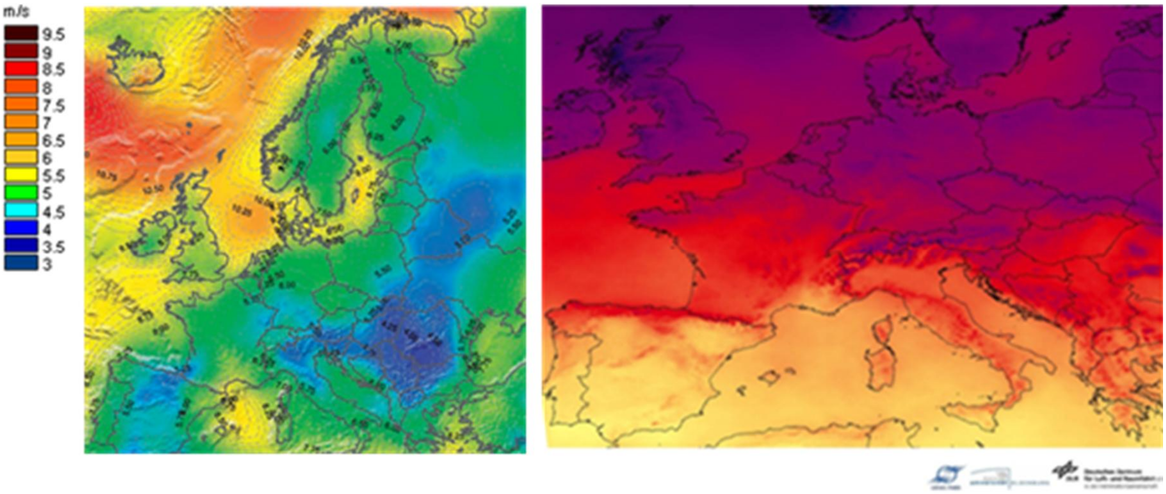
- **Short-run marginal cost.** The SRMC is the extra cost of one additional unit of power consumption. It is the minimum price at which all operating plant are recovering their variable costs. Since the optimisation includes start-up and part-load costs all plant will fully cover their variable costs, 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 *Electricity Market Quarterly Analysis*. As part of the same process we review our interconnection data, fuel prices, and demand projections. Please be aware that we have generally not used these assumptions as part of this project, but have instead used the input assumptions described in 3.2.

- **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). This 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.
  - Our wind data is from Anemos and is reanalysis data from weather modelling based on satellite observations. It is hourly wind speeds at grid points on a 20km grid across Europe, at hub height. Figure 39 below shows average wind speeds based on this data. Hourly wind speed is converted to hourly wind generation based on wind capacity locations and using appropriate aggregated power curves.
  - The solar radiation data is from Transvalor, and is again converted to solar generation profiles based on capacity distributions across each country. Figure 39 below shows average solar radiation based on this data.
- **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 39 – Average wind speeds and solar radiation in Europe



Sources: Anemos, data resolution 20km by 20km; Transvalor, data resolution 2km by 2km

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 example model results is show below in Figure 40 and Figure 41.

Figure 40 – Example of hourly dispatch and related metrics

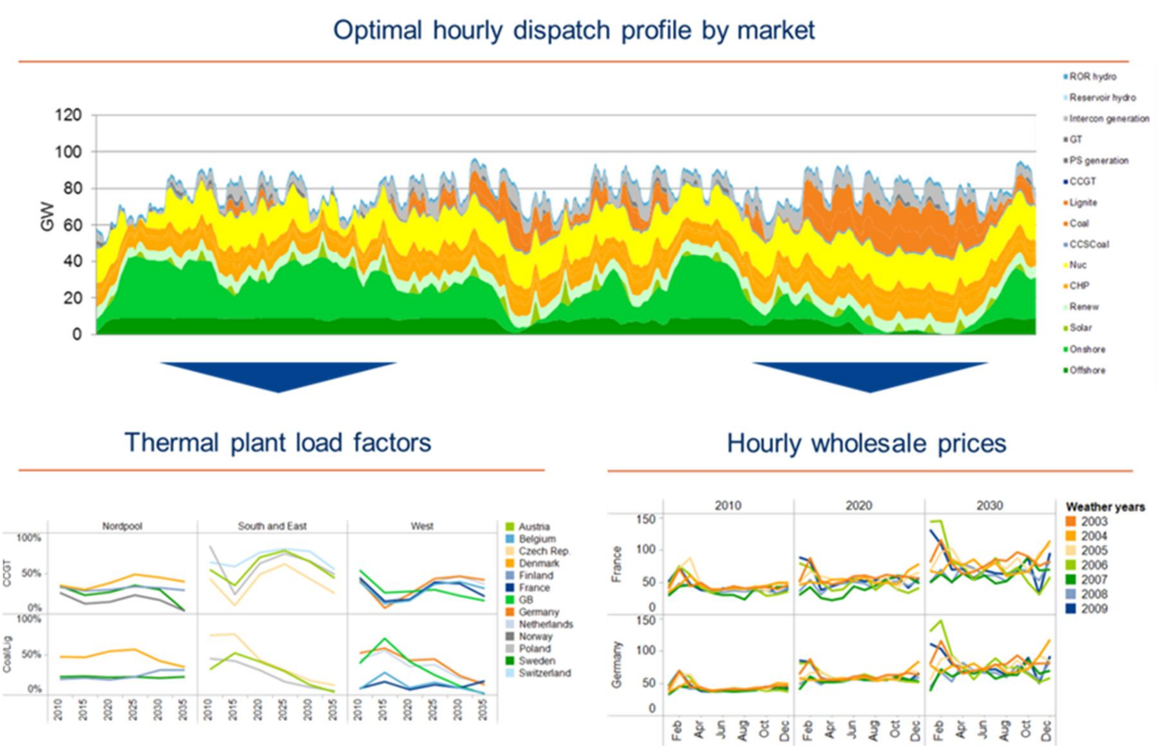
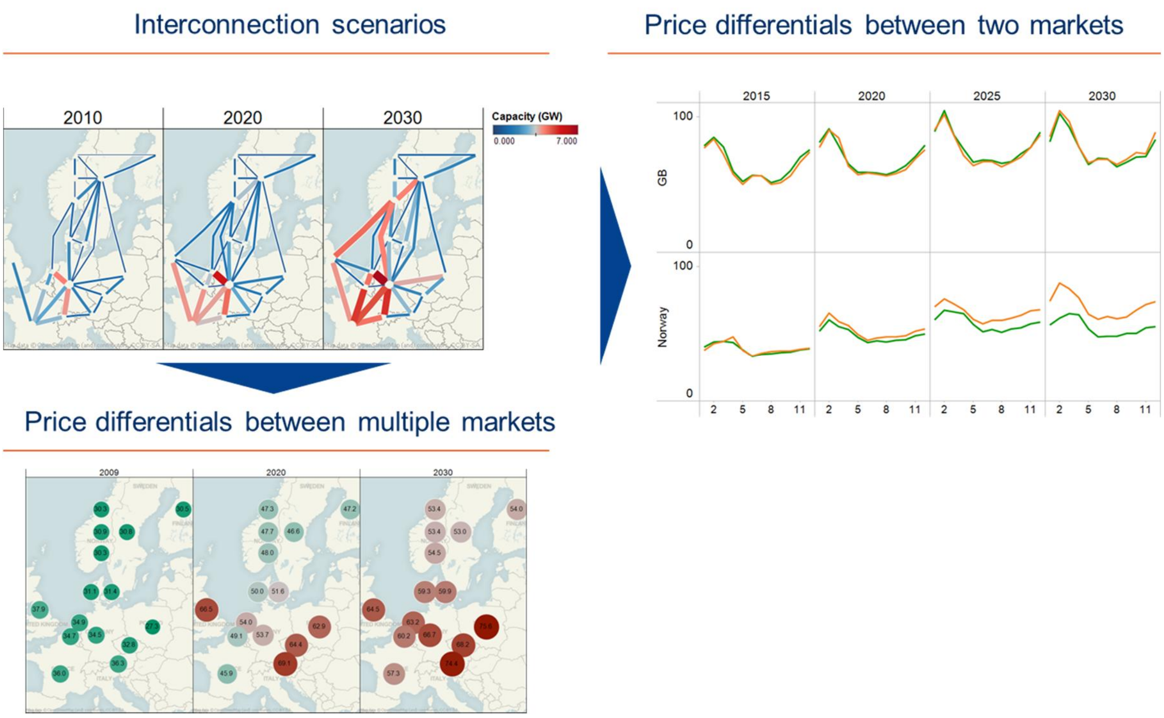


Figure 41 – Interconnector value assessment

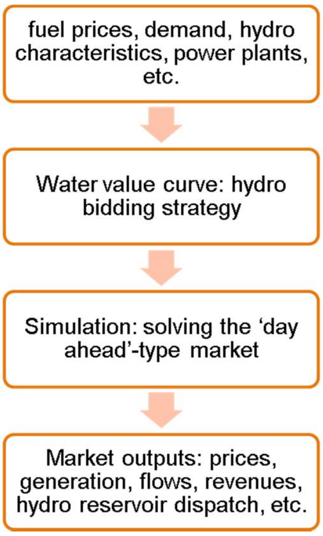


B.5 Description of the hydro dispatch optimisation

Pöyry has implemented a Stochastic Dynamic Optimisation (SDP) methodology to optimise reservoir hydro dispatch under uncertainty of future inflows. In the hydro-dominated areas like the Nordic region it is critical to use such a technique, as the uncertainty of future inflows greatly affects the pricing of electricity on the spot market. If all players knew their future inflows, they would price their water much more aggressively and would not hesitate to go down to very low reservoir levels. In reality, market players are conservative in their use of water, to ensure that they can always meet the demand from their customers even in very dry years. This optimisation methodology is used by most market players in the Nordics as one of the steps to determine their bidding price into the market.

The principle of the methodology implemented in *BID3* is described in Figure 42.

Figure 42 – Optimisation sequence



BID3 creates a 'bidding strategy' for reservoir hydro assets called 'Water Value Curve', whereby the dispatch decisions of reservoir hydro at any point in time are robust to a variety of future inflow situations.

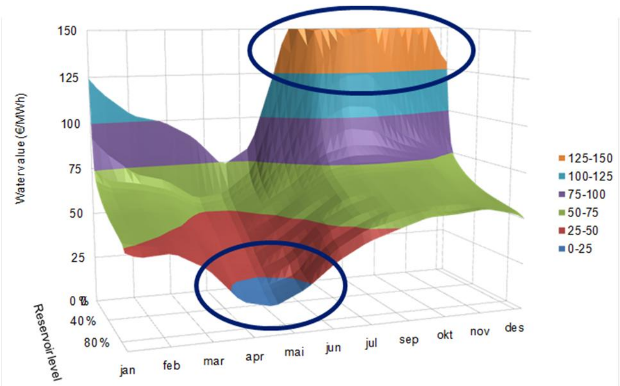
This takes the form of a bidding price for an asset, called 'water value', determined according to several parameters: the hydro reservoir level for the asset considered, the reservoir level in other assets, and the time of the year.

This bidding price is then used in the Market Simulation like a 'fuel price' for the use of water.

The water value represents the cost increase in electricity supply that the region would face if it had one less MWh of water in the reservoir. This opportunity cost is the value at which a hydro market player offers production into the market.

Figure 43 shows a simplified water value curve, where all assets in the scope are assumed to have the same reservoir level. Each week, the model determines a new bidding price for reservoir hydro depending on the reservoirs' level at the end of the previous week.

Figure 43 – Example water value curve

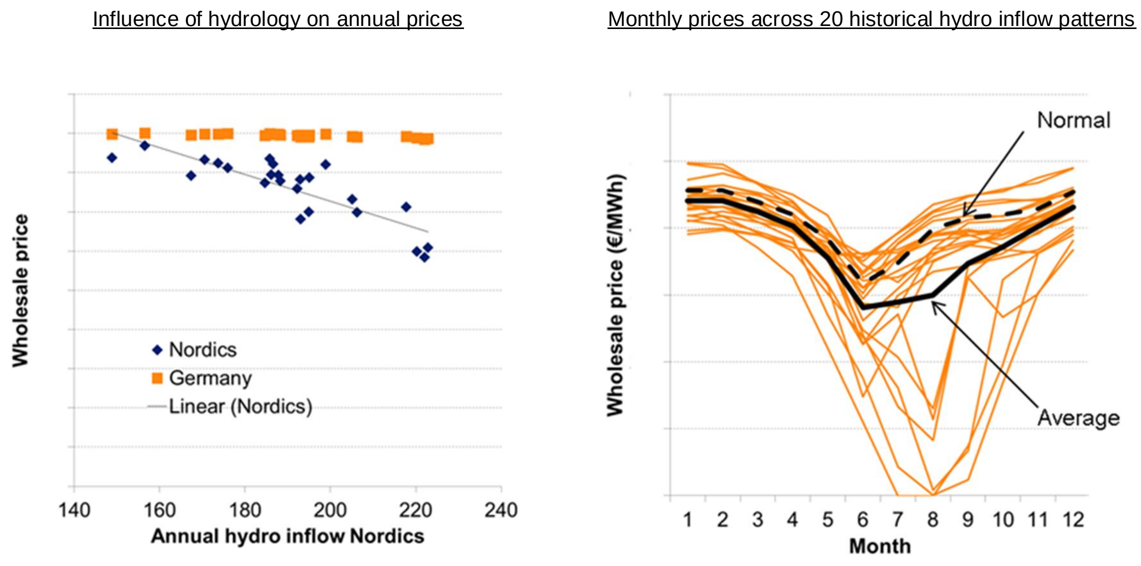


The two circled areas show interesting periods:

- When reservoirs are nearly empty before the winter period, water is expensive thus hydro players are only willing to produce when the power price is very high; and
- when reservoirs are nearly full near the snow melting period water is cheap, hydro players want to undercut other generation to avoid spilling in case of high inflow.

Figure 44 shows example of applications of this water value curve. The left-hand side picture shows the impact of hydrology on annual prices – the more inflow, the lower the price. The right-hand side picture shows monthly price results across twenty consecutive hydro inflow patterns, all other inputs being equal. Note that this picture does not represent the full range of weather-related price variations: dry years are often cold in the Nordics, which could create periods of price peaks in winter.

Figure 44 – Influence of hydrology on power prices



B.6 Purchase of BID3

BID3 is available to purchase, and has been used by many organisations (Figure 45). If you are interested in obtaining *BID3* or power plant datasets for your organisation please email BID3@poyry.com.

Figure 45 – BID3 clients

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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 Chapter 3. Detailed model scenario inputs are shown below.

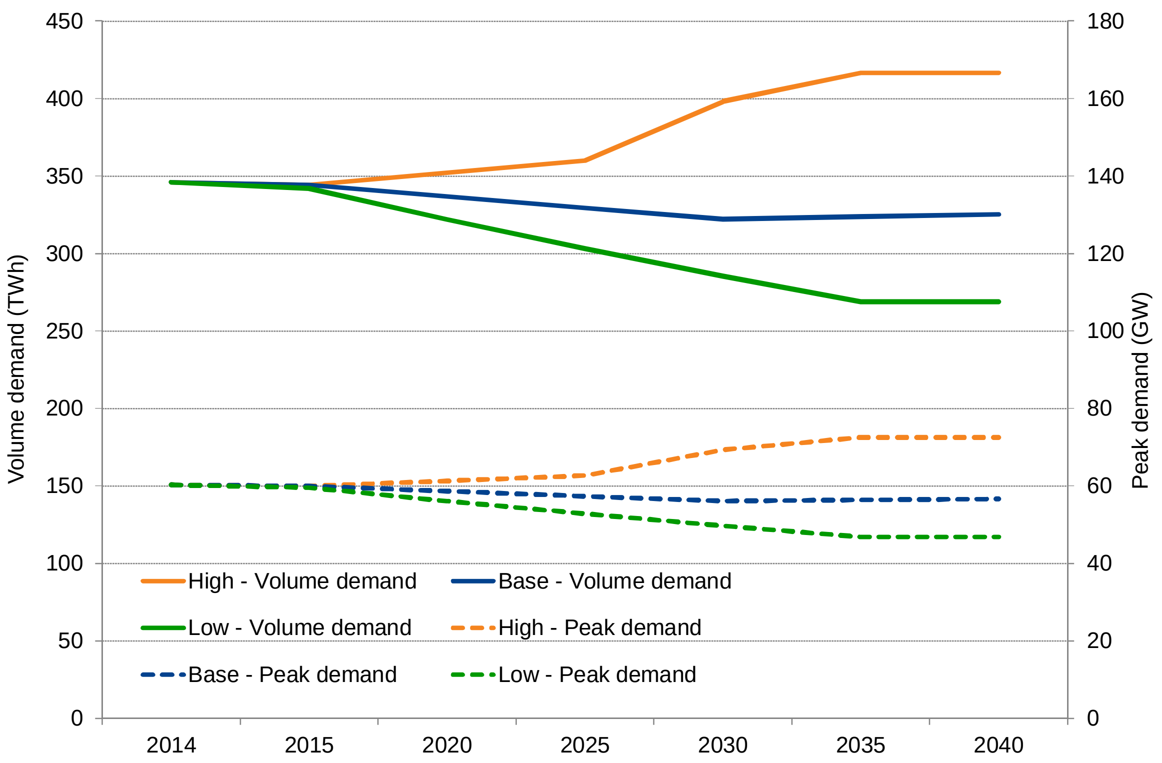
C.1 Demand assumptions

Three demand scenarios have been developed to span a range of future annual and peak demand. Key drivers of future demand growth are GDP and the potential electrification of the heat and transport sectors. This growth is 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. The moderate negative growth to 2030 is explained by relatively slow GDP growth more than counteracted and increased levels of energy efficiency.
- In the High scenario, higher GDP growth and the electrification of heat and transport lead to growing electricity demand. The demand assumptions that we used is based on the DECC High Scenario.
- In the Low scenario, very low GDP growth and continued energy efficiency measures lead to low demand projections. The profile used in this scenario is the 'Slow progression' that was used in the Base Case with the growth rate lowered by -0.75%.

The resulting demand projections are shown in Figure 46.

Figure 46 – Projections of total and peak demand for Great Britain (TWh)



C.2 Capacity mix assumptions

In our capacity scenarios, new entry broadly keeps pace with demand growth. In Great Britain, we have assumed 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[19]) to ensure that the capacity margin remains adequate at times when the system is tightest[20]; we model this against historical within year patterns of weather, demand, and plant outage.

Capacity mix in the Base Case

For the purposes of this study, we 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 the lower renewables capacity build consistent with National Grid's 'No Progression' scenario. Renewable expansion in the 'No Progression' scenario is still significant (with an increase from ~20GW in 2014 to 37GW in 2030) and this amendment was deemed necessary to derive a moderate view of renewables growth in line with the Base Case storyline[21].

In the Base Case, coal plants closures in GB are in line with EU policy and no new coal build is assumed. In addition to renewables expansion, gas forms the majority of new build with moderate levels of new nuclear developed in the 2020's and 2030's with. The high proportion of OCGT (compared to CCGTs) is justified by the support it receives in the capacity market.

In the rest of North West Europe (NWE), Pöyry Central projections of capacity have been used reflecting a continuation of growth in renewables combined with a slow increase in demand. Specifically:

- Coal plants retire in Ireland and Denmark (to some extent replaced by CCGT) and both countries see a major expansion in wind capacity.
- Both Germany and Belgium retire their nuclear plants in the mid-2020s in line with current plans although nuclear continues to dominate the French market.
- Germany in particular sees a continued increase in the level of installed renewable capacity, with Norway expanding wind capacity but maintaining a strong focus on hydro power.

Figure 47 and Figure 48 below show the installed capacity mix assumptions for Great Britain and the rest of the modelled regions in the Base Case.

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19 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.

20 i.e. that sufficient available capacity margin is maintained so that loss of load expectations are negligible.

21 Note that we have included a sensitivity analysis on the impact of higher GB renewables build on the interconnection modelling results – see Chapter 4.

Figure 47 – Installed capacity in the Base Case in Great Britain (GW)

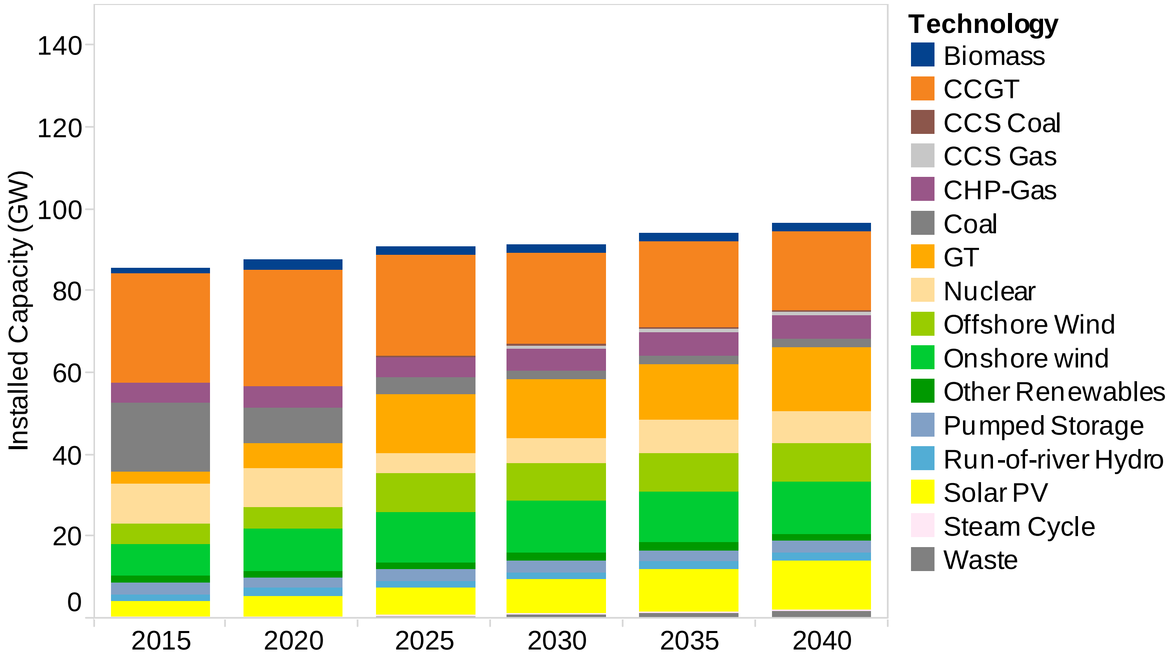
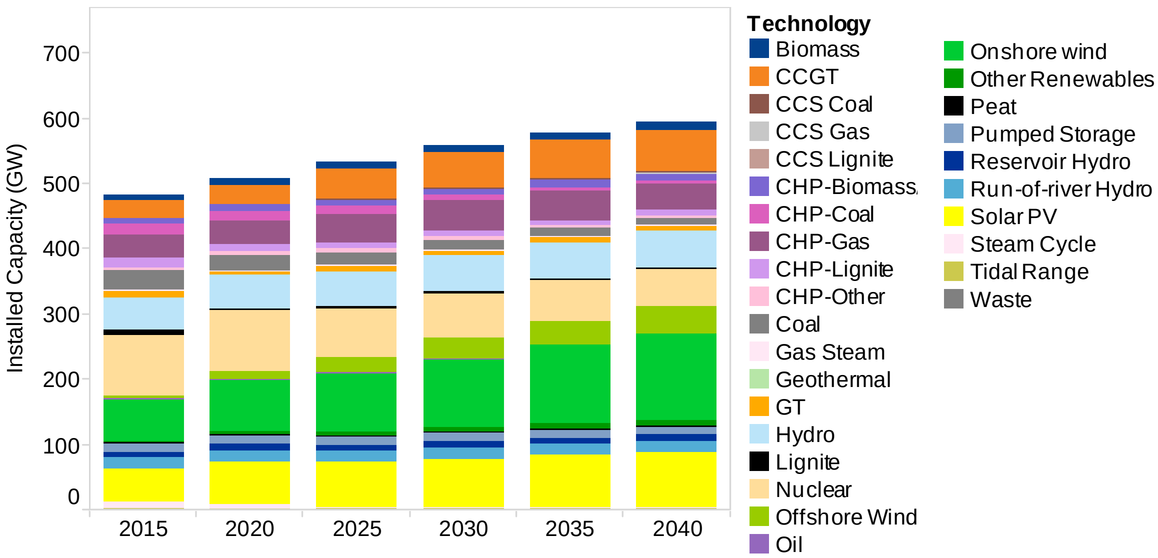


Figure 48 – Installed capacity in the Base Case in North West Europe (GW)



Capacity mix in the High scenario

The High scenario capacity evolution for GB is based on the DECC High scenario 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. We also see a small number of commercial CCS plants commission in the 2020s.

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 strong onshore wind growth with some offshore wind additions, and replaces retiring coal with CCGTs after 2030.
- Belgian nuclear plants close by 2026 and 4GW of new CCGTs come online by 2040 alongside some new gas-fired CHP.
- In the Netherlands, coal runs until 2040 and sees a strong renewables growth.
- While France is still dominated by nuclear, Germany closes it's nuclear by 2023 and sees a very strong growth of renewables.
- Denmark sees a strong growth in wind capacity and retires coal CHPs while Norway builds some wind capacity and stays focused on hydro.

Figure 49 and Figure 50 below show are installed capacity mix assumptions for Great Britain and the rest of the NWE modelled regions in the High scenario.

Figure 49 – Installed capacity in the High scenario in Great Britain (GW)

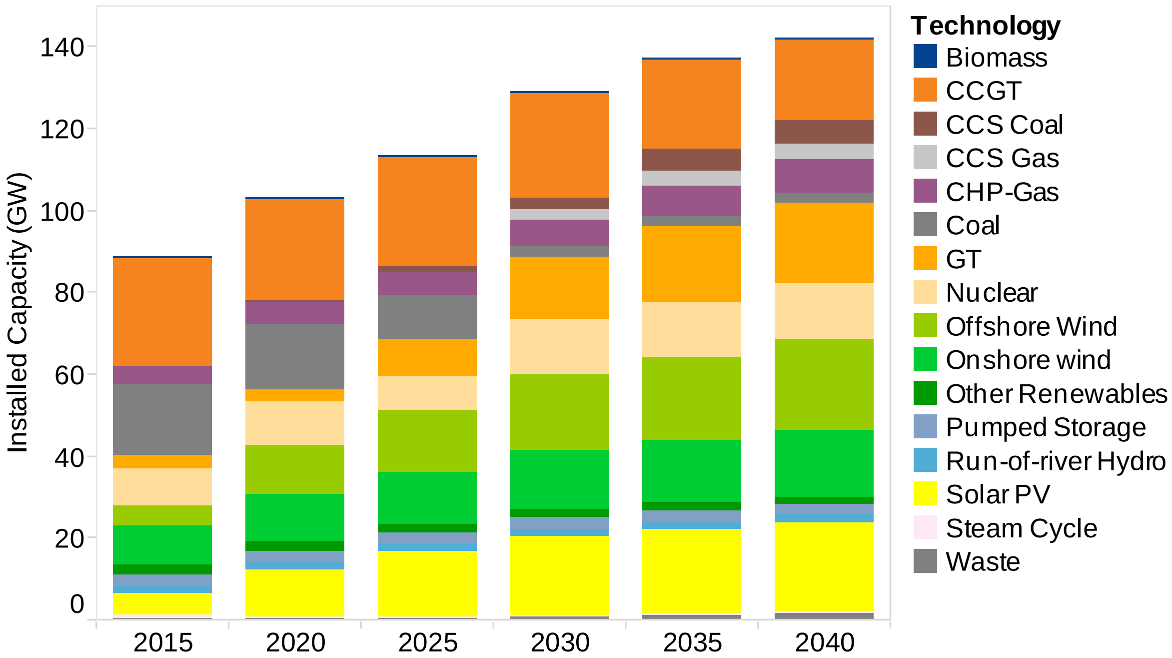
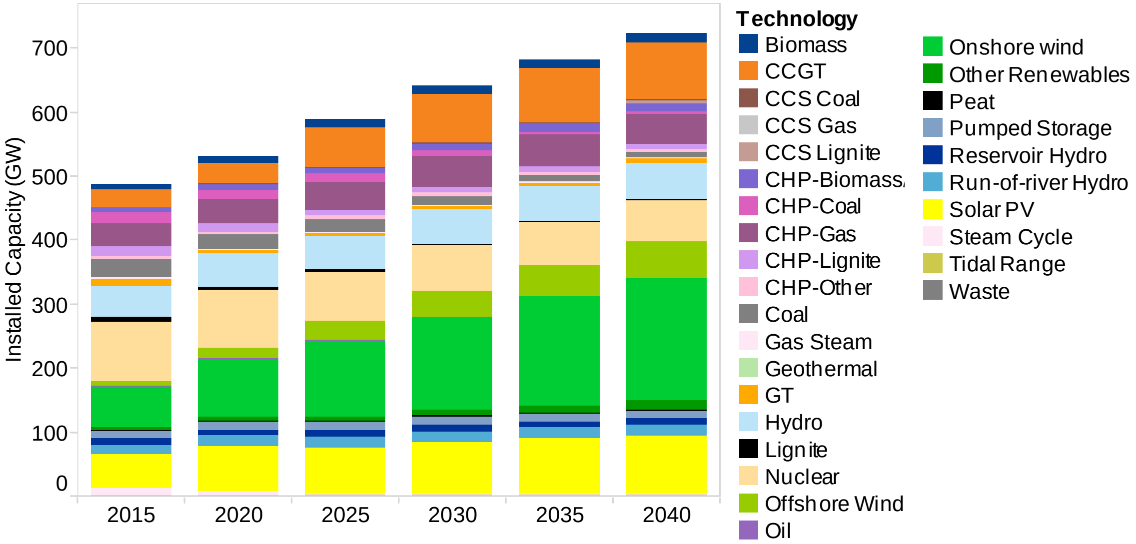


Figure 50 – Installed capacity in the High scenario in North West Europe (GW)



Capacity mix in the Low scenario

The Low scenario capacity mix for GB is based on the National Grid No Progression Scenario. Coal plants in Great Britain retire by the early 2020s but rapidly falling demand growth combined with renewable growth to 2020 lead to little requirement for new capacity before 2020. Beyond 2020 we assume that renewable growth stalls and that very few of the retiring nuclear plants are replaced. Any new capacity that is required is therefore largely to replace retiring capacity and is a mixture of CCGT and OCGT although CCGTs are favoured.

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:

- In Ireland, Belgium and France plants retire in the mid-2020's (coal plants in Ireland and France and nuclear in Belgium) but given the low demand, very little new build is required beyond the increases in renewables to 2020.
- In the Netherlands, demand is still growing slightly in this scenario and, combined with the retiring coal, there creates a need for small increases in gas capacity over and above the expansion of renewables to 2020. A similar story is seen in Germany where although demand is falling, retiring coal and nuclear plants do require some replacement by new gas-fired capacity.
- Denmark replaces coal with gas and biomass overtime and there is little change in Norway as it continues to rely on hydro.

The figures below show are installed capacity mix assumptions for Great Britain and the rest of the modelled regions in the Low scenario.

Figure 51 – Installed capacity in the Low scenario in Great Britain (GW)

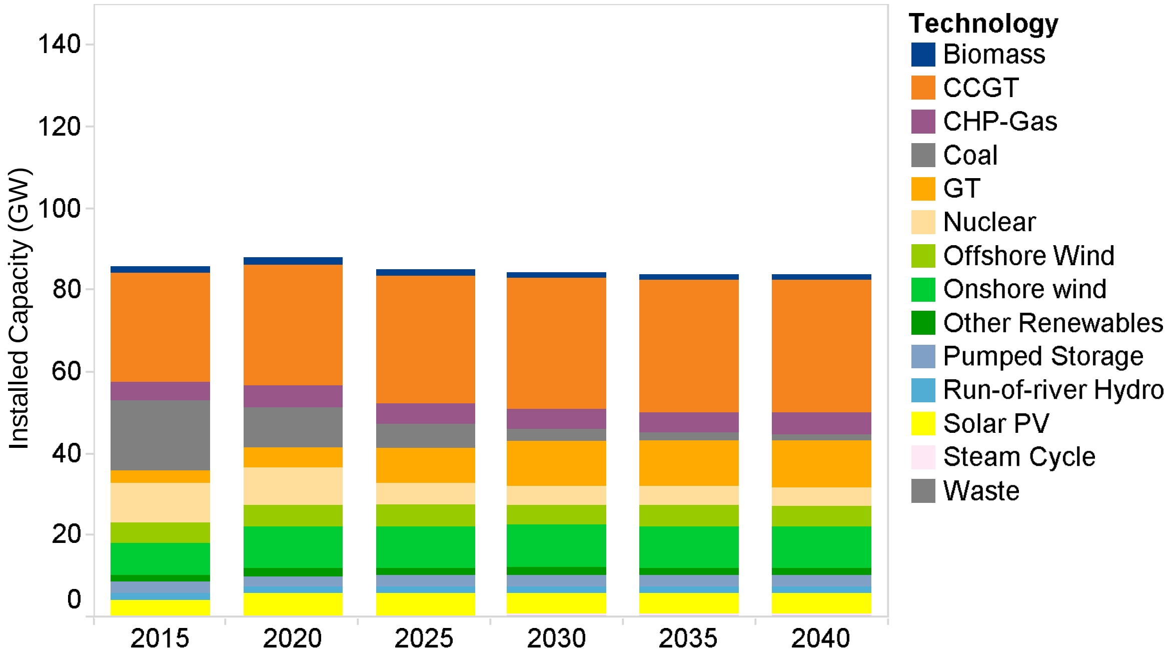
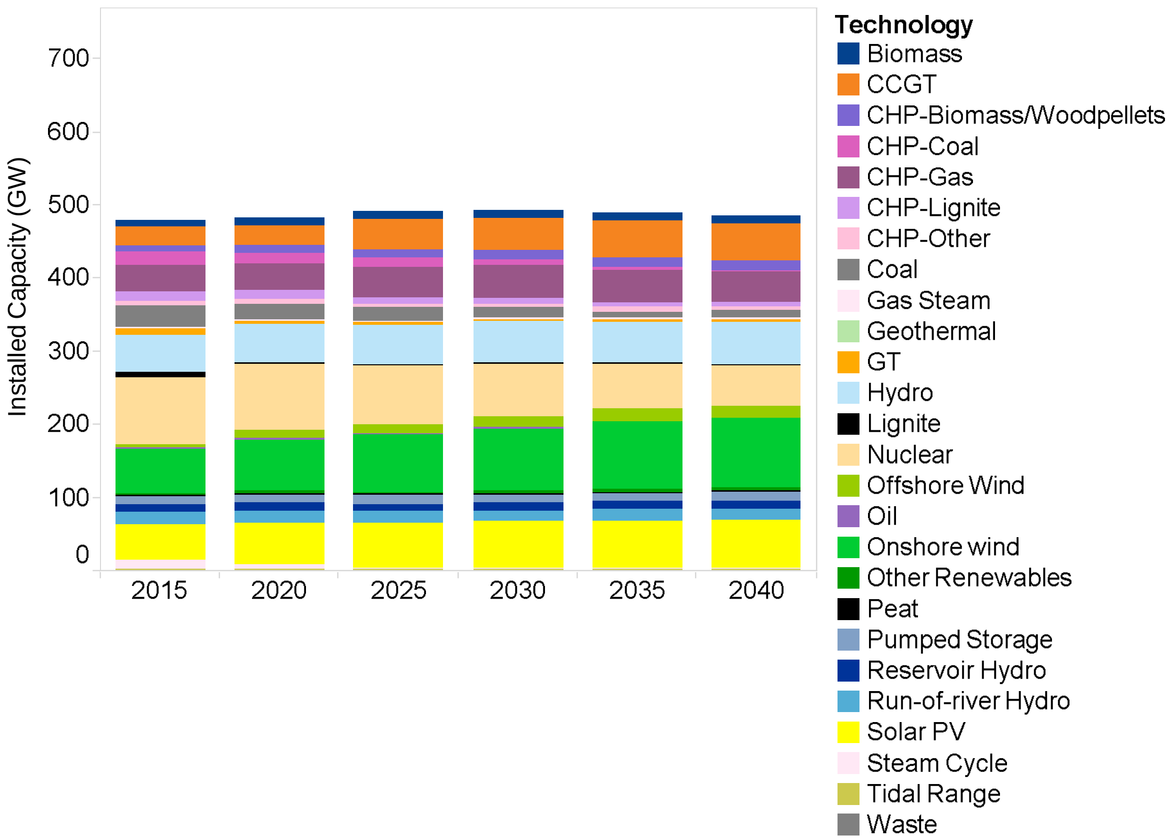


Figure 52 – Installed capacity in the Low scenario in North West Europe (GW)



C.3 Interconnection capacity

Table 4 lists our interconnection capacities for currently installed GB based interconnection capacity[22] for all three scenarios. We have assumed that this capacity is retained in all of our model scenario baseline runs.

Table 4 – Current GB Interconnection capacity assumptions (all scenarios)

Interconnector name	Connection with	Capacity (MW)
IFA	France	2000
BritNed	Netherlands	1000
East West	Ireland	500
Moyle	Ireland	450*
Total		**3950**

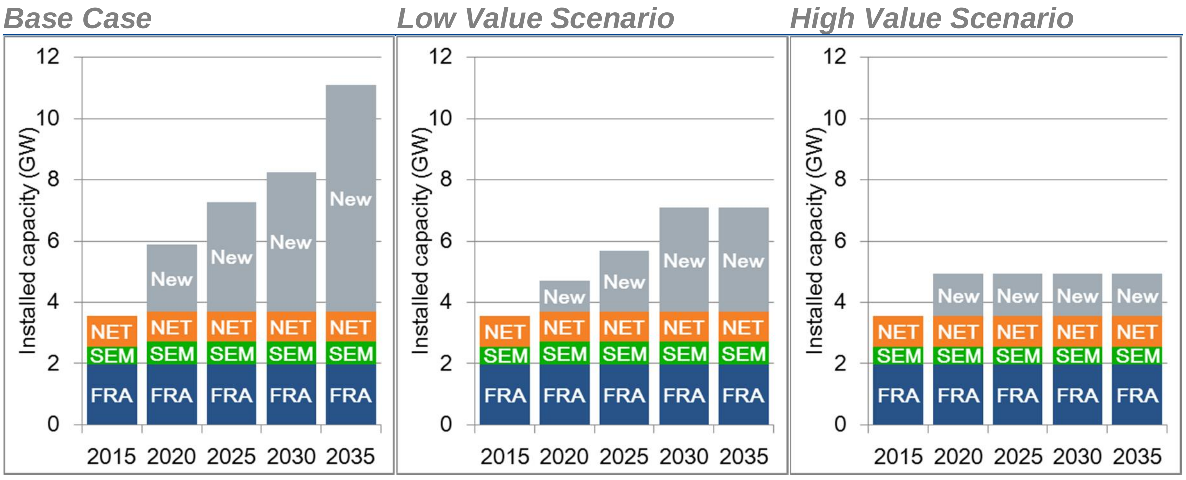
*Note: In the High scenario Moyle is kept at 250MW throughout in line with our assumptions for low levels of interconnection capacity in this scenario – see below.

In order to establish an internally consistent baseline for new build capacity in GB and in the rest of NWE, we have assumed that interconnection from GB to other countries is expanded in each of our core scenarios:

- In the Base Case interconnection capacity is assumed to increase in line with National Grid's Slow Progression scenario. This assumes a significant increase in capacity, such that new interconnectors commission between GB and France, Belgium, Norway, Ireland and Denmark, to reach a total of 11.2GW in 2040.
- High Scenario interconnection build is taken from the DECC High scenario to be consistent with the other capacity assumptions in this scenario. Despite the theoretically robust business case for new interconnection in the High Scenario, other concerns, for example by political, risk, revenue variability or supply chain considerations, are assumed to hinder commissioning with capacity expansion. This leads to relatively low increase in new interconnection in this scenario, with no new additional interconnection build after the currently planned Belgium and French expansion.
- In the Low scenario, the assumption for new build of interconnection capacity is taken from National Grid's No Progression Scenario, consistent with the demand and thermal capacity assumptions. In this scenario lower capital availability and a decrease in the absolute level of hourly price differences between countries leads to a low interconnector value and leads to lower interconnector build. In this scenario there is only limited capacity being built in Belgium, France and Norway.

22 We assume that wider NWE interconnection capacity expands in line with Pöyry's Q3 2014 assumptions in our three standard price projection scenarios.

Figure 53 – GB Interconnection capacity in the Base Case, High and Low (GW)



C.4 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 September 2013 Updated Energy and Emissions Projections. The scenario selected for the Base Case is DECC's Reference Scenario which is based on reference estimates of growth and fossil fuel prices. The scenarios selected for the High and Low scenarios are DECC's High and Low Price scenarios respectively which are designed to span a range of GB commodity price outcomes.

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 Q3 2014 projections. In all cases we have assumed a flat exchange rate of €1.18/£ and $1.59/£.

Figure 54 – Crude oil prices in Base Case, High and Low scenarios ($/bbl)

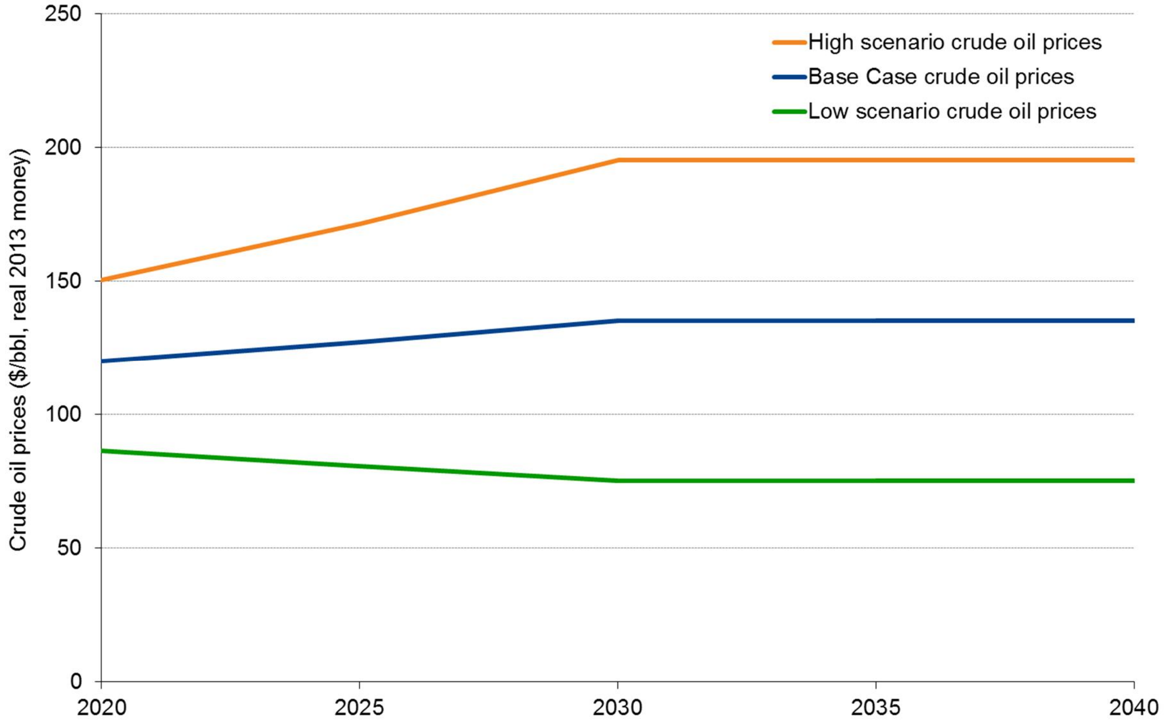


Figure 55 – ARA coal prices in Base Case, High and Low scenarios ($/tonne)

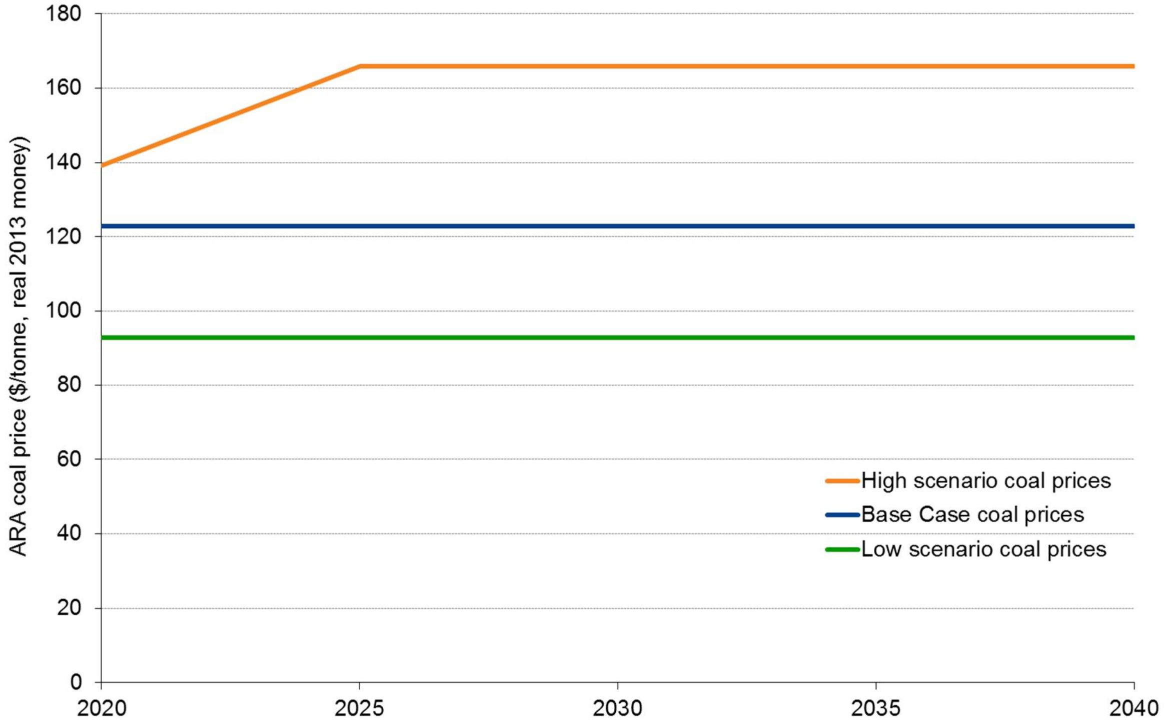
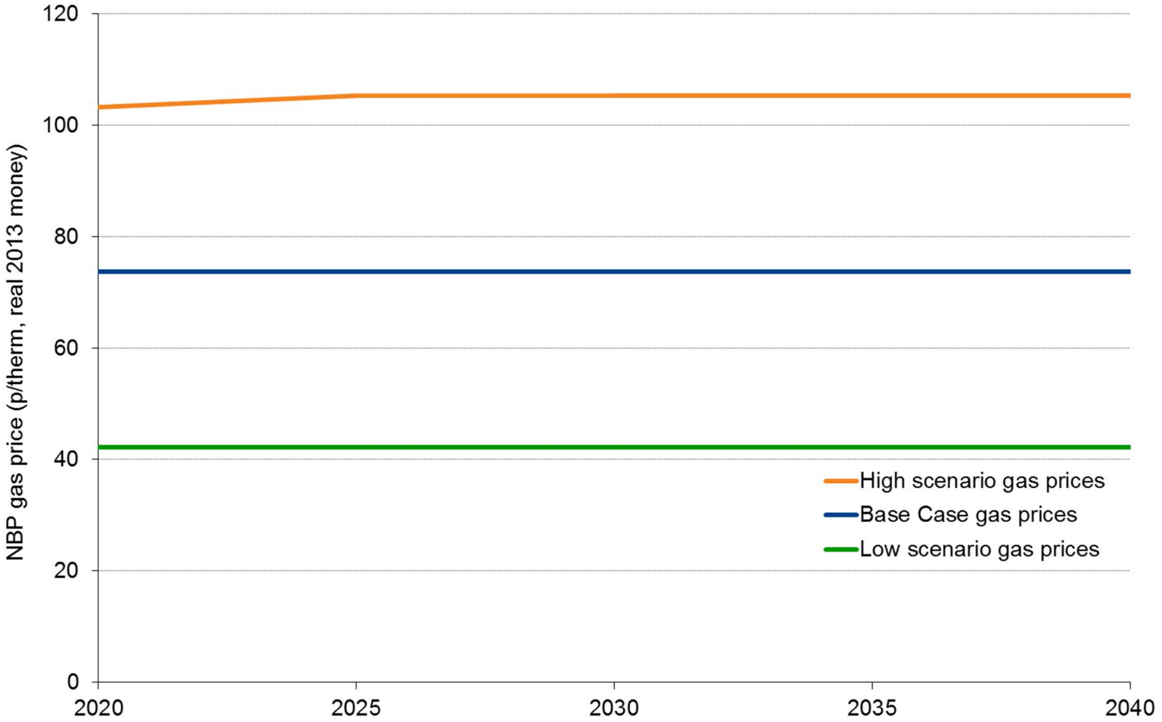


Figure 56 – NBP gas prices in Base Case, High and Low scenarios (p/therm)



C.5 The value of carbon

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 three modelled scenarios as none of the examined sources took into account the April 2014 budget announcements from the UK government regarding amendments to the carbon price floor.

EU ETS carbon allowances

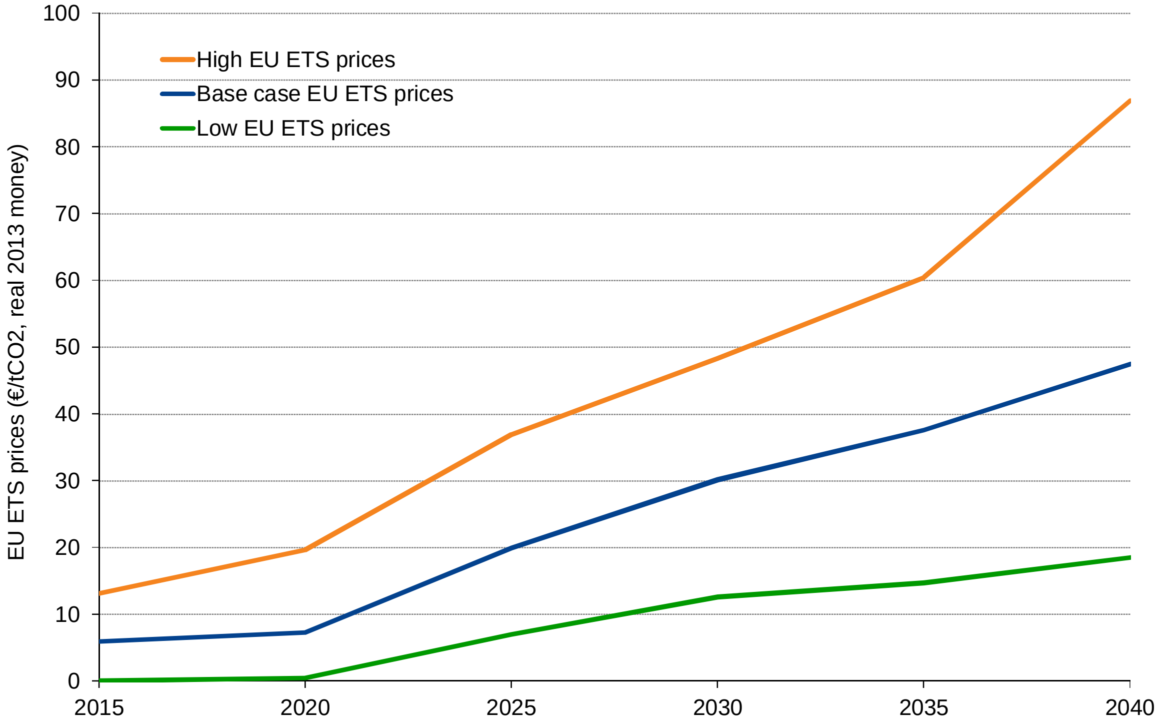
Pöyry's carbon model is used to derive projections of European Union Allowance (EUA) CO_2 credit prices.

Our **Low** and **Central** EUA price scenarios are consistent with the current requirement for a 20% reduction in EU Greenhouse Gases (GHG) over 1990 levels by 2020. Our **High** scenario takes account of ongoing discussions at EU level by assuming a more stretching 2020 EU GHG reduction target of 25%, with an equivalent decrease in emissions from EU ETS sectors. Beyond 2020, we assume that emission caps continue to tighten and are consistent with achieving a 71% emission reduction by 2050 in the **Low** and **Central** scenarios, and an 87% reduction by 2050 in the **High** scenario. The **High** scenario 2050 target is therefore consistent with the recently agreed tighter EC climate and energy proposals for 2030 whilst the **Central** and **Low** scenarios are consistent with pervious lower targets and plans for 'backloading' of allowances in the market[23].

Figure 57 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.
- In the **Central** scenario (used for the Base Case), medium-term prices are in line with the forward curve as the current uncertainty surrounding the 2020 and 2030 targets continues. Beyond 2020, although the move to the tighter proposed 2030 emissions target is never enacted in this scenario, increasing demand and a falling cap create scarcity in the market driving prices above €30/tCO_2 from 2030.
- In the **Low** scenario, prices fall quickly down close to zero as the market becomes very pessimistic on the prospects for successful policy intervention and the fundamental drivers of the current oversupplied market prevail. Prices do not recover at all until the 2020's and then only move above €10/tCO2 in the 2030s.

Figure 57 – EU ETS prices in Central, High and Low scenarios (€/tCO_2)



23 The tighter EC climate targets do not currently feature in our Central carbon price projections used in the Base Case as it has not yet been agreed how the associated targets on energy efficiency and renewable energy will be delivered by Member States. Adopting just one element of the new targets without consideration of others could lead to inconsistent carbon price forecasts.

UK Carbon Price Floor

HM Treasury (HMT) confirmed its intention to implement a carbon price floor in the UK in March 2011[24]. Under this scheme, generators will continue to pay for their emissions within the EU Emissions Trading Scheme (EU ETS), but they will 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 CPS rate for financial year 2013/14 has been set at £4.94/tCO_2; for financial year 2014/15 at £9.55/tCO_2; for 2015/16 at £18.08/tCO_2; and in March 2014, Budget 2014 set the rate for financial year 2016/17 at £18.00/tCO_2.

Due to concerns about the impact on the competitiveness of the UK economy and affordability, in Budget 2014 the UK Government capped the level CPS for financial years 2017/18 to 2019/20 at £18.00/tCO_2 (nominal money). The effect of the cap on 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 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 2018 to 2035.

- In our **Central** scenario (used in 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 2028. After 2028, 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 2035 at the 2020 target level of £34/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 £80/tCO_2 in 2030 (real 2013 money) when the rest of Europe pays around £22/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 due to continued economic pressure, a floor price significantly above the EU ETS price would be untenable over the long run. We therefore assume that the carbon price differential falls quickly such that by 2020 no carbon differential remains and all European generators face the same low carbon prices.

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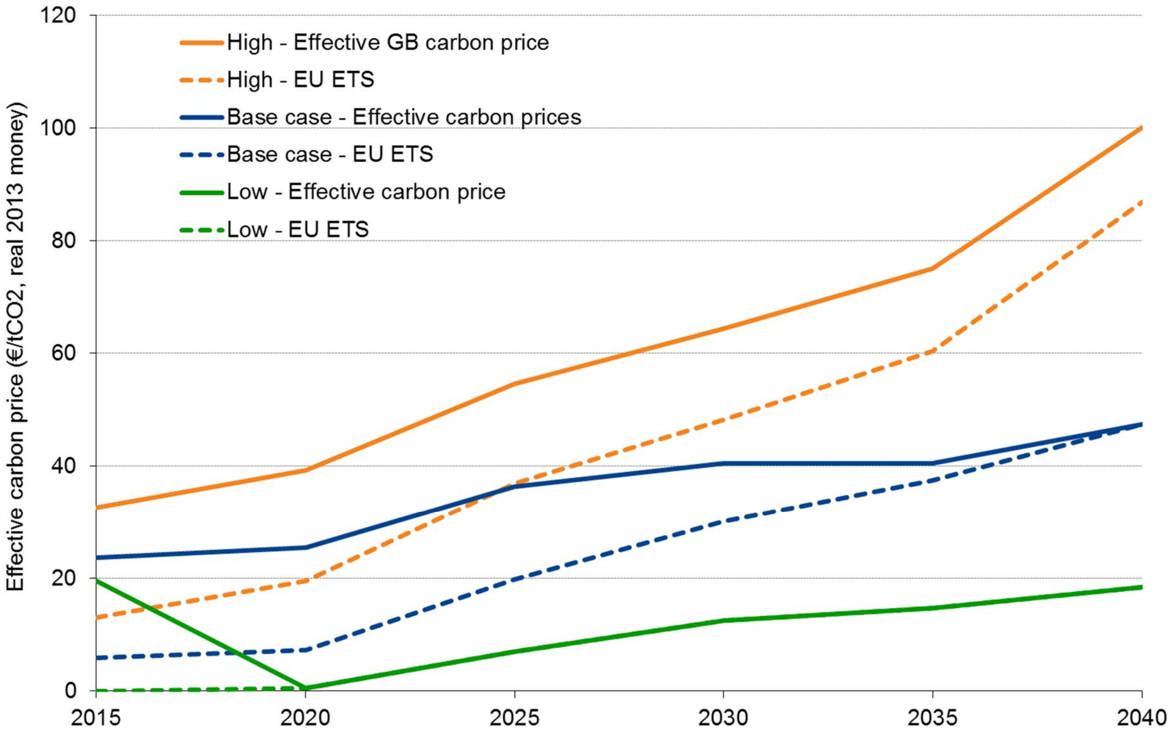
24 'Carbon price floor consultation: the Government response', HMT, March 2011.

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 58.

Figure 58 – Carbon price differentials (€/tCO2)



C.6 Selected Supply Curves for GB

Resulting example January supply curves for the Base Case in GB in 2020, 2030 and 2040 are shown in Figure 59, Figure 60 and Figure 61 respectively.

Figure 59 – GB Supply Curve: Base Case 2020 January Example Hour

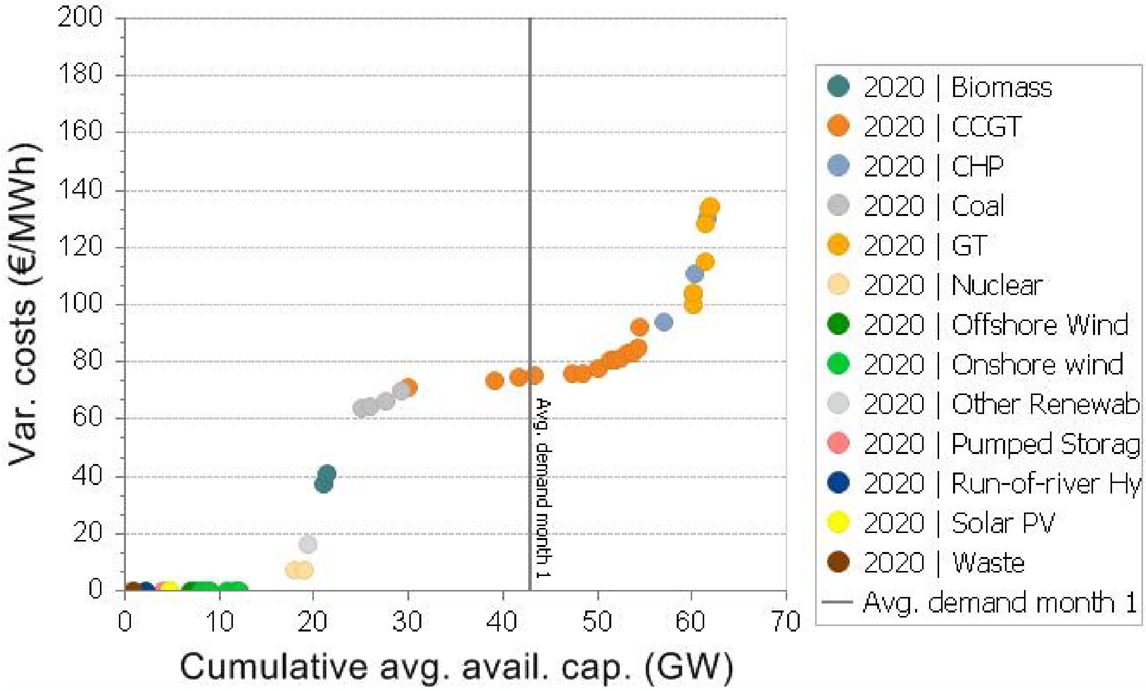


Figure 60 – GB Supply Curve: 2030 Base Case January Example Hour

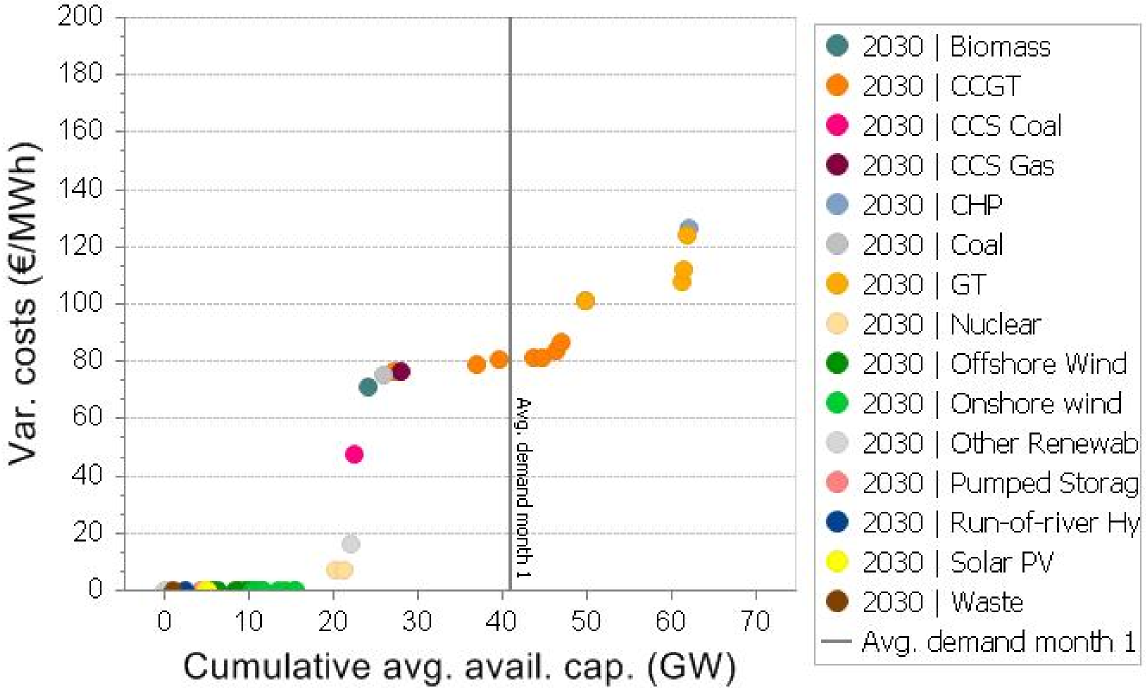
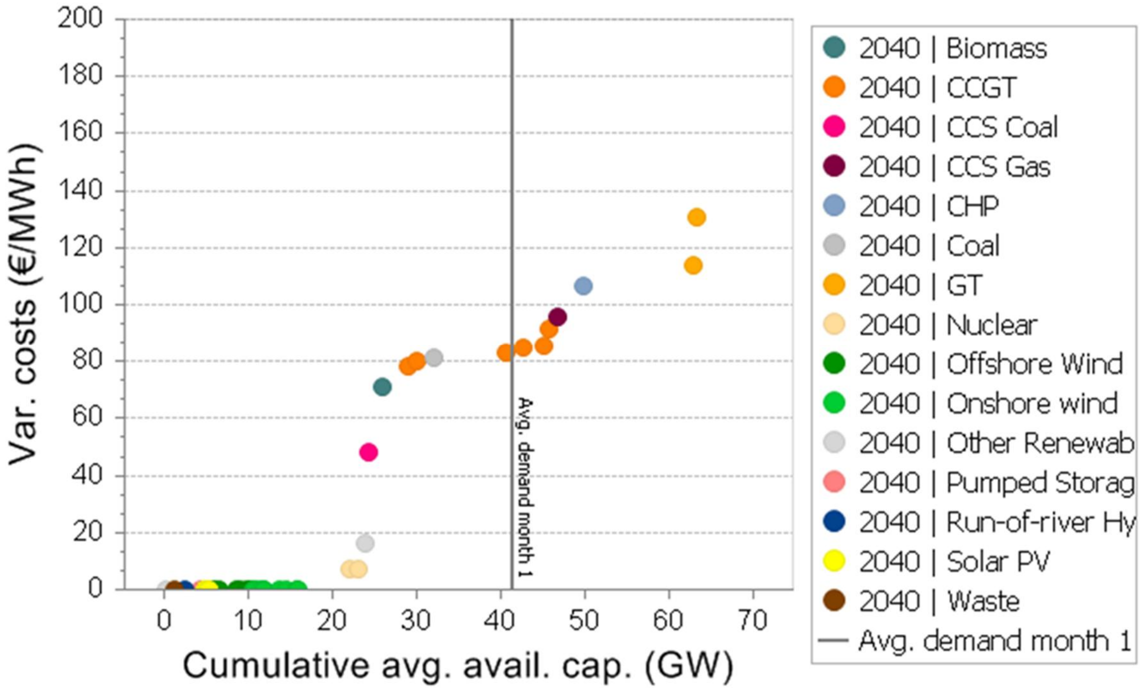


Figure 61 – GB Supply Curve: Base Case 2040 January Example Hour



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ANNEX D – CAPACITY MARKET MODELLING AND REVENUE ANALYSIS

Our general approach to capacity markets and the impact that they may have on interconnectors is discussed in 3.5.1 and 3.5.2 above. The introduction of a capacity mechanism may lead interconnectors to earn lower revenues from the energy market than they would in an energy only market – as the capacity market has a dampening effect on wholesale prices lower hourly price differentials may result leading to lower congestion rents. However, the interconnector may be able to earn additional revenue from direct participation in the capacity mechanism itself.

This Annex describes our modelling of the GB capacity market; our modelling of other NWE capacity markets; and the results of our sensitivity analysis on the impact of capacity market participation on interconnector revenues and social welfare.

D.1 GB Capacity Market

The introduction of a Capacity Market is a key component of the government's EMR proposals. With significant amounts of capacity due to close in the next decade, and the expected increase in intermittent generation by 2020 potentially reducing the operating hours of mid-merit plant, its introduction is intended to ensure that there are sufficient incentives on capacity providers in order to maintain an adequate security of supply.

The aim of the 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 will be 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.

With the first auction due to be held on 16 December 2014[25] (for delivery of capacity from 1 October 2018 to 30 September 2019 (i.e. four years ahead), the governing legislation of the Capacity Market has been advanced quickly in recent months and comprises the Energy Act 2013 (Royal Assent on 18th December 2013), the Electricity Capacity Regulations 2014 (enacted on 31st July 2014) and the Capacity Market Rules (re-published with amendments on 22nd August 2014).

Interconnectors will not be able to participate in the first auction in 2014 but current indications are that DECC will allow them to bid into the market from 2015 onwards. However, there is still considerable uncertainty on the value of the scheme to an interconnector owner due to:

1. Remaining policy risk, in part due to the need to create a mechanism that is compatible with EU Target Model arrangements.
2. If interconnectors are allowed to participate, what proportion of the total capacity will be allowed to earn revenue in the market – the percentage by which the total capacity is downgraded is referred to as the de-rating factor.

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25 In addition, auctions will be held one year ahead of delivery for demand side response (including embedded generation and smaller storage), with the first auction in 2015.

3. Clearing prices in the auction – price can clear at any level from €0/kW up to a cap of ~€90/kW[26] and will vary by year. The clearing price in a given year will be strongly influenced by the underlying need for new capacity – if little or no new capacity is required it is likely that the clearing price will be much lower. The maximum price we would see in a market that required no new or refurbished capacity is set by the price taker threshold of €30/kW. On average we project that, from 2020 onwards, the GB capacity market auction will clear at around €45/kW in Pöyry's standard Central scenario with a range of ~€30 to ~€75/kW under Pöyry's Low/High scenarios.
4. Uncertainty over the length of time the mechanism will operate – DECC outlines that it expects the Capacity Market to be required for at least 10 years, once implemented. However, it outlines its intention to review the need for a Capacity Market every five years, highlighting that they may feel it right to abolish the Capacity Market in future if the underlying electricity market develops sufficiently (particularly through improvements in market liquidity, an active demand side and more interconnection).

It should be noted that while participation in a capacity mechanism improves the interconnector business case and makes it less likely to hit any revenue floor levels. However, in principle it is largely a transfer of welfare (from producers/generators to interconnector owners[27]) and as such should not significantly impact the overall net welfare case of the interconnector.

Due to the uncertainties surrounding the ability of interconnectors to derive revenue from this (and other) capacity mechanisms we do not include capacity mechanism revenues in our base assessments of interconnector revenues and CBA analysis. Rather we have treated these revenues separately, as an upside and shown separately in the CBA sensitivity analysis.

However, as we assume the capacity mechanism will be operational whether or not interconnectors can participate, we have included the impact of the GB capacity mechanism on wholesale prices in GB in all of our market scenarios. We have also assumed that capacity markets are operational in selected other countries in Europe, summarised in the section below.

D.2 Capacity Markets in NWE

Capacity markets are currently in existence in a number of European countries including Ireland and Spain. However, in addition to the introduction of a GB capacity market, there are increasingly solid plans that capacity mechanisms will be adopted in many Continental European countries, with advanced plans in France and Italy, and debate in Germany.

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26 £75/kW in real 2012 prices: http://www2.nationalgrid.com/UK/Our%20company/Electricity/Market%20Reform/Announcements/Capacity%20Mechanism%20Auction%20Guidelines/

27 This assumes that the impact of the interconnector bidding into the capacity market means that the equivalent volume of alternative capacity is therefore unsuccessful. Assuming that the resulting price in the auction does not change, this simply results in a transfer of wealth from the owner of the alternative capacity to the owner of the interconnector (and thereafter potentially to consumers via the cap and floor mechanism)

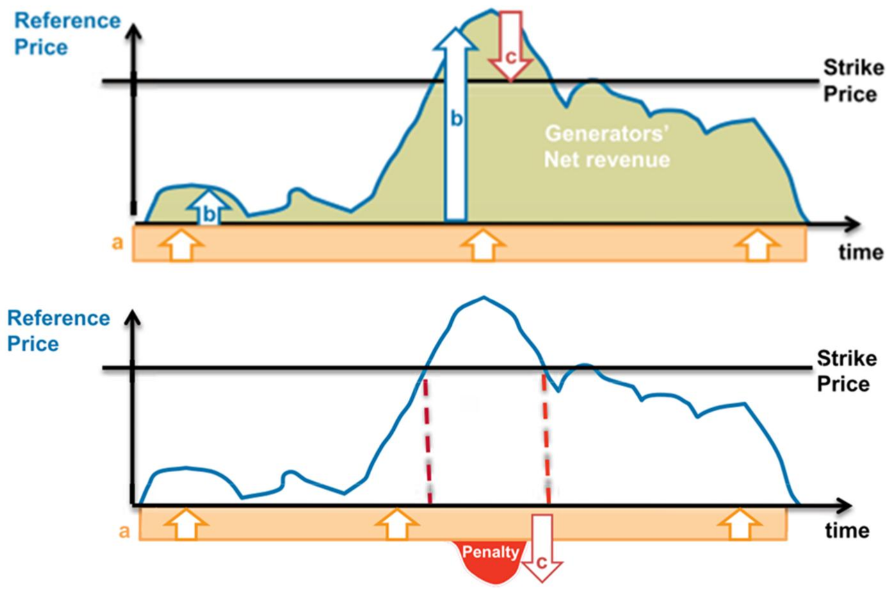
D.2.1 Ireland

Ireland has operated with a capacity mechanism since the inception of the Single Electricity Market (SEM) in 2007. Under the SEM Committee's I-SEM project, which is focused on the integration of the SEM with neighbouring markets in accordance with the European Target Model for electricity, the design of the current capacity payments mechanism has been reconsidered. The SEM-C's proposed decision is that the I-SEM will have a CRM and that it will take the form of a Reliability Option (RO).

Essentially a Reliability Option (RO) is a one way CfD issued by a centralised party to all successful bidders in a competitive auction. ROs have a strike price and a reference price. If the reference price goes above the strike price the holder of the RO pays the difference back. The RO holder receives an option fee, set in a competitive auction which acts as an additional payment over and above the energy price. Therefore, an RO is a call option that requires a plant to be generating when the system is stressed. Figure 62 shows an example of how an RO works; the holder receives a regular fixed payment (a), and revenue from the existing electricity market (b), but makes a return payment (c) when the reference price goes above the strike price.

It is expected that secondary trading will allow participants who are successful in the initial auction to trade their obligations to another party before RO commencement date. This will allow a more efficient overall solution in which participants can trade obligations should a lower cost project become available or where permitted or unexpected outage etc. become an issue for a party which has issued an RO.

Figure 62 – Example of a Reliability Option



Source: Annex C – Consultation on possible models for a Capacity Mechanism, DECC, 12 July 2011

In principle we would expect that an interconnector in Ireland could earn payments under the currently proposed Reliability Option approach. However, the ISEM proposal is currently under consultation and therefore some policy risk remains. In addition, there is significant market risk as it is unclear both:

1. at what price the Reliability Option auction will clear – current Q3 2014 projections are that the average clearing price will be around €70/kW in the Central case, although we regard this as highly uncertain given the status or the capacity market proposals and setup of the SEM; and
2. what percentage of the overall capacity of the interconnector could, on average receive payments under the Reliability Option Approach (i.e. what de-rating factor should be applied to an interconnector bidding into the Reliability Option auction).

In line with the approach taken for the GB capacity mechanism we have not included Irish capacity payments for interconnectors in our base CBA analysis but rather present them as a separate potential revenue element for the Greenlink interconnector in our sensitivity analysis.

D.2.2 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. 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 final decree determining the main layout was approved in December 2012 and RTE (the French TSO) released its latest proposals for approval by the energy ministry and the energy regulator on 10 April 2014. Prices for capacity certificates are highly uncertain at present due to uncertainty in both market operation and future capacity requirements in France. In our Q3 2014 scenario modelling prices average €60/kW in the Central, €40/kW in the Low and up to €100/kW in the High.

The revenues earned by generators will depend on their eligibility and ability to participate in the energy market and earn capacity revenues from the capacity obligation mechanism. For thermal plants, such as CCGTs, the additional revenue stream from the capacity obligation will be a key factor in establishing a commercially viable operation of these plants.

Current indications are that interconnectors will not be eligible for the initial capacity obligation period. Although eligibility criteria may change in the future, there appears to be significant policy based **eligibility** risk around interconnector income streams from the French capacity mechanism. In addition, connections to GB, where higher prices in GB generally imply a flow away from France, suffer from further risks around the **ability** of new GB interconnection to reliably contribute to capacity margins in France. Although not necessarily the case during system stress periods, these eligibility and ability issues create significant uncertainty as to the reliability of French capacity payments as an income stream for IFA2 and FAB Link.

We include the downward impact of the French capacity mechanism on French wholesale prices due to the erosion of scarcity rent from the relevant energy market in all scenarios. However, in light of the above described uncertainty, and in line with the approach taken for the GB capacity mechanism we have not included French capacity payments for interconnectors in our base CBA analysis. We instead present them as a separate potential revenue element for the FAB Link and IFA2 interconnector as part of the sensitivity analysis on the interconnector.

D.2.3 Capacity markets in wider European countries

There are increasingly solid plans that capacity mechanisms will be adopted in many Continental European countries. In addition to those presented above for GB, Ireland and France (the interconnected countries), there are relatively advanced plans in both Germany and Italy. Where such capacity markets are planned, we have accounted for these in our wholesale market projections via the capacity margins and wholesale prices that we have modelled.

We have not assumed any capacity income for the modelled interconnectors through these schemes, and any price and CBA impact is indirect.

D.3 Sensitivity Analysis: Capacity Market Interconnector Revenue Impact

Under our core modelled scenarios we have assumed that no interconnectors receive any form of capacity payments under the proposed European capacity mechanisms due to the current widespread uncertainty in their eligibility and ability to receive revenues.

Very broadly if an interconnector may participate in one or more capacity mechanisms it will increase the project revenues thereby decreasing the likelihood of support payments by consumers (and increasing the likelihood of payments to consumers above the cap). It will have no impact on the overall total welfare, and only very minor impact on the distribution of welfare between stakeholders and countries.

D.3.1 and D.3.2 show sensitivity analysis of the impact on the project business case of each of our modelled interconnectors from the addition of varying levels of capacity payments. All modelling shown in this annex is conducted using the MA build profile approach, but similar results would be expected in the FA case.

The key messages from the capacity payments sensitivities are (mainly referring to the average capacity payments sensitivity (described in section D.3.1):

- **For the interconnector business case, Capacity Market (CM) presents an upside**

  CM revenues decrease the risk of projects requiring floor payments. In particular for NSN and Viking Link, which are close to the floor in certain years in the Base Case, this risk would be much reduced by allowing projects to bid into the GB capacity market.

- **For Greenlink, CM appears essential to the business case**

  In the Base Case, Greenlink is consistently below the floor. When including CM revenues, the total project revenues are close to or above the cap.

- **For interconnectors participating in two capacity markets, the impact on overall GB welfare is minor**

  For the French projects (IFA2 and FAB Link) and Greenlink, CM participation in both markets presents a slight upside to overall GB welfare, as capacity market clearing price in the connected market is assumed to be higher than the GB capacity market clearing price.

- **Where the interconnector is only participating in one CM, this leads to a net transfer of welfare out of the country offering that CM**

  The revenue from the capacity markets are accrued to the interconnector, and therefore split between the two countries. As there are no CMs in Norway and Denmark, the GB capacity revenue NSN and Viking Link capture gets split between the countries. In these cases, this transfers wealth out of GB (from GB producers to the IC owners). However, the cap and floor mechanism means that GB consumers are benefited by the IC participation in the CM by lower floor payments and or higher cap payments across the core scenarios.

D.3.1 Capacity payments sensitivity 1: Average capacity payment levels

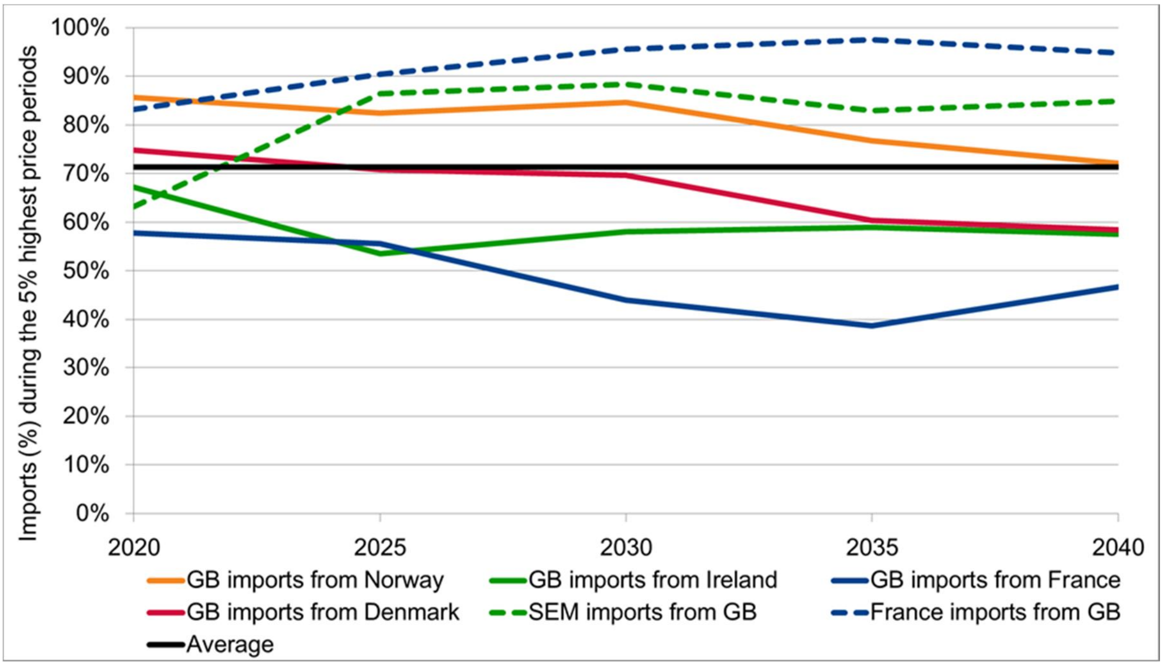
In our first sensitivity we have taken the following assumptions to model potential capacity payments to each interconnector:

1. The capacity mechanisms in GB, Ireland and France are assumed to clear at the Central 'average' level from Pöyry's Q3 2014 modelling, that is:
   - €45/kW in GB;
   - €70/kW in Ireland; and
   - €60/kW in France.
2. An interconnector is assumed to receive capacity payments for the level of capacity that is importing in the highest price 5% of hours in that country (i.e. it is de-rated for any high price periods in which interconnectors are exporting). For simplicity we have taken all these de-rating factors as constant across all interconnectors in all years based on the Base Case (de-rated to 70%) but note that they could vary by interconnector and scenario as indicated in Figure 63.
3. If an interconnector joins two markets which both have capacity markets it is assumed to be able to participate in both but only up to a maximum combined rating of 100% of the total capacity. For anything over 100% the capacity is de-rated equally on each side of the interconnector

Based on the above broad rules we have assumed that NSN and Viking have a 30% de-rating factor (i.e. 70% of capacity is allowed to bid in). For French and Irish interconnectors, which could be are involved in two capacity mechanisms, we have de-rated the capacity by 50% on each side. These de-rating factors are indicative only as conditions under which interconnectors may be able to participate in CMs across Europe as well as de-rating methodologies that may be used are currently highly uncertain as outlined in section 3.5.

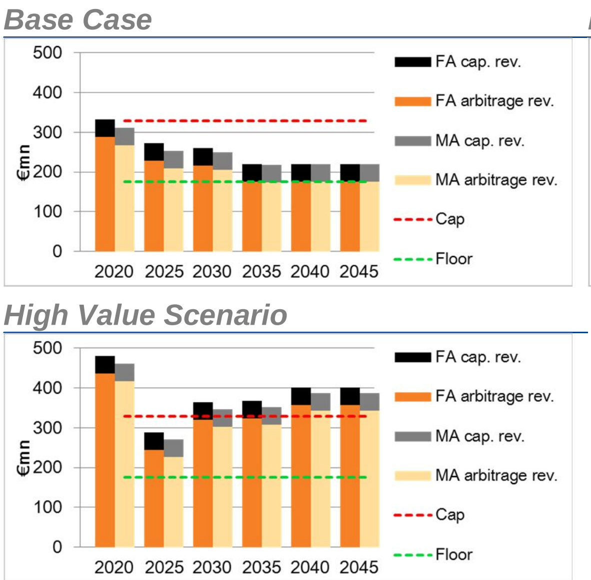
Figure 63 shows the capacity rating as calculated for each interconnector (i.e. 1 minus the de-rating factor) derived by calculating the import percentage during the 5% highest price periods and the calculated average across all interconnectors.

Figure 63 – GB capacity rating for each interconnector in each year



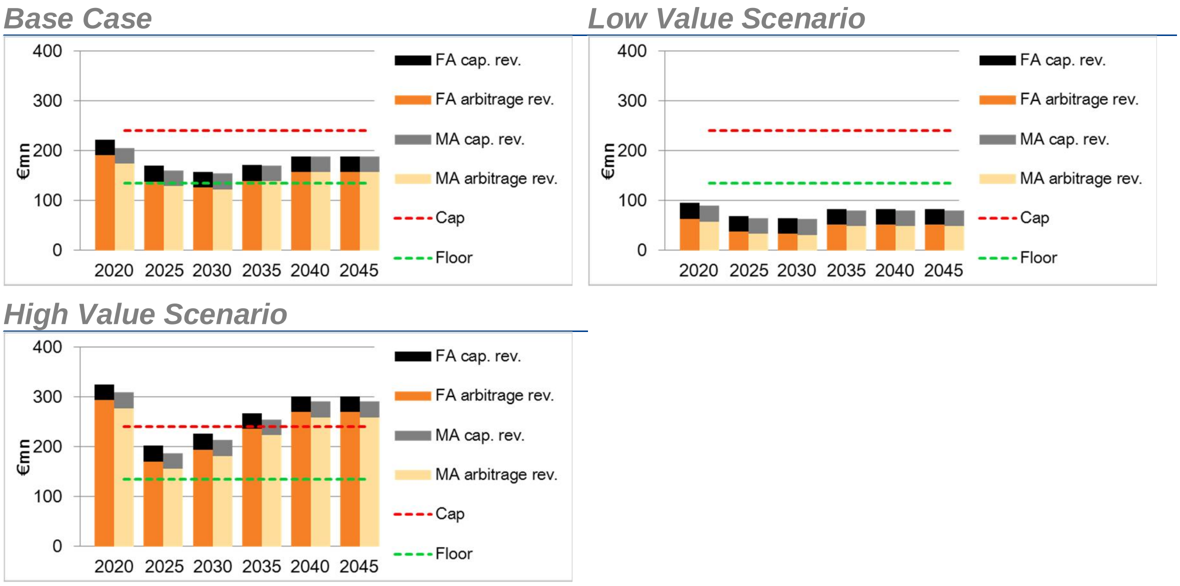
The resulting arbitrage revenues in the Base Case, High and Low scenarios (MA only, the capacity market revenues do not differ between MA and FA) are shown in Figure 64 to Figure 68. Where the impact on revenues and cap and floor payments is significant, commentary on these results is included in Chapter 4 within the corresponding interconnector sections.

Figure 64 – Revenue sensitivity for NSN: Average capacity payments



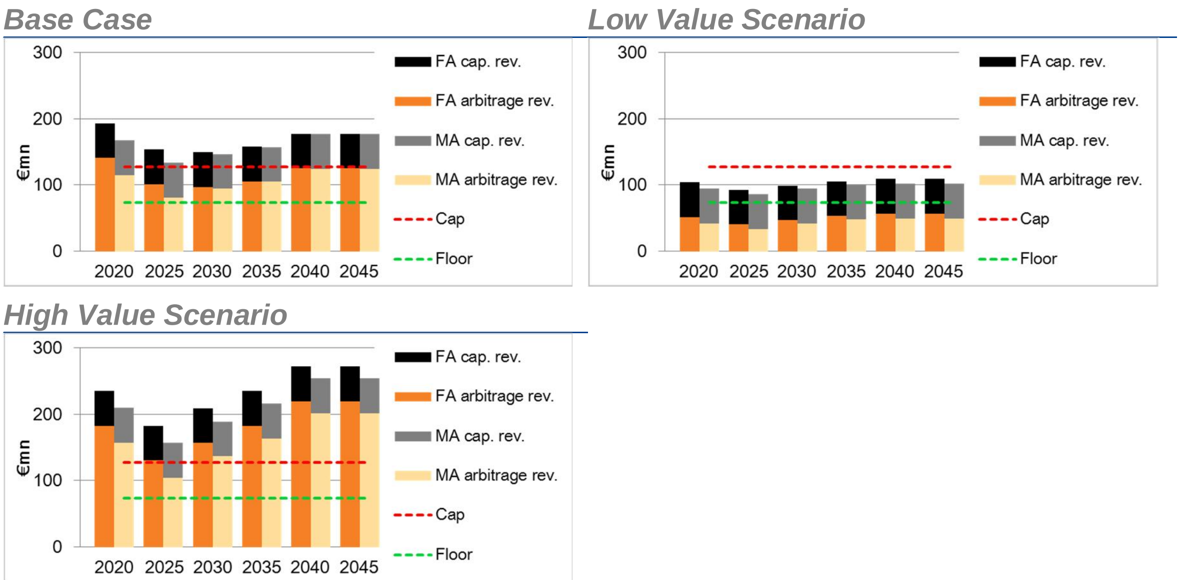
Source: Pöyry Management Consulting modelling for Ofgem

Figure 65 – Revenue sensitivity for Viking Link: Average capacity payments



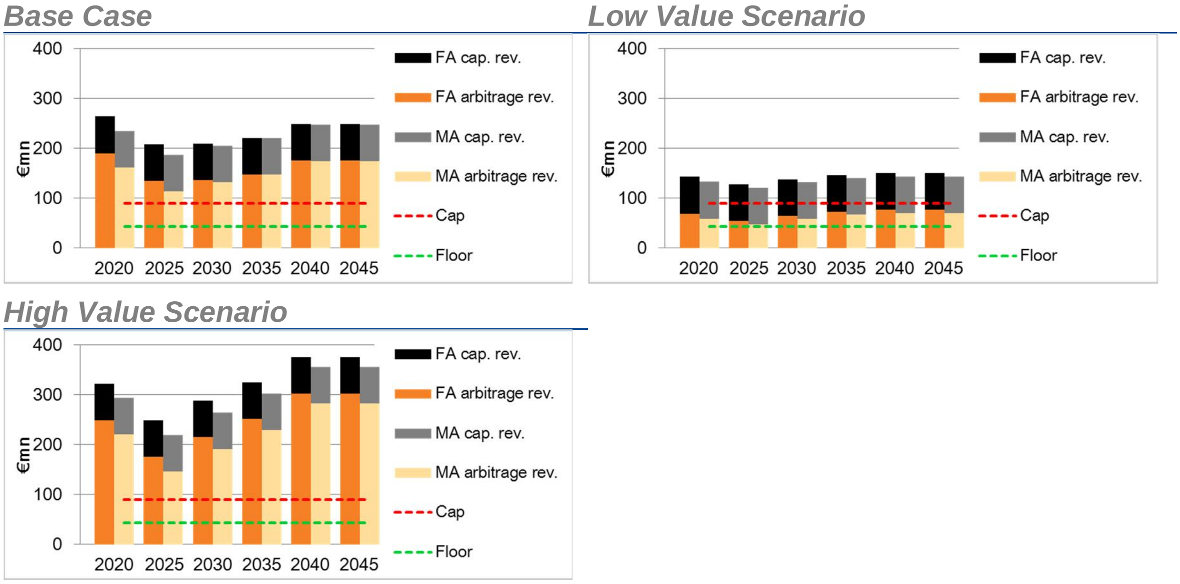
Source: Pöyry Management Consulting modelling for Ofgem

Figure 66 – Revenue sensitivity for IFA2: Average capacity payments



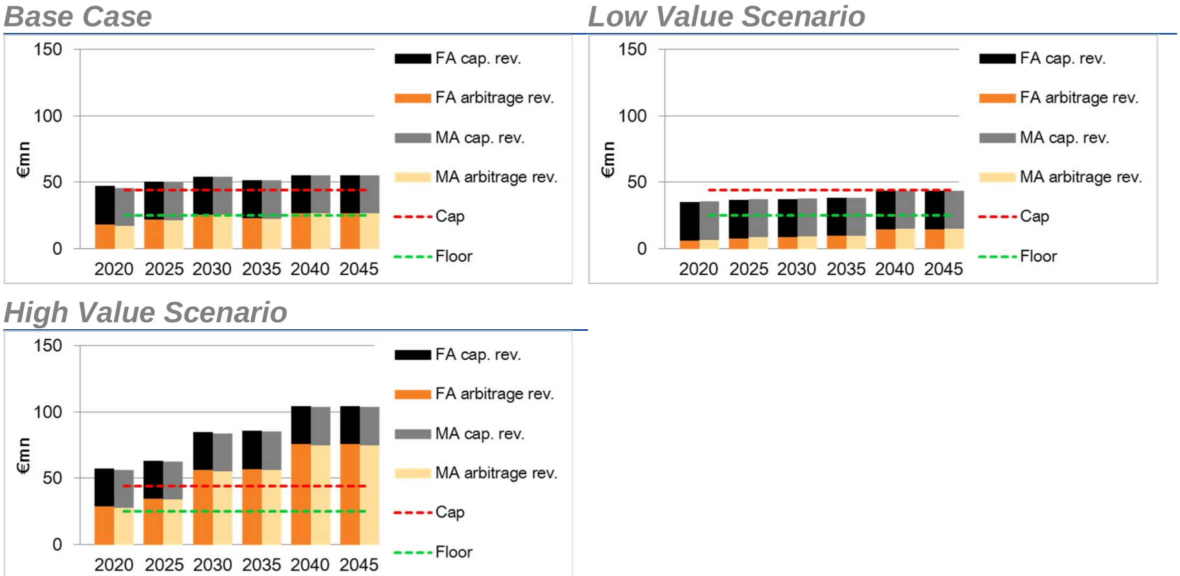
Source: Pöyry Management Consulting modelling for Ofgem

Figure 67 – Revenue sensitivity for FAB Link: Average capacity payments



Source: Pöyry Management Consulting modelling for Ofgem

Figure 68 – Revenue sensitivity for Greenlink: Average capacity payments



Source: Pöyry Management Consulting modelling for Ofgem

D.3.2 Capacity payments sensitivity 2: Downside over capacity payment levels

It is possible in a capacity market to see significant over procurement of capacity by the procuring party in a given year as capacity is usually procured a number of years ahead of time. Generally this will be because either:

- outturn demand much lower than was projected; or
- because more capacity is available than was assumed – e.g. interconnectors provide much higher levels of reliable capacity than was assumed in their de-rating factors.

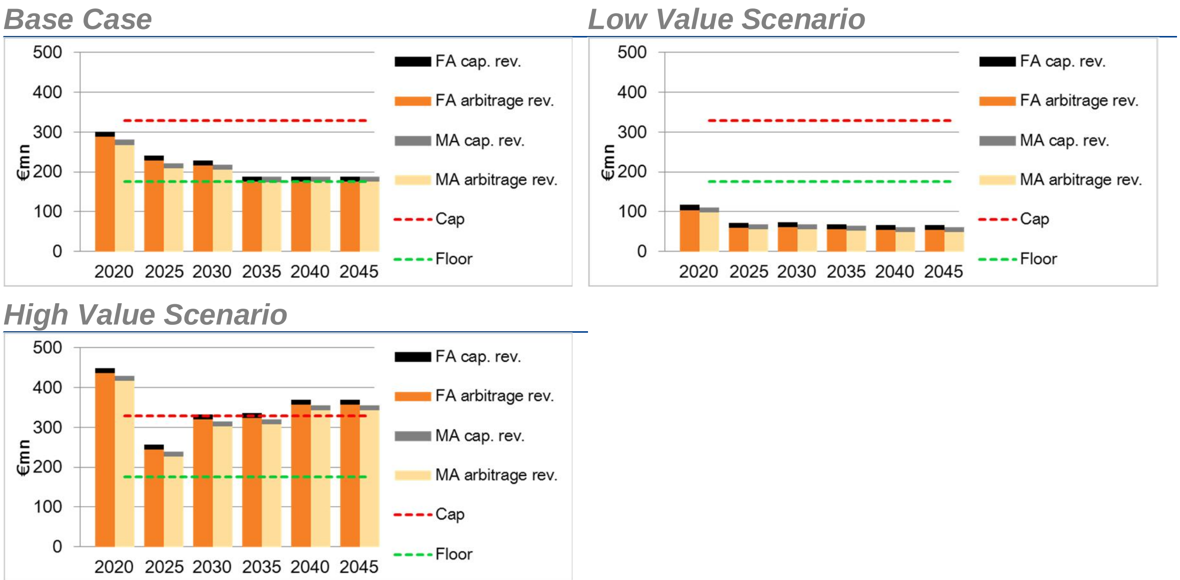
In this case we could expect see a ‘crash’ in the price of the capacity mechanism for subsequent auctions down to the levels associated with net avoidable costs (NAC) of existing plants on the system. Whilst the calculation of NAC is complex, and depends on revenues derived by power stations elsewhere, it is generally assumed that such a situation would lead to much lower prices in capacity auctions than in markets that need to incentivise new entry.

To model this over downside over capacity payment we have taken the following approach:

1. The capacity mechanisms in GB, Ireland and France are assumed to clear at 1/2 of the Central ‘average’ level from Pöyry’s Q3 2014 modelling, that is:
   – €22.5/kW in GB;
   – €35/kW in Ireland; and
   – €30/kW in France.
2. An interconnector receives capacity payments for only half of the capacity it was allocated under the first sensitivity. That is to say all de-rating factors are doubled such that the maximum capacity is 50% of the total (ICs participating in one CM are de-rated by 60% instead of 30%, ICs participating in two CMs are de-rated by 75% instead of 50%).

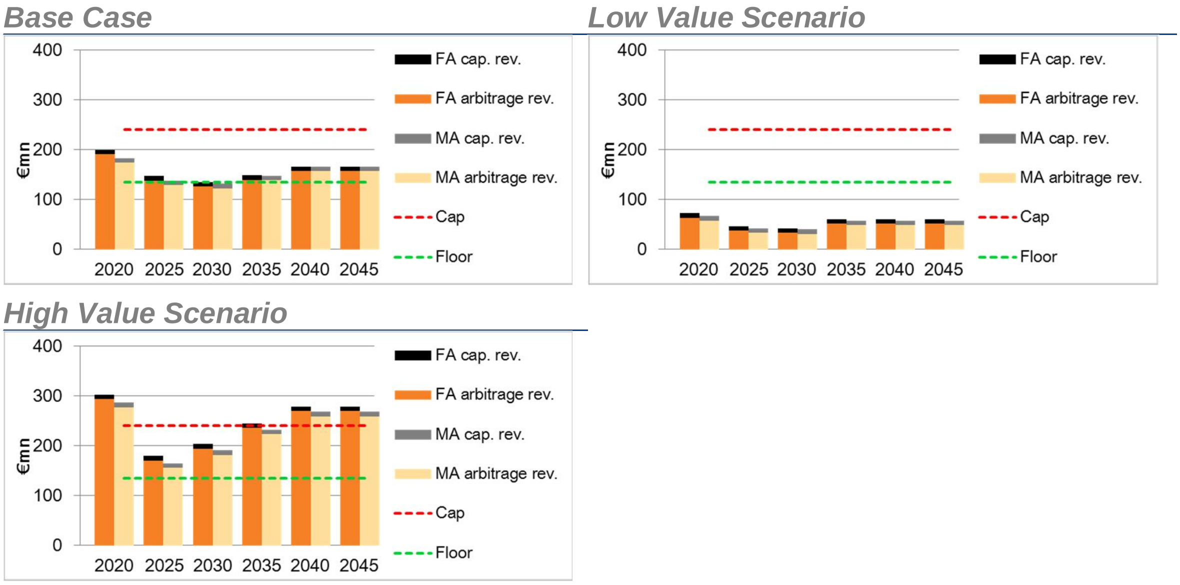
Capacity payment revenues in such an over capacity situation are much lower than those assuming full capacity mechanism payments. The resulting downside capacity market revenues for each interconnector in each modelled scenario are shown in Figure 69 to Figure 73 below. Where the impact on revenues and cap and floor payments is significant, commentary on these results is included in Chapter 4 within the corresponding interconnector sections.

Figure 69 – Revenue sensitivity for NSN: Downside capacity payments



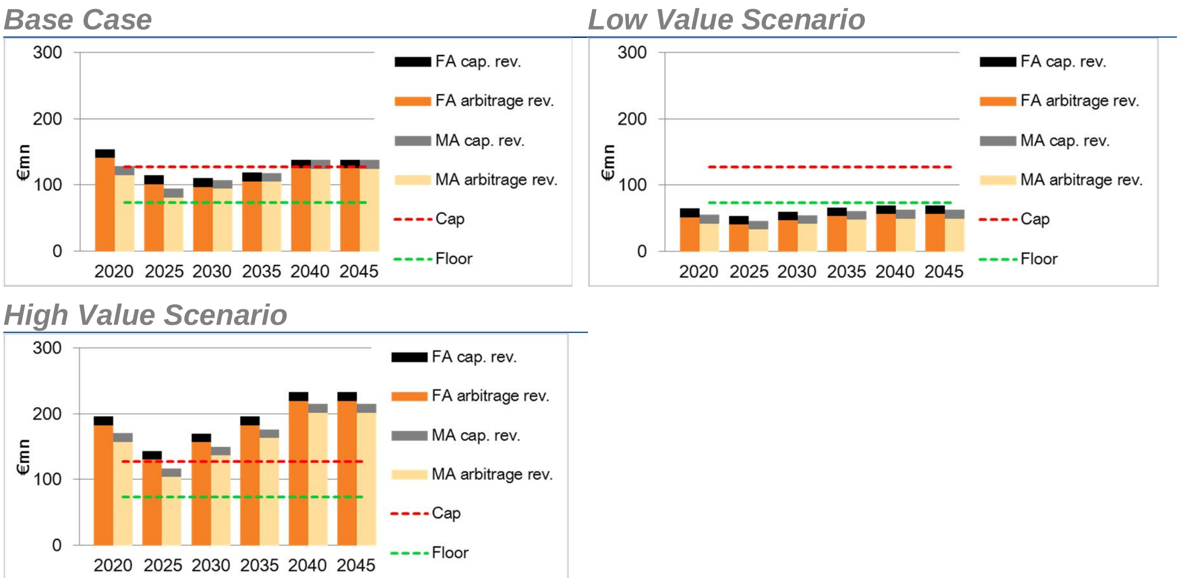
Source: Pöyry Management Consulting modelling for Ofgem

Figure 70 – Revenue sensitivity for Viking Link: Downside capacity payments



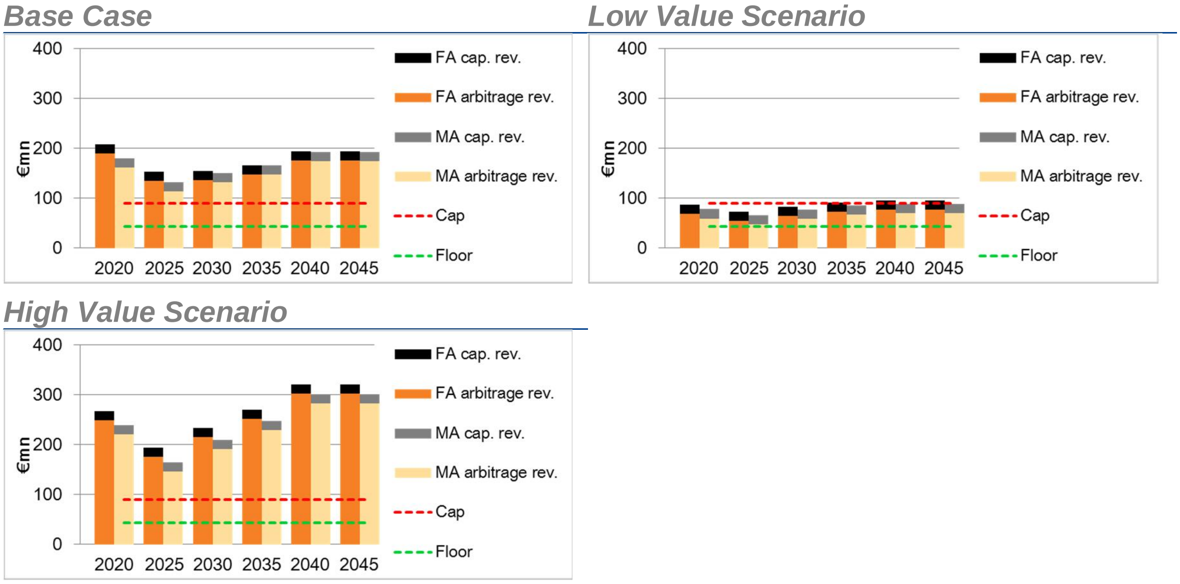
Source: Pöyry Management Consulting modelling for Ofgem

Figure 71 – Revenue sensitivity for IFA2: Downside capacity payments



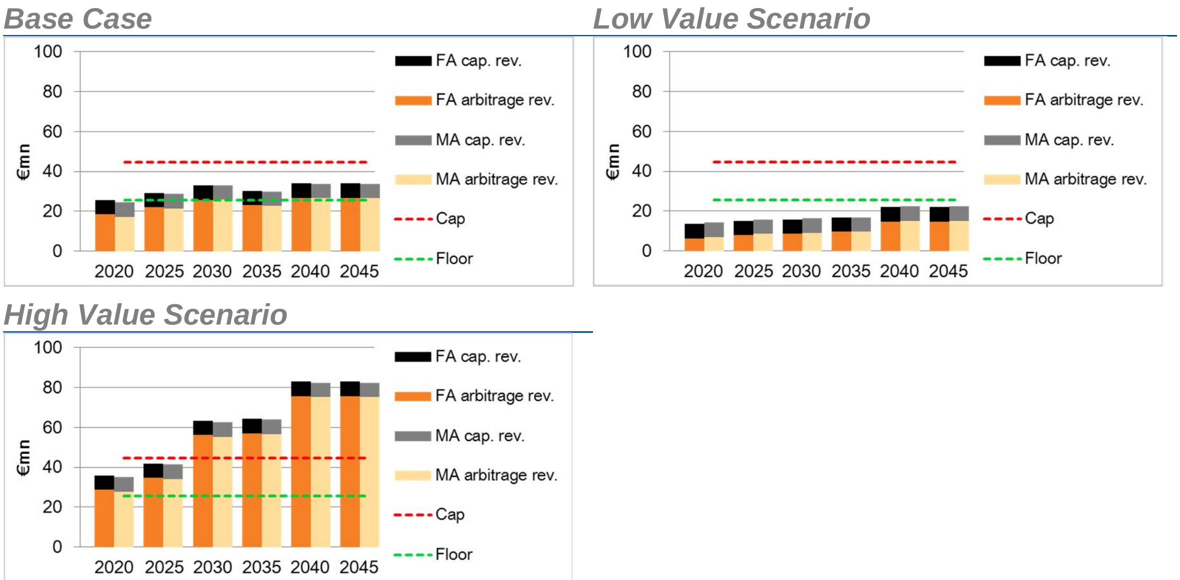
Source: Pöyry Management Consulting modelling for Ofgem

Figure 72 – Revenue sensitivity for FAB Link: Downside capacity payments



Source: Pöyry Management Consulting modelling for Ofgem

Figure 73 – Revenue sensitivity for Greenlink: Downside capacity payments



Source: Pöyry Management Consulting modelling for Ofgem

QUALITY AND DOCUMENT CONTROL

Quality control		Report's unique identifier: **2014/791**
Role	Name	Date
Author(s):	Stuart Murray Benedikt Unger Mike Wilks	December 2014
Approved by:	Gareth Davies	December 2014
QC review by:	Matina Delacovias	December 2014

Document control			
Version no.	Unique id.	Principal changes	Date
v1_0	2014/N/A	Draft version for comment	November 2014
v2_0	2014/791	Final version delivered	December 2014
v3_0	2014/791	Minor revisions	December 2014
v4_0	2014/791	Additional revisions	December 2014
v5_0	2014/791	Minor revisions	December 2014
v6_0	2014/791	Minor revisions	December 2014

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