Ofgem interconnector policy review – independent report

An AFRY report for Ofgem

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Making Future

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The report contains projections that are based on assumptions that are subject to uncertainties and contingencies. Because of the subjective judgements and inherent uncertainties of projections, and because events frequently do not occur as expected, there can be no assurance that the projections contained herein will be realised and actual results may be different from projected results. Hence the projections supplied are not to be regarded as firm predictions of the future, but rather as illustrations of what might happen. Parties are advised to base their actions on an awareness of the range of such projections, and to note that the range necessarily broadens in the latter years of the projections.

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1 Executive Summary

Ofgem has commissioned an analytical review of the cap and floor regime policy for interconnectors. Under three scenarios and a sensitivity, this shows that four connections (two each) to Northwest Europe and the Irish Single Energy Market have a positive total net welfare impact (considering GB and the respective connected markets). None of them have a positive socio-economic effect on GB consumers (except for those to Ireland in the High scenario). Projects generally require floor payments in the early period, but fall between cap & floor or above the cap from 2035 onwards.

Project background

Since the roll-out of the cap and floor regulatory framework for electricity interconnectors in 2014, Ofgem has granted the regime to nine interconnector projects. These projects were all subject to an assessment of their economic needs case as part of the Initial Project Assessment (IPA) process.

The social welfare Cost Benefit Analysis (CBA) to support the decision-making process regarding the IPA of these new interconnector projects, was carried out by AFRY Management Consulting (formerly Pöyry Management Consulting). This focused on the following:

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

AFRY's independent findings have been published by Ofgem and used in the decision-making process.

In 2020, the situation of electrical interconnectors connecting to GB has changed significantly. At the outset of the process in 2014, GB was poorly interconnected with other countries – this has changed, in part due to the success of the cap and floor regime. At the same time, the needs case for interconnectors has changed, due to the increasing decarbonisation ambition across Europe and the competition between interconnector projects.

Ofgem needs to understand whether further interconnection between GB and its neighbours is economically and commercially justified, whether that interconnection capacity benefits GB consumers and the wider energy system, and whether a cap & floor regime helps deliver beneficial projects.

Ofgem has commissioned AFRY Management Consulting ('AFRY') to perform this review, which relies on hourly electricity market modelling of the whole North West European region.

Approach overview

Market development scenarios

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

For the purpose of this review, we have developed a bespoke scenario that is based on recent publicly stated ambitions for decarbonising the electricity system in all modelled countries. The starting points for this 'Net Zero' scenario are National Grid's Future Energy Scenarios work (released in 2020)[1] as a basis for Great Britain; ENTSO-E's 'Global Ambition' scenario, developed for the TYNDP 2020[2], as a general reference for the countries surrounding Great Britain; and several country-specific reports and studies to reflect recent announcements.

Moreover, in order to carry out this review under a range of different market conditions, we have constructed a High and a Low interconnector value scenario. All scenarios are based on available public sources and combined with AFRY's market knowledge.

The scenarios used for the analysis in this report are the following:

— The Net Zero scenario is driven by Europe's ambition to reach net zero emissions by 2050. It reflects each country's characteristics such as renewables resource potential and demand. This scenario is consistent with a whole-economy net zero target at a European level (UK included) by 2050, compared to a 1990 baseline.

— The High interconnector value (High) scenario is driven by high GDP growth across Europe and a high ambition towards decarbonisation. This scenario is designed to represent a plausible extreme high view of future value drivers that can represent an upside case for the commercial and economic value of interconnector projects in GB.

— The Low interconnector value (Low) scenario represents a future of stagnating GB and wider European economies, and slower progress towards

1 https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2020-documents

2 https://www.entsos-tyndp2020-scenarios.eu/

decarbonising the energy system. This scenario is designed as a plausible extreme low view of future value drivers to represent a downside case for the commercial and economic value of interconnectors in GB.

— The BSUoS sensitivity is a variation on the Net Zero scenario. This represents a case where the BSUoS charge is no longer applied to generators in GB. This is in line with recommendations of the BSUoS task force.

Exhibit 1.1 summarises the main characteristics for each of the three main scenarios. This table also lists a Base case for comparison. This Base case scenario was developed for Ofgem for use in another review process, and has been used as the basis for developing the High and Low scenarios used in the analysis described in this report. This Base case has not been used in the analysis for this report.

Exhibit 1.1 – Overview of scenario assumptions

Driver	Net Zero	High scenario	Low scenario	Base case (for comparison)
Scenario basis	GB: National Grid's 'System Transformation' (FES ST) Others: various sources	GB: National Grid's 'Consumer Transformation' (FES CT) Others: Modified 'Global Ambition'	GB: National Grid's 'Steady Progression' (FES SP) Others: Modified 'Global Ambition'	GB: National Grid's 'System Transformation' (FES ST) Others: ENTSO-E's 'Global Ambition'
GB demand	FES ST	FES CT	FES SP & FES ST	FES ST
GB thermal capacity	FES ST CCS Biomass is reduced by 70% Hydrogen CCGT/GT capacity is reduced by 35%	FES CT CCS biomass replaced by CCS gas	FES SP	FES ST CCS biomass replaced by CCS gas
GB renewable capacity	FES ST	FES CT	FES SP	FES ST
NWE demand & capacity mix	ENTSO-E's 'Global Ambition' was a general reference Different specific sources were used for each country	Modified 'Global Ambition' Annual demand and capacities (solar PV, wind, battery) scaled to reflect change from FES ST to FES CT in GB CCS gas build increased slightly	Modified 'Global Ambition' Annual demand and capacities (solar PV, wind, battery) scaled to reflect change from FES ST to FES SP in GB CCS gas capacity replaced by CCGTs	ENTSO-E's 'Global Ambition' In the 2030s, some CCGT capacity is replaced with CCS gas; by 2040, 30% of the CCGT capacity is replaced by CCS gas
Interconnector capacity	FES ST	FES CT	FES SP	FES ST
Fuel prices	BEIS Fossil Fuel Price Assumptions (2019 Update), Central	BEIS (2019) High Trending from the BEIS Central 2020 value to 2025	BEIS (2019) Low Trending from the BEIS 2020 value to 2025	BEIS (2019 Update) Central
Carbon prices	FES Base Case	FES High Case Trending from the BEIS Projections 2020 value to 2025	2020 BEIS carbon prices kept flat until 2025 Afterwards, year-on-year increases as in FES Low Case	BEIS Energy and Emissions Projections (2018 Update)

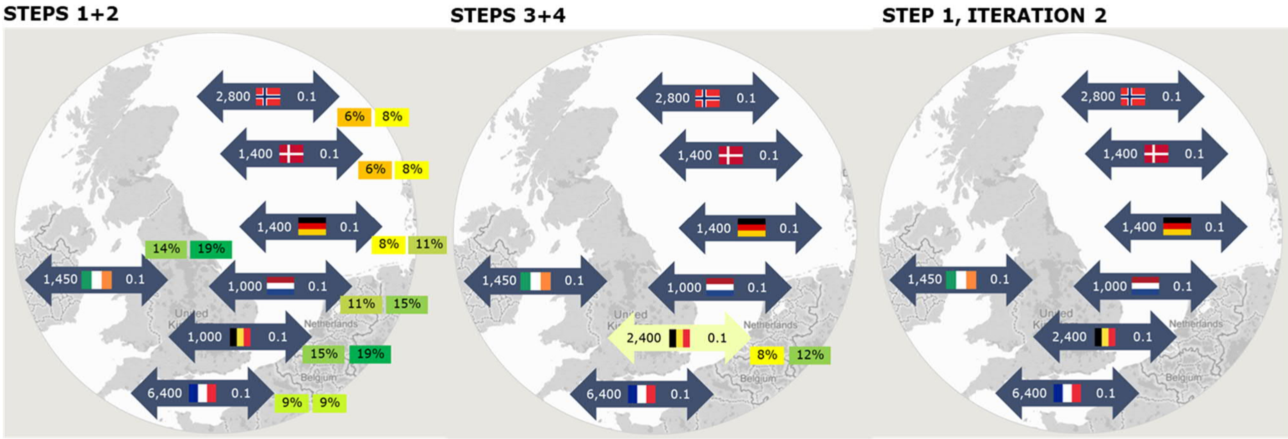
Note: In scenario basis, "Others" refers to Ireland, France, Belgium, Netherlands, Germany, Denmark and Norway. Capacity and demand for all the other European markets are assumed to be as per AFRY's Central scenario.

Policy review analysis approach

We have followed a step-wise approach to identify potential future interconnector projects. This takes into account the impact interconnectors have on each other's economic cases, and the dynamic nature of the market. In an iterative approach, (1) notional (additional) connections to each market/region are tested to determine an IRR against the current baseline. Then (2), the notional connection with the highest IRR (i.e. the most commercially attractive option) above a defined threshold is identified and (3) a standard sized interconnector to that market/region is added to the baseline. Then (4), if this larger project still meets the minimum IRR threshold, an updated baseline is produced and the process is repeated until there are no more viable projects.

Exhibit 1.2 gives a graphical representation of this step-wise approach.

Exhibit 1.2 – Indicative representation of the step-wise approach



Note: Numbers are indicative only. First IRR % refers to 2025, second value to 2030.

In order to then assess the societal impact of each identified interconnector, we have conducted a Cost Benefit Analysis (CBA), comparing the net present values (using a 3.5% discount rate[3] over a 25-year project life) of social welfare in the scenario without the assessed interconnector (the 'counterfactual') and with the assessed interconnector (the 'target case'). To show the impact of the particular interconnector being examined, all other factors are held constant between runs (e.g. other interconnector build, generation capacities and fuel prices).

While this analysis can identify potential interconnector capacity to specific countries, we recognise that there may be country-specific factors that cannot fully be captured in the modelling and it is therefore more appropriate to identify connections to groups of countries with similar characteristics, rather than one country in particular.

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

In this study, we therefore report the need for further interconnection to regions, rather than specific borders. We also acknowledge that multiple connections to the same market may be more difficult from several perspectives (e.g. cost, political reasons, network reinforcement and network operation), and connecting to multiple borders may bring additional benefits.

The regions for further interconnection to GB considered in this review are:

- Irish Single Energy market (Ireland and Northern Ireland);
- Nordics (Denmark or Norway); and
- Northwest Europe (Belgium, France, Germany or Netherlands).

Key assessment metrics

The assessment considers both CBA metrics (impact of the interconnector on the main socio-economic stakeholders – consumers, producers and interconnector owners), and how the cap and floor affects the interconnectors.

The CBA metrics taken into account in the review are:

- GB consumer welfare impact, which derives primarily from changes in costs due to wholesale electricity price movements from the introduction of the new interconnector;
- net GB welfare impact (which also includes producers and interconnectors in GB); and
- total net welfare impact (which also includes stakeholders on the other side of the link.

On the cap & floor side, the analysis examines the expected payments between interconnectors and GB consumers via the cap & floor regime. Any revenues exceeding the cap would be returned to GB consumers, if revenues fell short of the floor, GB consumers would pay the difference to the interconnector.

Overview of results

The results of the step-wise approach to identify additional interconnector capacity requirements in GB in 2025 and 2030 can be summarised as follows:

- The following additional capacities have a positive total net welfare impact (when considering GB and the connected country) in this period:
  - 1,400MW[4] interconnector capacity to Northwest Europe in 2025;
  - 1,000MW interconnector capacity to the Irish Single Energy Market in 2025;
  - 1,400MW interconnector capacity to Northwest Europe in 2030; and
  - 1,500MW interconnector capacity to the Irish Single Energy Market in 2030.
- All of these connections have a negative impact on GB consumers (except for the connections to the Irish Single Energy Market in the High scenario), as shown in Exhibit 1.3 below, due to the high share of exports from GB on all links.

[4] Note that Irish connections are added on 500MW increments, whereas all other connections are added in 1,400MW increments.

— None of the connections have a significantly positive impact on GB overall, as shown in Exhibit 1.4 below. The Irish projects are particularly negative, while the continental links show either marginal negative or positive effects.

— All projects have a positive total net welfare impact, when considering both GB and the neighbouring market, in the Net Zero and High scenarios, as shown in Exhibit 1.5 below.

— It is clear that interconnectors commissioning later perform better from an overall socio-economic perspective. This is due to the growing renewable share that leads to increasing price differentials.

The detailed analysis of identified connections also includes the identification of the need for a future regulatory regime for these projects, as shown in Exhibit 1.6 below. The results can be summarised as follows:

— In the Net Zero scenario (and the BSUoS sensitivity), every connection is affected by the cap & floor regime (either making cap payments or requiring floor payments. However, the impact of these payments is never large enough to significantly change the economic needs case.

— All connections would require large floor payments in the Low scenario.

— Only the Irish connections are expected to make cap payments – both in the High scenario, and the Irish link in 2030 also in the Net Zero scenario.

Exhibit 1.3 – GB consumer welfare impact: project comparison (€mn/GW, NPV at 3.5% over a 25-year project life, real 2019)

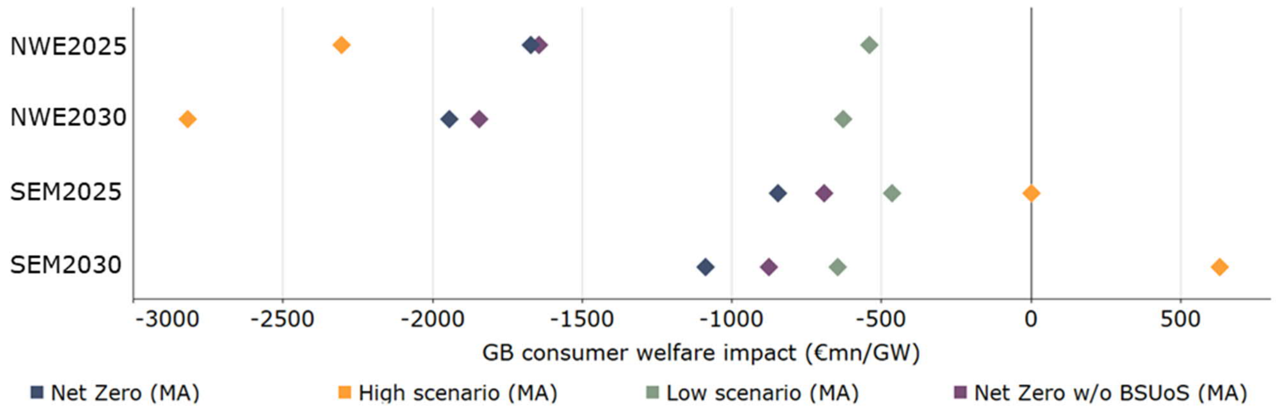


Exhibit 1.4 – GB net welfare impact: project comparison (€mn/GW, NPV at 3.5% over a 25-year project life, real 2019)

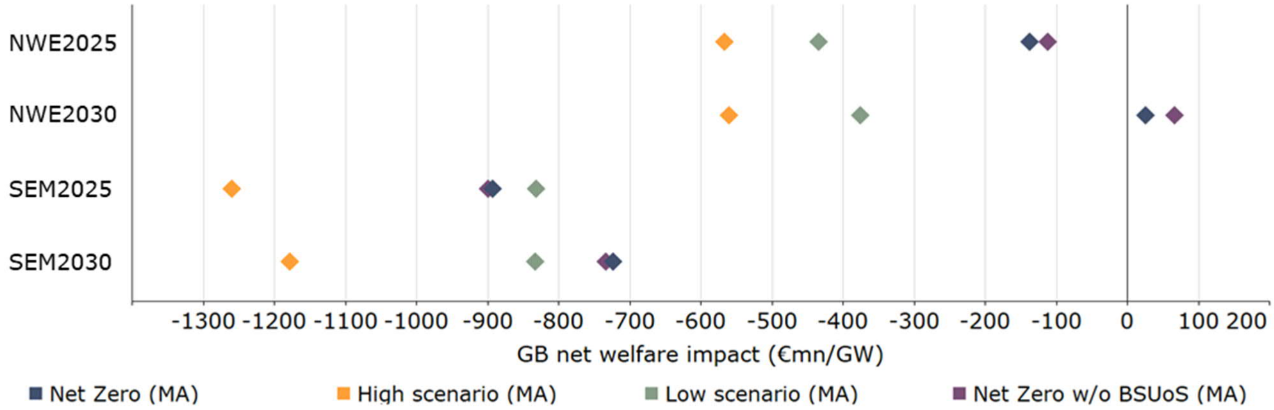


Exhibit 1.5 – Total net welfare impact: project comparison (€mn/GW, NPV at 3.5% over a 25-year project life, real 2019)

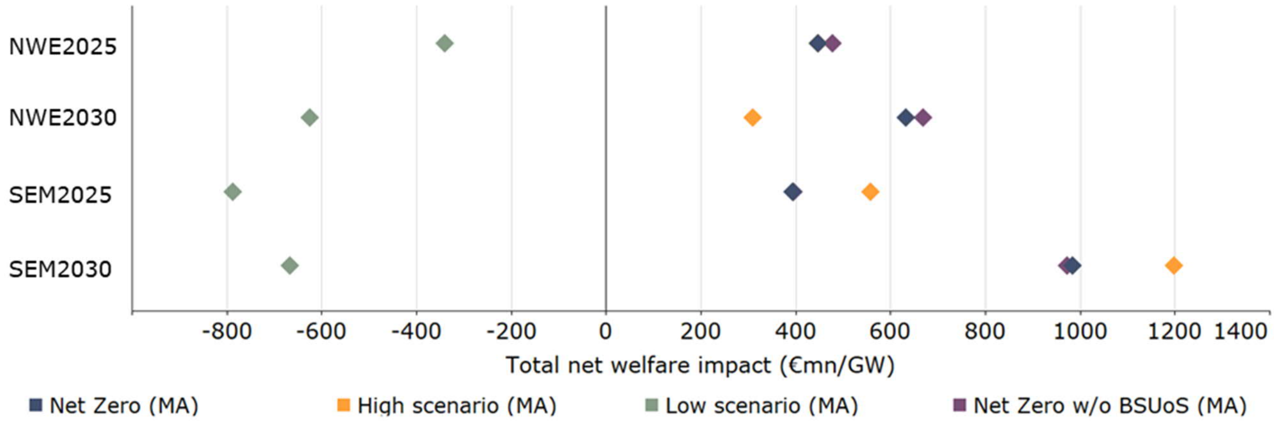
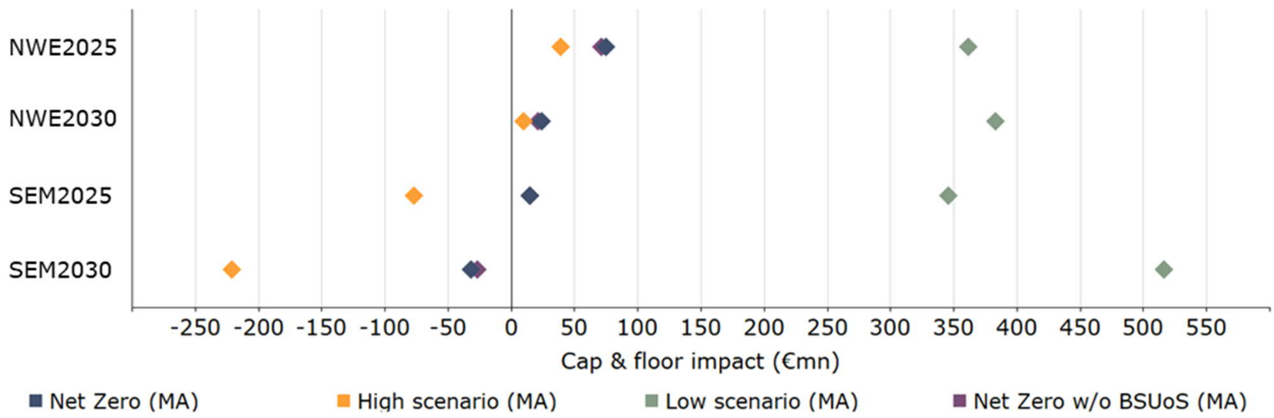


Exhibit 1.6 – Cap (-) & floor (+) payments to identified connections across scenarios (€mn, NPV at 3.5% over a 25-year project life, real 2019)



Final conclusions

The main conclusions from this assessment are as follows:

- If a Net Zero pathway is followed in GB and its neighbours, additional interconnectors are beneficial from an overall socio-economic perspective and are commercially feasible.
- As the economic case for additional interconnection is linked to the price volatility created by growing penetration of intermittent renewable power generation, interconnectors commissioned later in the period perform best in this analysis.
- None of the identified interconnectors benefit GB consumers (except for the links to the Irish Single Energy Market in the High scenario). This is due to the way GB and its neighbours are expected to meet their net zero ambitions. While GB has excellent offshore wind resources, other countries are expected to rely more on onshore wind, solar PV, nuclear, and other forms of low carbon generation. GB is also expected to utilise CCS biomass and CCS gas, often more so than its neighbours. These combined effects lead to GB becoming a net exporter of electricity. Therefore, additional interconnectors would be expected to export more than they import, leading to them having a negative effect on GB consumers.
- The effect of new interconnectors on GB overall is more nuanced. Producers generally benefit from increased exports, while other interconnectors' revenues are cannibalised. The resulting net effect in the Net Zero case is minor for continental links, and negative for Irish links.
- Combining GB and its neighbours, all projects have a total net welfare impact (when considering GB and the respective connected markets) in the Net Zero and High scenarios. It is likely that additional benefits could accrue to other European countries not investigated in this analysis.
- It should be noted that we assume no capacity market revenues for any of the assessed links. In fact, going forward, interconnectors are not expected to be able to directly access capacity markets under European legislation.
- It is likely that projects connecting in 2025, and to some extent in 2030, could require floor payments in the early years of their operation. However, going forward, revenues are expected to grow. From 2035 onwards, most connections' revenues would either be expected to fall within the band of cap & floor, or exceed the cap. It should be noted that this is based on an average expectation of project capex, opex and therefore cap & floor levels for each link.

2 Introduction and context

2.1 Introduction and project context

Since the roll-out of the cap and floor regulatory framework for electricity interconnectors in 2014, Ofgem has granted the regime to nine interconnector projects. These projects were all subject to an assessment of their economic needs case as part of the Initial Project Assessment (IPA) process.

The social welfare Cost Benefit Analysis (CBA) to support the decision-making process regarding the IPA of these new interconnector projects, was carried out by AFRY Management Consulting (formerly Pöyry Management Consulting). This focused on the following:

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

AFRY's independent findings have been published by Ofgem and used in the decision-making process.

In 2020, the situation of electrical interconnectors connecting to GB has changed significantly. At the outset of the process in 2014, GB was poorly interconnected with other countries – this has changed, in part due to the success of the cap and floor regime. At the same time, the needs case for interconnectors has changed, due to the increasing decarbonisation ambition in Europe and the competition between interconnector projects.

Ofgem needs to understand, whether further interconnection between GB and its neighbours is economically and commercially justified, whether that interconnection capacity benefits GB consumers and the wider energy system, and whether a cap & floor regime helps deliver beneficial projects.

Ofgem has commissioned AFRY Management Consulting ('AFRY') to perform this review, which relies on hourly electricity market modelling of the whole North West European region.

2.2 Conventions

The following conventions are used throughout the report:

- All monetary values quoted in this report are in Euros in real 2019 prices, unless otherwise stated.
- Annual data relates to calendar years running from 1 January to 31 December, unless otherwise identified.
- Unless otherwise attributed the source for all tables, figures and charts is AFRY Management Consulting.

2.3 Report structure

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

- Section 3 outlines the market development scenarios and sensitivities in which the future operation of the interconnection has been modelled.
- Section 4 contains the results from the policy review analysis; and
- Section 5 provides the summary and conclusions of the modelling and analysis.

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

- Annex A – This annex provides a detailed description of the Net Zero scenario.
- Annex B – This annex contains the detailed model inputs for the other scenarios.
- Annex C – This annex provides an overview of BID3, our pan-European electricity market dispatch and optimisation model.
- Annex D – The final annex provides information about our quality assurance process and the actual quality assurance statement.

3 Market development scenarios

The Net Zero scenario was developed to identify the potential future interconnection needs. In addition, two scenarios were assessed to span a wide range of interconnector value, namely the High interconnector value and the Low interconnector value scenarios (the High and Low scenarios are taken from the 2020 CBA review carried out for Ofgem). Scenario inputs were taken from public sources, such as National Grid's Future Energy Scenarios (FES), ENTSO E's TYNDP scenario work, and public announcements and scenarios from specific relevant countries. This section describes the development approach and inputs.

3.1 Scenario development overview

3.1.1 Major value drivers for electricity interconnection

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

In that regard, the crucial price and value drivers that we have considered are:

- Electricity demand and capacity mix

  Demand and capacity development always need to be viewed in conjunction. Higher capacity margins (capacity that exceeds demand) generally lead to lower prices within a country.

  Furthermore, the impact of demand changes on power prices is different depending on the composition of the supply curve which, in turn, depends on the generation capacity mix.

- Renewable deployment

  Large deployment of renewables, which are often envisaged in High decarbonisation scenarios, always result in low electricity prices. This because renewables are characterised by very low marginal costs. Renewables are likely to be one of the main drivers of the price differential among two connected markets because different penetration across the two markets can result in higher hourly price differential.

- Fuel prices

  The cost of thermal plants largely depends on fuel prices: higher fuel costs in one country than the other tend to drive higher electricity price differentials. However, a diminishing role for thermal plants will also diminish the impact of fuel prices on power prices.

- Carbon prices, grid charges and other elements

  Carbon policy and grid charging regulation influence the attractiveness of different types of generation within a market. Higher carbon prices generally lead to higher power prices in whatever region faces that price. Differences in carbon prices therefore lead to differences in power prices.

In addition, the existing volume of interconnection itself will also be a major driver of value for new interconnection. A consistent scenario for interconnector value should consider all aspects.

3.1.2 Development approach

For the purpose of this review, we have developed a bespoke scenario that is based on recent publicly stated ambitions for decarbonising the electricity system in all modelled countries. The starting points for this 'Net Zero' scenario are:

- National Grid's Future Energy Scenarios work (released in 2020)[5] as a basis for Great Britain;
- ENTSO-E's 'Global Ambition' scenario, developed for the TYNDP 2020[6], as a general reference for the countries surrounding Great Britain (i.e. Ireland, France, Belgium, Netherlands, Germany, Denmark and Norway);
- the RTE document published at the end of September 2020[7], based on which France's inputs are further developed;
- a German report published in October 2020[8], which is used as a guideline for Germany;
- Elia's 'Electricity Scenarios for Belgium towards 2050'[9], published in November 2017, utilised as a starting point for Belgium;
- the 'Climate and Energy Outlook (KEV) 2020'[10], published in October 2020, upon which inputs for the Netherlands are developed;

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5 https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2020-documents

6 https://www.entsos-tyndp2020-scenarios.eu/

7 https://www.concerte.fr/system/files/concertation/2020-09-25-RTE_CPSR_LQ.pdf. The N1 scenario is taken as a reference

8 Prognos, Öko-Institut, Wuppertal-Institut (2020): Towards a Climate-Neutral Germany. Executive Summary conducted for Agora Energiewende, Agora Verkehrswende and Stiftung Klimaneutralität

9 https://www.eliagroup.eu/-/media/project/elia/shared/documents/elia-group/publications/20171114_elia_4584_adequacyscenario.pdf

10 https://www.pbl.nl/sites/default/files/downloads/pbl-2020-klimaat-en-energieverkenning2020-3995.pdf

- BEIS's fossil fuel price assumptions (2019 Update)[11]; and
- AFRY's pan-European Quarterly Update for other assumptions relating to the electricity markets of all the other European countries.

3.2 Scenario assumptions

3.2.1 Description of scenarios

In order to assess the outcomes from this review under different market conditions, we have used some of the scenarios constructed under the 2020 CBA review carried out for Ofgem ('Near-term interconnector CBA – independent review'). These scenarios are aimed at assessing a reasonable range of outcomes for the overall economic benefit of new interconnection by capturing the effect of various scenario drivers. The scenarios are based on available public sources and combined with AFRY's market knowledge.

For the purpose of this policy review, a different scenario was developed to those used in the CBA review: a 'Net Zero' scenario. This scenario aims to reflect all the most recent commitments or announcements by countries in Europe towards reaching net zero emissions by 2050. In this review, we use the Net Zero scenario to identify potential interconnector capacity, and then to test their impact on socio-economic welfare. In order to provide a range of outcomes for this impact, we also use the High and Low scenario from the original CBA review, and a sensitivity based on the Net Zero scenario that assumes BSUoS to be removed from GB generators, in this impact assessment.

Exhibit 3.1 summarises the main characteristics for each of the scenarios, described below.

The Net Zero scenario has been developed to take a uniform approach on the decarbonisation commitment of the analysed countries and remove any large bias in the interconnector evaluation which depends on diverging decarbonisation agendas. The scenario reflects each country's characteristics such as higher/lower fuel prices, resource potential and demand profiles but takes away the effect of different decarbonisation commitment. This scenario is consistent with a whole-economy net zero target at European level (UK included) by 2050, compared to a 1990 baseline.

This scenario is designed to show interconnector needs and value in a world where all North West European countries succeed in their efforts to reach deep decarbonisation of their economies.

The High interconnector value (High) scenario is driven by high GDP growth across Europe which leads, along with accelerated electrification of heat and transport, to growing electricity demand. Fuel prices are assumed around 30% higher in 2025 compared to the Net Zero scenario in GB, and then follow a similar trend. EU ETS carbon prices rise continuously towards 2030 and then grow even stronger towards 2040. Carbon prices in GB are initially above ETS prices due to the carbon price support (CPS), but are in line with European prices from 2030. Renewable growth is very strong in both GB and other European

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11 https://www.gov.uk/government/publications/fossil-fuel-price-assumptions-2019

countries. Higher demand side response and battery capacity are used to balance high renewable penetration.

The drivers are combined such that they lead to relatively large hourly price differentials between countries. As such the scenario is designed to represent a plausible extreme high view of future value drivers that can represent an upside case for the commercial and economic value of interconnector projects in GB.

The Low interconnector value (Low) scenario represents a future of stagnating GB and wider European economies. This leads to somewhat lower growth in electricity demand compared to the Net Zero scenario in GB, and generally slower progression in energy markets. The EU ETS rises only very slightly until 2030, before growing more steadily until 2040. GB carbon price support remains, but results in flat carbon prices until the early 2030s. After that, GB carbon prices increase in line with the EU ETS, ensuring a differential stays in place. Renewables capacity grows much slower compared to the Net Zero scenario, in all countries.

Drivers are combined such that they lead to small hourly price differentials between countries. As such the scenario is designed as a plausible extreme low view of future value drivers to represent a downside case for the commercial and economic value of interconnectors in GB.

Exhibit 3.1 – Overview of scenario assumptions

Driver	Net Zero	High scenario	Low scenario	Base case (for comparison)
Scenario basis	GB: National Grid's 'System Transformation' (FES ST) Others: various sources	GB: National Grid's 'Consumer Transformation' (FES CT) Others: Modified 'Global Ambition'	GB: National Grid's 'Steady Progression' (FES SP) Others: Modified 'Global Ambition'	GB: National Grid's 'System Transformation' (FES ST) Others: ENTSO-E's 'Global Ambition'
GB demand	FES ST	FES CT	FES SP & FES ST	FES ST
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GB renewable capacity	FES ST	FES CT	FES SP	FES ST
NWE demand & capacity mix	ENTSO-E's 'Global Ambition' was a general reference Different specific sources were used for each country	Modified 'Global Ambition' Annual demand and capacities (solar PV, wind, battery) scaled to reflect change from FES ST to FES CT in GB CCS gas build increased slightly	Modified 'Global Ambition' Annual demand and capacities (solar PV, wind, battery) scaled to reflect change from FES ST to FES SP in GB CCS gas capacity replaced by CCGTs	ENTSO-E's 'Global Ambition' In the 2030s, some CCGT capacity is replaced with CCS gas; by 2040, 30% of the CCGT capacity is replaced by CCS gas
Interconnector capacity	FES ST	FES CT	FES SP	FES ST
Fuel prices	BEIS Fossil Fuel Price Assumptions (2019 Update), Central	BEIS (2019 Update) High Trending from the BEIS Central 2020 value to 2025	BEIS (2019 Update) Low Trending from the BEIS 2020 value to 2025	BEIS (2019 Update) Central
Carbon prices	FES Base Case	FES High Case Trending from the BEIS 2020 value to 2025	2020 BEIS carbon prices kept flat until 2025 Afterwards, year-on-year increases as in FES Low Case	BEIS Energy and Emissions Projections (2018 Update)

Note: In scenario basis, 'Others' refers to Ireland, France, Belgium, Netherlands, Germany, Denmark and Norway. Capacity and demand for all the other European markets are assumed to be as per AFRY Central scenario.

More detailed model input assumptions are provided in Annex A and Annex B – providing charts and figures for the Net Zero scenario and all the other scenarios, respectively.

3.2.2 Assumptions for GB interconnection & baseline

The interconnector baseline, i.e. the assumed interconnectors to be in place before 2030 across all scenarios, includes all existing projects, those under construction and those that were granted a cap and floor regime by Ofgem in either the first or second window. These are assumed to all be operational by

2025 or before. It is assumed that all existing and new projects will continue to operate until at least 2049[12].

The interconnector baseline is given in Exhibit 3.2 below.

Additional interconnector capacity is included in the various scenarios from 2030 onwards, to align the scenarios with FES and/or where economically justified. This is detailed in the annexes, in sections A.4 and B.4.

Exhibit 3.2 – Interconnector baseline to 2030

Interconnector	Connected market	Cable size (MW)	Status	Commissioned by[1]
Nemo*	Belgium	1,000	Existing link	-
Viking Link*	Denmark	1,400	Planning	2025
IFA	France	2,000	Existing link	-
IFA 2*	France	1,000	Existing link	-
FAB Link*	France	1,400	Planning	2025
ElecLink	France	1,000	Under construction	2023
Gridlink	France	1,400	Planning	2025
Neuconnect	Germany	1,400	Planning	2023
East West	Irish SEM	500	Existing link	-
Greenlink*	Irish SEM	500	Planning	2023
Moyle	Irish SEM	450	Existing link	-
Britned	Netherlands	1,000	Existing link	-
North Sea Link*	Norway	1,400	Under construction	2023
Northconnect	Norway	1,400	Planning	2025

Notes: * Denotes cap and floor projects; [1] Model is run for spot years only (2023, 2025, 2030, 2035, 2040), so actual expected commissioning date can deviate from 'commissioned by' date
Source: National Grid Interconnector register, 12 November 2020; and Ofgem

3.2.3 Internal consistency of scenarios

Each of our three scenarios starts with a set of assumptions based on a consistent storyline of GDP growth, decarbonisation ambition, energy demand and commodity prices that is based on a National Grid Future Energy Scenario. In addition to the underlying consistency of the storyline we have also examined the consistency of the scenarios using our standard scenario development processes.

As part of our standard scenario development process we apply a security of supply standard as a check on the internal consistency of new build assumptions in our scenarios. Although we aim to base our scenarios on the stated public sources as much as possible, it should be noted that in combining these two

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12 The end of the modelled period in this study is 2040, however socio-economic welfare analysis is carried out by looking at a 25-year project life. Therefore, 2040 outputs were extended until 2049. This is deemed to be an acceptable approximation, given that results in the distant future have a lower weight in the NPV calculation due to the effect of discounting.

sources, some deviation from either of the two underlying sets of inputs is expected. National Grid's and ENTSO-E's scenarios were not developed using a common framework and, especially in the long-term, may need adjustment to be consistent with each other as a combined scenario.

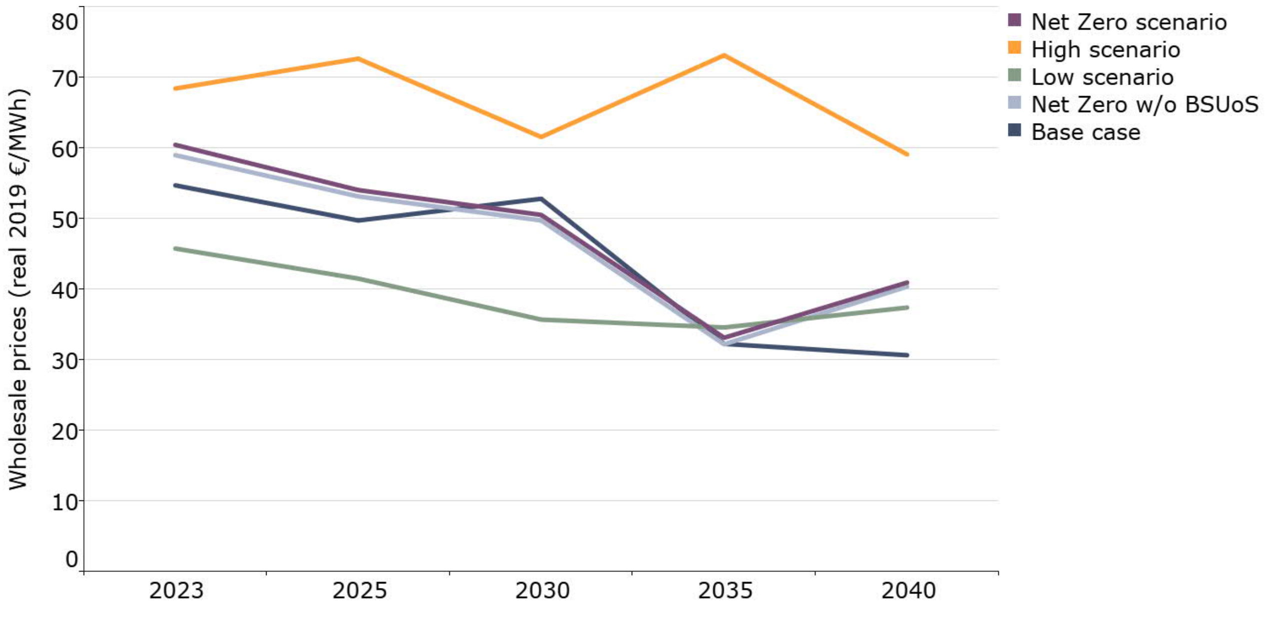
We ensure that capacity margins[13] are at or greater than 0%, that is, we ensure that no load loss occurs in the modelled period. Therefore, as described in the scenario inputs sections (Annex A – Net Zero scenario and Annex B – Other scenarios), some ad hoc capacity additions are made when needed in GB's neighbouring countries in some years. In the Low scenario, capacity margins are generally slightly above those required by our standard security of supply analysis. In this scenario, the lower demand (even decreasing in some countries) leads to a persistent state of over-capacity across North West Europe, which is consistent with a downside case for interconnector value.

3.3 Wholesale electricity prices per scenario

3.3.1 Wholesale electricity prices in Great Britain

Exhibit 3.3 shows the annual time weighted average wholesale electricity prices in our Net Zero, High and Low scenarios, as well as in the BSUoS sensitivity. Note that these prices reflect the scenarios before adding any additional potential interconnectors as described in section 4.1.2. The Base case prices are included for reference only and have not been used in the analysis conducted for this report.

Exhibit 3.3 – GB power prices



13 Capacity margins indicate the spare capacity over demand, accounting for a temperature driven demand profile plus hourly wind and solar yield and inflow of hydro plants.

— In the Net Zero scenario prices start at €54/MWh. Prices then decline down to €33/MWh in 2035, as renewables penetration, especially offshore wind, grows. From 2035 onwards, prices rebound somewhat due to growing demand and further rising carbon prices, reaching €41/MWh in 2040.

— In the BSUoS sensitivity, the absence of the BSUoS charge leads to slightly lower prices in GB (€0.9/MWh on average over the modelled period).

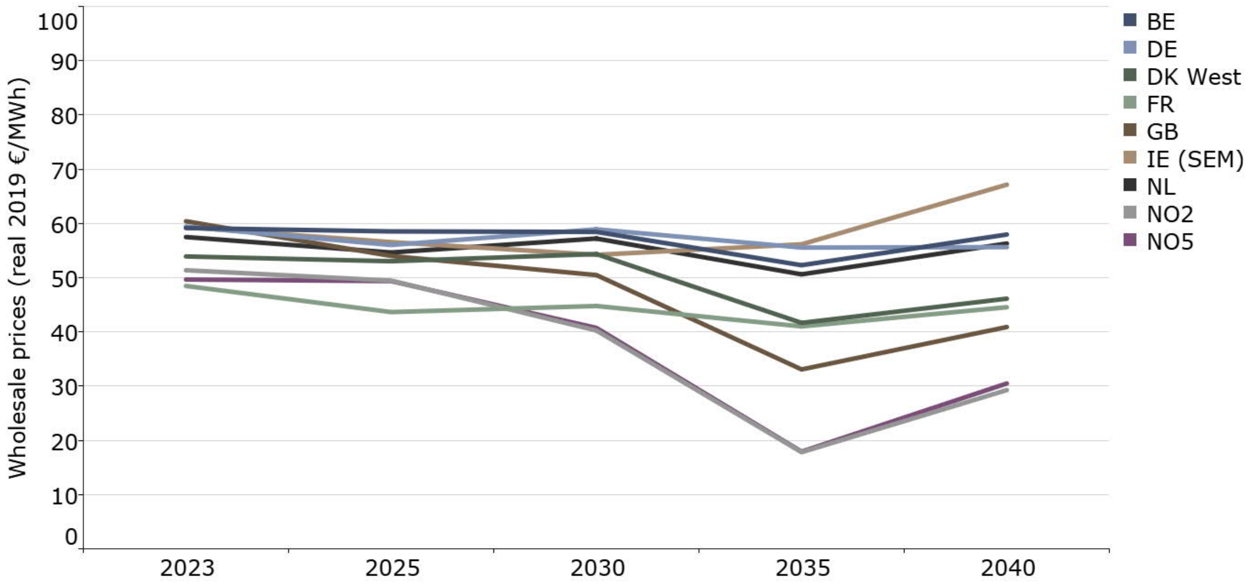
— In the High interconnector value scenario prices start at €73/MWh in 2025. The drop towards 2030 (€62/MWh) is caused by an increasing RES penetration. Prices rebound by 2035 up to €73/MWh, due to the stronger demand and a considerably higher carbon price. Prices are then expected to drop to €59/MWh in 2040 as a result of the increasing renewable penetration and nuclear capacity.

— In the Low interconnector value scenario wholesale prices are low in the short term (€41/MWh in 2025). Prices keep falling to €36/MWh in 2030 due to the increased renewable and nuclear capacity in GB (the latter peaking around 2030, before decreasing back to 2025 levels). In the period between 2030 and 2040, the ever-increasing renewable penetration is countered by some nuclear decommissioning, an increasing gas-fired capacity, the lack of CCS gas and hydrogen-fired plants, and an increasing carbon price. These elements combined put upward pressure on prices, reaching €37/MWh in 2040.

3.3.2 Electricity prices in the Net Zero scenario

The annual prices in the Net Zero scenario for GB and the modelled interconnected countries are shown in Exhibit 3.4 below.

Exhibit 3.4 – Wholesale power prices by country in the Net Zero scenario



— In 2023, electricity prices in Belgium, Germany, Denmark, GB, Ireland and Netherlands are relatively close, between ~€55/MWh and ~€60/MWh. Over time, prices in GB and Denmark decrease compared to the average, due to a higher offshore wind share. Prices in Ireland are highest in the long-term.

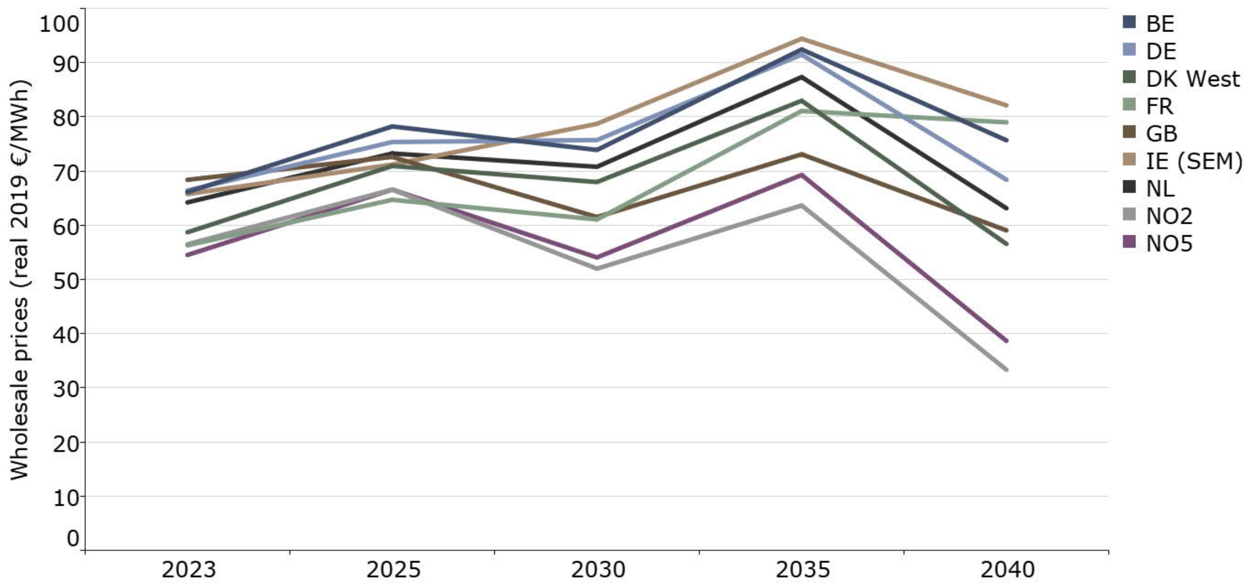
- French prices are lower than those in GB and many other countries in the short-term, due to the higher nuclear share in the country. French prices follow a relatively stable trajectory.
- Prices in Norway are below those of most continental European countries due to the country's reliance on hydro, and, from 2030 onwards, growing wind penetration. This also leads to very low prices in Norway in 2035 and 2040.

3.3.3 Electricity prices in the High scenario

Electricity prices in the High scenario are higher than in the Net Zero scenario in all countries, driven by increasing demand, fuel and carbon prices. The difference in prices between GB and continental Europe is also generally higher in this scenario driven by the different growth rates of demand and renewable capacity in each country.

Resulting modelled annual prices in the High scenario are shown in Exhibit 3.5.

Exhibit 3.5 – Wholesale power prices by country in the High IC value scenario



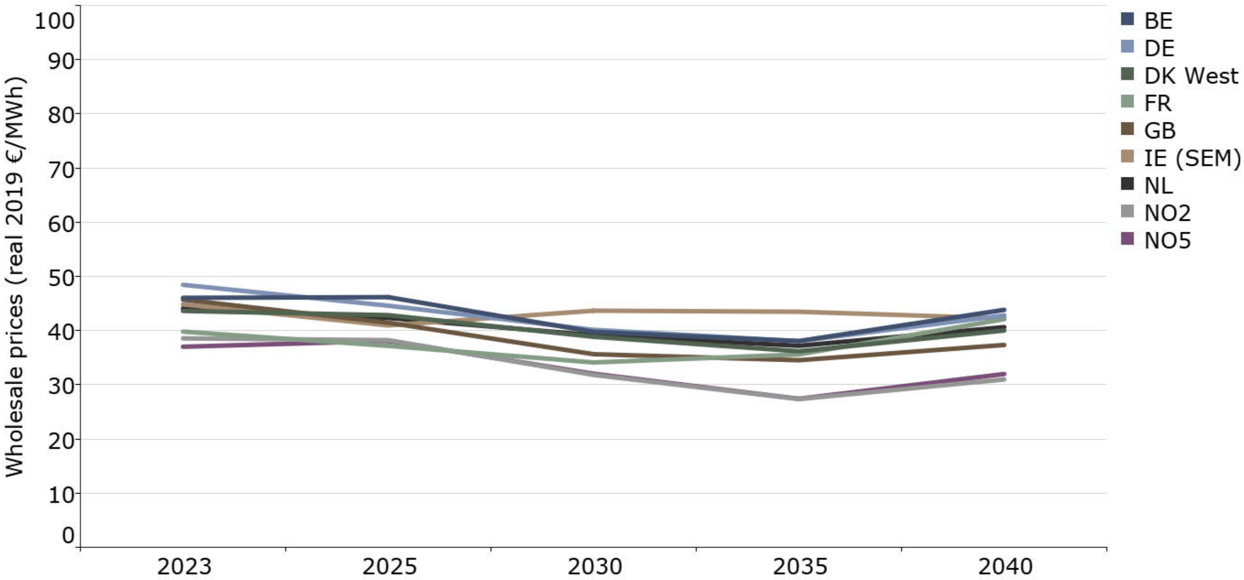
- Similar to the Net Zero scenario, prices in Belgium, Germany, Denmark, GB, Ireland and Netherlands start close to each other in 2023, while French and Norwegian prices are lower.
- Until 2035, prices increase in most countries, as demand, fuel and carbon prices, and technology costs are assumed to increase. In the long-term, there is a large range of average prices from very low-prices in Norway (~€35/MWh) to much higher prices in Ireland (>€80/MWh). GB prices are in the middle of these around €60/MWh in 2040.

3.3.4 Electricity prices in the Low scenario

Electricity prices in the Low scenario are, in the period 2020-2030, lower than in the Net Zero scenario across all the modelled countries, driven by lower fuel and carbon prices. In the long term, prices in the Low scenario become generally closer to the Net Zero scenario (and in GB, in 2035, even slightly higher), as a result of the lower renewable penetration, the larger share of gas-fired generation, and the lack of CCS and hydrogen technologies.

The difference in prices between GB and continental Europe is lower in this scenario. Lower demand increase and limited renewables development result in smaller differences in the average annual wholesale prices between countries. Annual wholesale power prices for the Low scenario are shown in Exhibit 3.6.

Exhibit 3.6 – Wholesale power prices by country in the Low IC value scenario

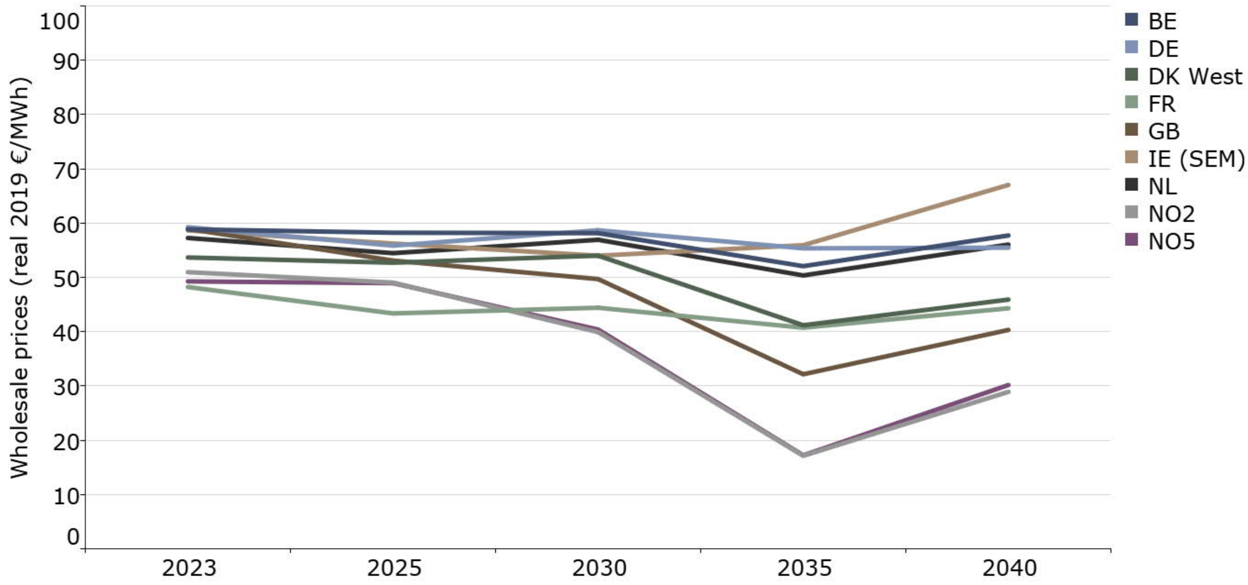


- Prices are lower in Norway and France (below €40/MWh), compared to relatively close average prices in all other countries (between ~€45/MWh and ~€50/MWh).
- Low demand, fuel and carbon prices lead to flat trajectories in many countries, and prices remain close to each other over the modelled period.
- In 2040, only Norwegian prices significantly deviate from the average (~€30/MWh), while prices in all other countries range between ~€37/MWh and €45/MWh.

3.3.5 Electricity prices in the Net Zero w/o BSUoS sensitivity

Electricity prices in the Net Zero w/o BSUoS sensitivity are shown in Exhibit 3.7. As already mentioned, they are very similar to prices in the Net Zero scenario: in the BSUoS sensitivity, the absence of the BSUoS charge leads to a slightly lower wholesale price in GB (€0.9/MWh on average over the modelled period).

Exhibit 3.7 – Wholesale power prices by country in the BSUoS sensitivity



— Wholesale prices in GB's neighbours remain very similar to the Net Zero scenario. The impact of the removal of the BSUoS charge in GB is a very slight decrease in power prices.

4 Ofgem interconnector policy review

This section presents the approach and results for the analysis of potential future interconnectors, their impact on different stakeholders and whether a cap & floor regime would affect these projects.
Analysis shows that four connections (two each) to Northwest Europe and the Irish Single Energy Market have a positive total net welfare impact (when considering GB and the respective connected market). However, all have negative impacts on GB consumers. All projects make or receive cap or floor payments in the Net Zero scenario, but not to an extent that it would impact the needs case materially (i.e. move a project from being net positive to net negative or vice versa).

4.1 Policy review introduction

4.1.1 Introduction and approach

The key questions Ofgem is considering when reviewing the cap & floor regulatory regime for interconnectors are the following:

- Question 1: Are there any future interconnector projects that are commercially and economically viable?
- Question 2: Do these potential interconnector projects bring benefits for GB consumers?
- Question 3: Does the existence of a cap & floor regime have an impact on the commercial and economic viability of these potential interconnector projects?

In order to answer these questions, AFRY has developed an approach based on identifying future projects and assessing their viability. The policy review is carried out using the following parameters:

- The analysis focuses on the period from 2020 to 2030.
- Commissioning dates were fixed to 2025 and 2030, as the time horizon for reviewing the policy was set to 10 years. This also helps keep the number of potential options manageable for the analysis.

- The connecting regions considered in this analysis are: Irish Single Energy Market (Ireland, Northern Ireland), Nordics (Denmark or Norway[14]), and Northwest Europe (Belgium, France, Germany and the). More detail on this aggregation is given below.
- In terms of connection capacities, many technical options could be applied. Subsea DC interconnectors projects in operation and under development in Europe are rated between 400MW and 2,000MW. For this study, we have chosen a standard project of 1,400MW, as it is currently the most common rating for GB projects. For Irish projects, we use 500MW.
- In order to estimate project IRR and economic impact, assumptions for capex, opex, and cap & floor levels need to be taken. AFRY's standard assumptions for sub-sea interconnectors costs (which take into account type, length and capacity of the cable) have been used. Cap & floor level estimates have been derived from these cost inputs.

As interconnector projects influence each other's economic cases, it is important to look at their viability over time: a more attractive project commissioning later could be negatively impacted by a less attractive (but still attractive) projects commissioning earlier. Therefore, we follow a step-wise approach for the identification of viable projects. Once projects are identified, we perform an assessment of their socio-economic welfare analysis that (1) confirms the economic viability of the project, (2) identifies the impact on GB consumers and (3) investigates the impact of the cap & floor regime on the project. The step-wise identification approach is described in section 4.1.2. For a description of the conceptual overview and the economic theory behind the CBA approach, as well as an overview of AFRY's modelling and calculations, we refer the reader to the public report 'Near-term interconnector cost-benefit analysis: independent report (cap & floor window 2)'[15], as published by Ofgem in January 2017. Section 2 and Annex A of that report detail the approach.

While this analysis can identify potential interconnector capacity to specific countries, we recognise that there may be country-specific factors that cannot fully be captured in the modelling and it is therefore more appropriate to identify connections to groups of countries with similar characteristics, rather than one country in particular.

In this study, we therefore report the need for further interconnection to regions, rather than specific borders. We also acknowledge that multiple connections to the same market may be more difficult from several perspectives (e.g. cost, political reasons, network reinforcement and network operation), and connecting to multiple borders may bring additional benefits.

The regions for further interconnection to GB considered in this report are:

- Irish Single Energy market (Ireland and Northern Ireland);
- Nordics (Denmark or Norway); and
- Northwest Europe (Belgium, France, Germany or Netherlands).

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14 Norway's electricity market is split into five zones. In this analysis, the zones NO2 and NO5 in Norway's Southern and Western regions are considered as potential connected areas.

15 https://www.ofgem.gov.uk/system/files/docs/2018/01/near-term_interconnector_cost_and_benefit_analysis_-_independent_report_.pdf

4.1.2 Step-wise approach

The step-wise approach to identify potential interconnector capacity in 2025 and 2030 takes into account the impact interconnectors have on each other's economic cases, and the dynamic nature of the market. The step-wise approach is an iterative approach following four steps:

— Step 1: First, the baseline of interconnectors (existing projects and those with a cap & floor regime in place) is represented in our model, in the Net Zero scenario. Then 'notional' additional interconnector capacity[16] is added to each of the considered markets. We add both 'notional' interconnectors commissioning in 2025, and 'notional' interconnectors commissioning in 2030.

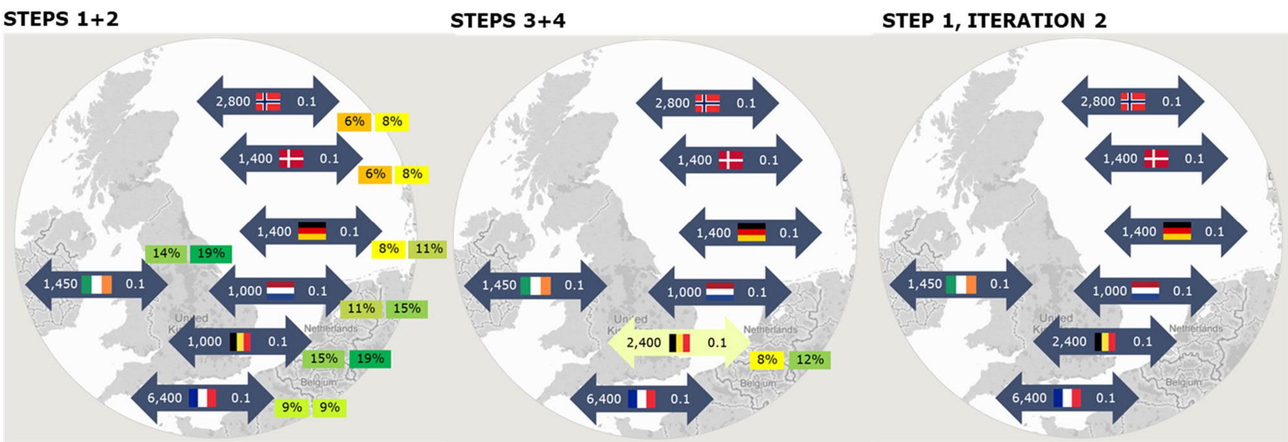
— Step 2: For each of the 'notional' interconnectors, the internal rate of return (IRR) is recorded and connections compared.

— Step 3: The 'notional' interconnector with the highest IRR (i.e. the most commercially attractive option) is then added to the baseline as a standard sized interconnector, and the model is re-run.

— Step 4: Finally, the now added project is tested against an assumed hurdle rate, to see whether the actual project would be commercially viable. If it is, then it will be added to the new baseline, and a next iteration will start with Step 1. If the project does not meet the criteria[17], the process is stopped and all thus far identified interconnectors form the full list of projects that will be assessed using CBA metrics.

A graphical representation of an iteration of the step-wise approach is given in Exhibit 4.1.

Exhibit 4.1 – Indicative representation of the step-wise approach



Note: Numbers are indicative only. First IRR % refers to 2025, second value to 2030.

16 0.1MW of capacity is added to the zones considered. This allows an assessment of the flows and potential revenues on these connections, without them actually affecting the electricity prices in any of the countries.

17 Investors in interconnector projects are assumed to require a return greater than 10%. As the cap & floor regime could potentially lower that figure, for the step-wise approach, we considered all projects with an IRR of greater than or equal to 7%.

4.2 Identified interconnector capacities

4.2.1 Overview of identified additional interconnector capacities

The step-wise approach to identifying potential additional capacity in 2025 and 2030 in the Net Zero scenario yielded four additional connections, listed in Exhibit 4.2. This table can be interpreted as the economically justified amount of interconnection to be added to Great Britain (from an overall economic perspective, irrespective of stakeholder groups or cross-border benefit allocation) given the scenario.

Exhibit 4.2 – List of potential interconnectors identified in the step-wise approach

Connection	Connecting to	Capacity	Commissioning year	Final IRR
NWE2025	Northwest Europe	1,400MW	2025	8.2%
SEM2025	Irish Single Energy Market	1,000MW	2025	7.2%
NWE2030	Northwest Europe	1,400MW	2030	10.8%
SEM2030	Irish Single Energy Market	1,500MW	2030	9.1%

Note: The identified interconnector capacities can consist of multiple projects.

As shown in the table, all of these interconnectors meet the minimum IRR criteria of 7%, defined as the threshold for this exercise. In the last step of the iteration, additional capacities were considered to both Northwest Europe and the Irish Single Energy Market, but the addition of either of these options dropped the IRR(s) below the threshold, and so the step-wise approach was terminated at this point.

While we used 1,400MW and 500MW as standard capacities for Continental and Irish links, respectively, when multiple interconnectors of this size were required in the same year, these were combined into a single connection.

It should be noted that as the share of renewables grows, so generally does the case for more interconnection. Therefore, even more interconnectors may be commissioned after the study period (2025-2030), deteriorating the case for the interconnectors examined in this study.

4.2.2 CBA of identified additional interconnector capacity in the Net Zero scenario

The socio-economic welfare impact of additional interconnector capacity identified above has been tested using the ‘Marginal Additional’ (MA) assessment approach. This approach is the most stringent test of the economic needs case. It investigates the impact of an interconnector assuming it is the last of a set of interconnectors (in this case, the five identified projects) to be commissioned.

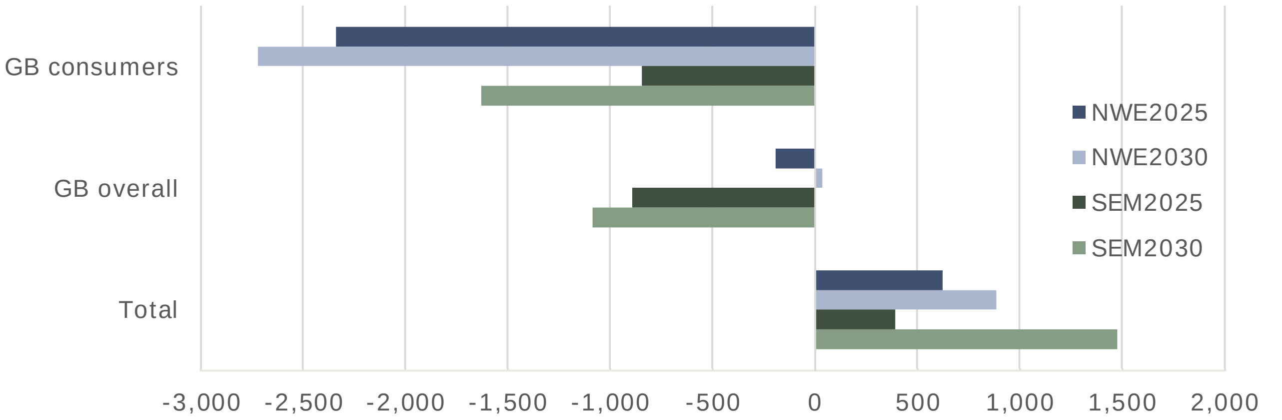
The three metrics analysed in this assessment are:

— the impact of the interconnector capacity on GB consumer welfare (including both the effect from changes to wholesale prices and payments under the cap & floor regime);

- the impact of the interconnector capacity on GB overall (consumers, producers and other interconnectors); and
- the impact of the interconnector capacity on GB and the connected country (total welfare).

First, we examine the impact of the identified projects on GB consumers, shown in Exhibit 4.3.

Exhibit 4.3 – Socio-economic impact of potential interconnector projects (€mn, NPV at 3.5% over a 25-year project life, real 2019)



Connection	Capacity	GB consumers	GB overall	Total
NWE2025	1,400MW	-2339	-192	625
NWE2030	1,400MW	-2719	37	887
SEM2025	1,000MW	-844	-892	393
SEM2030	1,500MW	-1628	-1085	1477

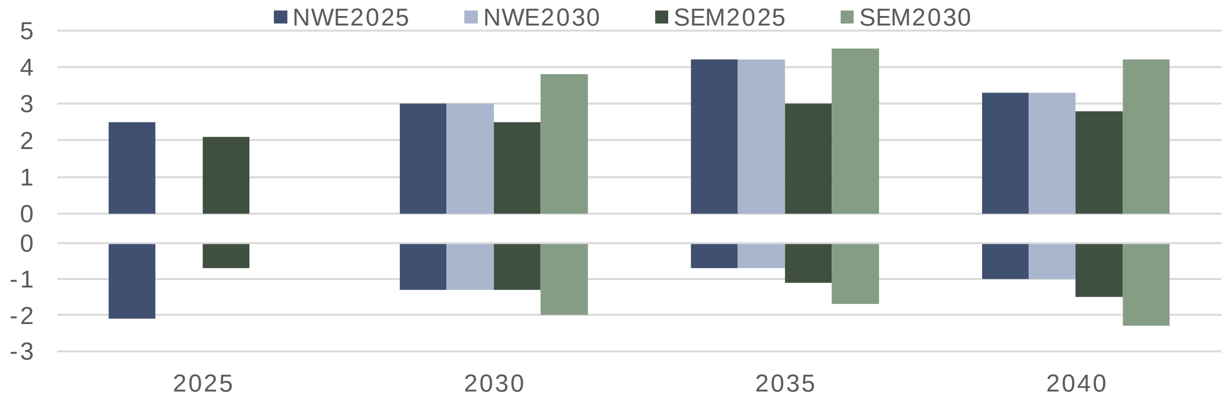
Note: This table does not assume a cap & floor regime for any of these new projects

The chart and table above give the results for the socio-economic welfare impact of the potential interconnector projects. It identifies, that:

- All identified connections show a negative impact on GB consumers, as they raise wholesale electricity prices in GB.
- The impact of connections connecting to Northwest Europe is more negative on consumers than the Irish projects.
- Conversely, Irish projects have a more negative impact on overall GB welfare than continental European projects. While the links to Northwest Europe have a minor impact on GB overall, the links to the Irish Single Energy Market exhibit a negative impact.
- All projects have a positive impact when considering stakeholders in both GB and the neighbouring country. On a per GW basis, the Irish projects show a larger benefit than the Northwest European projects..

In order to understand how these interconnectors affect stakeholders on either side of the link, we investigate the flows on these interconnectors, shown in Exhibit 4.4.

Exhibit 4.4 – GB imports and GB exports on potential interconnector projects (TWh)



Connection	2025	2030	2035	2040
NWE2025 import	2.1	1.3	0.7	1.0
NWE2025 export	2.5	3.0	4.2	3.3
SEM2025 import	0.7	1.3	1.1	1.5
SEM2025 export	2.1	2.5	3.0	2.8
NWE2030 import	N/A	1.3	0.7	1.0
NWE2030 export	N/A	3.0	4.2	3.3
SEM2030 import	N/A	2.0	1.7	2.3
SEM2030 export	N/A	3.8	4.5	4.2

Flows on these connections can be described as follows:

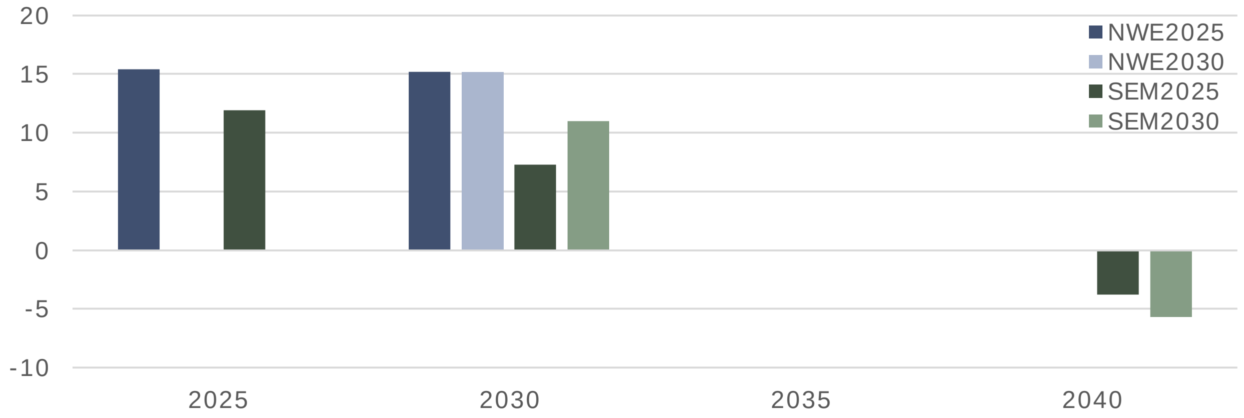
— For all connections, exports from GB are higher than imports to GB in all years. All cables are consistently net exporters from GB.

— Utilisation on all cables is relatively low, as the projects are generally relying on a small number of high price differential hours to capture congestion rents.

— Interconnector flows are shifting towards exports from GB between 2025 and 2035. In 2040, there is a slight reversal of this trend, although all cables remain strong net exporters.

In addition to identifying the socio-economic welfare impact, it will also be important to note whether any of these connections would be materially impacted by a cap & floor regime. Exhibit 4.5 shows the cap payments made by projects (as negative payments) and the floor payments made to projects (as positive payments).

Exhibit 4.5 – Cap (-) and floor (+) payments to identified connections (€mn, real 2019)



Connection	NPV	2025	2030	2035	2040
NWE2025	75.0	15.4	15.2	-	-
NWE2030	23.9	N/A	15.2	-	-
SEM2025	14.8	11.9	7.3	-	-3.8
SEM2030	-32.0	N/A	11.0	-	-5.7

The following observations can be made on potential cap & floor payments to the identified projects:

— The Northwest European links require floor payments in the early period. By 2035, revenues on these links remain within the band of cap & floor.

— Irish links require floor payments in the early period but are within the band of cap & floor in 2035. From 2040 onwards, the Irish links would provide cap payments to GB consumers.

— In NPV terms, the impact of cap & floor on the projects is relatively small compared to other stakeholder impacts. While the 2025 Northwest European link requires €75mn in NPV terms, no other link has a cap or floor impact above €35mn in either direction.

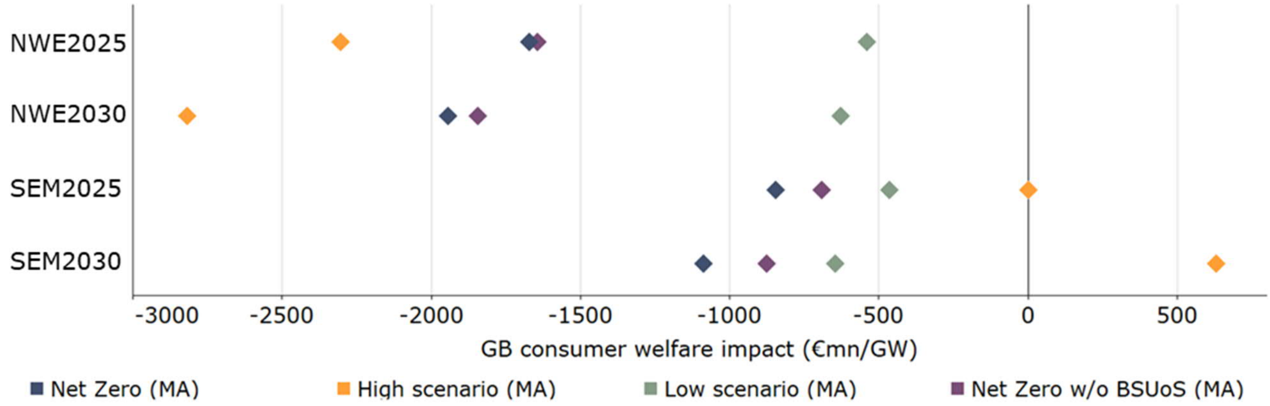
— None of the cap & floor payments would impact the final conclusion on the needs case assessment for any of the projects significantly.

4.2.3 CBA of identified additional interconnectors projects in other scenarios and sensitivities

The above list of connections has been identified using the Net Zero scenario developed for this purpose. Once identified, we have tested their socio-economic welfare impact (described in section 4.2.2). We have also tested the impact in three additional cases, the High scenario, the Low scenario, and a sensitivity on the Net Zero scenario where we remove BSUoS from GB generators (these scenarios are described in more detail in section 3.2.1).

Exhibit 4.6 shows the summary of the scenario analysis for the impact of the projects on GB consumer welfare.

Exhibit 4.6 – GB consumer welfare impact: project comparison (€mn/GW, NPV at 3.5% over a 25-year project life, real 2019)



This analysis highlights, that:

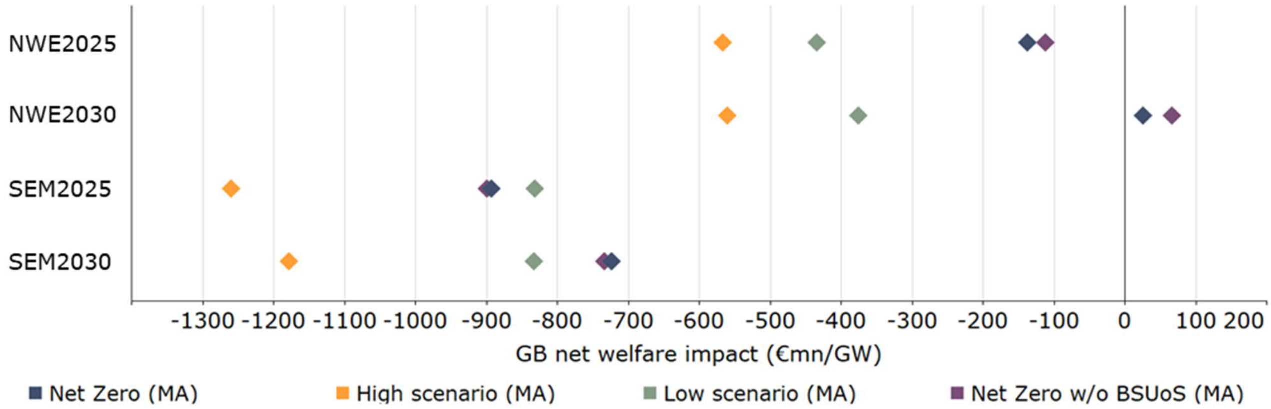
— The impact for GB consumers is negative for most connections, in the majority of the scenarios analysed.

— The exceptions are the High scenario results for the links to Ireland: although the SEM2025 link exhibits a close to zero impact on GB consumers, the SEM2030 link shows a benefit for GB consumers. This is the outcome of slightly lower GB power prices in the distant future (2040), thanks to the additional interconnectors to Ireland.

— For Northwest European connections, consumer benefit per GW is similar, exhibiting the most negative impact on GB consumers in the High scenarios, and the least negative impact in the Low scenario.

Exhibit 4.7 shows the summary of the scenario analysis for the impact of the capacities on GB welfare overall.

Exhibit 4.7 – GB net welfare impact: project comparison (€mn/GW, NPV at 3.5% over a 25-year project life, real 2019)



Note: In ROI2025 and ROI2030, the Net Zero scenario impact is almost overlapping with the BSUoS sensitivity impact.

This shows, that:

— The GB net welfare impact is negative in most scenarios and interconnectors investigated.

— Irish links perform worse than Northwest European links in this analysis.

— In the High scenario, the Irish links are affected by both a negative GB producer welfare impact and a negative other interconnector welfare impact. This results in the GB net welfare impact being particularly negative in the High scenario for these projects.

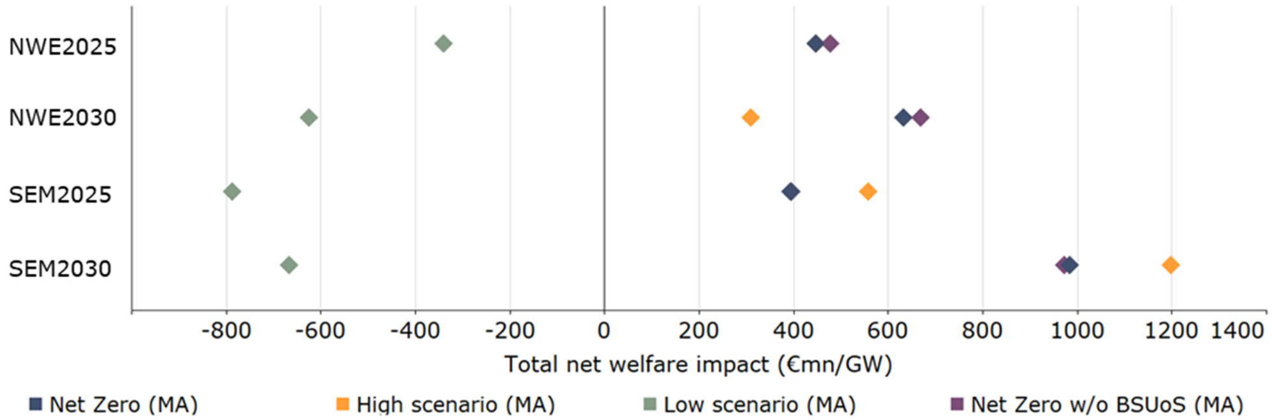
— Links connecting in 2030 perform better than those connecting in 2025. This is due to the continued growth in renewable penetration that is often the basis for interconnector needs cases.

— The only link with a positive net impact on GB in the Net Zero scenario is the Northwest European link in 2030.

— The order of scenarios is similar for all links. Generally, the BSUoS sensitivity shows the most beneficial results, followed by Net Zero, Low scenario and High scenario.

Finally, Exhibit 4.8 shows the summary of the scenario analysis for the impact of the projects on the welfare of stakeholders across GB and the respective connected country.

Exhibit 4.8 – Total net welfare impact: project comparison (€mn/GW, NPV at 3.5% over a 25-year project life, real 2019)



Note: In NWE2025, the Net Zero scenario impact is almost overlapping with the High scenario impact. Also, in SEM2025 the Net Zero scenario impact is almost overlapping with the BSUoS sensitivity impact.

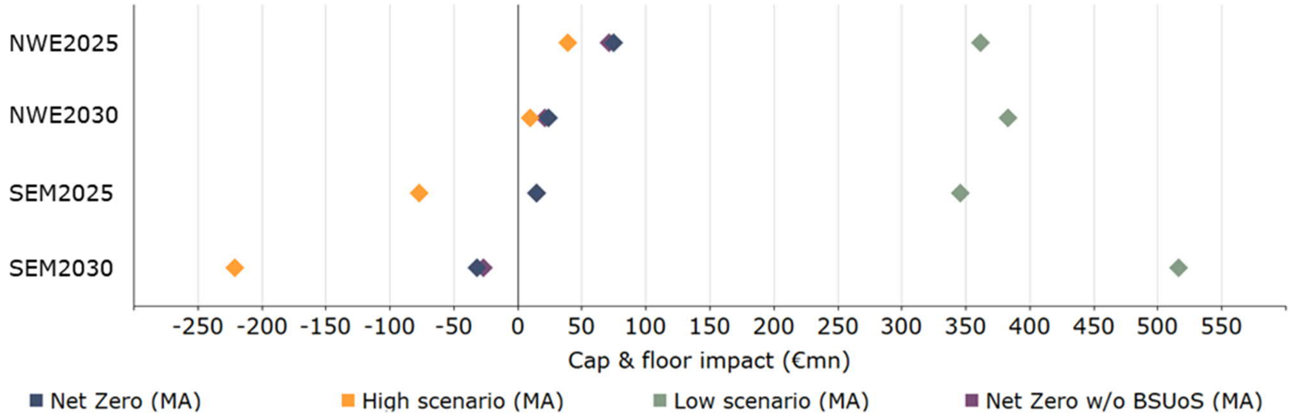
This analysis shows, that:

— In the Net Zero scenario, and in its sensitivity without BSUoS, the total net welfare impact is positive for all projects.

— While the Low scenario is a significant downside for all links, the High scenario does not represent a clear upside for the projects (the exception being the Irish links).

Lastly, Exhibit 4.9 shows the variation in cap & floor payments for these projects across scenarios.

Exhibit 4.9 – Cap (-) and floor (+) payments to identified connections across scenarios (€mn, NPV at 3.5% over a 25-year project life, real 2019)



Note: In all selected links, the Net Zero scenario impact is almost overlapping with the BSUoS sensitivity impact.

This indicates, that:

- In the Net Zero scenario (and the BSUoS sensitivity) all but one connection (the SEM2030) are net recipients of floor payments. However, these are generally small, and lower compared to the interconnectors' impacts on GB consumers.
- All of the connections would receive considerable floor payments in the Low scenario. The typically low price differential between price areas determines a reduced economic case for additional interconnectors, whose revenues are generally less than the assumed floors.
- In the High scenario, the Irish connections make the highest cap payments, and the continental projects receive the lowest floor payments across the scenarios developed. Greater price differentials lead to generally more profitable interconnectors, benefitting from the higher congestion rent.
- Interconnectors commissioned later need lower floor payments or make higher cap payments, as price differentials are expected to grow over time.

5 Summary of results and conclusions

5.1 Economic need for additional interconnection in GB

The results of the step-wise approach to identify additional interconnector need in GB in 2025 and 2030 can be summarised as follows:

- The following additional capacities have a positive total net welfare impact (when considering GB and the connected country) in this period:
  - 1,400MW interconnector capacity to Northwest Europe in 2025;
  - 1,000MW interconnector capacity to the Irish Single Energy Market in 2025;
  - 1,400MW interconnector capacity to Northwest Europe in 2030; and
  - 1,500MW interconnector capacity to the Irish Single Energy Market in 2030.
- All of these connections have a negative impact on GB consumers due to the high share of exports from GB on all of the links (except for the Irish projects in the High scenario).
- None of the connections have a significantly positive impact on GB overall. The Irish projects are particularly negative, while the links to Northwest Europe show either marginally negative or positive effects.
- All projects have a positive total net welfare impact when considering both GB and the respective neighbouring market in the Net Zero and High scenarios.
- Comparing the links connecting in 2025 to those connecting in 2030, it becomes clear that interconnectors commissioning later perform better from an overall socio-economic perspective. This is due to the growing renewable share that leads to increasing price differentials.

5.2 Economic need for a future regulatory regime for interconnectors

The detailed analysis of identified projects also includes the identification of the need for a future regulatory regime for these projects. The results can be summarised as follows:

- In the Net Zero scenario (and the BSUoS sensitivity), every project is to some extent affected by the cap & floor regime (either making cap payments or requiring floor payments in some years). However, the impact of these payments is never large enough to significantly change the connection's economic needs case.

- All projects would require large floor payments in the Low scenario.
- Only the Irish projects are expected to make cap payments – both in the High scenario, and the SEM2030 link also in the Net Zero scenario.

It should be noted that the minimum threshold IRR that was assumed for the analysis implies some regulatory framework to reduce risk exists. If that were not in place, the identified implied need for further interconnection could be lower, as the threshold would likely increase without such a framework.

5.3 Conclusions

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

- If a Net Zero pathway is followed in GB and its neighbours, additional interconnectors are beneficial from an overall socio-economic perspective and commercially feasible, based on the assumed IRR threshold.
- As the economic case for additional interconnection is linked to the price volatility created by growing penetration of intermittent renewable power generation, interconnectors commissioned later in the period perform best in this analysis.
- None of the identified interconnectors benefit GB consumers (except for the interconnectors to the Irish Single Energy Market in the High scenario). This is due to the way GB and its neighbours are expected to meet their net zero ambitions. While GB has excellent offshore wind resources, other countries are expected to rely more on onshore wind, solar PV, nuclear, and other forms of low carbon generation. GB is also expected to utilise CCS gas and CCS biomass, often more so than its neighbours. These combined effects lead to GB becoming a net exporter of electricity. Therefore, additional interconnectors would be expected to export more than they import, leading to them having a negative effect on GB consumers.
- The effect of new interconnectors on GB overall is more nuanced. Producers generally benefit from increased exports, while other interconnectors' revenues are cannibalised. The resulting net effect in the Net Zero case is minor for Northwest European links, and negative for Irish links.
- Combining GB and its neighbours, all projects have a positive total net welfare impact in the Net Zero and High scenarios. It is likely that additional benefits could accrue to other European countries not investigated in this analysis.
- It should be noted that we assume no capacity market revenues for any of the assessed links. In fact, going forward, interconnectors are not expected to be able to directly access capacity markets under European legislation.
- It is likely that projects connecting in 2025, and to some extent in 2030, could require floor payments in the early years of their operation. However, going forward, revenues are expected to grow. From 2035 onwards, most projects' revenues would either be expected to fall within the band of cap & floor, or exceed the cap. It should be noted that this is based on an average expectation of project capex, opex and therefore cap & floor levels for each link.

Annex A – Net Zero scenario details

A.1 Scenario development and purpose of the scenario

This annex presents an additional scenario that has been developed to evaluate the interconnectors assuming whole-economy net zero emissions are achieved across the analysed markets by 2050.

The Net Zero scenario has been developed to take a uniform approach on the decarbonisation commitment of the analysed countries and remove any large bias in the interconnector evaluation which depends on diverging decarbonisation agendas.

The scenario still reflects each country's characteristics such as higher/lower fuel prices, resource potential and demand profiles but takes away the effect of different decarbonisation commitment.

This scenario is consistent with a whole-economy net zero target at European level (UK included) by 2050, compared to a 1990 baseline.

As in this analysis the modelled period extends only until 2040, targets have to be assumed for the latter year. According to ENTSO-E's TYNDP 2020, a whole-economy net zero by 2050 would require a whole-economy emission reduction of 80% by 2040, compared to a 1990 baseline.

However, in this work we focus on the power sector (rather than in the whole economy), therefore, given that the power sector is one of the easier to abate sectors, it is reasonable to expect a more rapid decarbonisation compared to the whole-economy target by 2040.

In terms of baseline, power sector emissions are commonly measured against 2005 levels, as power emissions are subject to the EU ETS (which defines legal caps referring to a 2005 baseline). Now, a whole-economy emission reduction of 80% compared to a 1990 baseline is equivalent to a 79% whole-economy emission reduction compared to a 2005 baseline. This suggests that it should be aimed for a power-sector emission reduction greater than 79% (compared to a 2005 baseline) by 2040. From now onward, all the emission targets will be referring to the power sector, when not otherwise specified.

Therefore, for countries where publicly available net zero scenarios are not available, a power-sector emission reduction of at least 85% is assumed as a sensible target for 2040. This target applies to France, Belgium, the Netherlands, Denmark and Norway[18].

For Germany, a slightly more ambitious target is pursued (87% compared to a 2005 baseline), in line with a report published in October 2020.

Moreover, Ireland is assumed to have a 95% emission reduction target by 2040 (compared to a 2005 baseline). Such an ambition level is set within the range

18 It should be noted that Denmark's and Norway's power sectors are already characterised by extremely low carbon emissions.

spanned by Eirgrid's TES 2019 scenarios and is close to the most ambitious of their envisaged targets.

For GB, an emission reduction target of around 105% by 2040 is assumed (slightly reducing the 123% target as per FES' System Transformation, in line with other changes done in the capacity mix). This results in GB being more aligned with its neighbours, while it still remains the market leading the decarbonisation effort and it evolves in a way consistent with a 2050 whole-economy decarbonisation.

A.2 Scenario description

The Net Zero scenario represents a future which is driven by a strong decarbonisation agenda across Europe and in Great Britain. Fuel prices follow a moderate growth path, while carbon prices increase more steadily throughout the modelled period.

All the analysed countries have strong commitments in reducing emissions, which are however put in place in different ways. GB is the only country which aims at negative emissions from the power sector, with a large deployment of CCS biomass. Other European countries focus more on nuclear, when available, and hydrogen use in the power sector.

A.2.1 Sources of modelling approach

The scenario has been built using, once again, FES' System Transformation and ENTSO-E's Global Ambition as starting points. However, various changes have been applied to reflect the most recent policies' and expected developments of the power sector for each market.

Exhibit A.1 – Overview of the Net Zero scenario assumptions

	GB	Ireland	France	Germany	Netherlands & Belgium
Demand	· 2020-2040 CAGR of 0.9% · Demand increase after 2030 with electrification of heat and transport	· 2020-2040 CAGR of 2.7% · String increase of demand driven by electrification and data centres	· 2020-2040 CAGR of 0.6% · More modest demand increase, slower electrification of transport and heat	· 2020-2040 CAGR of 1.5% · Strong demand increase due to Heat and transport electrification	· 2020-2040 CAGR of 0.9% (NL) and 0.5% (BEL) · Demand increase is stronger in the Netherlands
Carbon price	· CPS higher than EU ETS price in the short term, equal to it from 2030 onward	· Carbon price to grow reaching €97.8/tCO2 in 2040			
RES deployment	· RES Capacity to reach 129GW in 2040. · Offshore wind is the preferred technology in the long term	· RES Capacity to reach 21GW in 2040. · Wind offshore and onshore are preferred to solar	· RES Capacity to reach 165GW in 2040 · Solar largely deployed	· RES capacity to reach 421GW in 2040 · Solar is the preferred technology	· RES capacity to reach 53GW (NL) and 29GW (BE) in 2040 · Solar widely deployed
CCS biomass	· CCS biomass used from 2030 · GB reaches the largest deployment of CCS biomass, 2.1GW in 2040	· Very limited use of biomass CCS	· Limited deployment of CCS biomass (0.4GW in 2040)	· Modest deployment of CCS biomass (1.1GW in 2040), current plans do not envisage large use of CCS technologies	· Modest build of CCS biomass in BE (0.6GW by 2040) but more significant in NL (1GW by 2040)
Nuclear capacity	· Strong deployment · Adding 4.8GW of new capacity by 2040	· No nuclear allowed	· Ageing nuclear plants are replaced by new capacity after 2035, 8.8GW are replaced by 2040	· No nuclear allowed	· No nuclear allowed
Hydrogen	· Hydrogen widely deployed with H2 CCGT and electrolysis available	· H2 plants are added to replace old conventional thermal plants and support the fast-growing demand	· A limited deployment of H2 plants is assumed	· Hydrogen is widely deployed with H2 CCGTs and electrolysis · Largest H2 CCGT capacity (14.5GW by 2040)	· Modest deployment of H2 and electrolysis

GB, as is the case in the FES 2020 System Transformation scenario, remains the most ambitious country in terms of emissions reduction within the power sector with the largest deployment of CCS biomass. Negative emissions from the power sector are expected to compensate for lower reduction in other sectors. Large deployment of renewables, especially offshore wind, is envisaged with a relevant role of hydrogen towards decarbonisation.

Ireland is expected to reduce emissions by 2040 following GB, with large deployment of renewables (especially onshore and offshore wind) reaching a 70% renewable penetration by 2030. Demand is expected to grow significantly and technologies such as hydrogen (and CCS biomass, to a limited extent) are expected to be needed in order to achieve the emission target. Inputs for Ireland reflect a scenario which is compatible with the FES scenario 'System Transformation' developed by National Grid for GB.

France's capacity mix is projected to see a growth in renewable capacity, especially solar, and the replacement of ageing nuclear plants after 2035. New nuclear will contribute in reducing emissions with a very limited use of CCS and limited additions of hydrogen CCGTs. France inputs are elaborated starting from the RTE document published at the end of September 2020[19].

Germany, on the other hand, is expected to focus the decarbonisation effort increasing the share of renewables and the electrification rate of the transport and heat sectors and developing a strong hydrogen economy. The use of carbon capture storage is limited to the long term and only to remove residual emissions which cannot be otherwise eliminated. German inputs are based on a report published in October 2020[20].

In Belgium, as well as in the Netherlands, decarbonisation is assumed to happen slightly more slowly and to accelerate towards the end of the modelling period. Belgium achieves its emission target thanks to its renewable capacity growth (particularly solar PV), some CCS biomass deployment and some hydrogen-fired capacity. Inputs for Belgium are developed using as a starting point the scenarios contained in Elia's 'Electricity Scenarios for Belgium towards 2050'[21], published in November 2017.

In the Netherlands, the more noticeable demand growth (compared to Belgium) is supported by an increasing renewable deployment – especially solar PV and offshore wind – yielding an 80% renewable penetration by 2030. Some coal plants are assumed to be converted to biomass by 2030, which also plays a role in generating zero-carbon electricity in the long term. Additionally, some CCS biomass and hydrogen plants contribute to reduce emissions even further and achieve the 2040 target. Inputs for the Netherlands are based on the 'Climate and Energy Outlook (KEV) 2020'[22], published in October 2020 by Netherlands Environmental Assessment Agency (PBL).

A.3 Capacity mix in the Net Zero scenario

The 'Net scenario has been constructed so to reflect GB's installed capacity mix as depicted in FES 'System Transition' scenario (FES ST). Offshore wind is the

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19 https://www.concerte.fr/system/files/concertation/2020-09-25-RTE_CPSR_LQ.pdf. The N1 scenario is taken as a reference

20 Prognos, Öko-Institut, Wuppertal-Institut (2020): Towards a Climate-Neutral Germany. Executive Summary conducted for Agora Energiewende, Agora Verkehrswende and Stiftung Klimaneutralität

21 https://www.eliagroup.eu/-/media/project/elia/shared/documents/elia-group/publications/20171114_elia_4584_adequacyscenario.pdf

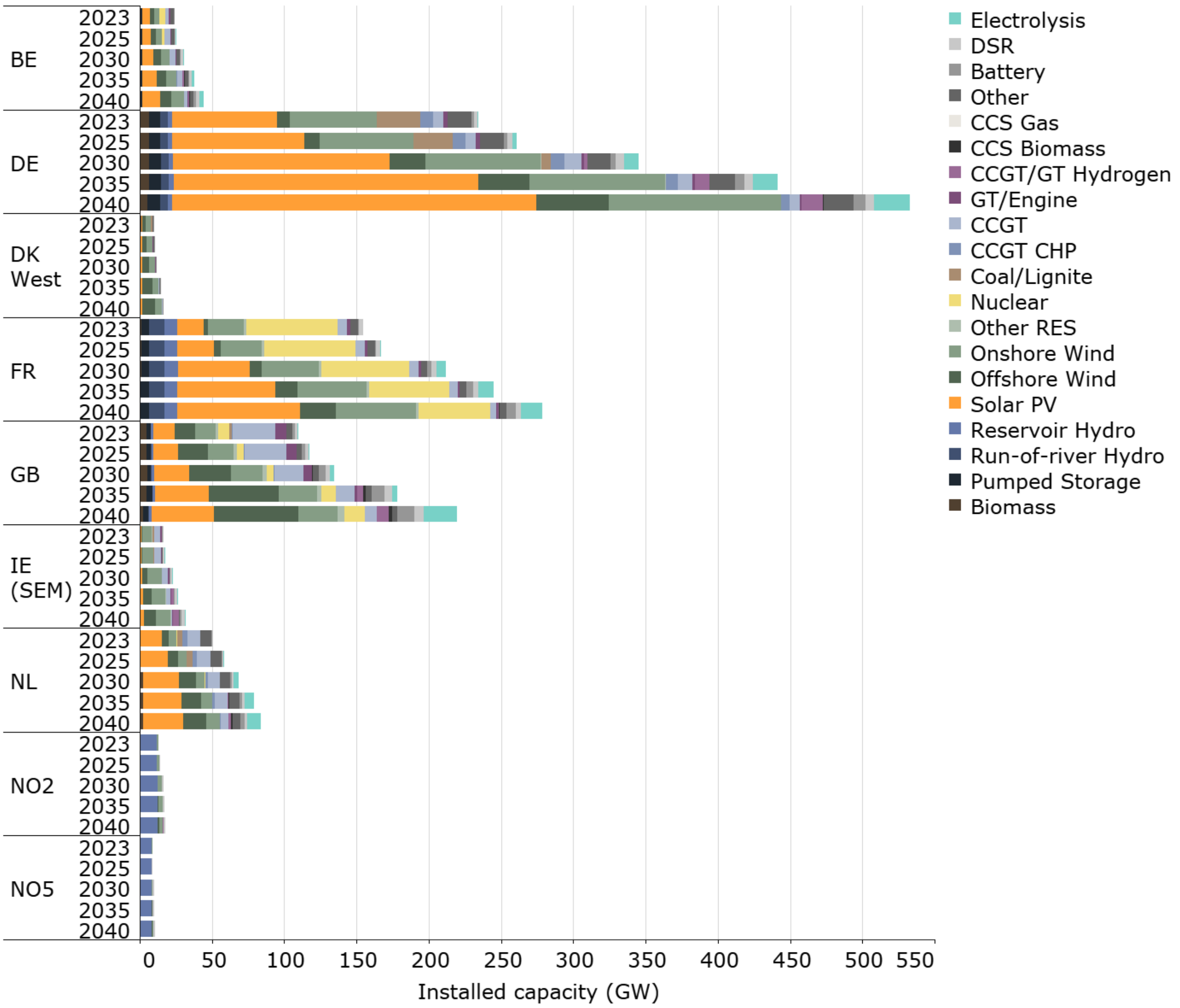
22 https://www.pbl.nl/sites/default/files/downloads/pbl-2020-klimaat-en-energieverkenning2020-3995.pdf

preferred renewables technology, and from 2030, CCS (including CCS biomass) is deployed across the country.

In the rest of the modelled countries, capacity assumptions are based on a number of published scenarios that reflect these countries' ambitions towards reaching net zero emissions. The starting point for capacities is the capacity mix as defined by ENTSO-E's 'Global Ambition' scenario.

Exhibit A.2 shows the installed capacity mix assumptions for Belgium, Great Britain, Ireland and the Netherlands in the Net Zero scenario.

Exhibit A.2 – Net Zero scenario capacity mix assumptions (GW)



A.4 GB interconnection capacity in the Net Zero scenario

As shown in Exhibit 3.2 in section 3.2.2 above, all existing projects and those that were granted a cap and floor regime by Ofgem in either the first or second window are assumed to be operational by 2025.

In the Net Zero scenario, as well as in the other scenarios, additional projects have been added, if economically justified, to match FES' total interconnector capacity from GB to its neighbours. The additional interconnectors that were selected were those identified as contributing to overall system cost minimisation based on our modelling (scenario development).

The additions implemented in the Net Zero scenario are identical to the additions implemented in the CBA Base case, which are presented in section B.4 below (Exhibit B.5).

A.5 Fuel price assumptions in the Net Zero scenario

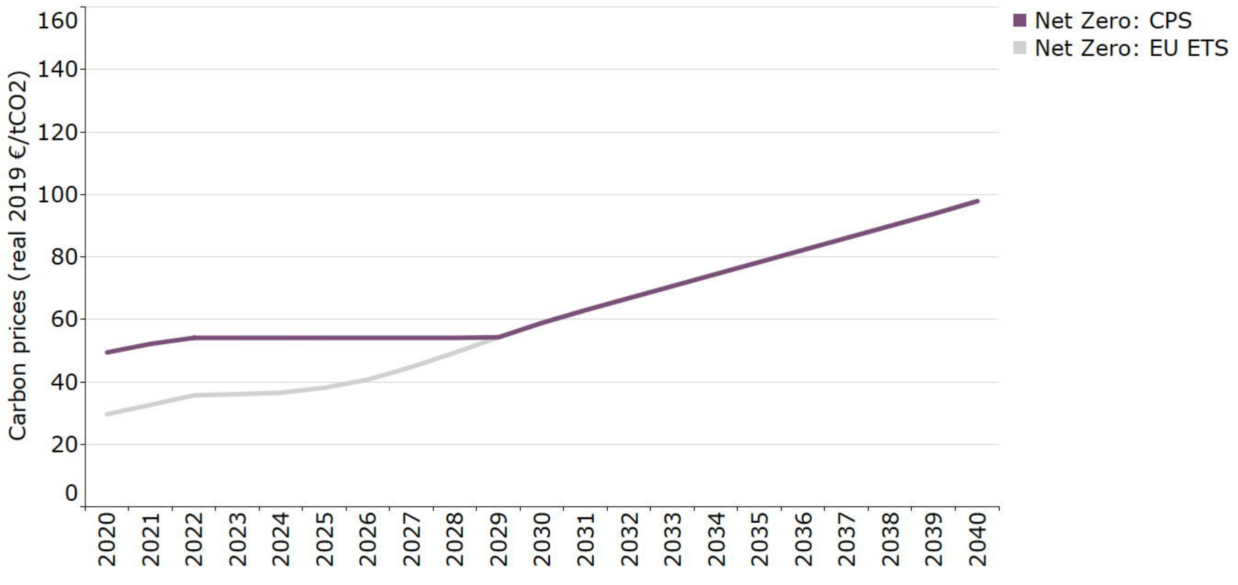
The fuel price assumptions used for the Net Zero scenario coincide with the fuel price assumptions used in the CBA Base case, which are described in section B.5 below.

A.6 Carbon price assumptions in the Net Zero scenario

Carbon prices affect electricity prices through their effect on the cost of thermal generators (oil, gas, coal). At the moment, all EU countries are covered by the EU ETS, while GB applies an additional element, the Carbon Price Support (CPS) on top of the EU ETS price. While this could change in the future, based on arrangements for GB leaving the European Union, we have used assumptions based on a continuation of the schemes currently in place.

For the Net Zero scenario, the National Grid's FES (2020 update) is used. In particular, carbon prices in the Net Zero scenario are based on National Grid's Base case carbon prices, as shown in Exhibit A.3.

Exhibit A.3 – Effective carbon prices in GB and EU ETS in the Net Zero scenario (€/tCO_2)



Annex B – Other scenario inputs and results

B.1 Annex introduction

This annex provides additional detail on the model inputs and assumptions used to construct the scenarios used in the analysis conducted for this report. This section describes three scenarios, a Base case, a High and a Low scenario. The Net Zero scenario used in the analysis for this report is based on this Base case, with changes detailed in the previous annex. The Base case is not used in the analysis (the Net Zero is used as the reference scenario in this analysis), but it has been used to form a basis for High and Low scenarios, and is therefore also described below.

The subsequent sections describe demand (B.2), capacity mix (B.3), interconnection capacity (B.4), fuel prices (B.5) and carbon prices (B.6). Section B.7 shows the wholesale price results for the Base case (wholesale prices for High and Low scenario were described above in sections 3.3.3 and 3.3.4).

B.2 Demand assumptions

Electricity demand assumptions are based on National Grid's Future Energy Scenarios (FES) for GB, and on the ENTSO-E 'Global Ambition' scenario for the rest of the modelled countries[23]. The annual demand projections discussed in this section do not include the additional demand coming from electrolysis, which is an output of our BID3 model.

- Base Case. The annual demand for GB is taken from the FES 'System Transformation', accounting for the share of each demand component: base demand[24], heat and transport. This approach allows to reflect the increasing electrification expected in each sector over the modelled period. For GB's neighbouring countries, the annual demand reflects the ENTSO-E's 'Global Ambition'.
- High scenario. The annual demand source for GB is the FES 'Consumer Transformation', reflecting each demand component's evolution. For GB's neighbours, a modified version of ENTSO-E's 'Global Ambition' is used, where the annual demand used in the Base case is scaled by a ratio defined, in each year, as the High scenario GB demand divided by the Base case GB demand. This results in GB's neighbours having a total annual demand scaled in line with GB.
- Low scenario. GB demand is constructed as a modified version of the FES 'Steady Progression' which is the FES scenario with the lowest heat and transport demand. The Low scenario GB demand is assumed to be the sum of base demand from FES System Transformation, and heat demand and

23 France, Germany, Netherland, Belgium, Norway, Denmark and Ireland.

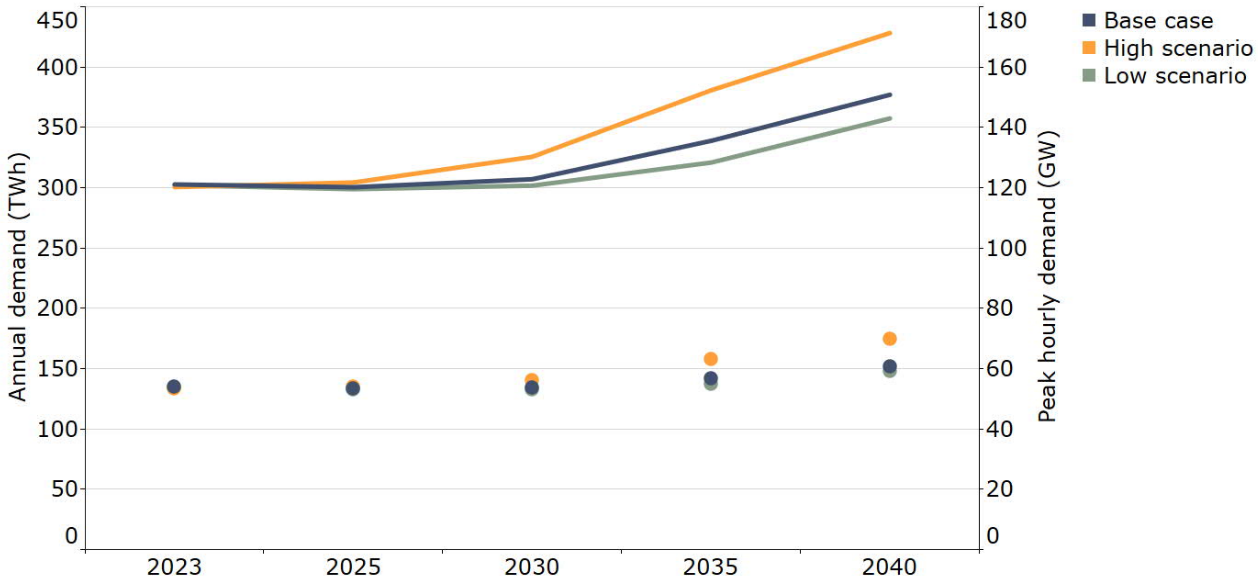
24 Base demand describes the sum of the demand components which in FES are referred to as: industrial and commercial, home appliances, and residential heating as of 2020. Post-2020, the additional residential heating demand is classified as the heating component of the demand.

transport demand from FES Steady Progression. This ensures the total annual demand in the Low case is the lowest across the three scenarios to reflect a situation with lower economic growth and stagnating demand. For GB's neighbours, a modified version of ENTSO-E's 'Global Ambition' is used. The Base case annual demand is scaled by a ratio defined, in each year, as the Low scenario GB demand divided by the Base case GB demand. This results in GB's neighbours having a total annual demand scaled in line with GB, but their base demand, heat and transport components having the same share as in the Base case.

While the annual demand is a model input, the peak demand is a model output, resulting from the assumed annual demand and the demand profiles used for each demand component (base demand, heat and transport). The source of the various demand profiles and the split of the total demand across the various categories[25] (base heat and transport) is AFRY Central scenario.

The evolution of GB demand in the three scenarios is shown in Exhibit B.1.

Exhibit B.1 – Projections of total and peak demand for Great Britain (TWh, GW)



Notes: Solid lines: annual demand. Dotted lines: peak hourly demand.

— In the Base case, the annual demand starts around 300TWh and is largely flat until 2030, before increasing to 377TWh in 2040. This is primarily due to transport demand stepping up post-2030. Base demand slightly declines, and heat demand modestly increases over time, balancing each other. Peak demand remains stable at about 53GW until 2030, before increasing to reach 61GW in 2040.

— The High scenario is characterised by a base demand similar to the Base case with a faster electrification of transport and a much stronger electrification of heat. This results in a more pronounced increase of annual demand, totalling

25 When the split is not available from the selected sources, i.e. for all countries excluding GB.

428TWh by 2040. Peak demand is highest in this scenario, reaching 70GW in 2040.

- The Low scenario's annual demand is similar to the Base case in the short term, as the base demand is identical, and transport and heat demand growth are limited before 2030. Afterwards, the spread between Low scenario and Base case increases, resulting in an annual demand of 357TWh in 2040. Nevertheless, the Low scenario has the slowest electrification of heat and transport among the three scenarios. The peak demand in the Low scenario is very close to the Base case in the short term, and starts diverging slightly from 2035 onward. In 2040, peak demand totals 59GW.

B.3 Capacity mix – principles and overview

The capacity mix in GB across the scenarios has been assumed to be in line with the corresponding FES scenario, with specific changes applied where necessary (e.g. to achieve internal consistency or consistency with the storyline), as described in the next sections. For all connected countries, the ENTSO-E 'Global Ambition' scenario represents the starting point, with changes applied to achieve consistency in each scenario across the different markets.

Our methodology also ensures that there are no hours of load loss in each market across the five weather years used in the modelling. That is, in all scenarios it is ensured that a sufficient capacity margin is maintained throughout the modelled period.

B.3.1 Capacity mix in the Base case

The Base case is consistent with National Grid' 'System Transformation' scenario for GB and with ENTSO-E's 'Global Ambition' scenario[26] for the other modelled countries. Changes have been applied to ensure consistency across the various analysed markets. Main changes in GB are as follows:

- CCS biomass capacity, which is widely deployed in GB according to the FES ST is completely absent in any other markets. This would lead to artificially high price differentials between GB and other markets. Therefore, to achieve a more consistent picture at a European level in terms of available technologies, CCS biomass in GB is replace by CCS gas.
- Electrolysis capacity from 2029 onward is reduced, to align electrolysis output with the FES ST expected production.

The following changes are applied to European countries from the 'Global Ambition' starting point:

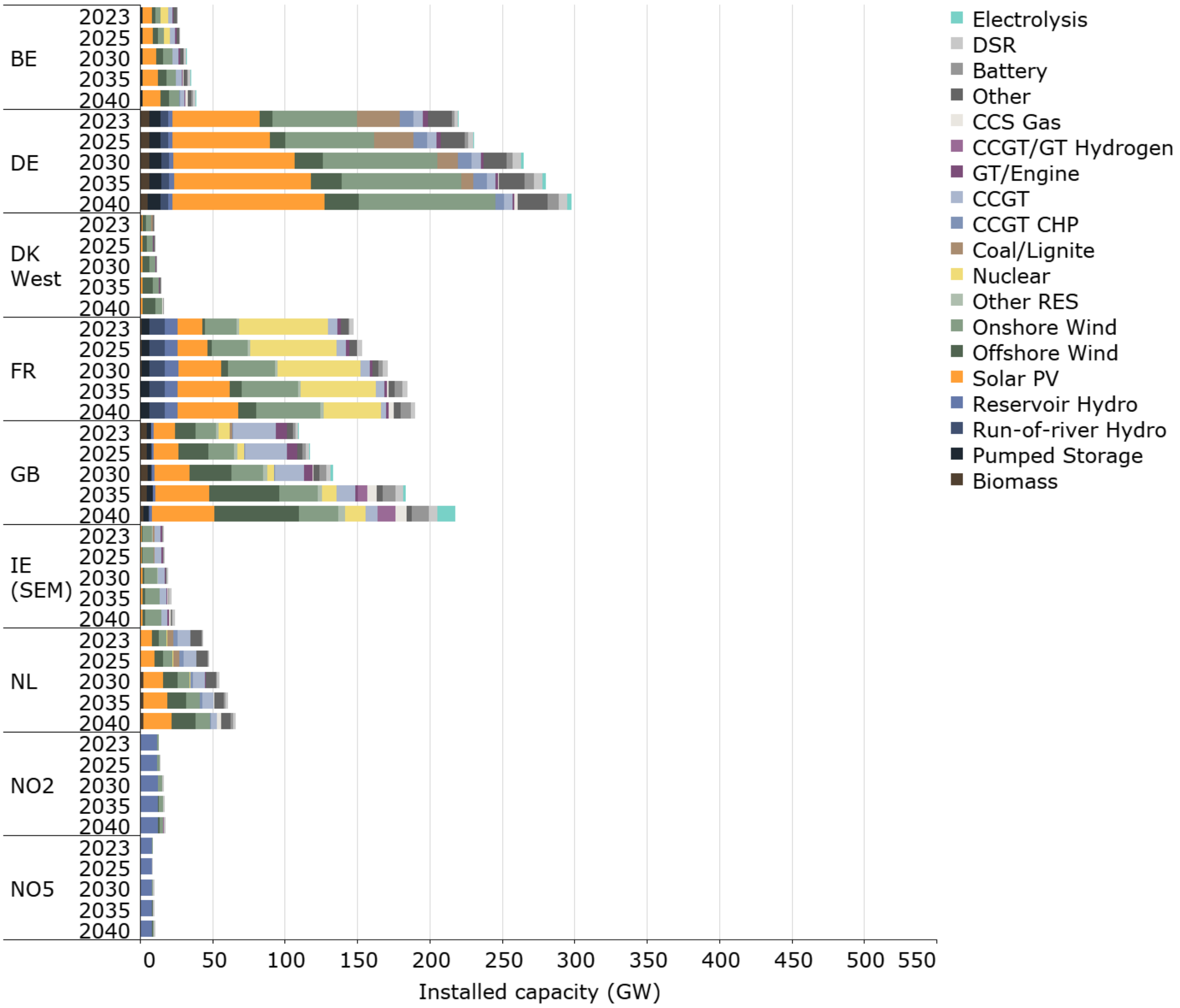
- Starting from the late 2020s, some CCGT capacity is removed to achieve expected levels of capacity margins and to be partly replaced by CCS gas capacity. The aim of introducing CCS gas is to make sure this technology is developed in GB as well as in other markets.
- Some new build nuclear is added in France after 2035 to replace decommissioning of ageing plats. Similarly to what happens in FES ST, where investments in nuclear capacity are expected in the future, France is also expected to replace some of its old capacity.

26 See: https://tyndp.entsoe.eu/scenarios/

— Two coal plants in the Netherlands are assumed to be converted to biomass in 2030.

Exhibit B.2 shows the installed capacity mix assumptions for Belgium, Great Britain, Ireland and the Netherlands in the Base case.

Exhibit B.2 – Base case capacity mix assumptions (GW)



B.3.2 Capacity mix in the High scenario

The High scenario has been built to reflect GB's installed capacity mix as depicted in National Grid's 'Consumer Transformation' as closely as possible. Specific adjustments, in line with what has been described for the Base Case, are:

— the CCS biomass capacity is entirely replaced by CCS gas capacity; and

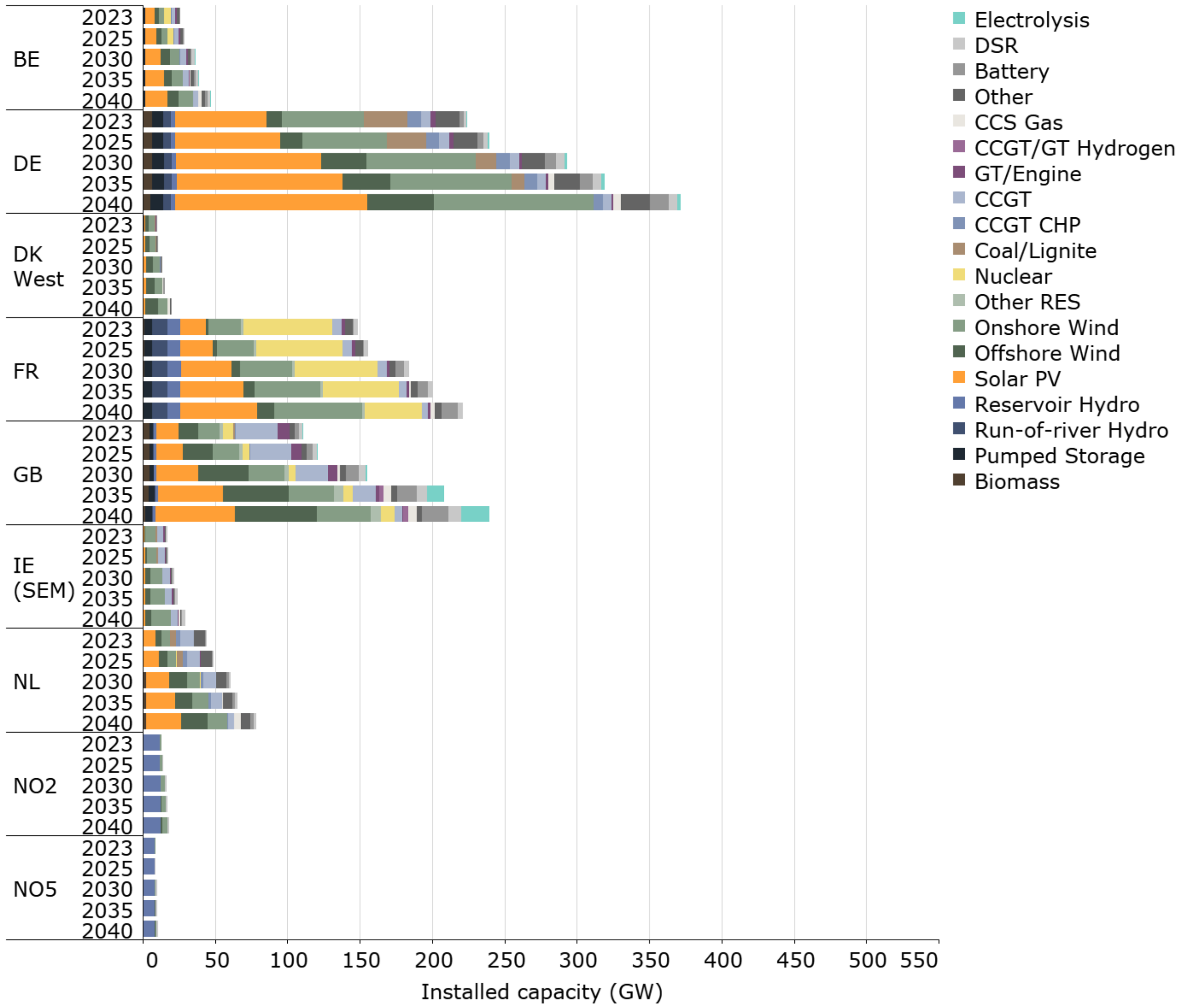
— the new build electrolysis capacity from 2029 is reduced.

In the rest of the modelled area capacity assumptions are based on a modified version of ENTSO-E's 'Global Ambition' scenario. The starting point for connected countries is the capacity mix as defined in the Base case, but the following additional changes are implemented in order to align assumptions:

- Solar PV, onshore wind, offshore wind and battery capacities are scaled so that, in each year, the same relative change that occurs in GB comparing its High scenario capacities with its Base case capacities also occurs in the other markets.
- After 2030, CCS gas capacity is increased across the region.
- Further offshore wind capacity is added in Belgium, Germany and the Netherlands.
- Some onshore wind is replaced with offshore wind capacity in Ireland and in Germany by 2040, to adjust to the higher offshore wind penetration in GB.

Exhibit B.3 shows the installed capacity mix assumptions for Belgium, Great Britain, Ireland and the Netherlands in the High scenario.

Exhibit B.3 – High scenario capacity mix assumptions (GW)



B.3.3 Capacity mix in the Low scenario

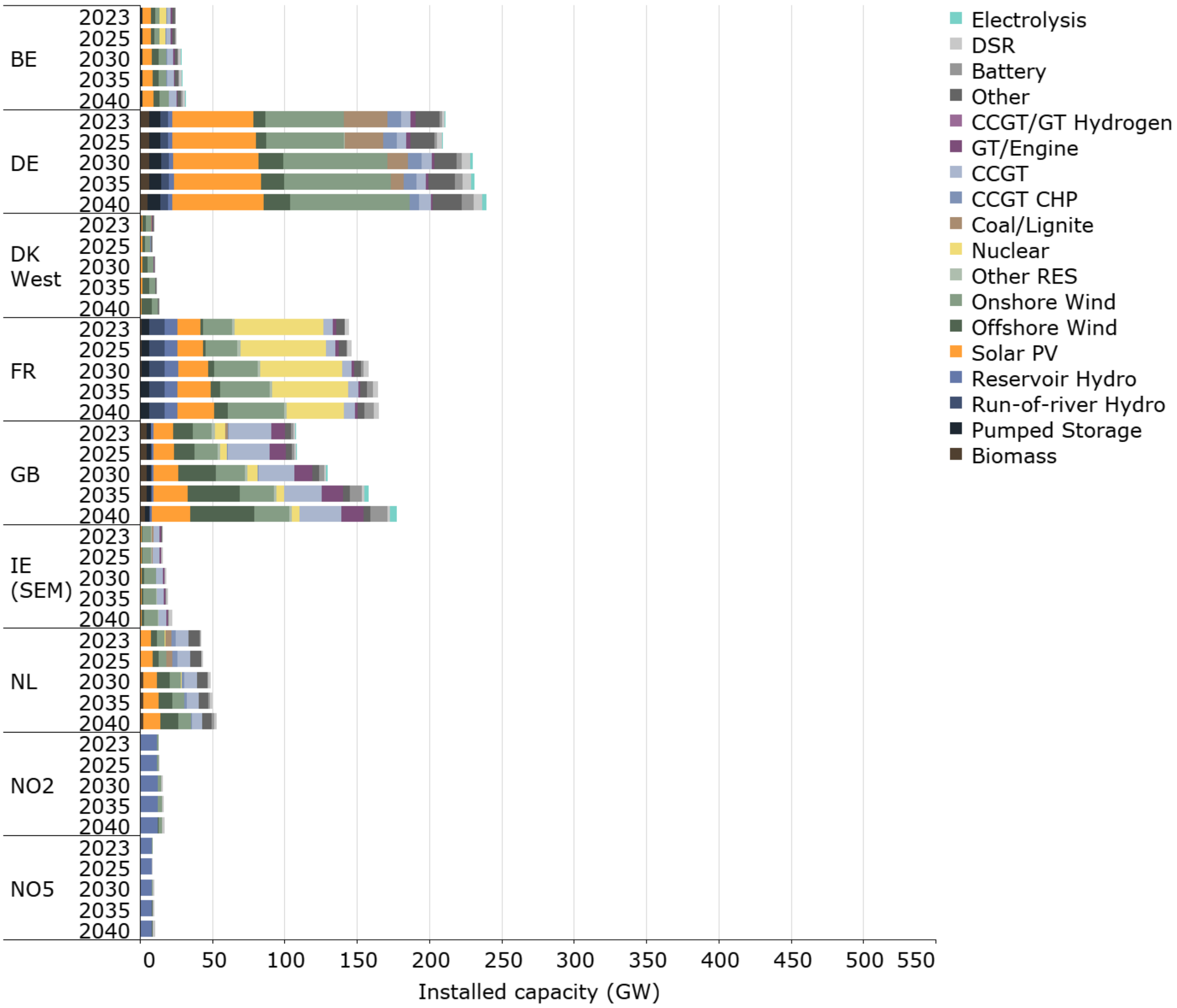
The Low scenario has been constructed so to reflect GB's installed capacity mix as depicted in National Grid's 'Steady progression' scenario (FES SP). The only change applied is represented by a reduction of the new build electrolysis capacity from 2029 onwards.

In the rest of the modelled countries, capacity assumptions are based on a modified version of ENTSO-E's 'Global Ambition' scenario which does not include any CCS deployment in line with FES SP. The starting point for renewables capacities is the capacity mix as defined in the Base case, where:

— solar PV, onshore wind, offshore wind and battery capacity is scaled so to that, in each year, the same relative change that occurs in GB comparing its Low scenario capacities with its Base case capacities happen in every other market.

Exhibit B.4 shows the installed capacity mix assumptions for Belgium, Great Britain, Ireland and the Netherlands in the Low scenario.

Exhibit B.4 – Low scenario capacity mix assumptions (GW)



B.4 GB interconnection capacity

As shown in Exhibit 3.2 in section 3.2.2 above, all existing projects and those that were granted a cap and floor regime by Ofgem in either the first or second window are assumed to be operational by 2025.

Additional projects have been added to match the FES' total interconnector capacity from GB to all its neighbours. In some instances, if economically justified in the respective scenarios, the overall capacity deviates from the FES assumptions, if this contributed to overall system cost minimisation based on our modelling during the scenario development.

The additions across scenarios are as shown in Exhibit B.5.

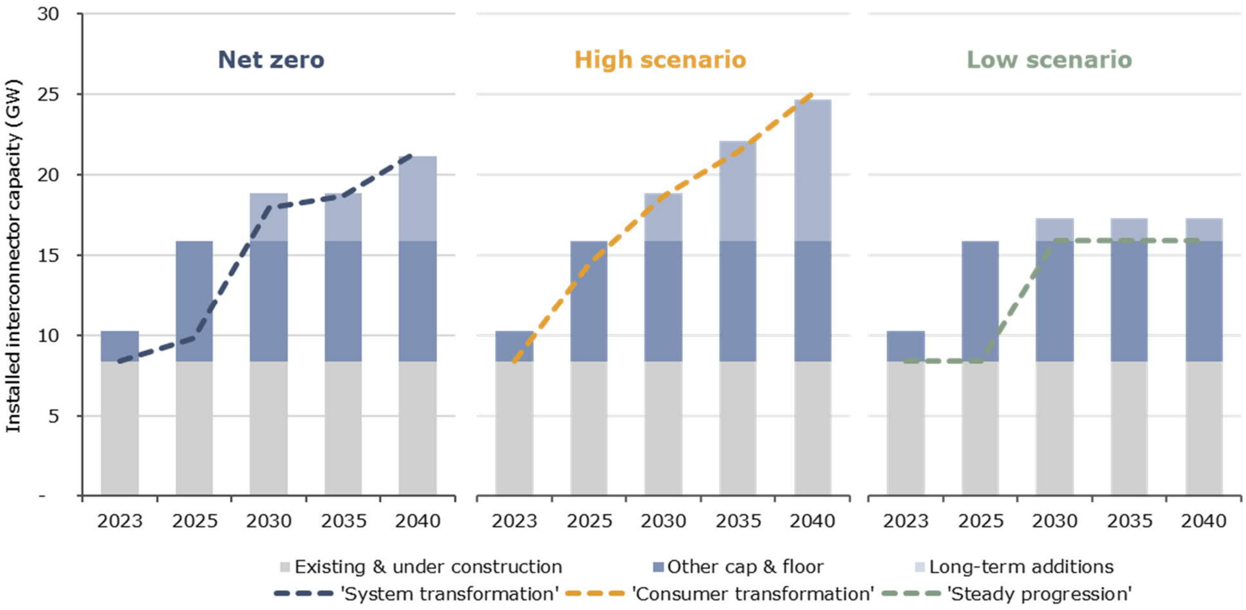
Exhibit B.5 – Additional interconnector capacities across scenarios in the long-term

Connected country	Base case	High scenario	Low scenario
Belgium	1,400MW (commissioned by 2030 400MW (by 2040)	1,400MW (by 2030) 400MW (by 2035)	1,400MW (by 2030)
Denmark	-	-	-
France	1,000MW (by 2040)	600MW (by 2035)	-
Germany	900MW (by 2040)	1,800MW (by 2035) 2,000MW (by 2040)	-
Ireland	-	400MW (by 2035)	-
Netherlands	1,600MW (by 2030)	1,600MW (by 2030) 600MW (by 2040)	-
Norway	-	-	-

Notes: Model is run for spot years only (2023, 2025, 2030, 2035, 2040), so actual expected commissioning date can deviate from 'commissioned by' date. Capacities are additive.

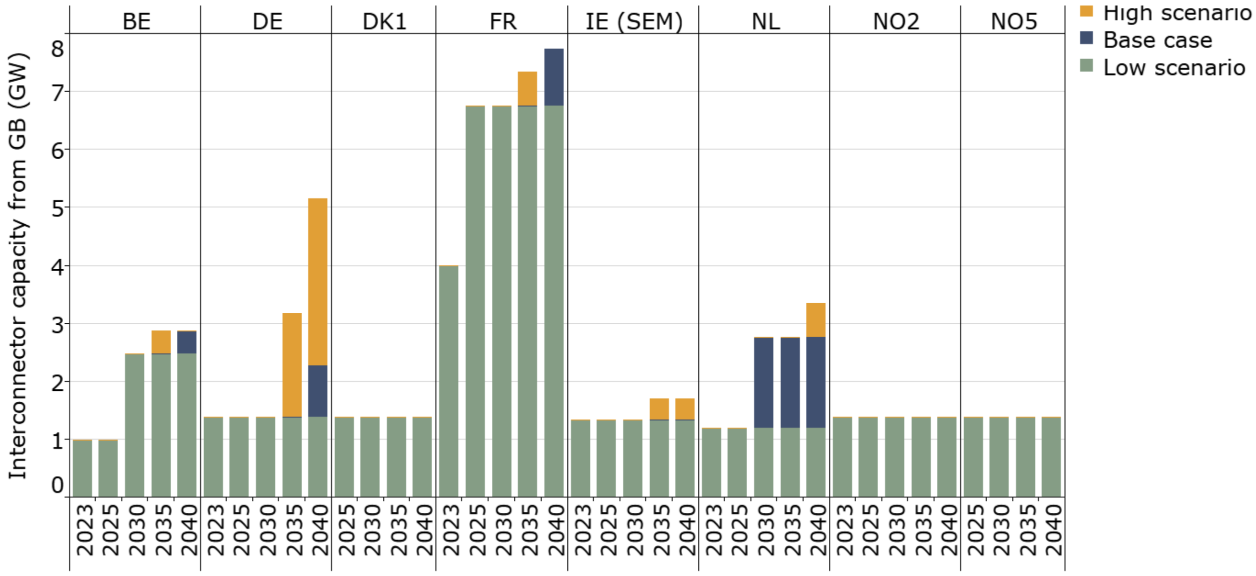
This compares to the overall capacities as given in the National Grid Future Energy Scenarios as shown in Exhibit B.6. Before 2030, differences between the baseline and the underlying FES are larger, due to the assumption of all cap & floor projects going ahead by or before 2025. From 2030 onwards, differences range between -300MW and +950MW in the Net Zero scenario, between -400MW and +600MW in the High scenario, and are +1,350MW in the Low scenario.

Exhibit B.6 – Total GB interconnector capacity in the baseline in each scenario



The total IC capacity from GB to each of its neighbours (and vice versa) is shown in Exhibit B.7.

Exhibit B.7 – Total interconnector capacity from GB to its neighbours (GW)



Note: Chart shows additions in Base case over Low scenario and High scenario over Base case. The only exception is the interconnection capacity between GB and France, where in 2040 the Base case capacity is greater than the High scenario capacity (7.7GW compared to 7.3GW).

B.5 Fuel price assumptions

Fuel prices in GB for each scenario were selected from BEIS' Fossil Fuel Price Assumptions 2019. The scenario selected for the Base case is BEIS' Central scenario for fossil fuel prices, while BEIS' High and Low have been used for the corresponding High and Low scenario developed for this study.

When BEIS' scenarios provided an international price – such as for Crude Oil and ARA Coal – the price has been used directly to generate prices for all the markets. For gas, the evolution provided by BEIS for GB gas has been used to estimate the price for all the other markets. Technically, the same price differential between GB and the other countries of the AFRY scenarios has been assumed to derive, from the BEIS GB gas prices, all the other markets' prices.

Crude oil, ARA coal and NBP gas prices for the three scenarios are shown in Exhibit B.8, Exhibit B.9 and Exhibit B.10, respectively.

Exhibit B.8 – Crude oil prices in Base case, High and Low scenarios ($/bbl)

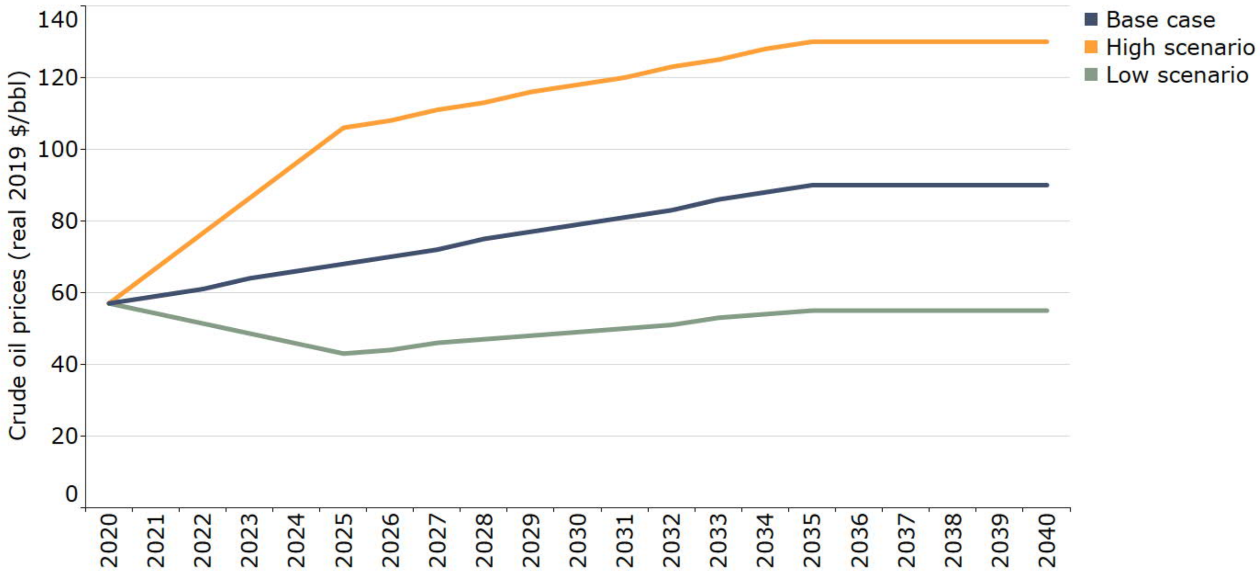


Exhibit B.9 – ARA coal prices in Base case, High and Low scenarios ($/tonne)

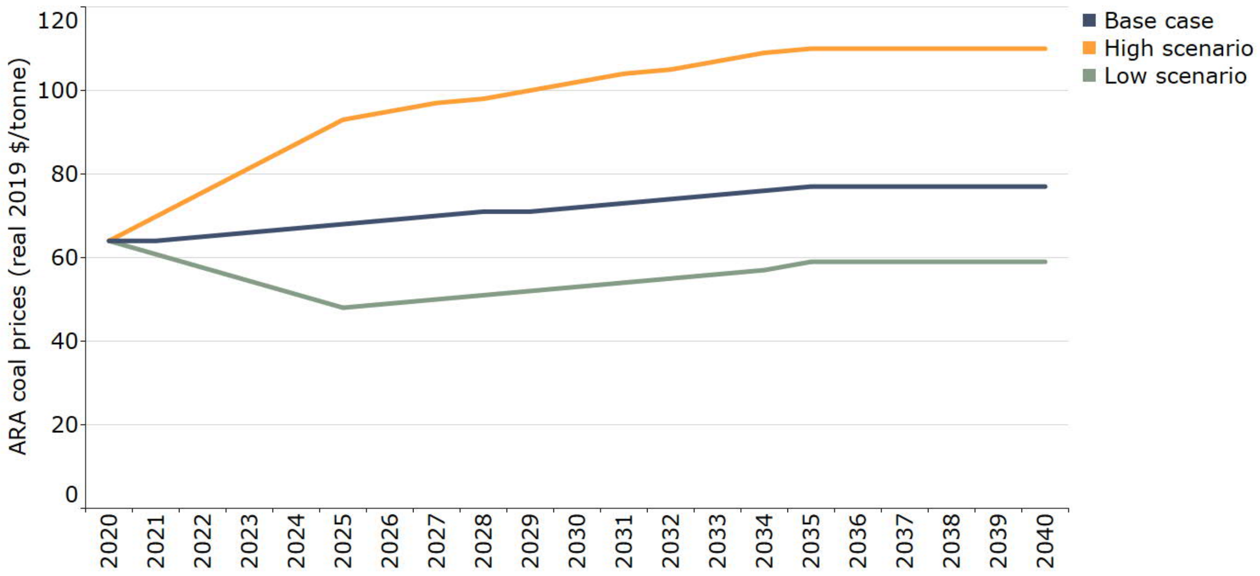
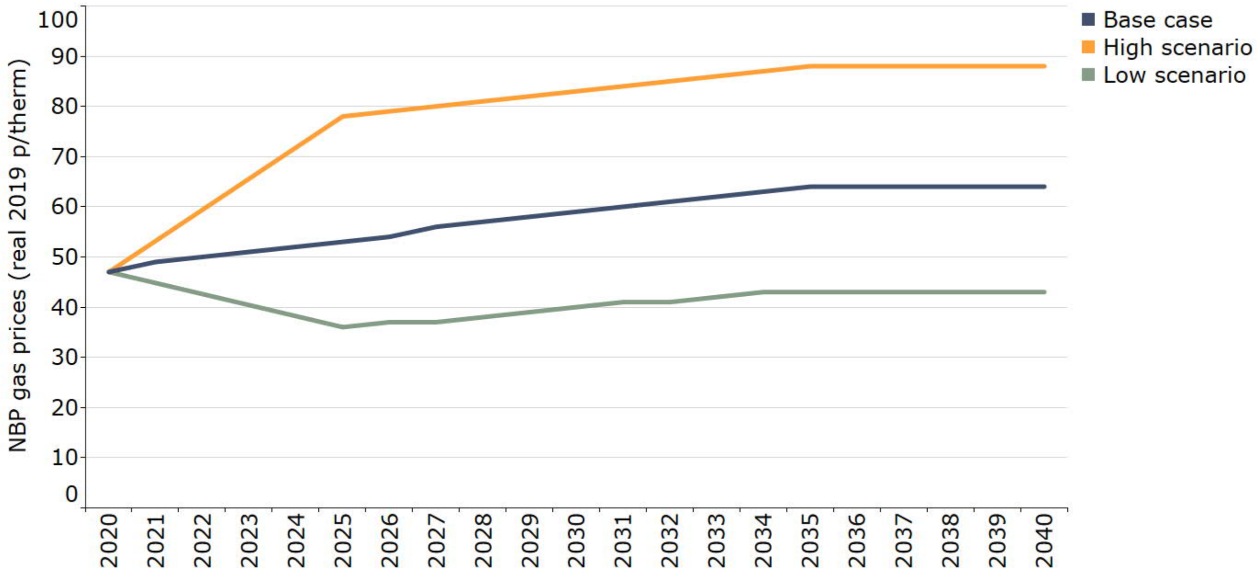


Exhibit B.10 – NBP gas prices in Base case, High and Low scenarios (p/therm)



B.6 Carbon price assumptions

Carbon prices affect electricity prices through their effect on the cost of thermal generators (oil, gas, coal). At the moment, all EU countries are covered by the EU ETS, while GB applies an additional element, the Carbon Price Support (CPS) on top of the EU ETS price. While this could change in the future, based on arrangements for GB leaving the European Union, we have used assumptions based on a continuation of the schemes currently in place.

For the Base case, the carbon prices for both the EU ETS price and the CPS are based on BEIS Energy and Emissions Projections (2018 update)[27].

For the High and Low scenario, the National Grid's FES (2020 update) is used.

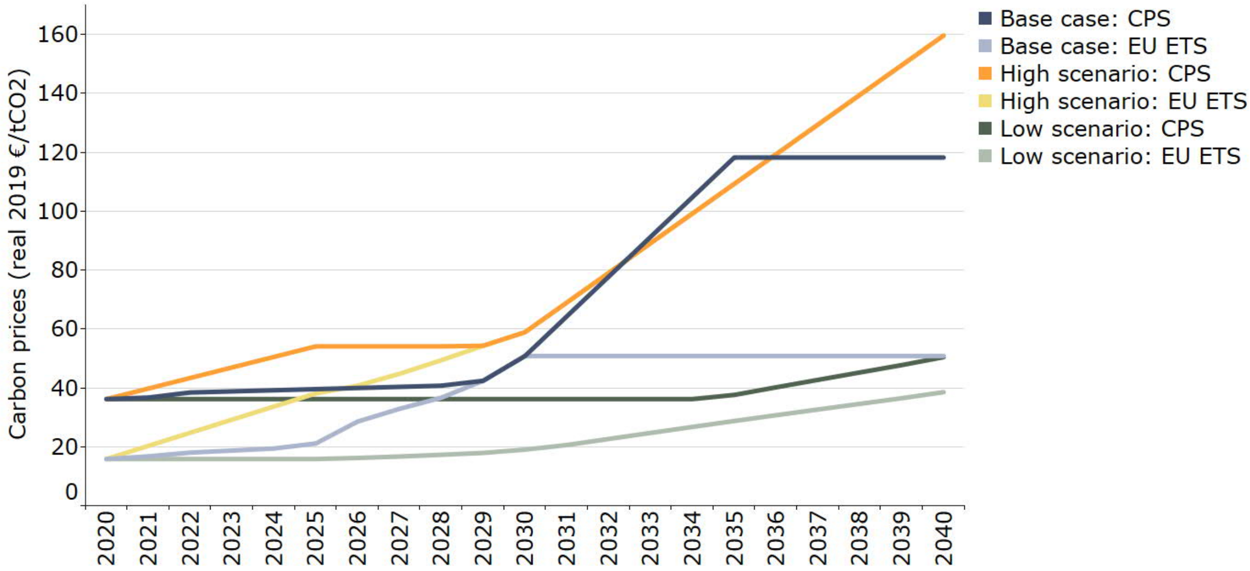
— Carbon prices in the High scenario are based on National Grid's High case carbon prices.

— The Low scenario is based on National Grid's Low case carbon prices. The carbon prices are assumed to remain flat in the period 2020-2025, and equal to the carbon price value in 2020 in the Base case (this applies both to the EU ETS prices and the CPS). Afterwards, the same year-on-year increases used in FES' Low case are applied, to both the EU ETS prices and the CPS. This approach ensures the Low scenario is characterised by a lower carbon price compared to the Base Case.

The resulting carbon prices used for the three scenarios are shown in Exhibit B.11.

27 https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2018

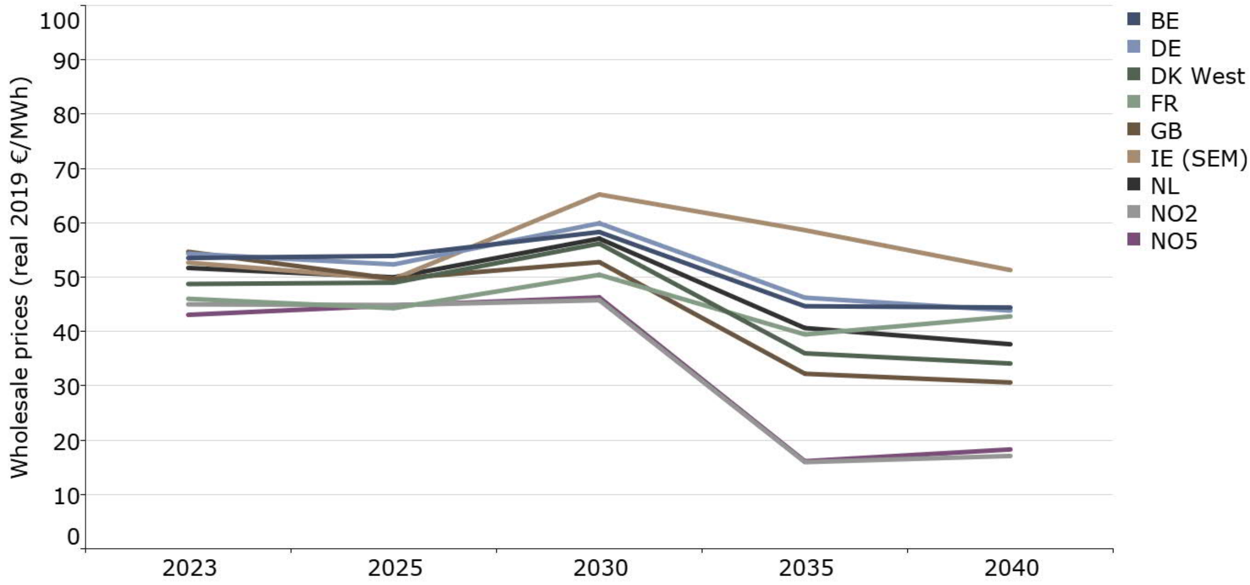
Exhibit B.11 – Effective carbon prices in GB and EU ETS across scenarios (€/tCO_2)



B.7 Electricity prices in the Base case

The annual wholesale prices in the Base case for GB and the modelled interconnected countries are shown in Exhibit B.12 below.

Exhibit B.12 – Wholesale power prices by country in the Base case



— In 2023, prices between GB, Denmark and most continental European countries (with the exception of France) are similar, between €50/MWh and €55/MWh. Prices then start diverging, with GB reducing further than many other countries, due to strong offshore wind growth. Irish prices in particular rise to higher levels, leading to larger differentials.

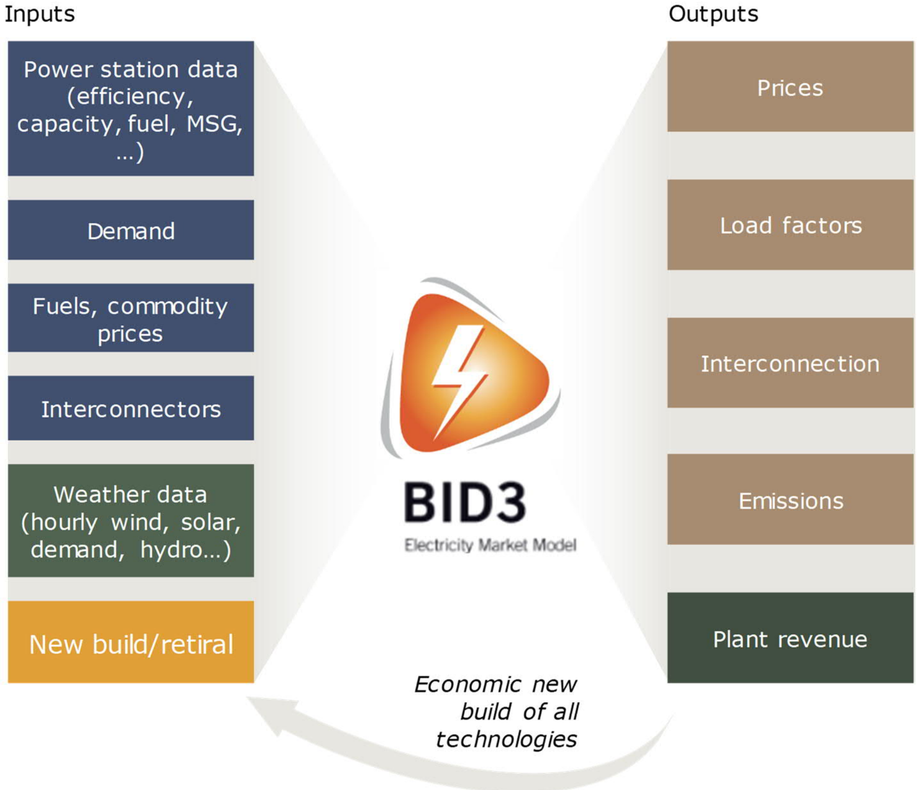
- French prices start lower than those in GB in the short-term, due to the higher nuclear share. However, from the mid-2030s, French average prices are above GB prices due to a lower renewables share.
- Prices in Norway are below those in all other countries due to the country’s reliance on hydro, and, from 2030 onwards, growing wind penetration.

Annex C – BID3 power market model

C.1 Overview of the BID3 model

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

Exhibit C.1 – BID3 overview



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

C.2 BID3 modelling approach

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

C.2.1 Producing a system schedule

— Dispatch of thermal plant. All plants are assumed to bid cost reflectively and plants are dispatched on a merit order basis – i.e. plants with lower short-run variable costs are dispatched ahead of plant with higher short-run variable costs. This reflects a fully competitive market and leads to a least-cost solution. Costs associated with starts and part-loading are included in the optimisation. The model can also take account of all the major plant dynamics, including minimum stable generation, minimum on-times and minimum off-times. Exhibit C.2 below shows an example of a merit order curve for thermal plant.

— Hydro dispatch. Reservoir hydro plants can be dispatched in two ways:

  — A perfect foresight methodology, where each reservoir has a one year of foresight of its natural inflow and the seasonal power price level, and is able to fix the seasonality of its operation in an optimal way.

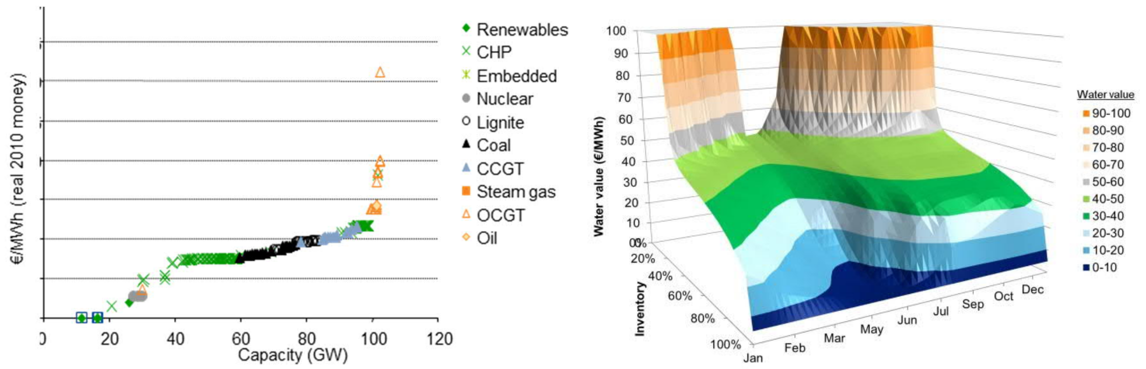
  — The water value method, where the option value of stored water is calculated using Stochastic Dynamic Programming. This results in a water value curve where the option value of a stored MWh is a function of the filling level of the reservoir, the filling level of competing reservoirs, and the time of year. Exhibit C.2 below shows an example water value curve.

— Variable renewable generation. Hourly generation of variable renewable sources is modelled based on detailed wind speed and solar radiation data which can be constrained, if required, due to operational constraints of other plants or the system.

— Interconnector flows. Interconnectors are optimally utilised – this is equivalent to a market coupling arrangement.

— Demand side response and storage. Operation of demand side and storage is modelled in a sophisticated way, allowing simulation of flexible load such as electric vehicles and heat while respecting demand side and storage constraints.

Exhibit C.2 – Thermal plant merit order and water value curve



C.2.1 Resulting power prices

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

— Short-run marginal cost (SRMC). The SRMC is the extra cost of one additional unit of power consumption. It is also the minimum price at which all operating plant are recovering their variable costs. Since the optimisation includes start-up and part-load costs all plant will fully cover their variable costs, including fuel, start-up, and part-loading costs.

— Scarcity rent. A scarcity rent is included in the market price – we assume power prices are able to rise above the short-run marginal cost at times when the capacity margin is tight. In each hour the scarcity rent is determined by the capacity margin in each market. It is needed to ensure that the plants required to maintain system security are able to recover all of their fixed and capital costs from the market.

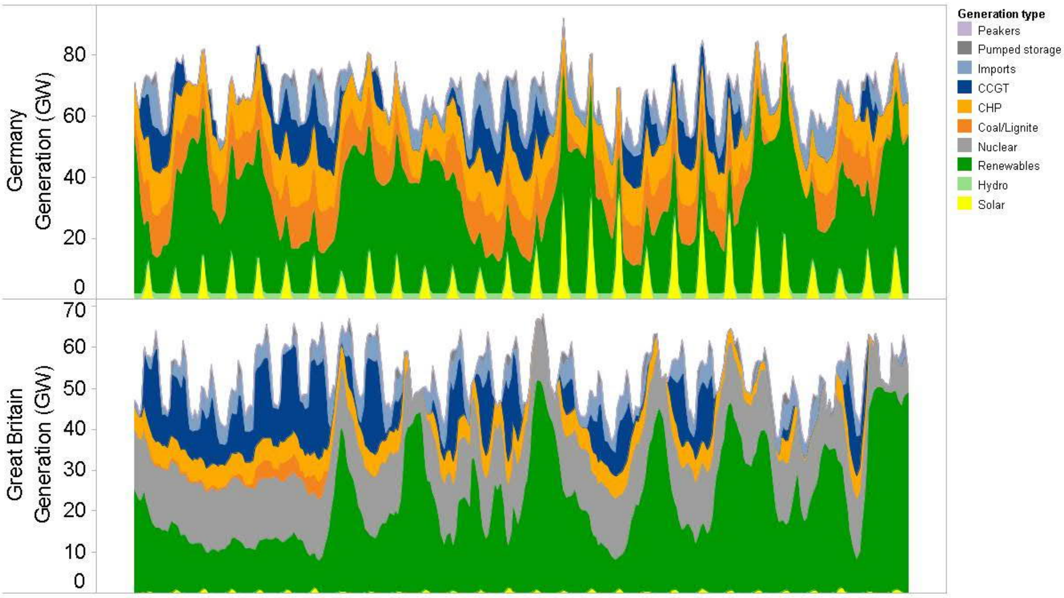
C.3 BID3 input data

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

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

  For wind data, we use hourly wind speeds at grid points on a 20km grid across Europe, at hub height. Hourly wind speed is converted to hourly wind generation based on wind capacity locations and using appropriate aggregated power curves. Detailed hourly solar data sampled at a 5km resolution is converted to solar generation profiles based on capacity distributions across each country. An example of the resulting profiles and generation mix is shown in Exhibit C.3.
- Fuel prices. AFRY 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.

Exhibit C.3 – Illustrative snapshot of future generation for a one-month period



C.4 BID3 model results

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

Exhibit C.4 – BID3 dashboards output examples (1/2)

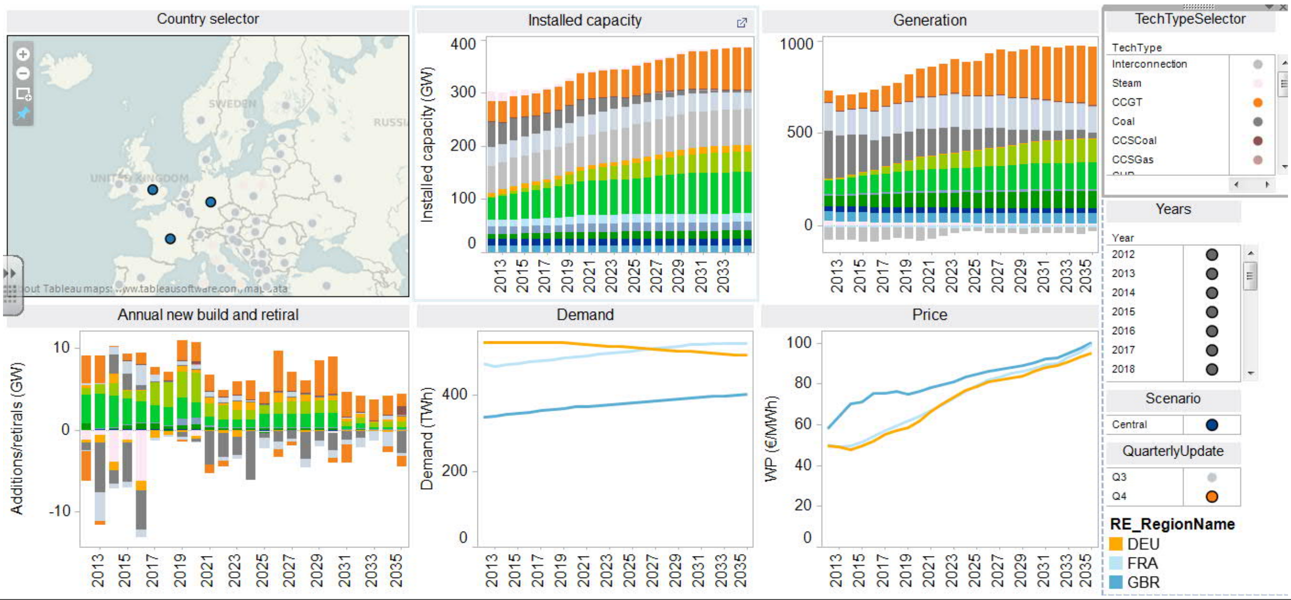


Exhibit C.5 – BID3 dashboards output examples (2/2)

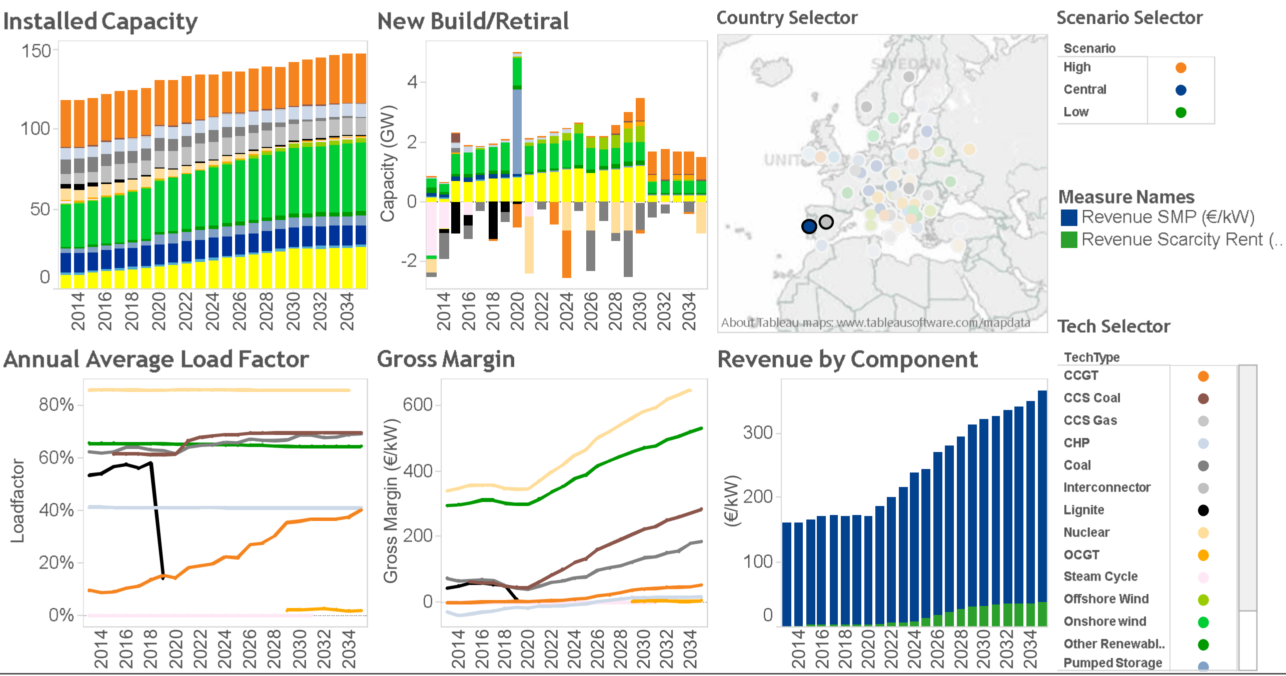
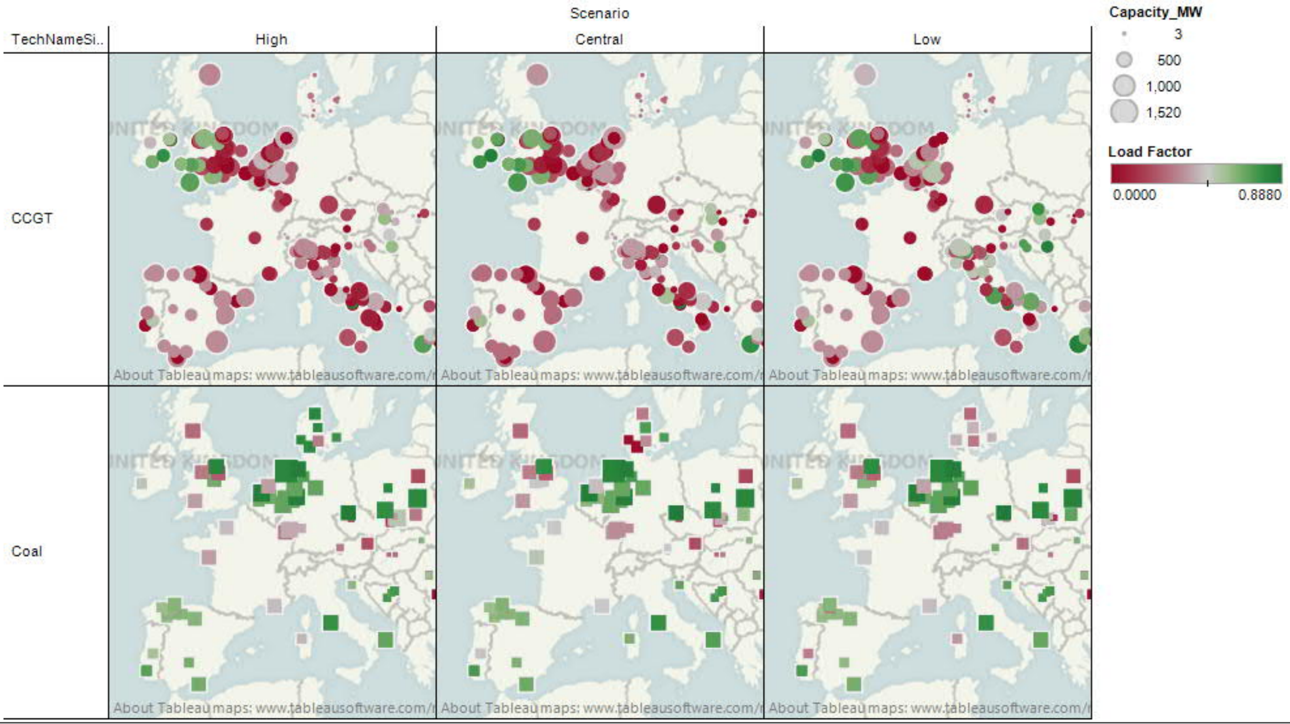


Exhibit C.6 – Geographical representation of results and mapping functionality



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

Annex D – Quality assurance statement

D.1 Quality assurance principles

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

Our Quality Assurance Plan has three main components:

— collaboration with Ofgem throughout the project;

— our internal Quality Assurance processes; and

— the provision of a Quality assurance statement by the project Quality Assurer.

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

D.2 Collaboration with Ofgem

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

D.3 Our internal quality assurance processes

AFRY operates an internal project and quality management system ('AFRY Propeller') designed to ensure that all our projects are completed to the high standard expected by our clients. Our internal quality assurance processes have included the following specific processes:

— allocation of our most expert consulting staff both at the analytical level and in the management and leadership of the project;

— a rigorous system of version control for modelling iterations and document production;

— analyst verification (i.e. error checking) of the model inputs, transformations and outputs using error checking scripts within the model, and sense checking (supervised by the project manager);

— modelling validation (ensuring the modelling approach is fit-for-purpose) by the project manager; and

— overall quality assurance provided by the Quality Assurer, who sits outside the project team day to day but provides internal challenge at each stage of the project in order to satisfy himself that the quality of the analysis is appropriate, thus enabling him to sign the Quality Assurance Statement that we provide for this project.

D.4 Quality assurance statement

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

TABLE OF EXHIBITS

Quality control

Roles	Name	Date
Authors	Benedikt Unger Aurora Manicardi Alessandro Crosara	21/12/2020
Approver	Gareth Davies	07/04/2021

Document control

Report Identifier: 2020/41X401149/PolicyReview_REPORT

Version	Date		Comments
v100	21/12/2020		Draft version for Client review
v200	09/04/2021		Final version
v300	04/05/2021		Further updates to final version

ÅF and Pöyry have come together as AFRY. We don’t care much about making history.

We care about making future.

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