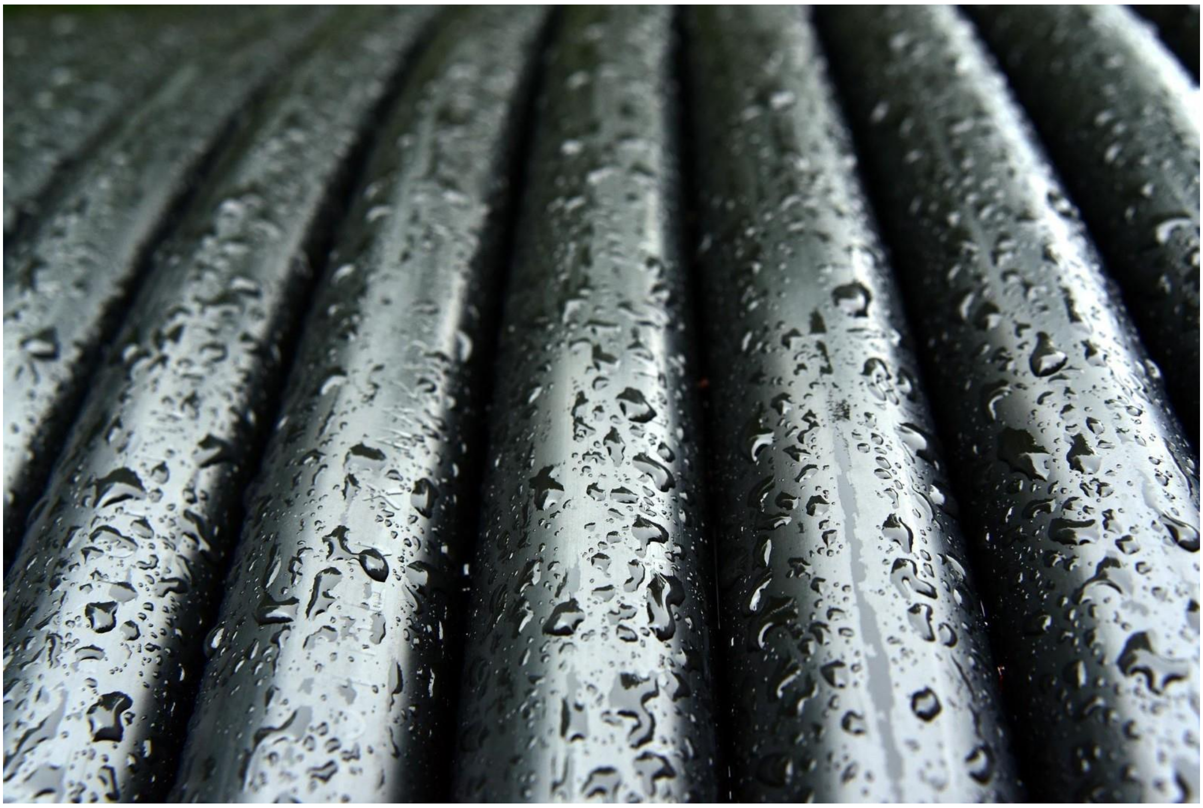
Ofgem

Market Modelling Analysis for Cap and Floor W3 and Offshore Hybrid Assets Pilot Projects

Market Modelling Report

01/03/2024



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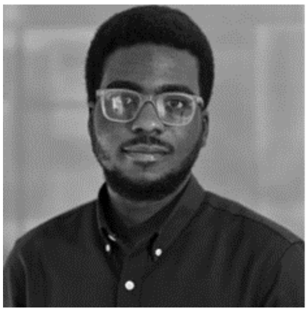

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Glossary

Acronym	Definition	Acronym	Definition
BECCS	Bioenergy with Carbon Capture and Storage	HMT	His Majesty's Treasury
BM	Balancing Market	IC	Interconnector
C&F	Cap and Floor	ID	Intra-day
Capex	Capital Expenditure	IEM	Internal Energy Market
CBA	Cost-benefit Analysis	IPA	Initial Project Assessment
CBAM	Carbon Border Adjustment Mechanism	I-SEM	Integrated-Single Energy Market
CCGT	Combined-cycle Gas Turbines	L1	Line 1
CCUS	Carbon Capture, Usage and Storage	L2	Line 2
CfD	Contract for Difference	LW	Leading the Way
CIP	Copenhagen Infrastructure Partner	MA	Marginal Additional
CM	Capacity Market	MCA	Multicriteria Assessment
CT	Consumer Transformation	MCL	MaresConnect Limited
DA	Day Ahead	MPI	Multi-purpose Interconnector
DESNEZ	Department of Energy Security and Net Zero	MRLVC	Multi-region Loose Volume Coupling
DSR	Demand Side Response	MVar	Mega Volt Ampere Reactive
EENS	Expected Energy not Served	MW	Megawatt
EMD	Electricity Market Design	MWh	Megawatt-hour
ENTSO-E	European Network of Transmission System Operators for Electricity	NGESO	National Grid Energy System Operator
ESO	Energy System Operator	NGV	National Grid Venture
ETS	Emission Trading Scheme	NIV	Net Imbalance Value
ETYS	Electricity Ten Year Statement	NOA	Network Options Assessment
EU	European Union	NPV	Net Present Value
FA	First Additional	OBZ	Offshore Bidding Zone
FES	Future Energy Scenarios	Ofgem	the Office of Gas and Electricity Markets
FS	Falling Short	OHA	Offshore Hybrid Asset
GB	Great Britain	Opex	Operating Expenses
GW	Gigawatt	OWF	Offshore Wind Farm
HM	Home Market	P2P	Point-to-Point

PINT	Put In One at the Time
RAG	Red, Amber, Green
REMA	Review of Electricity Market Arrangements
RES	Renewable Energy Sources
SEW	Socio-Economic Welfare
SO	System Operability
SoS	Security of Supply
SRMC	Short Running Marginal Costs
ST	System Transformation
t	Tonne
TCA	Trade and Cooperation Agreement
TCSNP	Transitional Centralised Strategic Network Plan
TINV	Transmission Investment
TO	Transmission Operator
TOOT	Take Out One at the Time
TYNDP	Ten Year Network Development Plan
USE	Unserved Energy
VoLL	Value of Lost Load
W	Window

Executive Summary

Introduction

This document presents the results of the electricity market modelling analysis commissioned by Ofgem to measure the market impacts of new interconnector (IC) and multiple-purpose interconnector (MPI)[1] projects applying for regulatory approval under the cap and floor (C&F) regime.[2]

This document should be read alongside the report by National Grid Energy System Operator (NGESO), describing the impacts of new projects on the energy system in GB, as well as the Multi-Criteria Assessment (MCA) report, bringing together the analysis conducted by Arup and NGESO. Both reports have been published alongside this document.

Background

Electricity ICs are physical links which allow electricity to flow across borders which can enable more efficient use of generation assets, bringing significant benefits to electricity systems. Offshore Hybrid Assets (OHAs) are a novel type of transmission infrastructure that combines cross-border trade of electricity and the transmission to shore of electricity produced by generation assets connecting along its route.

In Great Britain (GB), ICs are regulated under the Cap & Floor (C&F) regime. This regulatory framework was developed by Ofgem in 2014 to support investment in this type of infrastructure. In 2022, Ofgem launched a new application window for new IC (Window 3, or W3) as well as a new pilot regulatory framework for OHAs, largely based on the C&F regime.

The C&F regime is intended to ensure that ICs are financially safeguarded by setting a minimum agreed floor level for revenue. If the earned revenue falls below the floor, there will be a transfer of funds from consumers to IC owners. Conversely, if IC owners earn revenues above the agreed cap, the excess amount is transferred back to consumers through network tariffs.

Ofgem assess the impacts of each new candidate project to determine whether or not to award a C&F in principle at the Initial Project Assessment (IPA) stage of the regime. The assessment is made across a range of modelled socio-economic factors captured by the new Multicriteria Assessment (MCA) framework published by Ofgem in 2022. The MCA framework consists of seven categories measuring impacts on Socio-Economic Welfare (SEW), Network Costs, System Operability (SO), Flexibility, Decarbonisation, Security of Supply (SoS), and Hard-to-monetise impacts.

Ofgem has commissioned Arup to provide the modelling and analysis required to calculate the impacts described by the SEW, Decarbonisation and SoS impact categories. The results of this analysis will inform Ofgem's IPA decision, alongside other information provided by National Grid Energy System Operator (NGESO) and developers used by Ofgem to assess each project's ability to connect by the date indicated.

The W3 assessment considers more candidates and a more complex set of design and arrangements than in the previous ones. Ofgem progressed seven projects to the IPA stage W3. These projects are listed below.

Table 1 - W3 IC candidate projects applying to a C&F regime

Project Name	Developer	Type of Asset	Capacity (MW)	Connecting country	Operation date
Aquind	AQUIND	IC	2,000	France	2027

[1] Since the publication of CBA framework, the terminology to describe MPI projects has changed in Offshore Hybrid Assets (OHA). The new terminology will be used throughout this document.

[2] For more details, please visit: https://www.ofgem.gov.uk/publications/cap-and-floor-third-application-window-and-mpi-pilot-regulatory-framework-guidance-our-needs-case-assessment-framework

Project Name	Developer	Type of Asset	Capacity (MW)	Connecting country	Operation date
Aminth	Copenhagen Infrastructure Partner (CIP)	IC	1,400	Denmark	2031
Cronos	Copenhagen Infrastructure Partner (CIP)	IC	1,400	Belgium	2029
Tarchon	Copenhagen Infrastructure Partner (CIP)	IC	1,400	Germany	2030
NU-Link	Consortium	IC	1,200	Netherlands	2031
MaresConnect	MaresConnect Limited (MCL)	IC	750	Island of Ireland	2030
LirIC	Transmission Investment (TINV)	IC	700	Island of Ireland	2030

In parallel, Ofgem progressed two projects to the IPA stage of the OHA pilot regulatory scheme, listed below.

Table 2 - Projects at the IPA of Ofgem's OHA pilot regulatory scheme

Project Name	Developer	Type of Asset	Capacity (MW)	Connecting country	Operation date
LionLink	National Grid Venture (NGV)	OHA	1,800	Netherlands	2030
Nautilus	National Grid Venture (NGV)	OHA	1,400	Belgium	2030

To assess the economic needs cases for each project, Ofgem must consider:

1. The sources of project value, encompassing both costs and revenues, the main factors that drive them, and how they are affected by the C&F provisions.
2. The potential economic impact of these projects, including their effects on consumer surplus, producer surplus, and revenues for other ICs, including those regulated under a C&F mechanism.

Scope of the analysis

To answer these questions, Arup have analysed the impacts of each project under a set of three scenarios using two different modelling approaches to derive a range of feasible outcomes in terms of electricity prices between connected countries and the resulting electricity flows across each assessed project.

The analysis was based on an electricity market dispatch model developed in PLEXOS. The modelling used the Future Energy Scenarios (FES) created by NGESO to provide a range of outcomes. The outputs were then used to describe the impacts of each project under the three impact categories assessed by Arup: SEW, Decarbonisation and SoS.

Socio-Economic Welfare impacts

Each project was assessed to determine the impacts it is likely to have on the welfare of three key socio-economic groups: consumers, producers, and IC owners. These impacts are calculated on a Net Present Value (NPV) basis using HM Treasury Green Book methodology and through a Power BI model developed by Arup.

Consumer welfare is primarily affected by changes in energy costs due to wholesale electricity price movements caused by the introduction of a new IC or OHA. Consumer welfare also includes any payment to or from consumers such as those under the C&F regime and through low carbon support regimes, for example Contracts for Difference (CfDs).

Producer welfare is primarily affected by the change in gross margin revenues based on the variations in the wholesale electricity prices that follows the introduction of a new IC or OHAs. This also includes payments to and from consumers through CfDs.

Interconnector welfare is primarily affected by the change in revenue earned because of the variation in price differentials between the countries an IC or OHA connects. This category also includes payments through the C&F regime and the costs associated with the project under observation.

Decarbonisation impacts

Decarbonisation impacts are measured as the change in net CO_2 emissions in GB, the connected country and the other modelled European countries following the construction of a new project. This document also presents the monetary value of change in CO_2 emissions due to a new project in GB from both a market and societal perspective, as described in the new MCA framework.

Security of Supply

Security of supply is measured as Cost of Expected Energy not Served (EENS), i.e., the cost associated with Unserved Energy (USE) hours in the system when supply is not able to meet demand.

Approach

In order to measure the impact of each project, we have compared impacts on a Net Present Value (NPV) basis in a scenario without the assessed project (the counterfactual) and with the assessed project (the target case). All other factors in the analysis have been kept constant. The approach is consistent with HMT Greenbook accounting.

A key driver in IC and OHAs value is the existence and future development of other cross-border infrastructure in GB. To take account of this effect, Arup have assessed the eligible IC and OHA projects using two different approaches: ‘first additional’ (FA) and ‘marginal additional’ (MA) approaches.

FA approach

Using this approach, Arup analysed the value of each IC and OHA individually, assuming that it is the sole new project to be constructed. We did not consider the addition of any other cross-border project in GB beyond that timeframe in any scenario.

The FA approach allows Arup to explore the highest potential value of a new project, which is assessed across three market scenarios to determine the range of maximum values under different market conditions.

MA approach

In contrast to the above, with the MA approach, Arup examined the value of each interconnector in turn assuming that all candidate projects were built according to the connection date submitted in the W3 of C&F

regime and the OHA pilot programme. No other cross-border project is assumed to come online in GB after that point in any scenario.

The MA approach demonstrates the minimum potential value of a new project within each of the three market scenarios. This analysis allows Arup to obtain the range of minimum values under various market conditions.

Scenarios and assumptions

In line with the new MCA framework, Arup used publicly available assumptions in the analysis and ensured these were presented to and discussed with key stakeholders through two dedicated modelling workshops.

In order to measure the impacts that new ICs and OHAs can have under different market circumstances, Arup conducted the analysis using three different scenarios taken from the Future Energy Scenarios 2022 developed by NGESO:

- **Leading the Way (LW):** This scenario represents the FES scenario with the fastest credible decarbonization path, incorporating significant lifestyle changes and a combination of hydrogen and electrification for heating. This scenario is Net Zero compliant.
- **Consumer Transformation (CT):** The CT scenario involves electrified heating, consumers who are willing to change their behaviour, high energy efficiency, and demand-side flexibility. This scenario is Net Zero compliant as well.
- **Falling Short (FS):** The Falling Short (FS) scenario within the FES is characterized by the slowest credible decarbonization path, minimal behaviour change, and a focus on decarbonization in power and transport, excluding the heat sector. As the name suggests, this scenario does not meet the Net Zero target.

In order to simulate the effect of different weather conditions on energy prices, generation dispatch and electricity flows, each scenario of this study has been run three times for each modelled year using historical data for wind, solar radiation, and temperature. Arup selected three weather years (1990, 2007, 2010) describing the best, worst and average conditions for renewable energy production in GB. These weather runs have then been averaged out to generate the results of this analysis.

Overview of the SEW results

For brevity, this section presents an overview of the SEW results under only the MA approach. The full set of results under all the relevant indicators are described later in the document.

Overall, under the FES scenarios, GB decarbonises faster than its neighbours, leading to lower GB electricity wholesale market prices compared with other oversea countries. Therefore, all projects assessed are used primarily to export electricity from GB to its neighbours. Consequently, new projects often lead to an increase in GB prices which translates into an increase in GB producers SEW and a decrease in GB consumers SEW.

In general, all W3 IC projects benefit from the high price differentials between GB and the relevant connecting countries. Most of the projects assessed earn enough revenue to offset their cost and avoid the need for floor payments, with some of the earnings enough to generate cap payments.

OHA projects experience lower price differentials between GB and the offshore bidding zone (OBZ) they connect to. This in turns translates into lower revenue, which is not enough to fully offset the project costs. These projects are more likely to floor payments from consumers.

W3 interconnector projects

Figure 1 below shows the change in total SEW assessed between the target case and the counterfactual associated with each W3 IC project. Total SEW is composed of GB consumer, GB producer and GB IC welfare. The results of the analysis show that:

- **The majority of projects lead to an increase in total SEW in GB in all scenarios compared to the counterfactual.** This is primarily due to strong increases in GB producers SEW as projects lead to an increase in GB electricity wholesale market prices, offsetting the reduction in GB consumers SEW.
- **LirIC and MaresConnect lead to negative total SEW in GB.** For each project, the consumers SEW losses are not fully offset by producer and IC SEW gains. Additionally, due to their capacity, these two projects do not fully exploit the high price differentials between GB and Integrated-Single Energy Market (I-SEM).[3] The revenue earned is not enough to offset the cannibalisation impacts on other projects, leading to negative IC SEW. This further reduces total SEW.

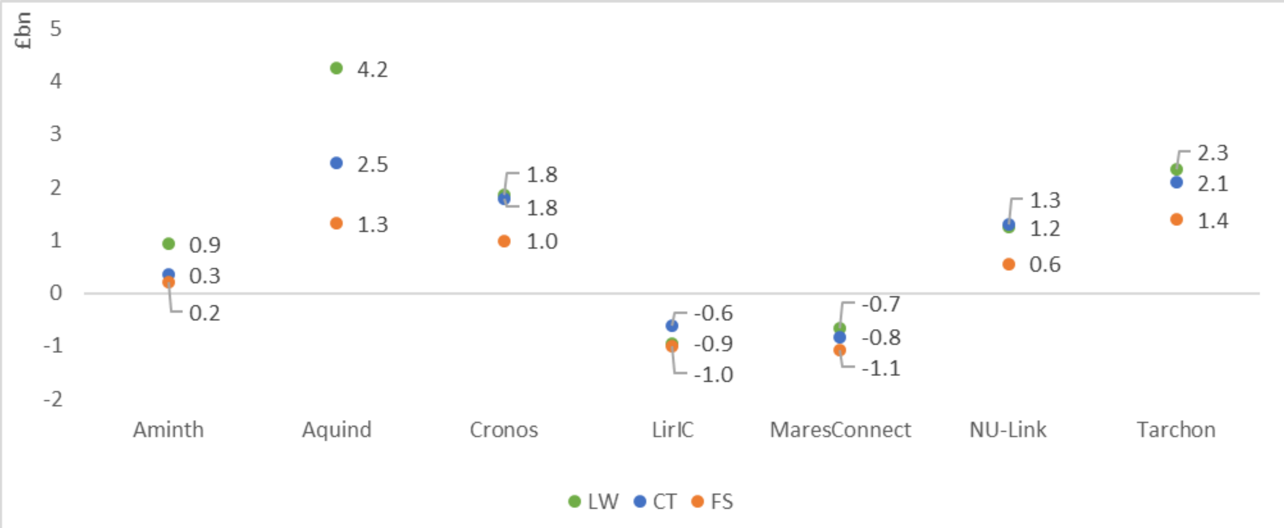

Figure 1 - GB total SEW impacts of each W3 IC project under MA (£bn, real 2022)

Figure 2 below shows the change in consumer SEW between the target case and the counterfactual associated with each W3 IC project assessed. The results of the analysis show that:

- **Most of the W3 IC projects assessed lead to a decrease in consumers SEW compared to the counterfactual in almost all scenarios.** This is because the majority primarily export electricity from GB to the connecting country, applying upward pressure to GB prices. Consequently, GB consumers pay more for their electricity.
- **From a consumer perspective, CT represents the worst-case scenario in terms of additional interconnectors.** In this scenario, GB prices are consistently lower than those of its neighbouring countries due to very high renewable energy source (RES) generation capacity installed. This in turn favours high and continuous GB exports, putting upwards pressure on GB prices.
- **Aminth and Aquind lead to higher consumers SEW in LW compared to the counterfactual**. These projects import the most electricity in this scenario, contributing to a significant reduction in EENS costs once they are introduced. This in turns lowers the GB wholesale prices to the benefit of GB consumers.

[3] Since 2018, the I-SEM is the wholesale electricity market for Ireland and Northern Ireland. It brings together these two markets into an all-island arrangement.

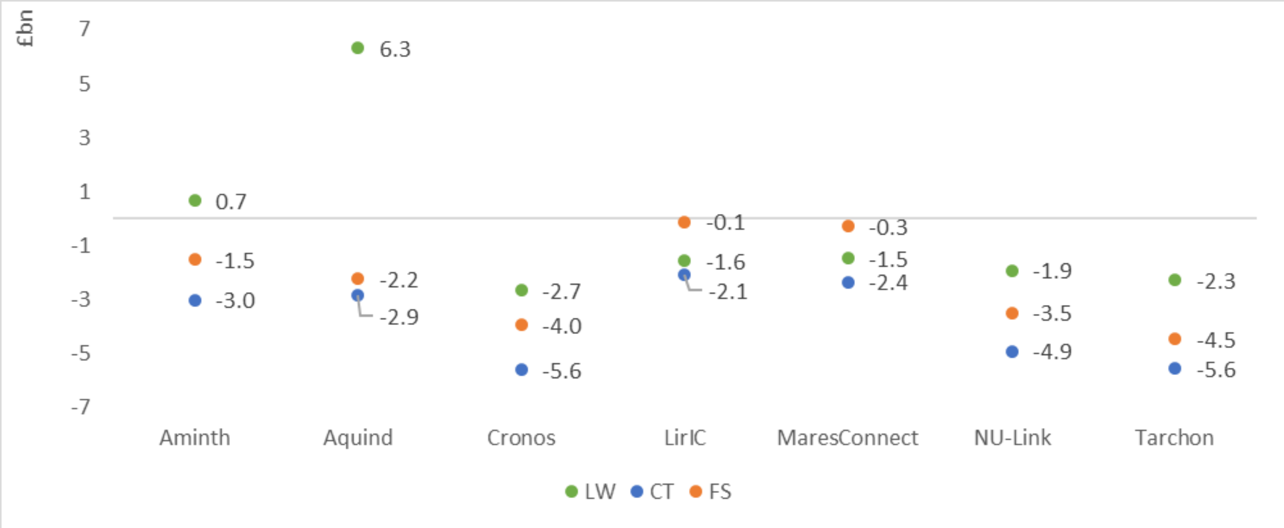

Figure 2 - GB consumer SEW impacts of each W3 IC project (£bn, real 2022)

OHA projects

Figure 3 shows the change in total SEW assessed between the target case and the counterfactual associated with each OHA project.

- **LionLink generates an increase in total SEW in GB in LW, but only a marginal impact in CT and FS.** In LW, total SEW is driven by strong consumers SEW gains as the project helps mitigating EENS costs. This translates into lower electricity wholesale prices in GB and an increase in consumer SEW. In the other two scenarios, the consumers SEW losses are offset almost fully by producer SEW gains.
- **Nautilus leads to an increase in total SEW in GB in all scenarios**, as consumers SEW losses are offset by producer SEW gains.

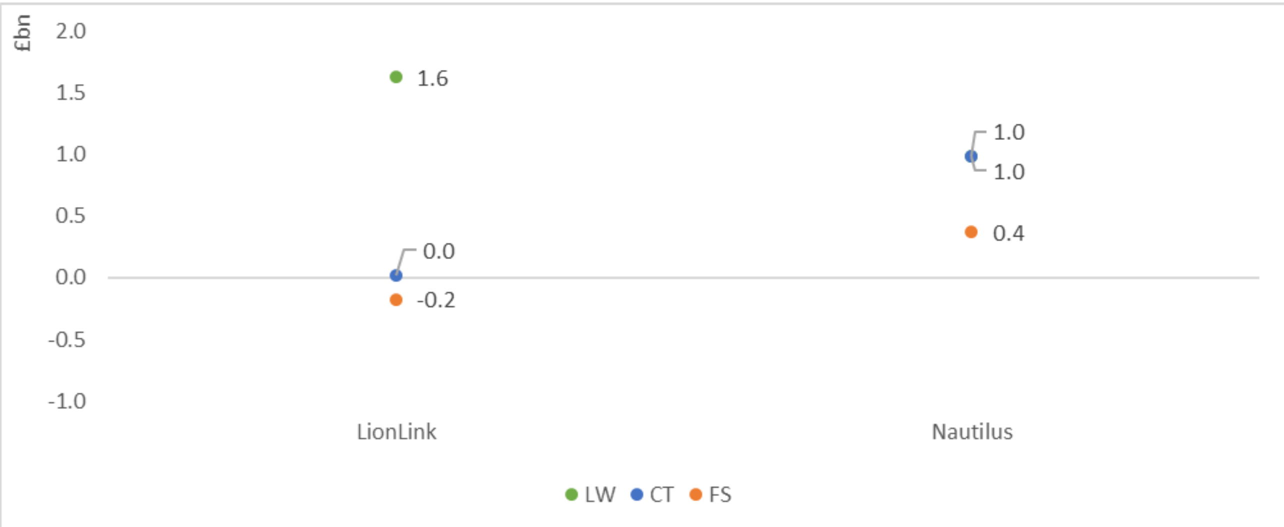

Figure 3 - GB total SEW impacts of each OHA project (£bn, real 2022)

Figure 4 below summarises the change in consumer SEW between the target case and the counterfactual associated with each OHA project assessed. The results of the analysis show that:

- **Both OHAs lead to a decrease in consumers SEW compared to the counterfactual**, as both projects are primarily used to export electricity from GB towards their respective connecting country. This in turn increases GB wholesale prices, to the detriment of consumers.
- **LionLink is positive for GB consumers only in LW**, as the project contributes significantly to the reduction of USE hours in GB and its associated costs by importing cheaper electricity into GB in periods of system stress.
- **The CT scenario has the worst impact from a consumer perspective**, as in this scenario, GB presents consistently lower prices than its neighbouring countries. This leads to sustained exports from GB and a consequent increase of the wholesale price in GB compared to the counterfactual.

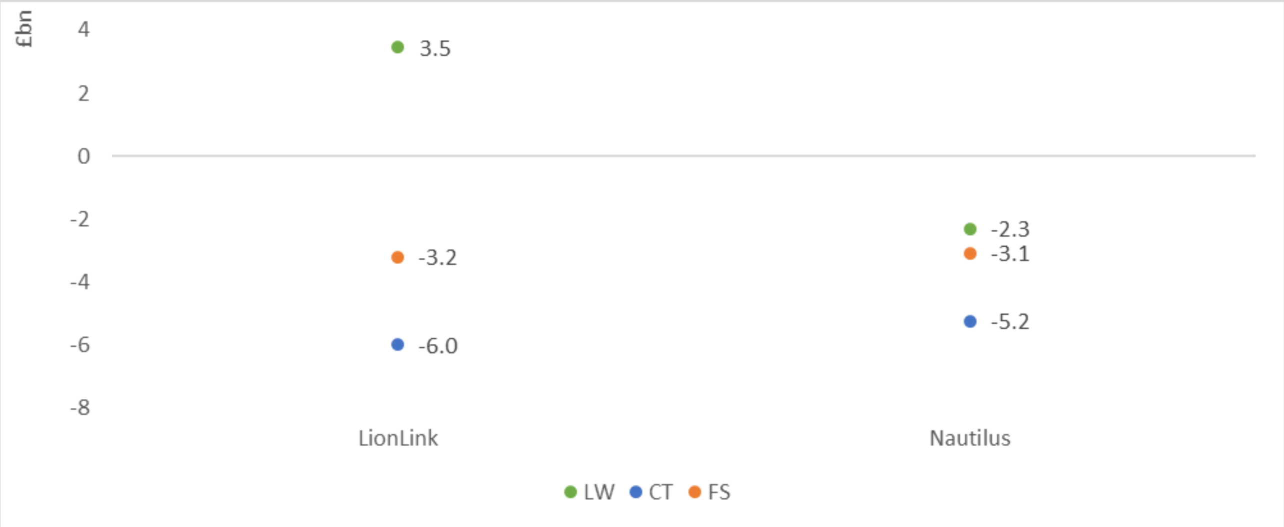

Figure 4 - GB consumer SEW impacts of each OHA project (£bn, real 2022)

Conclusions

Considering the results of the analysis conducted, Arup reached the following conclusions:

- **In our analysis, GB decarbonises more rapidly than the other modelled countries, leading to lower wholesale market prices in GB compared to its neighbours**. The impacts associated with each of the projects assessed are primarily determined by this market dynamic.
- **By connecting GB to countries with higher average wholesale prices, all projects generate significant SEW reduction for GB consumers in the vast majority of the assessed scenarios** as they lead to higher electricity prices in GB. Conversely, they often increase producer SEW.
    - CT is the worst-case scenario as GB wholesale prices are consistently the lowest among the relevant countries, due to the high shares of RES generation capacity assumed for GB. This leads to sustained exports throughout the modelled period, increasing GB wholesale prices.
    - In LW and FS, all projects import on average more compared to CT. These imports mitigate the overall increase in GB wholesale prices and therefore limit the negative impacts on consumers SEW that most projects have.
    - Only Aminth, Aquind and LionLink deliver consumers SEW gains in LW, as they are projects that import the most, contributing significantly to a reduction in the cost of unserved energy.
- **From a GB perspective, most projects lead to an increase in total SEW.** Only LirIC and MaresConnect deliver negative or marginally negative SEW impacts.
    - Producer SEW gains often fully offset or marginally exceed consumers SEW losses.

    - Projects with higher capacity usually earn more revenues, offsetting almost completely the losses caused to existing projects and avoiding significantly negative IC SEW impacts. They also lead to more cap payments, mitigating consumers SEW losses.

- **In terms of decarbonisation impacts, most projects lead to an increase of CO_2 emissions in GB**. As these projects are primarily used to export electricity from GB, they usually increase its wholesale prices. This allows more thermal generation to be dispatched in GB compared to the counterfactual.
    - Considering the higher volumes of installed thermal generation capacity in FS, this is the scenario where emissions increase the most.
- **Nonetheless, all projects significantly contribute to the decarbonisation of Europe as a whole.** By importing cheap electricity from GB, the average wholesale prices in the relevant connecting countries decrease. This creates a beneficial ripple effect, whereby downward pressure is then applied to the wholesale electricity prices of their own neighbouring countries, displacing more thermal generation.
- **All projects significantly improve SoS by importing electricity into GB at times of system stress in LW, reducing the number of USE hours in the system**. This translates in substantial cost savings for GB consumers compared to the counterfactual.

1. Introduction

1.1. Interconnectors and Offshore Hybrid Assets

A traditional point-to-point (P2P) IC is an electricity cable that physically connects by sea or land the networks of two different countries, allowing for the trade of electricity across their markets. ICs can help to balance the demand and supply of electricity, providing additional flexibility to better manage the intermittency of renewable energy generation. This in turn, may also help the efficient integration of renewables by providing them with more market routes and hopefully reducing the amount of curtailed wind.

Additionally, they can improve overall security of supply by connecting a country to a wider pool of generation, improving energy supply diversity and resilience. Allowing for trading across different markets, they can also help lowering consumers' energy bills or increasing generator revenues.

An OHA is a novel asset type that connects the electricity networks of two countries as well as generation assets along its route. Hence, an OHA combines the cross-border electricity trade with other activities such as the transmission of electricity generated, for example, by an offshore wind farm (OWF).

OHAs can provide other benefits in addition to those of traditional ICs. By allowing the same cable to be used for cross-border trade and offshore transmission, these assets can reduce the impact on coastal communities and the marine environment as well as the overall infrastructure costs required to deliver the same output.

Interconnectors have long been considered a facilitator of the energy transitions, and both types of assets can greatly contribute to the UK Government's Net Zero targets.

1.2. The Cap and Floor regime

The C&F regime is the regulatory framework developed in 2014 by Ofgem, the GB energy regulator, to incentivise investment in ICs. Under the regime, ICs are subject to a revenue cap whilst benefitting from guaranteed revenues at the floor. If revenues exceed the cap, payments are made by the IC owner to electricity consumers in GB. If revenues fall below the floor, payments are made by GB consumers to the IC owner.

Considering the potential liability onto consumers under the regime to top up revenues if required, Ofgem conducts a cost-benefit analysis (CBA) to assess the economic needs case of new eligible projects. The results of the CBA inform the IPA decision of which projects to grant a C&F regime in principle.

Since the launch of the C&F regime through the pilot project Nemo Link in 2011, Ofgem opened two application windows in 2014 (W1) and 2016 (W2), assessing and awarding a C&F regime to nine IC projects with a total capacity of 8.35 GW, bringing the total GB IC capacity to 14.35 GW once completed.[4] These projects are listed in Table 3 below.

[4] These figures do not include NorthConnect, for which regulatory approval was withdrawn by Ofgem in December 2022 due significant delays and lack of realistic prospect of it being delivered.

Table 3 - IC projects approved under the C&F regime

Project name	Connecting country	Nominal capacity (MW)	Regulatory regime	Estimated delivery date
Nemo Link	Belgium	1000	C&F Pilot	2019
IFA2	France	1000	C&F W1	2021
NSL	Norway	1400	C&F W1	2021
Viking Link	Denmark	1400	C&F W1	December of 2023
Greenlink	Ireland	500	C&F W1	End of 2024
FAB Link	France	1250	C&F W1	Q1 2031
GridLink	France	1400	C&F W2	Q1 2031
NeuConnect	Germany	1400	C&F W2	2028
NorthConnect	Norway	1400	C&F W2	Discontinued

1.2.1. Third application window under the C&F regime

Due to the significantly increased appetite to invest in IC capacity and the substantial changes in the UK's energy landscape, in August 2020, Ofgem decided to review its IC policy,[5] regulatory framework and approach ahead of any further C&F application windows. This was to ensure that further cross-border projects and the regulatory framework for their delivery remain in consumers' best interest.

In December 2021,[6] Ofgem published its decision setting out the next steps for IC regulation. The decisions relevant to this document included:

- the opening of a third C&F application window (W3) for ICs;
- the launch in parallel of a pilot C&F scheme for OHAs, inviting OHA developers to apply for C&F regime; and
- the review of the CBA framework used to assess new IC and OHA projects.

Following the assessment of eligibility criteria, Ofgem progressed to the IPA stage a total of seven eligible applications from IC project developers under W3 and two from OHA project developers under the pilot regulatory scheme for OHAs. These are listed Table 4 and Table 5 below.

Table 4 - W3 IC candidate projects applying to a C&F regime

Project Name	Developer	Type of Asset	Capacity (MW)	Connecting country	Operation date
Aquind	AQUIND	IC	2,000	France	2027
Aminth	CIP	IC	1,400	Denmark	2031

[5] Open letter: Notification to interested stakeholders of our interconnector policy review, Ofgem, August 2020.

[6] Interconnector Policy Review: Decision, Ofgem, December 2021.

Project Name	Developer	Type of Asset	Capacity (MW)	Connecting country	Operation date
Cronos	CIP	IC	1,400	Belgium	2029
Tarchon	CIP	IC	1,400	Germany	2030
NU-Link	Consortium	IC	1,200	Netherlands	2031
MaresConnect	MCL	IC	750	Island of Ireland	2030
LirIC	TINV	IC	700	Island of Ireland	2030

Table 5 - OHA projects applying to Ofgem's pilot regulatory scheme

Project Name	Developer	Type of Asset	Capacity (MW)	Connecting country	Operation date
LionLink	NGV	OHA	1,800	Netherlands	2030
Nautilus	NGV	OHA	1,400	Belgium	2030

Ofgem has commissioned Ove Arup & Partners Limited (Arup) to assess the impacts of W3 and OHA projects listed above. This analysis will support Ofgem in reaching IPA decision to award any of these projects either a C&F regime or the newly developed OHA regime in principle.

Arup conducted its analysis based on the most recent MCA framework approved by Ofgem, described in the following section.

1.3. Overarching differences of the analysis required under W3 and for OHAs compared to previous windows

It is important to note that the analysis required under W3 is significantly different and more complex than that carried out in previous windows for two fundamental aspects: the number of projects to assess, and the different CBA approach to follow.

1.3.1. Inherent complexities of W3 and OHA pilot scheme

The analysis required under W3 and the OHAs pilot framework is significantly more complex than previous assessments. For this round of C&F applications, Arup had to model a total of nine new projects, two of which are First-Of-A-Kind assets such as OHAs, connecting to six different countries under different connection dates, under three different scenarios.

These elements represent inherent complexities from a modelling perspective as they multiply substantially the number of modelling combinations required, the geographical scope of the model, the amount of data to process, and therefore increasing modelling uncertainties. The modelling for the main analysis required Arup to simulate 1,620 years' worth of market dispatch behaviour. All forecasting is by nature uncertain and not perfect. The higher the complexity of the model, the more difficult it becomes to forecast something. The modelling approach is discussed in more detail in Chapter 2 of this document.

Updated MCA framework for the C&F regime

Another key difference from previous C&F windows is the adoption of an updated assessment framework through which new IC and OHAs projects are assessed at the IPA stage. This was in recognition of the fact that the economics behind interconnector projects have been rapidly changing in the current Net Zero context.

As cross-border capacity increases and more renewable energy generation capacity is deployed to meet the UK climate targets, the structural price differentials between GB's and its neighbours' electricity markets are reduced, affecting the distribution of economic welfare between consumers, producers, and IC developers.

However, ICs and OHAs can also play a key role in managing intermittent renewable energy generation, meeting peak electricity demand by providing flexibility to the energy system, as excess generation can be shared with connecting countries. This could also potentially reduce constraint costs as well as increase security of supply. This highlights the renewed importance of a correct and complete assessment of these benefits to ensure the nature and measure of potential impacts of new ICs and OHAs are accounted for. In 2022, Ofgem commissioned Arup to conduct a review of its previous CBA framework and of the feedback provided by key stakeholders throughout the years. Based on Arup recommendations, in July 2022,[7] Ofgem published an updated Multicriteria Assessment (MCA) framework composed of 7 standalone impact categories describing the potential impacts of new IC and OHA projects applying for regulatory approval, summarised in Table 6 below.[8]

The new MCA framework allows Ofgem to assess a broader range of impacts through a much more granular and detailed level of information compared to previous windows, and to consider the trade-offs that each project presents. Under W1 and W2, the analysis was primarily focused on the assessment of Socio-Economic Welfare (SEW) impacts, whilst decarbonisation and security of supply impacts were treated only qualitatively.

The framework aims at quantifying and monetising as many indicators as possible to estimate the overall monetary impacts that a project can deliver across multiple categories. For this reason, the new framework envisages a much closer collaboration than before between Ofgem's consultants and NGESO to ensure the compatibility between their respective analysis.

Table 6 - Impact categories and indicators under the updated CBA framework for the C&F regime

Impact category	Indicator	Unit	Party responsible for the analysis
SEW	Consumers SEW	£bn	Ofgem's consultant
SEW	Producers SEW	£bn	Ofgem's consultant
SEW	Interconnectors SEW	£bn	Ofgem's consultant
SEW	Total SEW	£bn	Ofgem's consultant
Network costs	Onshore works	£bn	Relevant Transmission Operators (TO)
System operability	Frequency stability	MW/h	NGESO
System operability	Frequency response savings	£bn/ MWh	NGESO
System operability	Voltage stability	MVar	NGESO
System operability	Reactive response savings [9]	£bn/MVar	NGESO
System operability	Black start [9]	£bn	NGESO
Flexibility	Balancing Market impacts [9]	£bn	NGESO

[7] For more detail, please see: Cap and Floor Third Application Window and MPI Pilot Regulatory Framework – Guidance on our Needs Case Assessment Framework, Ofgem, July 2022.

[8] For more details on each indicator and the methodology used to calculate them, please refer to: Future Interconnectors Assessment Framework, Arup, July 2022.

[9] We note that, in its report, the NGESO refers to the indicator 'Reactive response savings' as Reactive Power Savings, to the indicator 'Black start 'as Restoration, and to the indicator 'Balancing Market impacts' as Constraint costs.

Decarbonisation	CO_2 reduction (SEW)	£bn	Ofgem's consultant
Decarbonisation	CO_2 reduction (Societal value)	£bn	Ofgem's consultant
Decarbonisation	RES integration (avoided RES spillage) [10]	MWh/y	Ofgem's consultant
Decarbonisation	RES integration (additional RES capacity)	MW	Ofgem's consultant
Decarbonisation	Overall decarbonisation	t	Ofgem's consultant
Security of Supply	Cost of EENS	£bn/MWh	Ofgem's consultant
Hard to monetise impacts	Environmental impact	qualitative	Developers
Hard to monetise impacts	Local community impacts	qualitative	Developers
Hard to monetise impacts	Noise/Disturbance	qualitative	Developers
Hard to monetise impacts	Landscape	qualitative	Developers
Hard to monetise impacts	Other impacts	qual/quant	Developers

1.4. Overview of this report

On this basis, the key impact categories covered by Arup and presented in this report are:

- SEW;
- Decarbonisation; and
- SoS.

The System Operability and Flexibility impact categories are assessed by NGESO and are presented in a separate report by NGESO and published on Ofgem's website.

This document and the NGESO report form the analytical basis of the MCA framework. The results described in these two documents are then summarised and presented together in the MCA report, which is also published on Ofgem's website.

1.4.1. Conventions

We used the following conventions throughout this report:

- The price base is real 2022 (calendar year average) money in British Pounds unless otherwise specified. All NPV figures have been calculated using a 3.5% discount rate as per HM Treasury Green Book guidance.[11] This has been applied over a 25-year project life for each IC and OHA project assessed.
- Because the FES dataset ends in 2050, the results of the analysis for year 2050 have been used to cover the full 25 years of the C&F regulatory period applicable to a project where necessary.
- All years are expressed in calendar years.

[10] Following consultation with Ofgem, it was agreed that the best party to calculate this sub-indicator would NGESO considering the in-house expertise and technical capabilities. Please note that NGSO refers to this indicator as 'avoided RES curtailment'.

[11] For more details, please see the guidance here.

- For each project, we present the results under each indicator for GB only. For SEW, we also present the total impacts of a project between GB and the connecting country.
- Where not specified, figures, charts, tables, and diagrams should be attributed to Arup.
- In order to calculate welfare transfer between consumers, producers and interconnector owners, the cap and floor levels for each project assessed are based on Ofgem's assumptions. These are indicative and subject to change by Ofgem as market conditions change and projects' costs are updated. Therefore, the results presented in this report are up to date at the time it was published but may change in the future.

  The cap and floor levels were calculated by Ofgem using the cost assessment templates submitted by developers as part of their application to the OHA pilot or the third window in October 2022 or January 2023 respectively. The calculation assumes a 50:50 cost sharing between GB and the connecting jurisdiction for the third window interconnectors, and a 50:50 split on line 1 for the OHAs. The cap and floor model used W2 parameters given the outstanding policy decisions regarding the financial parameters to use for W3 at the time of calculating the cap and floor values in September 2023. The approach for the OHAs was consistent with that for W3 interconnectors and therefore did not account for any proposals deriving from the June 2023 regime consultation, such as implementing a narrow cap and floor.

1.4.2. Report structure

The remainder of the report is structured as follows:

- Chapter 2 describes the approach and methodology used to assess the impacts of new proposed ICs and OHAs.
- Chapter 3 presents the results of our analysis for the SEW, Decarbonisation and SoS impact categories.
- Chapter 4 summaries the key results and conclusions.

We have also included a number of Annexes in the report:

- Appendix A and B includes the full set of results for each project under all scenarios and modelling approaches.
- Appendix C describes all the main modelling decisions made following our stakeholder engagement.
- Appendix D summarises the CBA provided by the developers as part of their IPA submissions.
- Appendix E provides a description of how price is formed in an Offshore Bidding Zone (OBZ).

2. Approach and methodology

Arup was commissioned to deliver the analysis required to assess impacts on SEW, Decarbonisation, and SoS associated with each W3 and OHA project. In line with W1, W2 and the new MCA framework, Arup assessed these impacts in the countries connected by a project on three stakeholder groups: consumers, producers and interconnector owners.

To deliver this analysis, Arup has conducted an electricity market modelling exercise using PLEXOS and a specially developed pan-European model to measure the impacts on electricity flows, wholesale market prices and generation dispatch that each W3 and OHA project will deliver as it connects. To assess the economic impacts on the relevant stakeholder groups, and the interaction between the W3 IC and OHA projects, Arup developed an economic model for Ofgem in Power BI. This model was largely based on the CARAMEL Light model developed by Afry under W1 and W2.[12]

To assess the impacts of each interconnector, Arup have conducted a Cost Benefit Analysis (CBA), comparing the NPV (using a 3.5% annual discount rate over a 25-year project life) of SEW, changes in carbon emissions and changes in cost of EENS 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 built, generation capacities and fuel prices).

This section of the report covers the principles that Arup followed in developing the analysis, the costs and benefits it captures, the modelling approach and the methodology followed, the key assumptions used, its key strengths and limitations.

2.1. Underlying principles of the analysis

When developing the analysis required under W3 and the OHAs pilot scheme, Arup has integrated the stakeholders' feedback on previous assessments collected during the review of Ofgem's CBA framework in 2022. Generally, this revolved around three main topics:

- Lack of transparency and inconsistency in how the scenarios utilised were selected and developed;
- Disagreement and lack of transparency with some of the underlying assumptions used; and
- Disagreement with elements of the modelling approach followed.

Additionally, as explained in section 1.3, this analysis is significantly more complex than previous Ofgem's CBAs. The changes implemented to the CBA framework also meant that a much closer collaboration with NGESO than before was required. This is in order to build a set of scenarios and assumptions with as much alignment as possible between the results of our separate analyses.

In order to address all the above, Arup adopted the following general principles:

- **Transparency**. Arup ran two modelling workshops with key stakeholders such as project developers, their advisors, Ofgem and the Department of Energy Security and Net Zero (DESNZ). These provided a platform to set out, discuss and shape the conceptual and modelling approach as well as the inputs to be used in Arup's analysis. Fundamentally, Arup sought to use publicly available information to align as much as possible with the ESO approach.

[12] Poyry, now called Afry, was firstly commissioned by Ofgem to deliver the market model analysis in 2014 under W1. For more information, please refer to: https://www.ofgem.gov.uk/sites/default/files/docs/2015/03/791_ic_cba_independentreport_final.pdf

- **Auditability and replicability.** To help developers understand the approach, Arup has provided a Databook and set out the assumptions and scenarios used in the modelling.[13]
- **Compatibility with NGESO analysis.** To ensure as much alignment and compatibility as possible between the results from NGESO's and Arup's separate analyses, we selected inputs and assumptions that could be utilised by NGESO's modelling team.
- **Developing a workable model** able to deliver the complex analysis required under W3 and the OHA pilot scheme. This meant balancing practical modelling considerations with an effective analysis delivering an insightful set of results supporting Ofgem's decision making process. Key aspects of the modelling approach and assumptions used are in sections 2.3 and 2.4. Section 2.5 summarises the modelling simplification implemented.

2.2. Scope of our analysis

This section describes the main costs and benefits that have been calculated as part of Arup's analysis: SEW, decarbonisation, and SoS. SEW impacts are calculated through a model developed in Power BI and are split by the three main stakeholder groups. Decarbonisation and SoS impacts are instead based on direct outputs from PLEXOS.

2.2.1. Main costs and benefits assessed by Arup

The main impact on SEW of a new IC or OHA project is the variation in wholesale market prices in the countries it connects. This affects different stakeholder groups in different ways, depending on how the new projects affect wholesale market prices of the connected countries.

The difference in price dictates the direction in which the electricity will flow between the newly connected countries. Keeping all other things equal, in a scenario where Country A has higher wholesale market prices than Country B, a new IC or OHA will be used to import cheaper electricity from Country B into Country A. This has several implications, described in Figure 5 below.

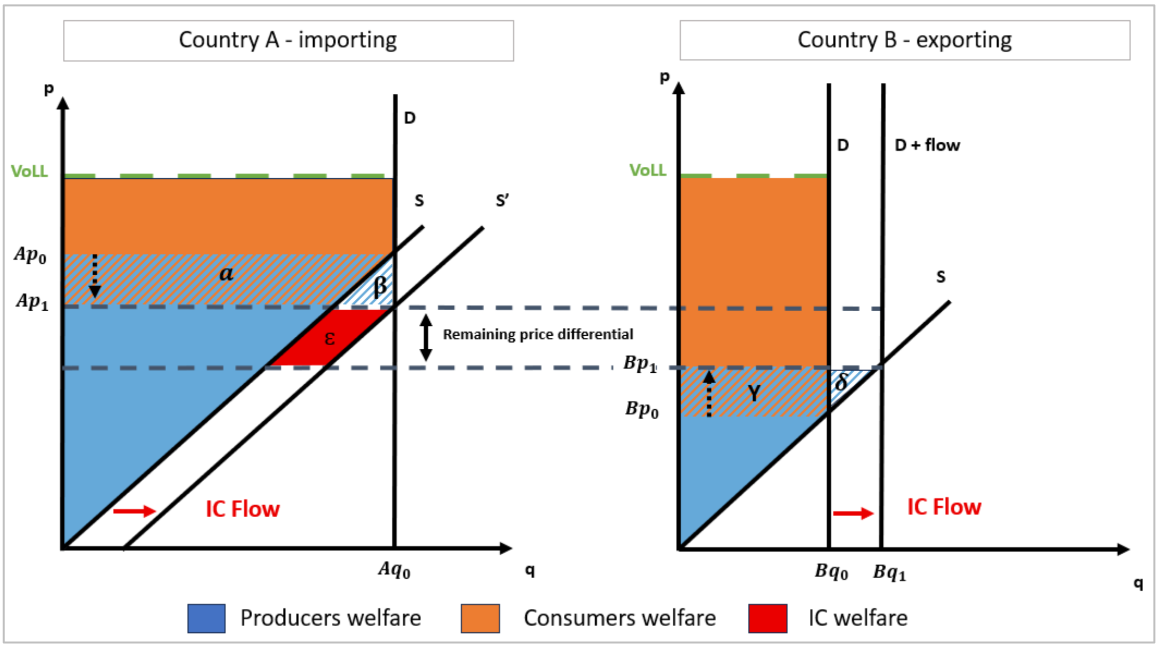

Figure 5 - Economic value of an IC or OHA project

[13] Arup did not publish information and data that project developers have considered to be commercial sensitive to preserve confidentiality.

The additional cross-border capacity of a new project (D) would put downward pressure on the wholesale market price of Country A (Ap_0), allowing consumers of that country to purchase electricity at a lower price (Ap_1). Consumer savings are represented by the shaded areas α and β. Conversely, by adding cross-border capacity, producers of country B can access higher market prices (Bp_1) to sell their electricity, increasing their revenues. These gains are represented by the shaded areas γ and δ. Finally, the new project would earn revenues based on the price differentials between Country A and Country B, presented by the red shaded area ε.

It is important to stress that the opposite dynamics will also take place. The producers in Country A will see a reduction in the wholesale market price at which they will be able to sell their electricity, negatively impacting their revenues. On the other hand, consumers in Country B will have to pay higher prices than before.

Increasing cross-border capacity between Country A and Country B will have a negative impact on existing projects. If we assume that another project connecting Country A and Country B is built, consumers in Country A and producers in Country B will benefit, respectively, from even lower and higher prices. However, the reduction in price differential between the two countries translates a loss of revenues for the first project.

In conclusion, a new project can potentially realise a large and diverse range of benefits for interconnector owners, power generators, and consumers. However, it will also create costs for others largely dictated by the direction of flow of the interconnector in a given period.

For this reason, and in line with previous assessments, Arup presents the net benefit of a project in GB, which reflects the sum of all the benefits less the sum of the costs for each stakeholder group and a project's specific costs (i.e., Capital Expenditure (CAPEX) and Operating Expenses (OPEX)). We also present the total SEW benefits of the project across the two countries.

The following paragraphs describe the costs and benefits making up the SEW of each stakeholder group.

Consumers SEW

Consumers SEW includes:

- **Changes in wholesale market prices**, due to the addition of a new IC or OHA project. These changes will affect the costs of electricity for consumers in the countries connected.
- **Changes in payments from or to consumers under the C&F regime**. When the revenues earned by a given project are below the floor, these will be topped up by consumers. When revenues are above the cap, these are transferred to consumers. This represents a transfer of welfare between consumers and project developers, and it is applied to all ICs and OHAs subject to a C&F regime.
- **Changes in the costs of the Capacity Market (CM).** The CM ensures security of electricity supply by providing a payment for reliable sources of electricity. IC, OHA, and generators can participate in the CM market. This payment is intended to recover the missing money that electricity generators require to keep their assets up and running and available for supplying consumers. This ensures that there is enough generation capacity reserved exclusively to meet a country's security of supply standard. Consumers directly finance the CM through their energy bills. As such, this is a transfer of SEW value from consumers to producers and ICs. Details on how we have estimated the total cost of the CM is described in section 2.4.8.

- **Changes in the costs of Contract for Difference (CfD) scheme.** Renewable and low carbon energy generators are often supported through schemes such as the CfD mechanism. The contract guarantees the generator a stable level of revenues at a pre-agreed level (the strike price) for the duration of the contract. If the wholesale market price exceeds the strike price, the generator pays back to consumers the extra revenues. On the contrary, if the wholesale market price is below the strike price, consumers top up the generator's revenues up to that level. Consumers pay for the CfD cost through the electricity bills. This is another example of welfare transfer between consumers and producers.

Producer SEW

Producer SEW include:

- **Changes in wholesale market prices**, due to the addition of a new IC or OHA project. This will affect the gross margin for energy production, calculated as the revenues from electricity production less the costs of fuel and carbon emissions.
- **Changes in revenues under the CfD scheme,** as described above.

Interconnector and OHAs SEW

SEW for interconnector and OHA owners include:

- **Changes in revenues from arbitrage payments** captured by the IC or OHA owners when they offer cross-border capacity to trade electricity across markets. These revenues depend on the price differentials between those market. We have assumed implicit trading arrangements between the UK and the EU, meaning that interconnectors and OHAs receive all arbitrage payments directly.
- **Changes in CM revenues** earned by the IC or OHA project on either or both sides of the asset by participating in the CM. These revenues contribute towards the calculation of payments under the C&F regime.
- **Changes in the payments from or to consumers under the C&F regime** based on the revenues earned by the ICs or OHAs. For each project, revenues from arbitrage payments and CM revenues are summed together before being compared to the respective cap and floor levels.
- **Cannibalisation of revenues** across IC and OHA projects, where the changes in electricity flows and price differentials between countries caused by a new project lead to higher or lower revenues on existing ICs and OHAs.
- **Costs of constructing and operating** an IC or OHA, including the electricity transmission losses incurred when electricity flows across the project. For these costs, Arup used the information submitted by developers as part of their application for a cap and floor regime.[14] [15]

For all three measures of SEW, the impacts of each project are expressed in NPV terms, using a 3.5% discount rate, over a 25-year period representing the duration of the C&F regime.

2.2.2. Accounting for changes in SEW

To correctly understand the SEW results for each project, it is important to understand how the changes between the target case and the counterfactual of the components of consumers, producers and IC SEW described above are accounted for in our analysis.

[14] The costs submitted by developers have been reviewed by Ofgem as part of the IPA stage process. Arup used the reviewed costs for this analysis.

[15] For those project developers that did not provide information on the expected loss factors, Arup utilised industry standard values.

- For consumers, any additional cost is treated as a decrease in SEW. Conversely, any reduction in costs is treated as an increase in SEW. For example, an increase in the wholesale market price, floor payments, CM costs and payments required under the CfD scheme leads to lower consumers SEW in the target case compared to the counterfactual.
- For producers, any additional revenue is treated as an increase in SEW. Conversely, any decrease in revenue is treated as a decrease SEW. For example, an increase in the wholesale market price and payments (and therefore revenue for producers) required under the CfD scheme leads to higher producers SEW in the target case compared to the counterfactual.
- Similarly, for IC SEW, any increase in revenue is treated as an increase in SEW. Any cost or decrease in revenue is treated as a decrease in SEW. For example:
    - CAPEX and OPEX negatively impact IC SEW.
    - Floor payments from consumers to IC and OHA projects are treated as additional revenue the project owners receive on top of what they earn, therefore increasing IC SEW.
    - Cap payments from IC and OHA projects are treated as a loss in revenue as the project owners do not keep that revenue for themselves, decreasing IC SEW.

2.2.3. Other costs and benefits assessed by Arup

Through PLEXOS, Arup was able to derive the key information required to describe the impacts of a new project on decarbonisation and SoS. These are:

- **Variation in CO_2 emissions** in GB and the connected country, following changes to the generation dispatched in both after a project connects. This value is used to calculate:
    - the indicator 'CO_2 reduction (SEW)' by multiplying it by the market value (i.e., price) of CO_2. Please note that this monetary value is already captured in the formation of the electricity wholesale market price of the countries modelled, which in turn feeds into the SEW calculations. As such, this indicator is presented separately and in isolation to avoid double counting.
    - For GB only, the indicator 'CO_2 reduction (Societal value)'. This is done by multiplying the variation in CO_2 emissions by the price delta between the societal value[16] and the market value of CO_2. The resulting monetary value is additional to that captured by the SEW indicator. The approach assumes away the UK Emissions trading scheme and treats the changes in CO_2 as purely the result of Interconnectors. The social costs of damage, which is based on estimates on the marginal damage of one tonne of CO_2, is then used to provide a monetary value for these emissions.
    - The indicator 'Overall decarbonisation', which captures the change in emission across all the modelled countries. A range is provided for this indicator based on the different approaches for valuing CO_2 savings. The social costs of carbon is, generally, significantly higher than the market value based on emissions trading allowances.
- **Cost of Expected Energy not Served (EENS).** This measure describes the costs associated with an interruption of electricity supply due to insufficient resources to meet demand needs in a given zone and during a given time period. The value of this measure is obtained by multiplying the volume of energy not served (USE) by the Value of Lost Load (VoLL) set at £6,000 per MWh, and it is done automatically within PLEXOS.[17] This indicator can be viewed as measuring the security of supply

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[16] The societal value of CO_2 is taken from HMT supplementary guidance to the Green Boo, data table 1-19: https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

[17] The second phase of the P305 'Electricity Balancing Significant Code Review Developments' was implemented on 1 November 2018 and saw the VoLL increase from £3,000/MWh to £6,000/MWh. Source : Elexon https://www.elexon.co.uk/documents/groups/isg/2022-meetings-isg/255-

impact of interconnectors as it based on changes in energy demand that cannot be through generation. The cost of EENS feeds into the electricity price formation and consequently in the SEW calculations.

2.2.4. Costs and benefits not assessed in this report

The following benefits and costs have not been calculated by Arup:

- **Flexibility and System Operability.** The indicators describing these two impact categories have been calculated by NGESO and are presented separately in a dedicated report produced by NGESO.
- **The indicator 'RES integration (avoided RES spillage)**' has also been calculated by NGESO, as it was considered the best placed party for such analysis.
- **Welfare impacts linked to trades on the intra-day markets.** As explained in section 2.4.7, this would have added little value to the analysis.
- **Competition benefits in the CM** in terms of reduced capacity market clearing prices (which would translate in lower revenues for producers and lower costs for consumers) or direct displacement of generation assets in the auctions. This would have added additional complexities to the analysis. More details on the assumptions used to assess impacts in the CM market can be found in section 2.4.8.
- **Competition benefits in the connected markets** in terms of enhanced liquidity which is outside the scope of the analysis.

Table 7 below summarises the costs and benefits included and excluded in this analysis and report.

Table 7 - Summary of cost and benefits included in this report

Cost or benefit	Calculated by	Included
Changes in wholesale market prices	Arup	Yes
Payments from or to consumers under the C&F regime.	Arup	Yes
Costs of /revenues under the CM	Arup	Yes
Costs of / revenues from CfD scheme	Arup	Yes
Revenues from arbitrage payments	Arup	Yes
Cannibalisation of revenues	Arup	Yes
CAPEX and OPEX	Developers	Yes (SEW impacts are net of these costs)
Variation in CO_2 emissions	Arup	Yes
Cost of Expected Energy not Served	Arup	Yes
Flexibility and System Operability	NGESO	No
Intra-day market welfare impacts	n/a	No
Competition benefits in the CM	n/a	No
Competition benefits in the connected markets	n/a	No

july/isg255-08-annual-review-of-the-value-of-lost-load-and-loss-of-load-probability-2022/#:~:text=1.3%20The%20Value%20of%20Lost,under%20Section%20T%2C%201.6A.

2.3. Modelling approach

2.3.1. PLEXOS and Arup's economic interconnector assessment model

The underlying electricity market modelling for this study has been conducted using Arup's in-house PLEXOS Pan-European model. The model is run on the commercial modelling platform PLEXOS using data and assumptions discussed during the two stakeholders' workshops organised by Arup.

Following a similar approach to W2 of the C&F regime, the modelling approach employed for conducting the CBA is based on a combination of Arup's pan-European electricity market modelling and an economic assessment model developed by Arup for Ofgem in Power BI. The Power BI based model used the CARAMEL Light model developed by Afry as a starting point and was adapted to fit the specific requirements of W3 of the C&F regime. The Power BI model also includes as inputs the results of NGESO's analysis to provide Ofgem with the full set of results for each project assessed under the MCA Framework. Figure 6 below shows the main steps in our modelling approach.

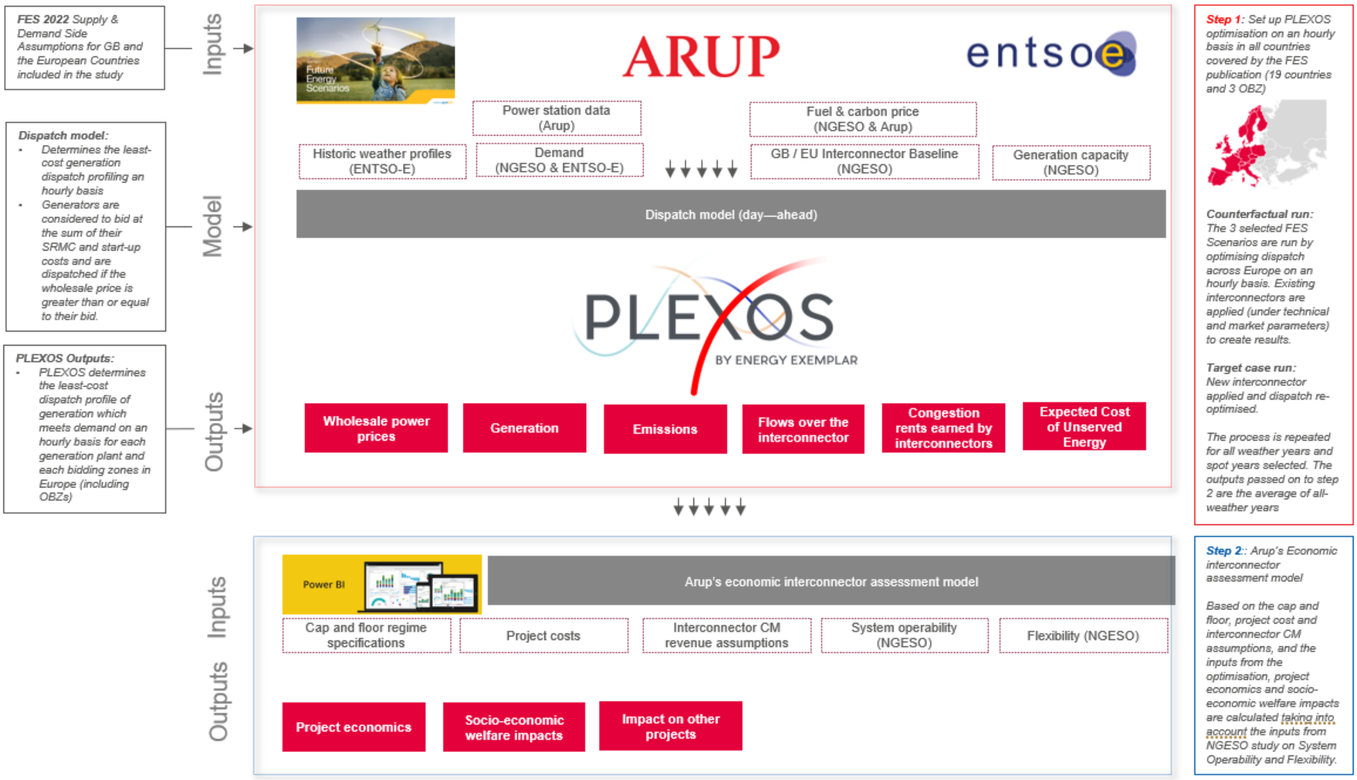


Figure 6 - Modelling Approach

Assessment of a project's impact

In order to measure the impact of a project, it is required to perform two model runs:

- a counterfactual run, representing the initial state of the energy markets modelled without the project under assessment; and
- a target case run, with every element from the counterfactual run being kept constant (IC baseline, commodity prices, weather years, etc.) except for the project under assessment, which is added to the simulation as per the connection date indicated by the developer (as described below).

The impacts of a specific project are calculated as the difference in each relevant indicator measured between the target case run and the counterfactual run.

As described in section 2.1.1, a new IC or OHA will affect the wholesale market prices of the countries to which they connect. This in turn will affect the behaviour of all the other projects, both existing and future ones, connecting to those countries. It is therefore important to account for the build profile of new cross-border capacity when assessing a W3 or OHA project.

To do so, in the analysis for W1 & W2, Afry considered two different build profiles:

- the **First Additional (FA) case**, where the project assessed is the first and only one among the candidates to be built; and
- the **Marginal Additional (MA) case**, where the project assessed is the marginal (last) project of the candidates to be built.

Arup considered this approach to be effective in capturing the range of impacts that a new project could deliver and found it aligned with the PINT (Put In One at the Time) and TOOT (Take Out One at the Time) methodologies presented in the CBA guidelines published by the European Network of Transmission System Operators for Electricity (ENTSO-E).[18] Therefore, Arup adopted the same approach with only one variation, described below.

All W1 and W2 projects indicated the same connection date when applying for regulatory approval (i.e.,2017 and 2022, respectively). Under the MA case, this meant that the project under assessment was considered as if connecting after all the other candidates.

In W3 and for the OHA pilot scheme, the same approach is not replicable. Each project has its own specific connection date ranging from 2027 to 2031. Therefore, Arup and Ofgem – in consultation with the developers at the workshops – decided to use the connection date provided by the developers in both the FA and MA cases (e.g., staggered approach). For the MA case, this means that each project under assessment connects as scheduled, not after all the other candidate projects have been built. The other candidate projects are also assumed to connect on the date provided by their developers. [19]

Whilst it was recognised that the projects with an early connection date will have a competitive advantage, the staggered approach is less discriminatory than artificially delay the connection date of the project assessed, which could be by up to five years in some cases. Arup notes that the C&F regime includes different incentives to mitigate the risk of overly optimistic connection dates proposed by candidate projects. We note that Ofgem has also conducted a due diligence review on the connection dates proposed by W3 projects as part of their deliverability assessment, which is a key component of the IPA decision making processes.

It is important to flag that this approach has been applied to both IC and OHA projects, as both types of assets are assessed within the same simulation.

First Additional (FA) case

Under the FA case, Arup analysed the value of each IC and OHA project individually assuming that it is the only new IC or OHA to be constructed in GB among those considered.

[18] For more information, please visit: https://consultations.entsoe.eu/system-development/tyndp-2024-cba-implementation-guidelines/

[19] Unless the developer provided a specific connection date, it was assumed that a project would connect on the 1st of January of the connection year provided by the developers.

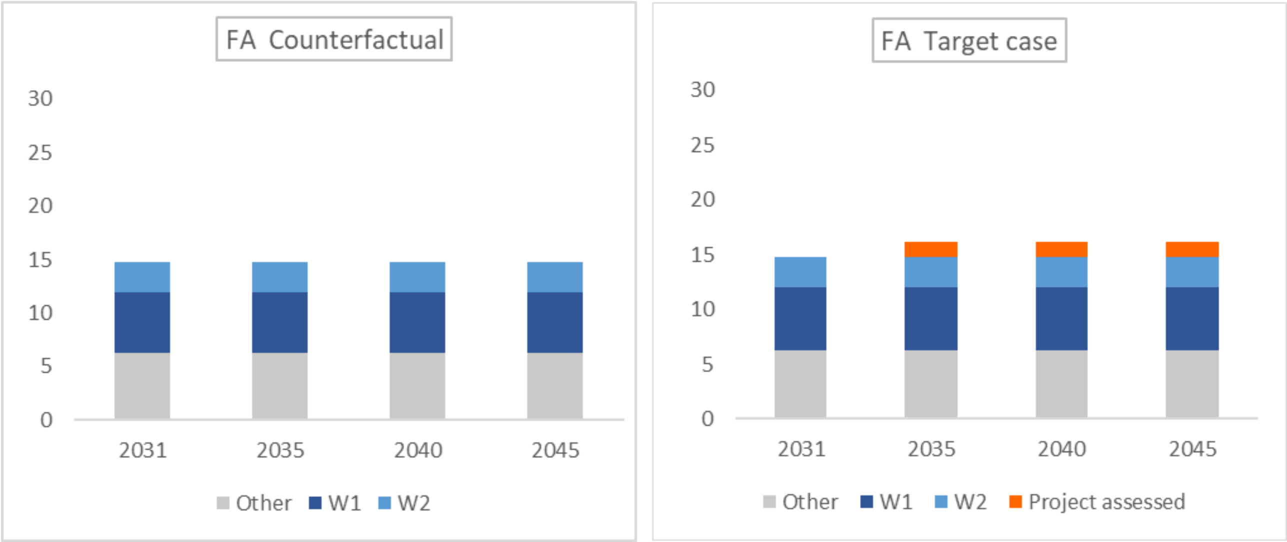


Figure 7 - Cross-border capacity in GB assumed in the counterfactual and target case runs under FA (GW)

We do not consider the addition of any additional cross-border capacity beyond 2031 in any scenario. It is worth nothing that two IC projects which are part of the GB IC baseline, FABLink (W1) and GridLink (W2), are assumed to become operational in 2031.

This FA target case represents the likely most favourable SEW outcome for each project assessed, as it removes the additional direct (or indirect) competition posed by a new IC or OHA connecting to the same (or a different) country. Therefore, it allows Arup to define the theoretical upper limit of value of the project under consideration. By adopting this case under different market conditions represented by the three scenarios selected, Arup is also able to determine the range of maximum values of a project.

Marginal Additional (MA) case

In contrast to the above, with the MA approach, Arup examined the value of each interconnector in turn assuming that all candidate ICs and OHAs were built in GB according to the connection date submitted by the developers.

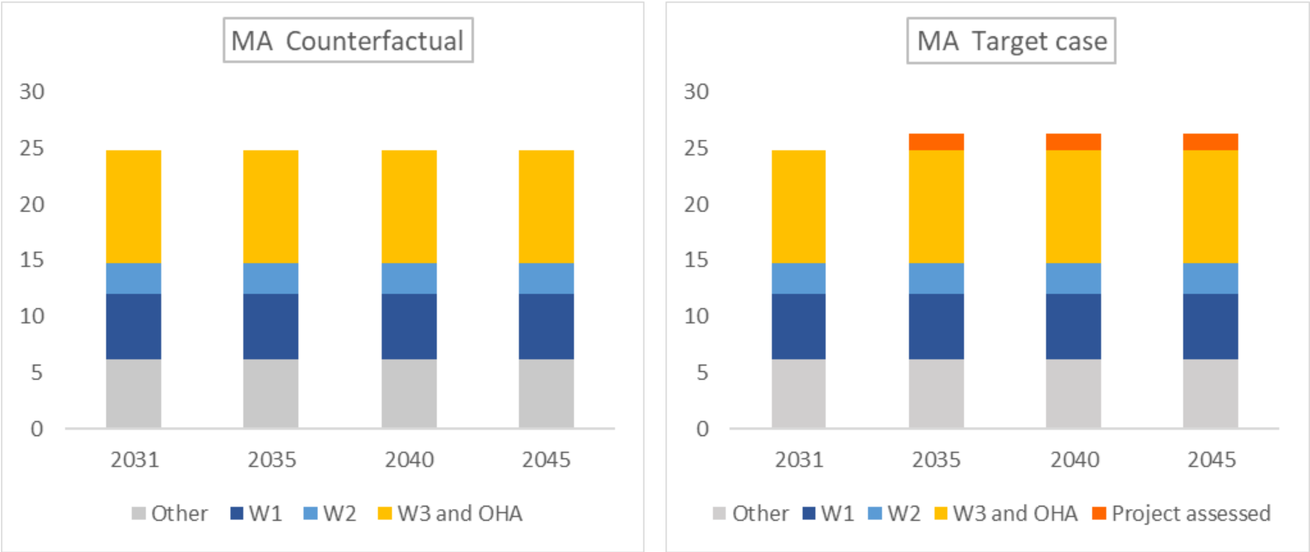


Figure 8 - Cross-border capacity in GB assumed in the counterfactual and target case runs under MA (GW)

As per the FA case, no other interconnection is assumed to come online after 2031 in GB in any scenario. It is worth nothing that two IC projects which are part of the GB IC baseline, FABLink (W1) and GridLink (W2), are assumed to become operational in 2031.

The MA methodology demonstrates the likely minimum potential SEW value of the W3 project under consideration within each of the three market scenarios, as it measures the impact of a new project in a much more competitive market. This analysis allows Arup to obtain the range of minimum values under various market conditions, using the three selected FES scenarios.

2.3.2. Modelling the Cap and Floor regime

For the purpose of this assessment, Arup modelled all IC and OHA projects individually. For those existing and applicant projects which have received or applied for a cap and floor regime, Arup modelled its effects to determine payments from and to GB consumers. The projects assumed to be regulated by a cap and floor regime are:

- Nemo Link;
- all W1 projects;
- all W2 projects[20]; and
- all W3 IC and OHA candidate projects.

As described in section 2.2.1, the revenue streams making up the total revenues of a project are (i) arbitrage revenues, and (ii) CM revenues (calculated for both GB and the connected country), where applicable.

Under the C&F regime, the revenues earned by an IC or OHA project are compared against the specific cap and floor of that project. The revenues considered for this correspond to the share of total revenues earned by a project in GB. For all the W3 IC projects (but not the two OHA projects – see below), the GB share is assumed to be split on a 50:50 basis in all scenarios as indicated by Ofgem. For existing or already approved projects regulated by a cap and floor regime, we utilised the share defined by Ofgem in the relevant IPA decisions for those projects.

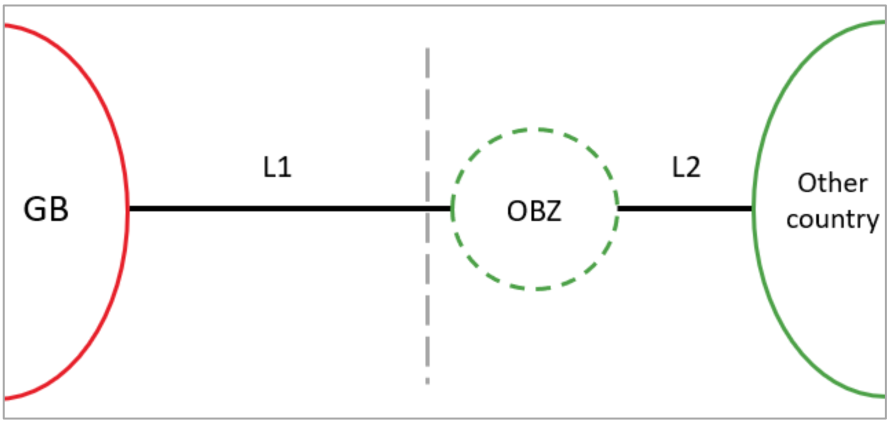
Therefore, if the share of revenues attributable to GB by an IC or OHA project exceeds the cap for that project in any given year, the excess is paid by the project owner to GB consumers. Conversely, if the share of revenues attributable to GB by an IC or OHA project do not reach the floor for that project in any given years, then the missing revenues are paid by GB consumers to the project owner.

This mechanism represents a direct transfer of welfare between IC and OHA owners and GB consumers. It also implies a transfer of welfare between GB and the other connected country. In fact, the share of total revenues for GB also captures revenues streams realised in the other connecting country (e.g., through the CM mechanism of that country, if applicable), and vice versa, contributing to the calculation of cap and floor payments in GB.

Cap and floor regime for OHAs

With regards to the two OHAs, a different approach is used to take account of the effect of these hybrid projects' configurations. For the calculation of the C&F payments, Arup considered only the revenues earned by the cross-border line of the OHA (Line 1, or L1), connecting GB to the Offshore Bidding Zone (OBZ) within the jurisdiction of the other connected country, on a 50:50 basis. Revenues earned by the line connecting the OBZ to the shore of the other connecting country (Line 2 or L2) were not factored in the cap and floor payment calculations.

[20] Except North Connect, for which the C&F regime was withdrew by Ofgem in 2022.



Drawing 1 - Stylised configuration of the two lines (L1 and L2) that compose the two OHA projects assessed in this document

Section 2.4.5 provides more details on the modelling assumptions and approach taken with regards to OHAs.

2.4. Scenarios and other key assumptions

As explained in section 2.1, Arup utilised publicly available information to define the inputs underpinning our analysis. This approach ensures the transparency, auditability, and replicability of our analysis. In this section, we describe in detail the key assumptions and other aspects of our analysis.

2.4.1. Market scenario overview: FES 2022

In order to assess the possible range of impacts that each W3 project might deliver, three market scenarios have been used in our analysis. Each scenario presents a different set of market conditions for additional cross-border capacity.

As per the underlying principles described in section 2.1 and in agreement with Ofgem, Arup selected the three market scenarios from FES 2022. The FES are developed by NGESO to represent different pathways to decarbonise the GB energy system, with each scenario following a specific narrative of how that would occur. The FES are considered the best source of publicly available information as they are a well-known and widely used set of assumptions that undergo a detailed scrutiny and review process. Using FES also ensures analytical alignment between Arup and NGESO analysis, which is required under the new CBA framework under the C&F regime.

The selection was based on the amount of cross-border capacity assumed in each FES scenario, which is shown in Figure 9 below.

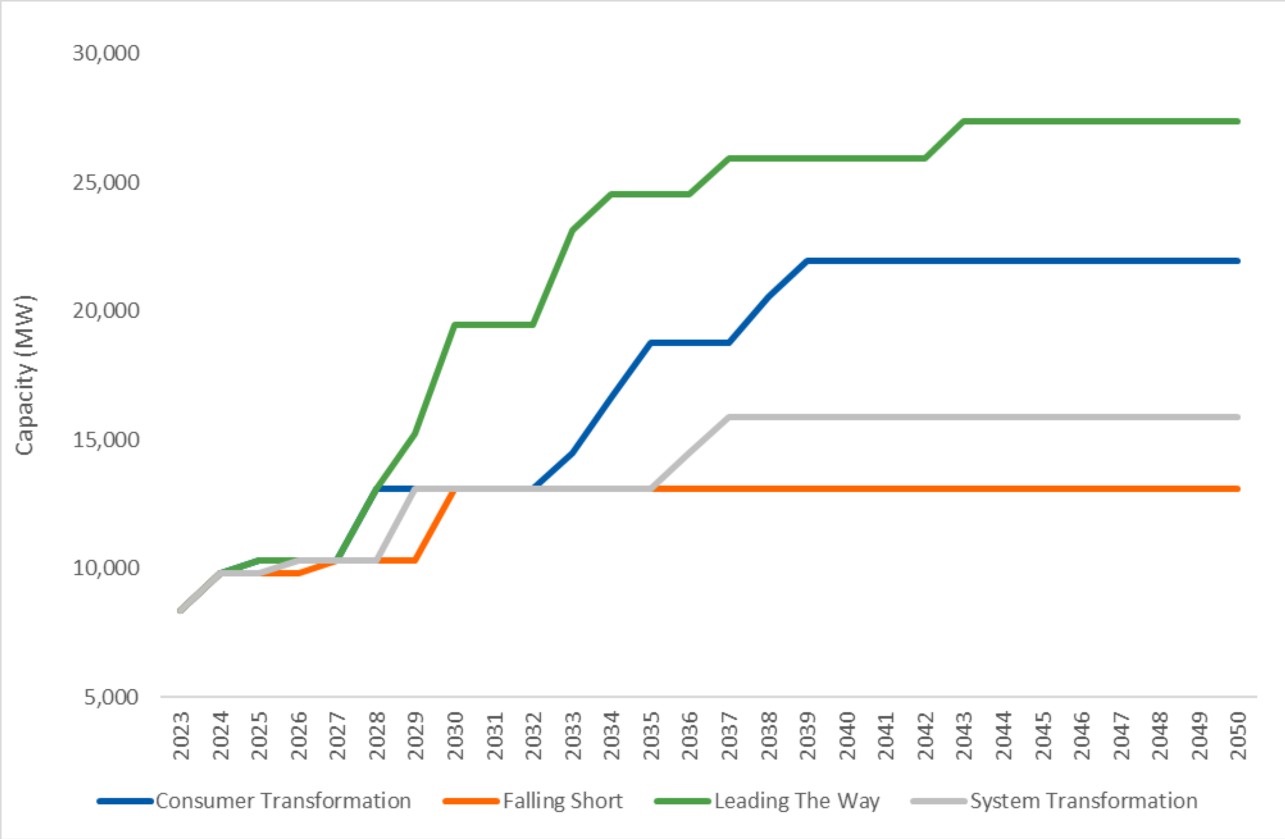


Figure 9 – Cross-border capacity in GB under the FES 2022 (MW)

We used this measure as a proxy for price differentials between GB and connected countries. The need for cross-border capacity is primarily driven by price differentials. Hence, it can be assumed that FES scenarios with high (or low) cross-border capacity are also the scenarios with high (or low) price differentials between GB and its neighbours, representing the best (or worst) scenario from an interconnector perspective. This rationale was also supported by NGESO, and a high-level review of the price differentials under the various scenarios corroborated this assumption.

On this basis, Arup initially selected the following as the High, Base and Low Case scenarios:

- **Leading the Way (LW) – High Case scenario**. This scenario represents the FES scenario with the fastest credible decarbonization path, incorporating significant lifestyle changes and a combination of hydrogen and electrification for heating. This scenario is Net Zero compliant.
- **Consumer Transformation (CT) – Base Case scenario**. The CT scenario involves electrified heating, consumers who are willing to change their behaviour, high energy efficiency, and demand-side flexibility. This scenario is Net Zero compliant as well.
- **Falling Short (FS) – Low Case scenario.** The Falling Short (FS) scenario within the FES is characterized by the slowest credible decarbonization path, minimal behaviour change, and a focus on decarbonization in power and transport, excluding the heat sector. As the name suggests, this scenario does not meet the Net Zero target.

The labelling of a High, Base and Low Case scenario was initially required under the preference building process of the MCA framework discussed at the modelling workshop with key stakeholders. The initial intention was to assign a RAG rating based on the performance under a specific scenario (either the High, Base or Low Case one)[21].

However, key stakeholders flagged during the workshop that such assessment approach could have been detrimental to some projects. Developers argued that the FES are not specifically developed to assess cross-border projects, as they are not designed to describe more or less favourable market conditions for trading electricity. Consequently, not all projects would have performed consistently positively (or negatively) under the same scenarios due to their design. For example, a project might have performed better under the Base Case scenario than under the High Case scenarios, affecting the final RAG rating.

Arup acknowledged this point and in agreement with Ofgem, it was decided to move away from basing the RAG rating of a project under the High, Base and Low Case scenario. Therefore, such wording has not been utilised in this analysis. The selection of three FES scenarios described above was nonetheless maintained as they still provide a reasonable range of potential outcomes.

Assumptions for European countries

The market fundamentals of the European countries covered by NGESO in their FES 2022 report are strongly inspired by reports from national electricity Transmission System Operators, national regulators, and the ENTSO-E Ten Year Network Development Plan (TYNDP). Two scenarios have been developed: EU Consumer Transformation (CT) and EU System Transformation (ST).

This data set has been made available to stakeholders and is in the public domain for the first time since the FES publication started (see tab ES2 “European electricity supply data table” of the FES 22 data workbook). This data sets out NGESO’ electricity installed capacity and annual demand assumptions for European countries as included in NGESO’s pan-European dispatch model.

NGESO worked with Afry to develop the two European scenarios. This included the co-creation of a set of modelling assumptions such that the scenarios broadly align with NGESO’s GB System Transformation and Consumer Transformation scenarios. However, since there are four FES GB scenarios (CT, LW, ST and FS) the EU FES scenarios have been paired as following:

The scenario EU CT has been paired with GB CT and GB LW. The scenario EU ST has been paired with GB ST and GB FS.

As the scenarios were created in Q4 2021, they do not include recent market developments such as those that came about following the war in Ukraine.

Further considerations on scenarios selection

It was agreed with Ofgem and Energy System Operators (ESO) not to use ST because CT provided capacity levels much closer to the middle point between FS and LW when compared to ST. As such, CT also includes higher cross-border capacity (and therefore higher price differentials, as described earlier) than ST, representing a more favourable case for project developers.

It is important to remember that the FES are internally consistent scenarios from which only the GB cross-border capacity assumption needs to be changed in order to implement the FA and MA approaches described in section 0. Under the MA approach, the resulting cross-border capacity would be much higher than the one originally assumed in ST to meet demand, compared to CT. This would make ST a much more challenging scenario for any new cross-border projects.

By the same rationale, FS was selected as it includes the lowest amount of cross-border capacity between (and therefore higher price differentials) GB and the connected countries. Whilst we acknowledge that FS is not a Net Zero compliant scenario, it still describes a scenario where significant decarbonisation of the energy system is achieved. Therefore, FS represents a plausible scenario required in our assessment to

[21] For more information, please refer to the MCA report published alongside this document.

account for the risk and to assess the impact of potentially overdelivering cross-border capacity, especially under MA where the resulting cross-border capacity is significantly higher than the one assumed originally in FS. The scenarios we have used should be the best range, with bookends of the upper and lower bounds, with which to test the projects.

Finally, for the same analytical reasons described in section 2.1, we decided not to modify the assumptions contained in FES to reflect latest policy and market developments in GB and the connecting countries. Doing so would have undermined the consistency of the scenarios, changing the narrative for which they have been selected. Further, this allows for an entirely neutral approach for assessing projects, avoiding the risk of developers lobbying and cherry-picking assumptions that would favour their projects. Augmenting the scenarios also limits the replicability of the results by third parties and delays the publication of the results. The key assumptions that differ from the FES scenarios is the amount of cross-border capacity in GB and the EU DSR capacities. This is discussed in more detail in section Interconnector capacities2.4.2 later on.

Wholesale market prices

In the following paragraphs we outline the resulting wholesale price curves generated by PLEXOS for GB and the relevant oversea countries under LW, CT and FS. The curves shown assume that all the W3 and OHA projects under consideration in this study are built (i.e., MA approach) and are the averages of all the weather years used in this study (i.e., 1990, 2007 and 2010).

Leading the Way

Figure 10 below shows the resulting price curves in LW. Electricity prices in GB remain among the lowest as the country is assumed to decarbonise more quickly than its neighbours, averaging at £55/MWh across the modelled period. It can be noted that prices increase from 2040 onwards, peaking at £62/MWh in 2045.

This is due to a combination of factors such as Carbon Capture, Usage and Storage (CCUS) Combined-Cycle Gas Turbines (CCGT) increasingly setting the market price in a context of growing intermittent generation combined with the highest CO_2 price of the three scenarios. By 2050, the LW scenario has 4.2 times less Bioenergy with Carbon Capture and Storage (BECCS) capacity than in the CT scenario and 1.9 times less nuclear capacity than in the CT scenario. Additionally, these two technologies have SRMC lower compared to CCUS Gas. These factors contribute to a higher annual wholesale price average compared to the CT scenario. This scenario also presents the highest volumes of intermittent renewable generation in GB.

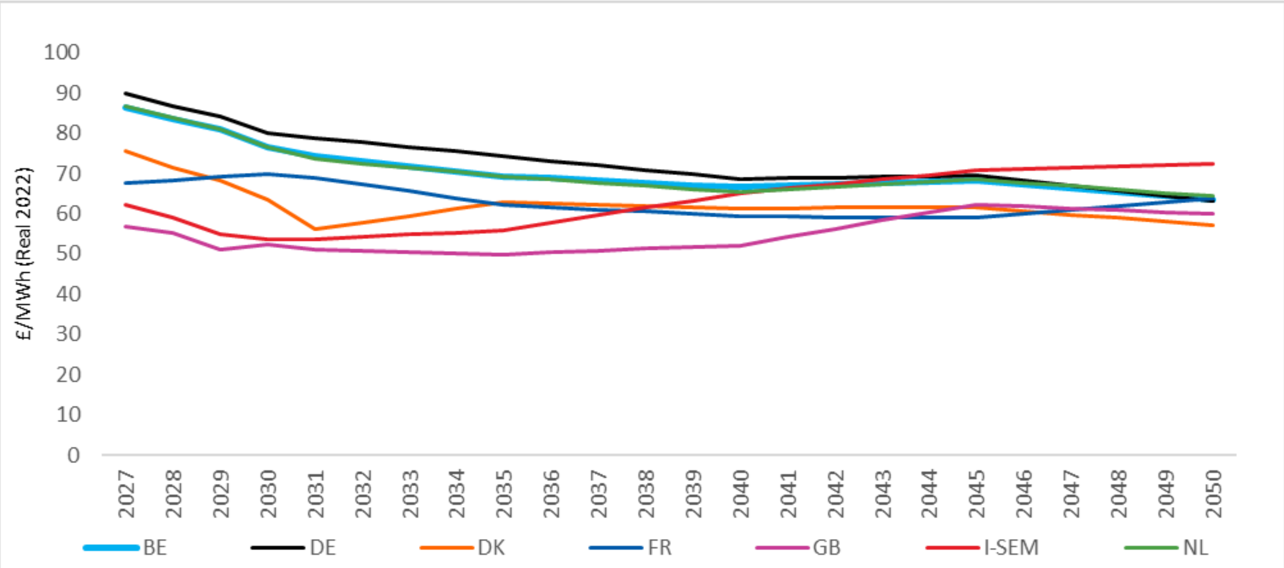


Figure 10 - Wholesale power price curves in LW (£/MWh, real 2022, average of all-weather years)

Prices in the relevant oversea countries are generally higher than GB ones, averaging between £62 - £73/MWh, generally decreasing throughout the modelling period as more RES comes online. The resulting price differentials with GB are between £7 - £18/MWh.

Consumer Transformation

Figure **11** below shows the resulting price curves in CT. In CT, GB presents the highest volumes of offshore wind capacity installed among the three scenarios selected. Furthermore, installed nuclear capacity is also the highest of the three selected FES scenarios by 2050. Consequently, electricity prices in GB remain among the lowest, averaging at £46/MWh throughout the modelled period.

Prices in the relevant connecting countries remain higher than GB as they decarbonise at a slower pace, averaging at between £58 - £69/MWh. This is the scenario presenting the highest prices differentials with GB, averaging at between £10 - £23/MWh.

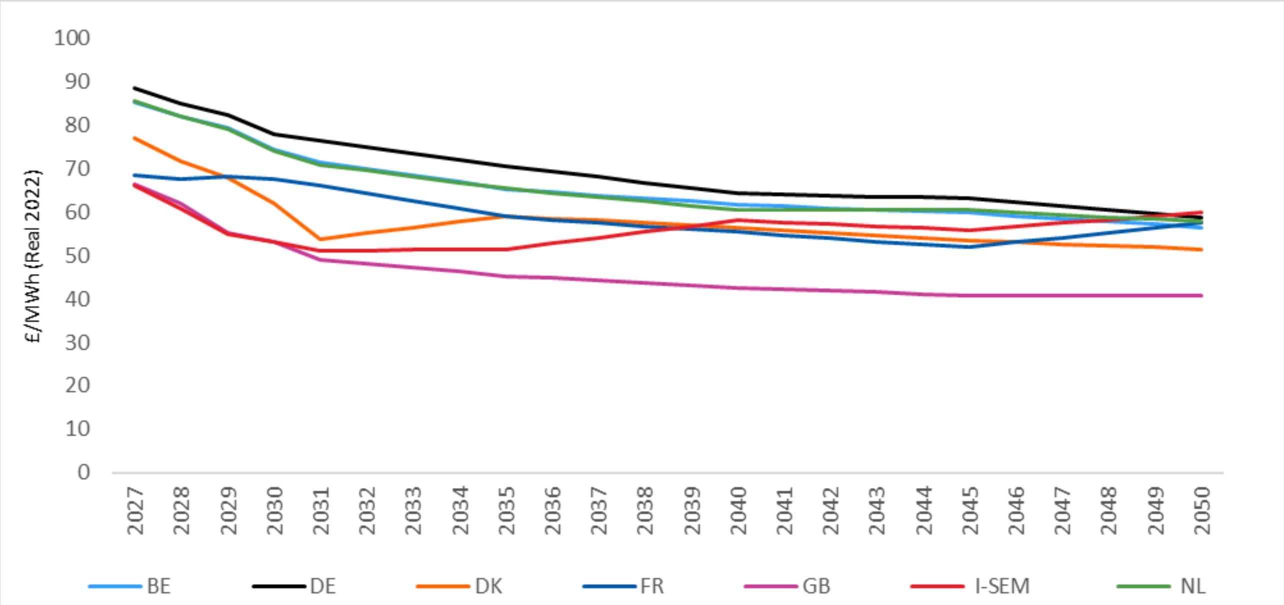


Figure 11 - Wholesale power price curves in CT (£/MWh, real 2022, average of all-weather years)

Falling Short

Figure 12 below shows the resulting price curves in FS. In FS, the electricity price in GB starts quite high at the beginning of the modelling period (£86/MWh) and decreases gradually following the increase in low SRMC RES installed capacity (though by 2050, FS is the scenario with the lowest intermittent RES capacity). This is the scenarios with the highest annual average price for GB at £60/MWh.

Prices in the relevant connecting countries follow a similar trend, starting high at the beginning of the modelling period (between £76 - £93/MWh) and then decreasing gradually, for an average price between £59 - £74/MWh across the modelled period.

This is the scenario presenting the lowest price differentials between GB and relevant connecting countries, averaging between £1- £14/MWh.

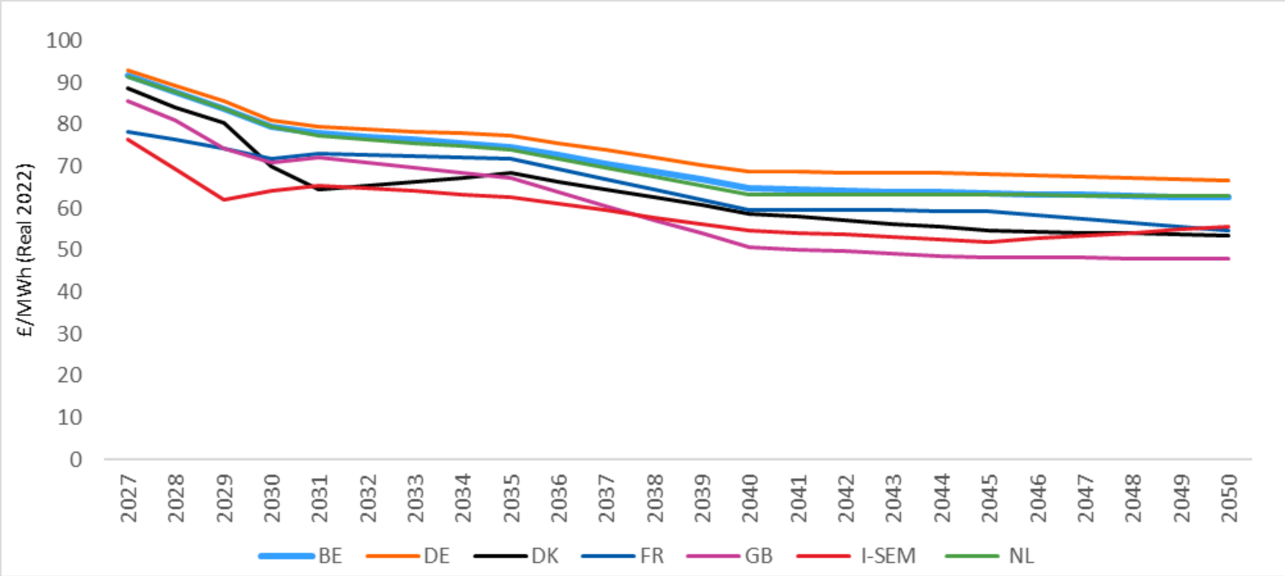


Figure 12 - Wholesale power price curves in FS (£/MWh, real 2022, average of all weather years)

Geographical scope

The geographical scope of the FES was used in this analysis and includes Austria, Belgium, Czech Republic, Denmark, Finland, France, Great Britan, Germany, the island of Ireland, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, Slovenia, Spain, Sweden, and Switzerland. In this report, we refer to these country as 'Europe' or 'European countries'. Arup did not model Corsica, Sardinia and Sicily and other territories not attached to the mainland.

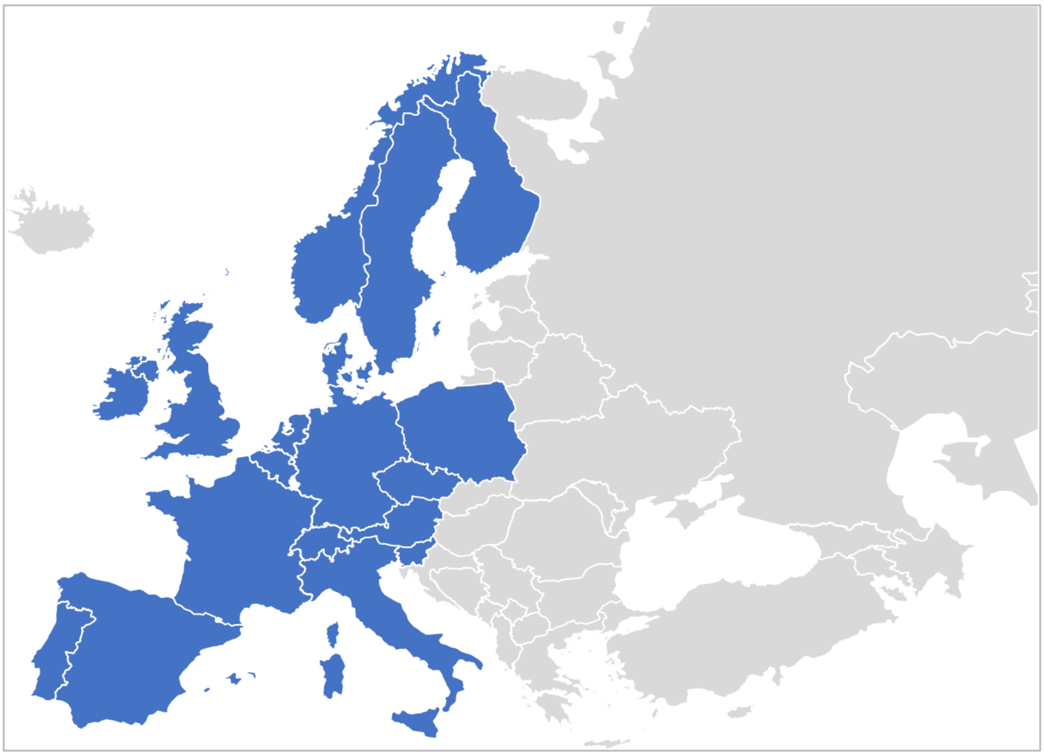


Figure 13 - Geographical coverage of FES 2022 [22]

[22] Please note that Figure 13 is a political map of Europe. As such, island and other territories not attached to the mainland are shown individually although in our modelling they are considered as part of the national bidding zone(s) of the state they belong to.

2.4.2. Interconnector capacities

In order to assess the impacts of new projects in GB, we kept the interconnector capacity baseline in GB constant under all scenarios. The interconnector capacity baseline is the amount of capacity in place before the commissioning of any W3 and OHA projects.

The GB interconnector capacity baseline is composed of:

- Existing IC projects;
- IC projects currently under construction; and
- IC projects that have been granted a cap and floor regime or other regulatory approval by Ofgem.

This is the same approach used by Ofgem under previous application windows, and it was followed for the assessment of both IC and OHA projects applying under W3. No further IC or OHA projects are assumed to be built in GB beyond W3.

The full list of projects included in the capacity baseline is included in the Table 8 below.

Table 8 - GB interconnector capacity baseline

Project Name	Connecting country	Capacity (MW)	Assumed connection date in the analysis
IFA	France	2,000	1986
Moyle	Northern Ireland	450	2002
BritNed	Netherlands	1,000	2011
EWIC	Ireland	500	2012
Nemo Link	Belgium	1,000	2019
IFA2	France	1,000	2021
NSL	Norway (NO5)	1,400	2021
ElecLink	France	1.000	2022
Viking Link	Denmark (DK1)	1,400	2023
Greenlink	Ireland	500	2024
GridLink [23]	France	1,400	2031
NeuConnect	Germany	1,400	2028
FAB Link [21]	France	1,250	2031

European interconnector capacity baseline

The interconnection capacity baseline for the modelled European countries is assumed to be the same across all FES EU scenarios. These capacities assumptions are based on the assumptions (namely, the high case scenario) developed by Afry, the consultants procured by NGESO to develop some aspects of the FES

[23] The connection dates for these two projects have been communicated by Ofgem after engagement with the relevant project developers.

scenarios. As such, the detailed set of assumptions are considered to be commercially sensitive and are not included within the FES 2022 data workbook that is available on the ESO website.

In order to maintain the principle of transparency, and in agreement with NGESO, Afry and Ofgem, we made available to stakeholders the aggregate levels of interconnection capacity assumed in the FES EU scenarios for the relevant connecting countries. For avoidance of any doubt, the European interconnector capacity baseline excludes the W3 and OHA projects.

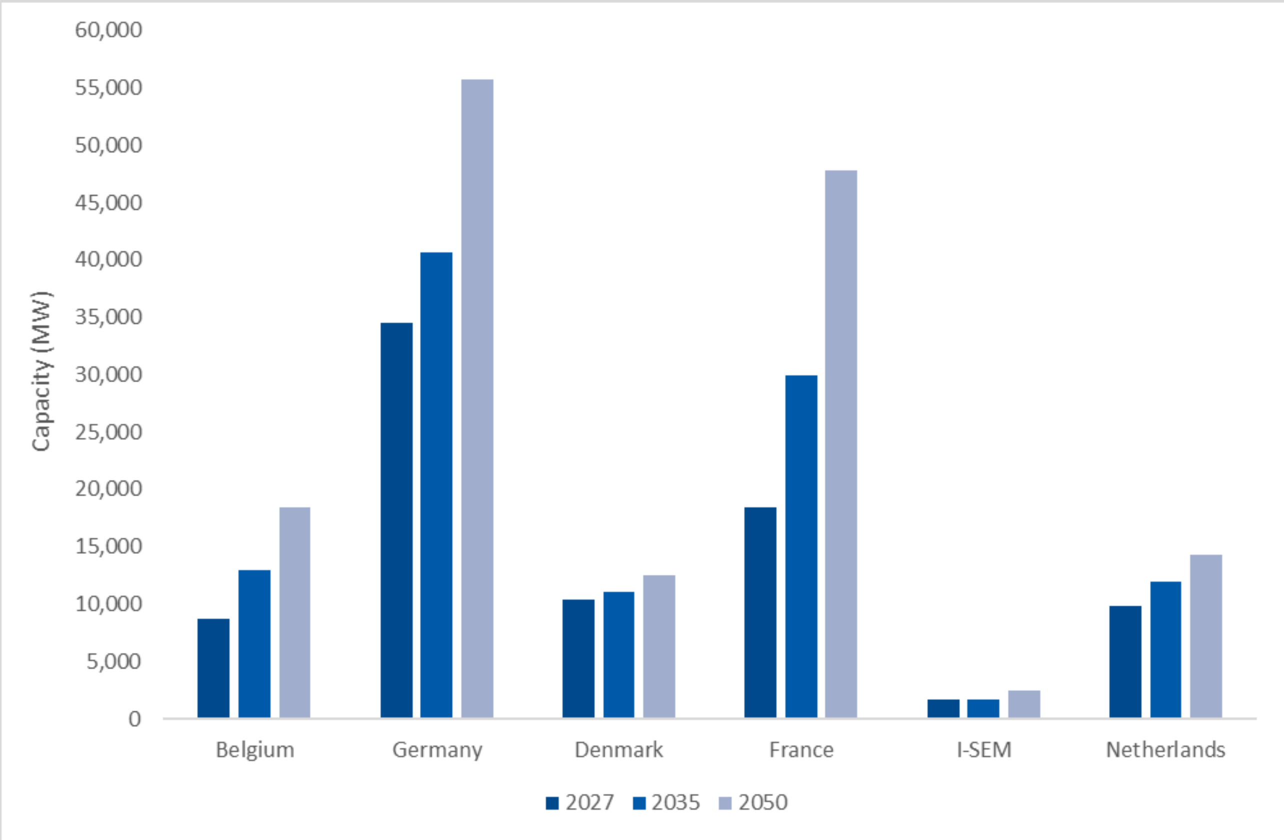


Figure 14 - Baseline interconnector capacity assumed in the EU FES Scenarios (EU ST & CT) for the relevant connecting countries (MW)

Decommissioning

In our analysis, we did not assume that any of the existing and new projects will be decommissioned. Rather, all projects are assumed to continue operating until the end of the modelling period for this analysis.

It was decided not to include decommissioning as it was not possible to develop a retirement schedule based on reliable data on the actual useful life of an IC project. Additionally, we understand the current IC operators have plans in place to refurbish the existing assets and continue their operation over the modelled period. This was considered to be a reasonable simplification benefitting the overall modelling process and timeline.

Implication of a fixed baseline on de-rated system margins

During the stakeholder engagement phase of the study, one stakeholder pointed out that the de-rated system margins [24] implied by the FES scenarios were implausibly high and well outside the historical range in GB between 5%-8%. It was suggested that the FES scenarios should be modified to fit within that range, to avoid

[24] The de-rated capacity margin measures the amount of excess supply above peak demand. De-rating means that the supply is adjusted to take account of the availability of plant, specific to each type of generation technology.

creating an unfavourable market environment for new cross-border projects whereby supply from generators already outstrips demand.

Arup looked into the FES 2022 GB capacity mixes (with no modifications and including the aggregate interconnector capacity) and there are several instances (either on scenario or year basis) where the system margin was significantly outside the 5-8% range. It should also be noted that the same exercise was undertaken for the capacity mixes used in W2. Similarly, there were several instances (scenarios/years) where the de-rated system margin was significantly outside the 5-8% range. No system margin re-balancing modifications appear to have been undertaken.

By 2035, the UK Government has set out a target to be able to run a fully decarbonised electricity power system. There will be much higher volumes of weather dependent renewables, storage, and more interdependence with neighbouring countries through electricity interconnection. There will be times when weather conditions will lead to very low output from renewable generation. These weather conditions may extend beyond GB affecting neighbouring countries too. There will need to be sufficient additional resources in the resource mix to deliver clean, reliable power at these times i.e., to maintain security of supply and ensure adequacy.

The ESO is currently undertaking long-term adequacy studies to assess the potential risks to security of supply and to ensure there are sufficient available resources to meet electricity demand throughout the years out to 2050. The current quoted range system margin range of 5% to 8% may no longer be a suitable measure beyond 2030.

Therefore, Arup did not undertake margin re-balancing modifications on the selected FES 2022 scenarios.

2.4.3. Forecasting horizon and Spot Years

Arup modelled a total of nine spot years for each W3 and OHA project assessed. As described in section 2.3.2, each project has a different connection date between 2027 and 2031. Considering the relevance of the first year of operation for an IC or OHA project, Arup agreed with the developers on the need to model the first operational year for each project in full. In addition, Arup modelled other four spot years, namely 2035, 2040, 2045 and 2050, for a total of five spot years modelled in full for each project.

Arup then linearly interpolated the data between the relevant five spot years for each project to generate the intermediate data point required to determine its impacts over 25 years, which is the length of the C&F regime. For those projects that operates beyond 2050, Arup carried over 2050 values.

It was decided not to extend the modelling horizon to align with the useful asset life of an IC or OHA project. This was done for several reasons:

- The FES scenarios are only available up to 2050. Running a grid expansion study to cover a longer time horizon would have added a significant computational load.
- Extending the demand forecast by running a grid capacity expansion would have introduced a spurious sense of accuracy, with the difference in results compared to repeating the 2050 values being heavily discounted due to the discount rate utilised in this analysis.
- Balancing the impact on the modelling process against the additional insights gained was deemed unfavourable compared to simply carrying over the 2050 values.

2.4.4. Weather years

In order to simulate the effect of different weather conditions on energy prices, generation dispatch and electricity flows, each scenario of this study has been run three times for each modelled year using historical data for onshore and offshore wind, solar radiation. These weather runs have then been averaged out to generate the results of this analysis.

The weather data was taken from ENTSO-E's TYNDP 2022 Climate data set[25]. The selection of the weather year used in this analysis was based on the average combined load factor for onshore wind, offshore wind, and solar generation. Arup selected three weather years describing the best, worst and average conditions for renewable energy production in GB. Using this approach, the following whether years where selected:

- 1990: High case weather year
- 2007: Base case weather year
- 2010: Low case weather year

In agreement with Ofgem[26], it was decided to simulate only three weather years due to the already substantial number of runs required by this analysis. Whilst the three years selected are not necessarily the most recent ones, they represent the widest average range possible in terms of renewable energy sources (RES) performance within TYNDP 2022 data set. As such, it was considered an appropriate and necessary simplification to capture the effects of different weather conditions.

2.4.5. Trading arrangements

Following the exit of the UK from the European Union (EU), the UK is no longer part of the Internal Energy Market (IEM). A key consequence is that electricity trading between the UK and EU members now occurs under explicit capacity auctions. Under explicit auctions, the transmission capacity on an interconnector is auctioned to the market separately and independently from the trade of electrical energy via a central algorithm.

Under the EU-UK Trade and Cooperation Agreement (TCA), new cross-border trading arrangements are being developed with the aim to reintroduce more efficient implicit capacity auctions through the concept of multi-region loose volume coupling (MRLVC). Under implicit auctions, interconnector capacity and electrical power are allocated in the same process, i.e., the auctioning of transmission capacity is included implicitly in the auctions of electrical energy in the market as one product.

Considering the commitment of both the UK and the EU in implementing the MRLVC concept, we have assumed that electricity is traded based on implicit capacity auctions. This means that cross-border flows are assumed to perfectly correspond to price differentials between markets, even if these are minimal. This is a required modelling simplification, although it should be acknowledged that IC and OHA operators are commercially incentivised to flow electricity when the price differentials are high enough to generate enough revenue to at least recoup the costs of operating the asset.

2.4.6. Modelling OHAs

By including cross-border transmission capacity in their design, OHA projects will directly impact all other IC projects currently applying for regulatory approval, as well as all other existing projects. Therefore, it was considered necessary to assess OHAs alongside traditional P2P IC projects using the same set of base assumptions and methodologies.

Nonetheless, the development of a few additional assumptions only relevant to OHA projects was required. These have been described below.

OHA configuration

To model the OHA projects considered in this analysis, Arup created a PLEXOS object composed by two lines: a cross-border transmission line between the GB and the OWF within the other country's jurisdiction

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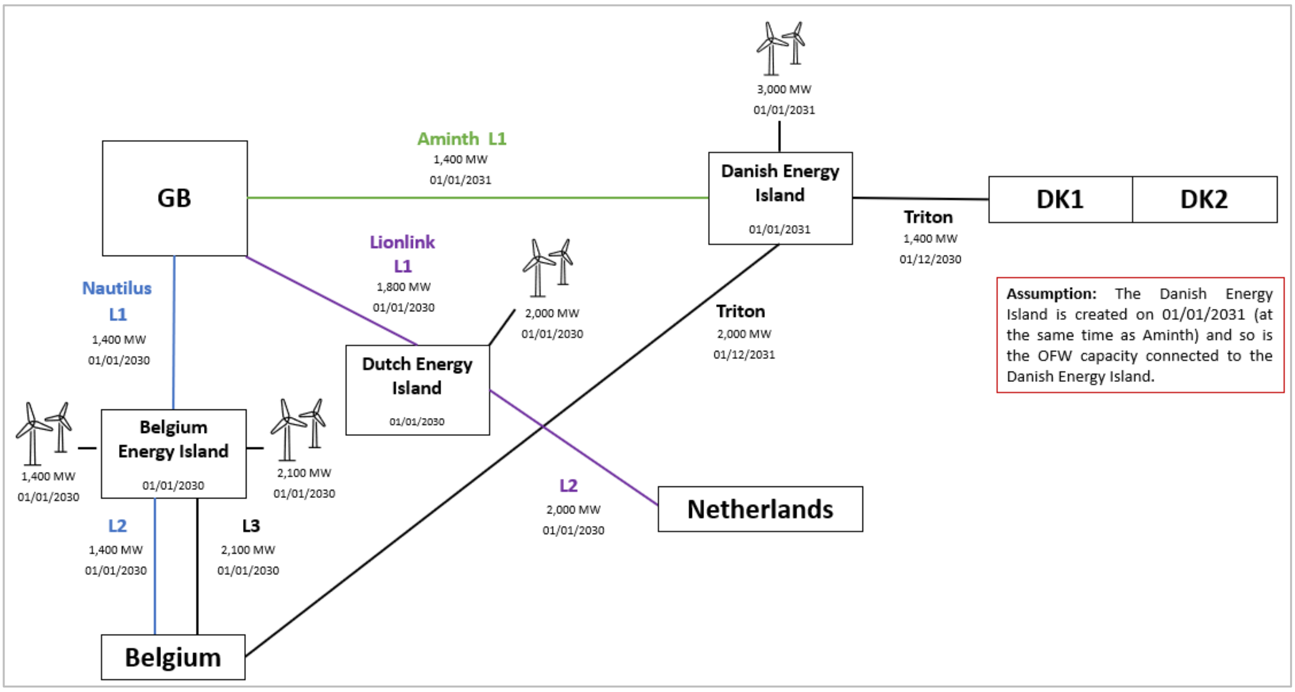
[25] ENTSO-E TYNDP 2022 Climate Data Set link

[26] NGESO used 2013 for its constraint costs analysis as it provides good agreement to an average derived from running a range of weather years.

(Line 1 or L1) and the offshore transmission asset connecting the OWF to the shore of the respective country, entirely placed within the jurisdiction of that country (Line 2 or L2).

The drawing below represents how the OHAs have been configured in our study.



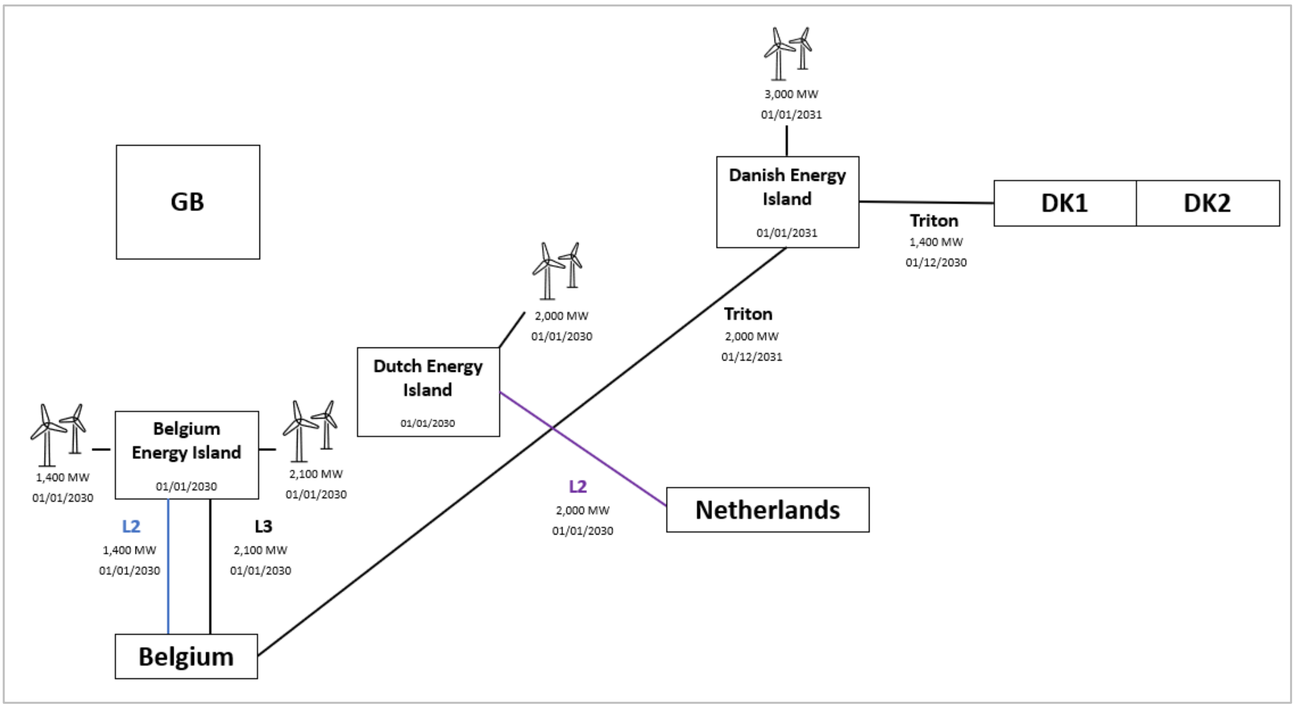
Drawing 2 – Assumed OHA configuration

Based on the design and information provided by the developers, the OWF connecting to the OHA was placed within the jurisdiction of the connecting country. The jurisdiction only indicates which offshore wind pattern to allocate to the OWF. For example, the OWFs attached to the Belgium energy island will be associated with the Belgian offshore wind pattern. The jurisdiction of an energy island has no other bearing on the modelling.

Counterfactual used

The counterfactual used in Arup's analysis includes only the OWF and its respective offshore transmission link (L2). In other words, in the counterfactual, it is assumed that the development of the offshore wind asset is independent from the delivery of the OHA itself. Consequently, the same level of offshore generation capacity is assumed in both the target case and the counterfactual.

This is aligned with the latest information provided by the OHA developers and the CBAs they have submitted. Drawing 3 below shows the counterfactual used.



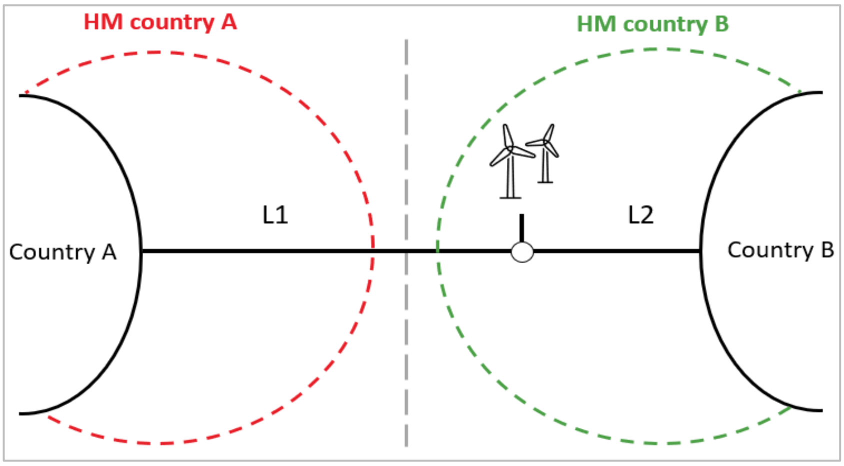
Drawing 3 - OHA counterfactual configuration[27]

Market arrangements

Currently, two possible market arrangements applicable to the OWF connecting to an OHA are under consideration: the Home Market (HM) model and the Offshore Bidding Zone (OBZ) model.

The HM model is effectively the status quo and reflects the model currently used for rational connections of OWFs to shore. Under the HM model, the OWFs connected to an OHA will be part of their domestic (or 'home') bidding zone (i.e., 'market'). In this model, the OWF is considered to have priority access to the OHA cable over cross-border electricity flows to/from the connecting country.

This means that the OWF will always be guaranteed a proportion of the capacity on the OHA to transport the electricity it generates to its domestic market. Because the OWF is part of its home bidding zones, it will always bid into its domestic market, and thus receive the price of that market.

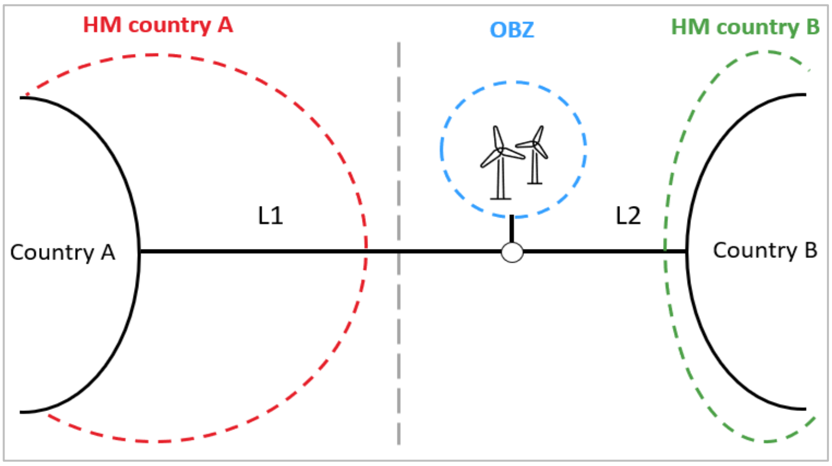


Drawing 4 - Home market arrangement

[27] Please note that Aminth is not considered by Ofgem as an OHA project from a regulatory perspective. The project was included in the drawings above only for illustrative purposes.

The OBZ model envisages the creation of a separate bidding zone within which the OWF connected to the OHA operates. In this model, the OWF will compete with bids and offers from other market players in the onshore bidding zones connected by the OHA for access to the cable. Assuming that implicit trading arrangements are in place, a central algorithm will match those bids and offers and dispatch the OWF to optimise the overall use of the asset.

This means that the OWF is expected to receive the lowest price of the two onshore bidding zones to which it is connected. This is because the central algorithm will match the OWF with demand in the lower priced zone, allowing the capacity of the cable to export supply from that lower priced zone to connected higher price zone.[28]



Drawing 5 - Offshore bidding zone market arrangement

Arup's analysis assumed that all OHA projects assessed will operate under OBZ market arrangements, as indicated by the respective project developers. However, Arup acknowledge that different trading arrangements could exists in the short terms.

Other considerations

As already covered in section 2.3.2, in agreement with Ofgem, only the GB portion of the revenues earned over L1 of an OHA project were used to calculate the relevant C&F payments for that project. Arup used a 50% split assumption for the revenue. Similarly, only the GB portion of costs associated with L1 have been netted off the IC SEW indicator for that project. The total revenues earned by L2 are allocated to the country in whose jurisdiction the OWF is based.

Finally, in terms of SEW allocation between countries, the SEW associated with the OWF connecting to an OHA is allocated to the country connecting to GB in whose jurisdiction the OWF is based.

2.4.7. Intra-day market modelling

Arup excluded intra-day (ID) modelling from the scope of this work. Arup considered two options before reaching this decision.

- Use the PLEXOS interleave functionality along with our internal Net Imbalance Volume (NIV) calculation methodology to model the Balancing Market (BM) as a proxy for the intra-day horizon. Arup decided against this option following internal discussions and consulting with Energy Exemplar as it would add significant model run-time and cost in an already model heavy scope.

[28] More detailed information of these models, their respective benefits and costs, can be found in Ofgem's recent consultation on 'Market Arrangements for Multi-Purpose Interconnectors', which can be found on Ofgem's website: https://www.ofgem.gov.uk/publications/consultation-regulatory-framework-including-market-arrangements-offshore-hybrid-assets-multi-purpose-interconnectors-and-non-standard-interconnectors

The expectation is that there should not be significant value in terms of enhancing the accuracy of the results. The change between the Day Ahead (DA) and the BM timeframes is channelled through the shift in the DA Load (BM Load = DA Load + NIV) – this set up is more sensible to the breaking of the link DA→BM→DA.

- Apply the Net Imbalance Volume uncertainty at the DA load. Arup decided not to proceed with this option either as it would mean altering the FES demand assumptions with limited improvement in the accuracy of results. In essence, this option would still fall short of reflecting the real-time market conditions accurately.

2.4.8. Calculation of Capacity Market revenues

As described in section 2.2.1, the Capacity Market (CM) is aimed at recovering the missing revenue not available from market sources for generators that are required to ensure reliability of supply. The CM payment (£/kW) is defined through a pay as clear auction. This means all the eligible assets receive the same payment (CM clearing price) on a per kW basis. ICs do participate in the current CM, and Arup assumed that OHAs will be able to participate in the CM in the future.

As described in the Afry CBA for W2 projects[29], the participation of IC and OHAs in the CM can lead to one of three outcomes:

1. **Lower clearing price:** This can occur in the case that the IC or OHA prices out more expensive generation. In other words, the lower interconnector's bid in the CM may prevent certain generators with a more acute missing problem to obtain a CM contract.

2. **Same clearing price:** Even though more expensive generation is displaced, producers could increase their bidding price to the level the clearing price would have been if interconnectors did not take part in the auction.

3. **Higher clearing price:** The producers increase their bidding price to ensure they recover all the revenues they would have in the case interconnectors did not participate in the auction.

Arup agrees with the view previously taken by Afry under W2 that all these outcomes are equally likely. Therefore, we have assumed the clearing price is the same for the FA, MA, both in the target case and counterfactual (i.e., the second outcome of those listed above).

However, the clearing price will fluctuate depending on the year and the scenario. In Arup's model, the clearing price is set by the generator or generator class with the highest missing money amount (£m) that was required to generate in each year. This is then converted to £/kW by dividing it with the capacity of the corresponding asset.

$$Clearing\ Price\ (\frac{£}{kW})_{Year\ i} = \frac{Missing\ money\ (£)_{\ Most\ expensive\ generator}}{Capaity\ (kW)_{Most\ expensive\ generator}}$$

The other variable of the CM is the volume of capacity procured in each annual auction. Arup have assumed that the capacity considered within the FES scenarios for the European countries is adequate to meet the security of supply standards for the corresponding countries. For GB, there is no need for such an assumption as the FES publication clearly states the scenarios all GB FES scenarios are adequate to meet the security of supply standards. The volume of capacity procured under the CM each year in Arup's model is defined by adding the capacity of all the generators eligible to participate in the CM each year.

[29] For more information, please refer to: https://www.ofgem.gov.uk/sites/default/files/docs/2018/01/near-term_interconnector_cost_and_benefit_analysis_-_independent_report_.pdf

$$Capacity\ Market\ Revenue_{\ Asset\ j} = Clearing\ Price\ (\frac{£}{kW})_{Year\ i} \times Derated\ Capacity_{Asset\ j}$$

To calculate the total capacity for producers, IC and OHAs, Arup has used de-rating factors. For producers, Arup has used the de-rating factors from the latest auction, whilst for ICs and OHAs, Arup used the derating factors used by the developers.

Table 9 – W3 IC de-rating factors

Project Name	Capacity (MW)	Connecting country	Operation date	Derating Factor
Aquind	2000	France	2027	61%
Aminth	1400	Denmark	2031	55%
Cronos	1400	Belgium	2029	64%
MaresConnect	750	I-SEM	2030	49%
LirIC	700	I-SEM	2030	49%
Tarchon	1400	Germany	2030	62%
NU-Link	1200	Netherlands	2031	61%

Table 10 - OHA projects de-rating factors

Project Name	Capacity (MW)	Connecting country	Operation date	Derating Factor
LionLink	1800	Netherlands	2030	61%
Nautilus	1400	Belgium	2030	64%

Based on the methodology described above, the CM revenues achieved by individual IC and OHA project remain unchanged in each of the FA, MA, and target case. Note that despite of the fact that we have assumed the clearing price is the same for the FA, MA, both in the target case and counterfactual, the clearing price remains flat. The total IC and OHAs revenues will be different between the counterfactual and the target case as the total IC capacity will change. As a result, the total consumers SEW (cost to consumers) will also change.

2.4.9. Calculation of Contract for Difference costs

Under the CfD scheme, the generator is guaranteed a stable level of revenues at a pre-agreed level (the strike price) for the duration of the contract. The contract is paid for by consumers.

To calculate the total cost of the CfD support scheme to consumers (i.e., revenue to producers), Arup calculated the total amount of payments made to generation eligible for a CfD. This was done by multiplying the total amount of eligible generation with the difference between the reference and the strike price.

$$CfD\ Cost = \sum CfD\ Eligible\ Generation\ Volume\ \times\ (Strike\ Price - Reference\ Price)$$

The strike prices for each technology were set using DESNZ's levelized cost of electricity estimates according to the Generation Cost Estimate report 2023.[30]

[30] For more information, please refer to https://www.gov.uk/government/publications/electricity-generation-costs-2023

The reference price used is the wholesale price for each settlement period during which each eligible low carbon technology exported to the grid.

Arup have made different assumptions on the share of total low carbon capacity supported by CfD on a technology basis. Arup considered four types of technologies supported by CfD: solar, onshore, and offshore wind and nuclear.

For solar, onshore, and offshore wind, we have calculated the share of the CfD supported capacity based on the total capacity in the CfD Register [31] for all proposed capacity in auction rounds 1 to 5. We assumed that this proportion remains flat post 2027. For nuclear capacity, we estimated the share of capacity supported by CfD by assuming that Hinkley Point C and all the Small Modular Reactor capacity will be receiving CfD support. Based on these assumptions, the share of low carbon generation supported by CfD is shown in the table below.

Table 11 - Assumed share of low carbon generator supported by CfD

Technology	Consumer Transformation	Leading the Way	Falling Short
Onshore Wind	20%	17%	28%
Offshore Wind	60%	57%	87%
Solar PV	18%	14%	26%
Nuclear	71% dropping to 47% in 2050	71% dropping to 44% in 2050	71% dropping to 47% in 2050

Low carbon support payments are a function of the generation volume eligible for support and the price differential between the strike price and the reference price.

- An IC or OHA project can lead to higher or lower wholesale power, which in turn affects the level of support consumers are required to cover through their bills. In general, higher wholesale power prices lead to lower top up payments on a per MWh basis and vice versa.
- Apart from prices, additional IC or OHA capacity would also impact the volume generated by low carbon generation. This is because it can lead to lower or higher generation curtailment. When exports are increased from GB to other countries, it is expected that less volume will be curtailed as demand would overall be higher. On the contrary, if any of the projects leads to lower generation, we may notice increased curtailment.

The impact of additional IC and OHA capacity on wholesale prices counterbalances their impact on renewable generation curtailment. New cross-border capacity that leads to increased exports from GB (hence less renewable generation curtailment) should also lead to increased wholesale prices. Less renewable generation curtailment would lead to more volume eligible for CfD support hence higher CfD payments required for consumers as per the equation above. Conversely, inflated wholesale prices due to increased exports would lead to reduced level of support required by consumer on a per MWh basis [32]. Therefore, their impact on consumers SEW has been looked at on a case-by-case basis by Arup.

[31] This can be found at https://cfd.lowcarboncontracts.uk/

[32] Increased imports would impact renewable generation curtailment and prices in the opposite direction.

2.5. Limitations and modelling simplifications

2.5.1. Limitations

Latest market and policy developments

- **Revised national energy policies.** As already explained in section 2.1, the use of publicly available information such as NGESO's FES was a fundamental requirement to ensure the transparency, auditability, and replicability of Arup's analysis, as well as analytical alignment with NGESO.

  Modifying the assumptions in the FES to reflect the most recent policy and market developments in both GB and other oversea countries would have undermined these key principles. Similarly, it would have been difficult to distinguish between which market or policy developments to include considering the numerous reforms ongoing in both the UK and EU.

As such, this analysis did not consider developments such as:

- **REMA.** This analysis does not account for the potential outcomes of the Review of Electricity Market Arrangements (REMA). REMA is considering changes to the current market design in GB to either zonal or nodal market. If such changes were to be implemented, they would likely have a significant impact on the analysis of interconnectors, their flows and impacts on system constraints.

  According to the Ofgem report titled 'Assessment of Locational Wholesale Pricing for GB', published in October 2023[33], the introduction of locational pricing could potentially impact the business cases for both existing and future IC and OHA projects. The report suggests that instances may arise where price differentials between the locational GB market and the connected European bidding zone prices could converge. Such convergence is less likely to occur to the same extent under the current single-price design in GB. Since the development of ICs and OHA projects hinges on capturing the price differential (i.e., congestion rent) between connecting points, some projects might experience reduced revenues, while others could see increased revenues. For projects operating under a C&F regime, changes in revenues might affect consumer support payments. For instance, decreased revenues could elevate the risk of consumers having to contribute additional funds to meet the floor level.

- **EU energy market reforms.** This analysis does not account for recent policy and market developments in other European countries and in the EU, such as the Electricity Market Design (EMD) reform launched in 2023.

- **CBAM**. The effects of the new Carbon Border Adjustment Mechanism (CBAM) announced by the UK and EU have not been considered due to their limited direct impacts on power markets. The potential secondary effect(s) these mechanisms could have on the power market through the UK Emission Trading Scheme (ETS) are possible but deemed too complex or of low impact to model within the scope of this study.

- **FES 2023.** To run its own analysis, NGESO requires the output from the Network Options Assessment (NOA) and the Transitional Centralised Strategic Network Plan (TCSNP). These identify which reinforcement projects will be approved based on the latest FES and Electricity Ten Year Statement (ETYS). Whilst NGESO had access to FES23 during the course of this analysis, the reinforcement requirements will be only available in February 2024.

  Therefore, NGESO could not use FES 2023 to determine the SO and Flexibility impacts of new projects. Consequently, to avoid using two different version of the FES publication and in order to ensure as much alignment as possible with NGESO's analysis, Arup also used FES 2022.

[33] For more information, please refer to: https://www.ofgem.gov.uk/publications/assessment-locational-wholesale-pricing-great-britain

Modelled periods and weather years

As already discussed in section 2.4, in order to reduce the number of model runs required, Arup modelled fully nine spot years per W3 and OHA project assessed, under three weather years and three FES scenarios. Arup then interpolated the results between the five modelled years. Considering the relevance that the first year of operation of each W3 and OHA project has in the interpolation process, Arup modelled fully each connection year.

Arup selected three weather years describing the best, worst and average conditions for renewable energy production in GB. Usually, a higher number of weather years is used to better understand the impacts that weather can have on the energy sector. However, in agreement with Ofgem, it was decided to simulate only three weather years due to the already substantial number of runs required by this analysis. Whilst the three years selected are not necessarily the most recent ones, they represent the widest average range possible in terms of RES yearly generation level within TYNDP 2022 data set. As such, it was considered an appropriate and necessary simplification to capture the effects of different weather conditions.

European Electrolysis Electricity Demand.

The EU demand data provided by in the FES 2022 data workbook do not account for the electricity load resulting from networked electrolysis. To address the gap in the FES dataset, Arup sought to incorporate this source of load into the model using outputs from NGESO’s modelling. However, the endeavour encountered significant data challenges such as but are not limited to:

- NGESO’s output only goes up to 2042, requiring carrying over values for 13 years in order to cover the modelled time horizon (up to 2055 for some of the assessed projects).
- Difficulties in disentangling electrolysis load connected to the transmission network from that connecting to the distribution network for the European countries included into the model. Therefore, Arup assumed that the electrolysis load was largely served by dedicated RES.

Additionally, the EU capacity mixes provided by in the FES 2022 data workbook do not account for Demand Side Response (DSR) capacities. It was unfortunately not possible to extract the data in an exploitable format from NGESO’s model. Proxy quanta derived from ENTSO-E TYNDP 2022 were used instead. The levels of DSR capacity used reached by 2050 a total aggregate value of 703MW in the EU CT scenario and 622MW for the EU ST scenario in the EU countries with a W3 candidate or an OHA.

2.5.2. Modelling simplifications

Stacked approach

GB was modelled on a generator-by-generator basis, whilst all other countries were modelled using a stack approach, i.e., grouping generators by technology type. This does not mean that the total capacity of a specific technology was modelled as a single generator or ‘block’ (e.g. a single nuclear power plant with 8GW of generation capacity). Rather, Arup modelled multiple clones of a representative unit of that specific technology.

This was done to enable the closest alignment possible between Arup and NGESO among the 18 other countries included into the model. Another key reason was the impact on simulation speed as representing 18 countries’ supply side on a generator-by-generator basis and run 1,620 years’ worth of power market simulation would have proven impractical. A test case has shown that the variation in terms interconnector flows, and revenues were negligeable.

3. Market modelling results

3.1. Introduction

This section of the report presents the results of our analysis on a project-by-project basis. Considering the volume of data generated, we have presented only the results under the MA approach.

Whilst the FA results represent the theoretical upper limit of value of a project, it can also be argued they are overly optimistic as they assume that only one additional cross-border project will be built up to 2050. On the other hand, the MA results can be labelled as overly pessimistic, as they assume that all the candidate W3 IC and pilot OHA projects will be built. However, they represent a valid stress test to assess the performance of any new project, as if a project performs well or moderately well under the MA approach, it is extremely likely that the project will perform even better under the FA approach.[34]

Nonetheless, for completion and transparency, the full set of results has been included in Appendix A and Appendix B.

General considerations

The results cover impacts on (i) SEW, (ii) decarbonisation, and (iii) security of supply.[35] We have also provided information regarding price differentials between GB and its neighbours, electricity flows and the estimated revenues of each project against its respective indicative cap and floor levels. Unless specified, the results are shown for all three FES scenarios considered, and they are the annual average of the three weather scenarios used.

As shown in section 0, GB prices tend to be below those of the relevant connecting countries as the UK decarbonises more quickly than its neighbours under FES. This means that the assessed projects are primarily used to export cheaper electricity from GB, which in turn contributes to an increase in the GB wholesale electricity price and a decrease in the price of the relevant connecting countries. This also leads to accordingly similar trends in terms of decarbonisation impacts in GB and the relevant connecting countries.

Changes in CO_2 emissions in the target case compared to the counterfactual are a product of the interaction between price changes and the assumed energy capacity mixes of a country. With few exceptions, an increase in the wholesale market price of a country leads to higher emissions in that country. This is due to the fact that, thanks to higher prices, more expensive thermal generation is dispatched compared to the counterfactual. The opposite applies, whereby lower prices force only cheaper generation sources (e.g., RES) to be dispatched to meet demand.

Countries presenting high volumes of thermal generation capacity in their energy mix will see bigger changes in emission compared to countries with higher volumes of RES capacity, even if these are determined by only minor variations in their wholesale market price. Importantly, also the period in which a price change occurs is relevant, as most modelled countries tend to have more thermal generation capacity in the early years of the modelled period, and to decarbonise significantly afterwards.

We have presented the results for LionLink and Nautilus. The behaviour of the OHA projects assessed is determined by the price differentials between the GB, the Dutch and Belgian markets, as well as between these and the OBZ within which the OWF is located. We have provided more details on this topic in Appendix E.

[34] Please note that this statement does not imply how Ofgem will reach an IPA decision.

[35] For detailed information on the underlying methodology used to calculate these impacts, please refer to the following report: Future Interconnectors Assessment Framework, Arup 2022.

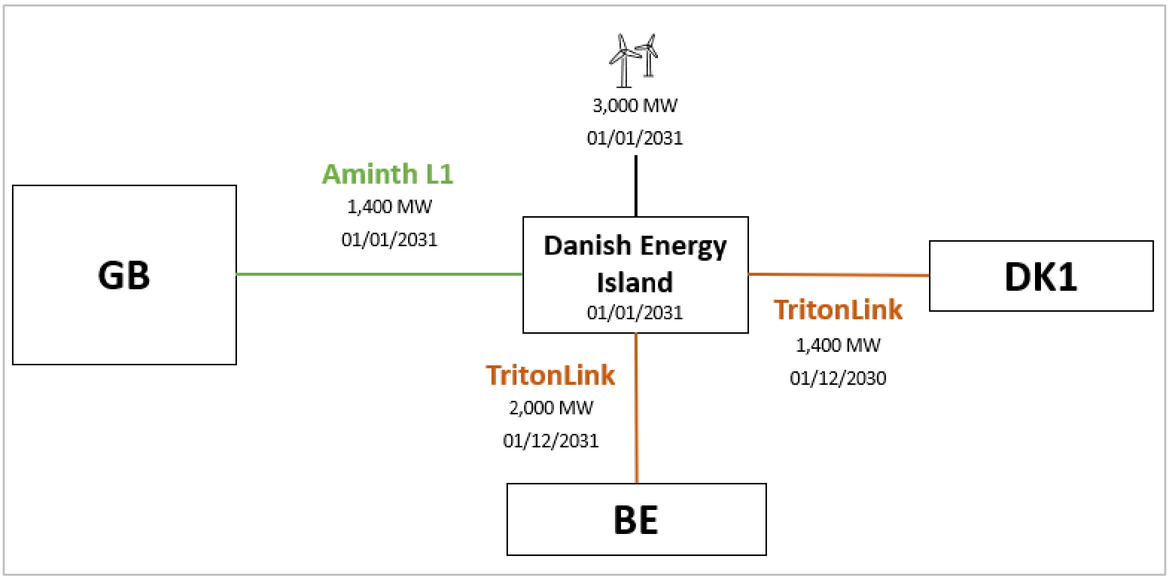
3.2. W3 interconnectors results

3.2.1. Aminth

3.2.1.1. Overview and SEW impacts

The Aminth project has been modelled as a 1.4 GW IC between GB and the energy island currently under development in Danish national waters (L1). The Danish energy island is assumed to be operating as an OBZ including a 3.0 GW OWF.

The OBZ is connected to Denmark and Belgium via the TritonLink project with a transmission line of 1.4 GW and one of 2 GW, respectively.[36] The energy island and OWF are assumed to be built in 2031. This is shown in Drawing 6 below.



Drawing 6 - Assumed configuration of the Aminth project

[36] Please note that the configuration of Aminth proper was based on the information submitted by the developers in their CBA. The configuration of TritonLink was based on its TYNDP 2022 project sheet, available here.

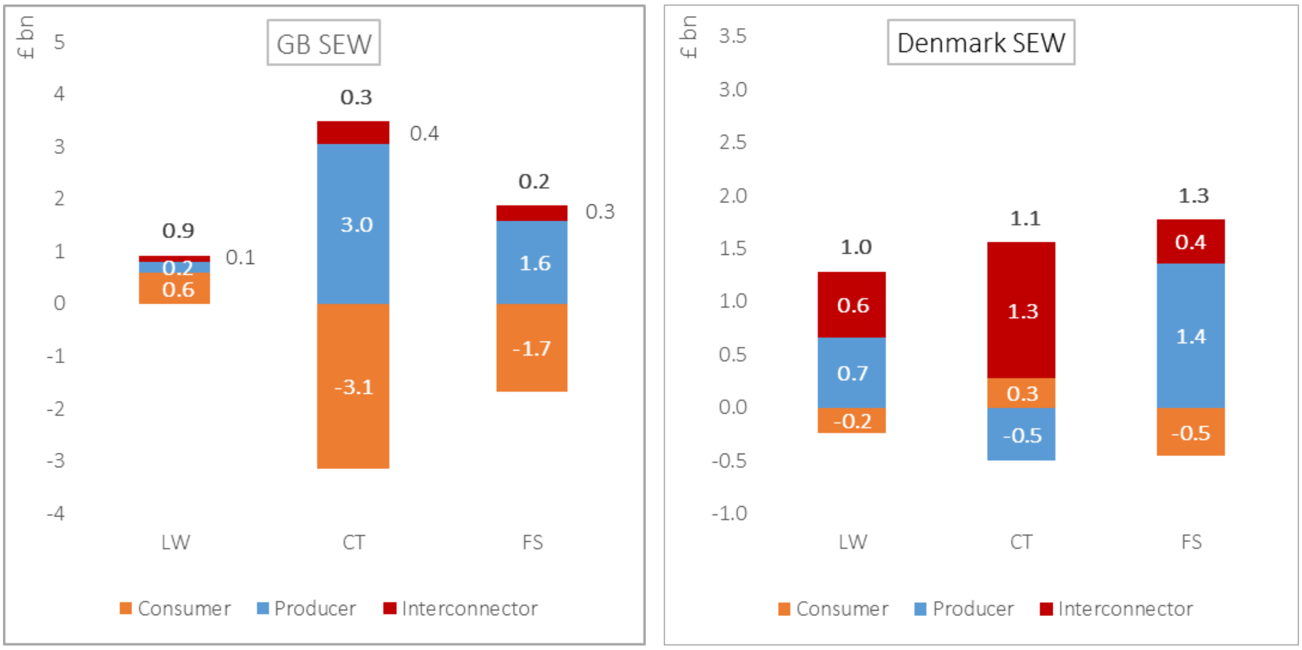


Figure 15 - SEW impacts of Aminth in GB and Denmark (£bn, real 2022, NPV)

The key conclusions from our analysis are:

- **The total SEW impacts in GB are marginally positive in all scenarios,** driven by strong producer SEW and positive IC SEW.
- **In GB, Aminth delivers marginally positive consumers SEW in LW and negative consumers SEW in CT and FS**, as in LW, the project is used to import more electricity into GB compared to the other scenarios. This in turn drives lower wholesale prices in GB compared to the counterfactual, benefiting GB consumers. In other scenarios, the project is primarily used to export electricity from GB, increasing GB prices.
- **IC welfare in GB is marginally positive in all scenarios.** Aminth's revenues partially offset the project costs and the cannibalisation effects on other existing projects. Due to lower revenues, additional floor payments are required for W1, W2 and W3 projects from consumers compared to the counterfactual. As explained in section 2.3.2, these floor payments are considered as additional revenue for developers. Therefore, these increase the welfare of IC owners as a whole, leading to marginally positive IC SEW.
- **In Denmark, Aminth delivers positive overall SEW in each scenario.** Aminth delivers positive consumers SEW in CT as it is used primarily to import electricity from GB, and negative consumers SEW in LW and FS when the project is used to export electricity to GB. Larger producers SEW gains are seen in LW and FS. IC SEW increase also thanks to the revenue generated by L2.

3.2.1.2. Economic fundamentals and flows

The key economic and commercial driver for the project is the difference in market prices between GB, Belgium, Denmark and the Danish OBZ. Figure 16 below shows the annual average wholesale prices in GB, Denmark, Belgium and the Belgian OBZ.

The Danish power market is characterised by a high share of renewable generation capacity from the onset of the study horizon at 90% of the total generation capacity. Wind is the predominant generation technology within renewable generation capacity. The share of renewable generation capacity remains at a high level across the horizon of the study in both European FES scenarios. Coal generation capacity is phased out in all scenarios. Gas-fired generation capacity typically sets the price at the beginning of the study horizon. Towards the end of the horizon, price is set more frequently by lower SRMC technologies.

In LW, GB has a lower average wholesale electricity price compared to Denmark and the Danish OBZ until the 2040s, when the fundamental changes to the GB capacity mix lead to higher wholesale prices in GB compared to Denmark and the Danish OBZ. Over the 25 years considered, the UK price averages at £56 MWh, whilst the Danish and OBZ price average at £59.8 MWh and £54.0 MWh, respectively.

In CT, GB prices are the lowest of those observed on average over 25 years (£42.6 MWh) compared to those in Denmark (£54.5 MWh) and the OBZ (£46.9 MWh), driven by very high shares of offshore wind generation capacity. Price differentials between GB and the Danish OBZ are the highest in this scenario (£4.3 MWh on average).

Finally, in FS, prices in GB start relatively high and decrease consistently as more RES generation capacity is deployed and fuel prices decrease, averaging at £54.2 MWh over 25 years. The average price in Denmark and in the OBZ is £58.5 MWh and £53.0 MWh, respectively. This is the scenario with the lowest prices differentials between GB and the Danish OBZ, averaging at £1.4 MWh. .

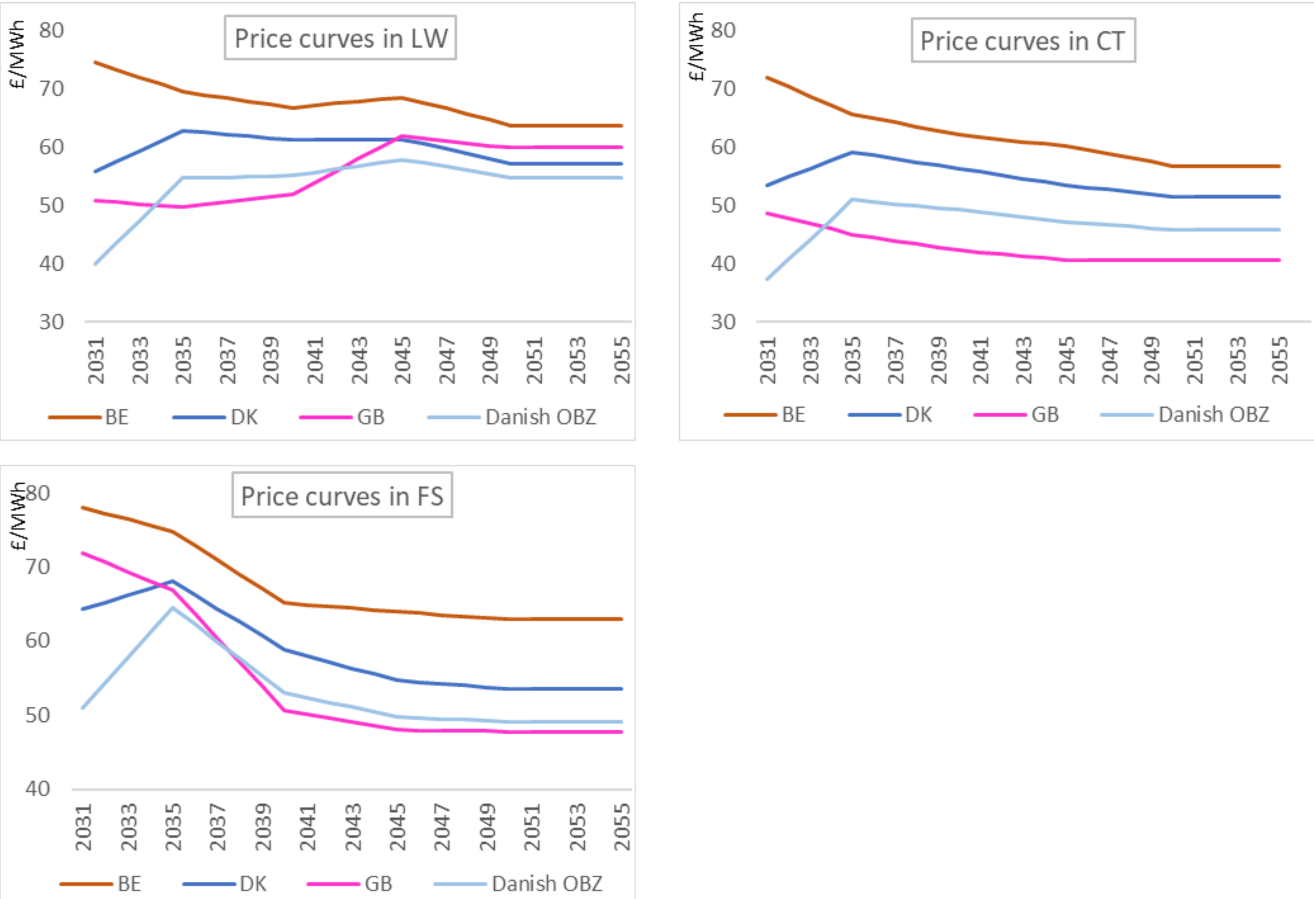


Figure 16 - Price differentials between GB and Denmark (£/MWh)

The price differentials described above largely determine the direction of the electricity flows across the project. These are shown in Figure 17 below.

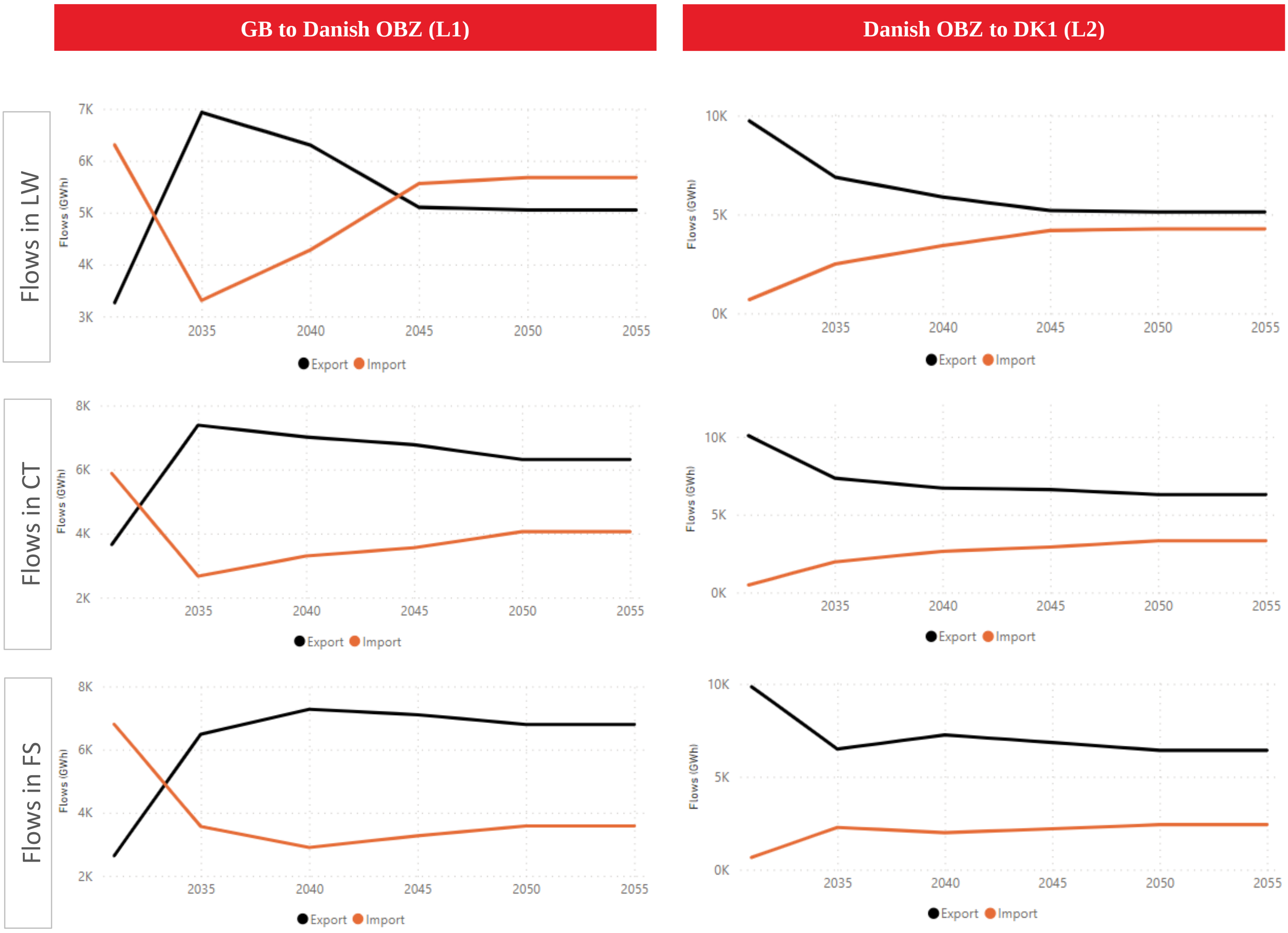


Figure 17 - Electricity flows across Aminth and L2 (GWh)

In LW, Aminth (L1) imports electricity from the Danish OBZ early on and increasingly after 2041 as cost of EENS drives up prices in GB. This leads to a decrease in exports from the Danish OBZ to Denmark (L2) and subsequent increase in imports.

In CT and FS, flows are relatively similar as GB prices are higher compared to the Danish OBZ and then rapidly decrease. Imports on L1 from the OBZ follow a similar trend, decreasing rapidly in favour of rising exports from GB as it becomes the cheapest market. L2 flows reflect this, with exports from the OBZ to Denmark decreasing and being replaced by higher GB exports.

3.2.1.3. Revenues and impacts on consumers

Figure 18 below shows the GB portion of revenue on L1, based on a 50:50 split with Denmark. Considering price differentials and flows described, Aminth earns a significant share of its revenue through imports. This is particularly true in LW, where import revenue represents 57% of the total over 25 years. In CT and FS, imports represent 31% and 42% of the total, respectively.

Aminth is likely not to require floor payments after CM revenue is considered, particularly in FS. Some cap payments are instead likely to be expected from 2045 onwards in CT.

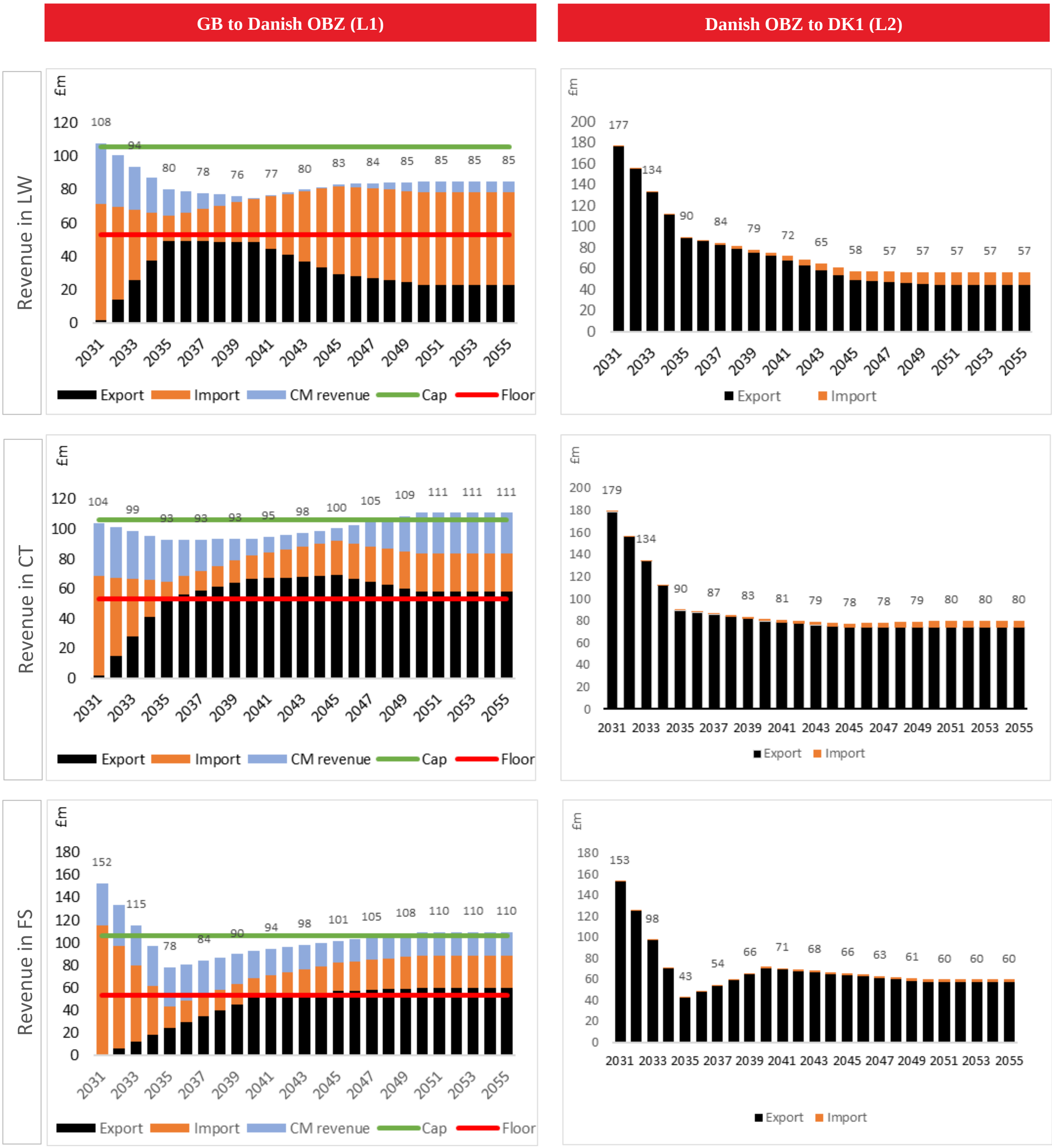


Figure 18 - GB share of revenues earned by Aminth and L2 (£m, real 2022)

3.2.1.4. Decarbonisation impacts

In GB, Aminth leads to a very marginal decrease in CO_2 emissions in LW, and net increase in FS and CT. In

Denmark, the project leads to marginal decrease in emissions in all scenarios. From a European perspective, the projects contribute to a significant reduction in emissions across Europe, as shown in Figure 19 below.

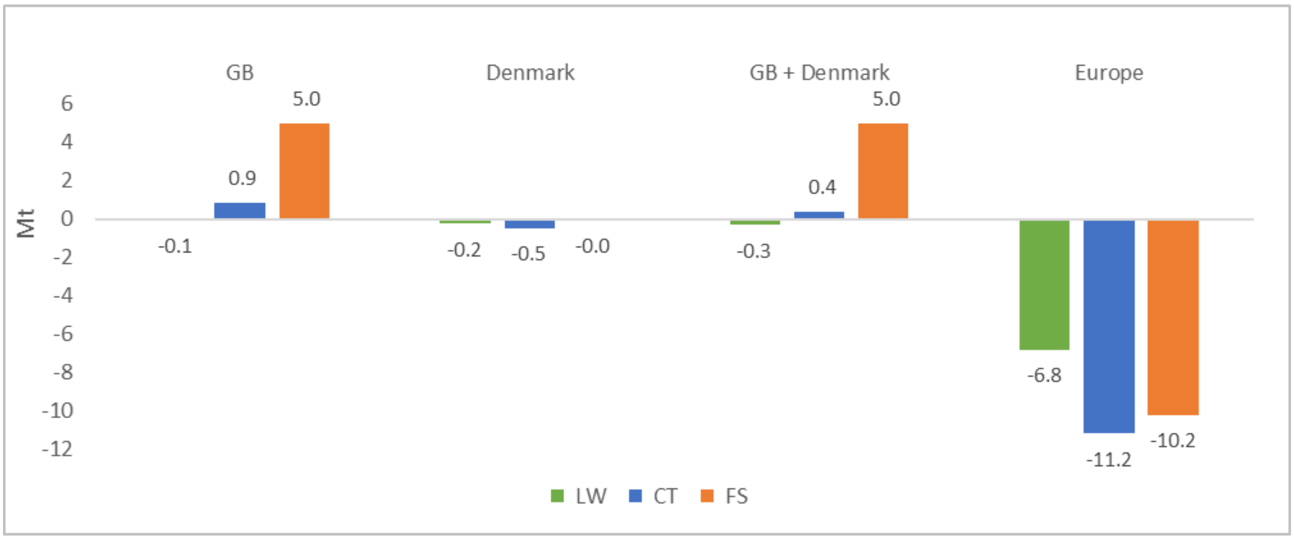


Figure 19 - Changes in CO_2 emissions due to Aminth (Mt)

In GB, in CT and FS, Aminth is largely used to export electricity from GB, leading to higher wholesale prices. Consequently, more expensive thermal generation is dispatched compared to the counterfactual, leading to an increase in emissions. In LW, Aminth causes GB prices to slightly decrease on average as the project imports electricity from the OWF in the first years of operation and in the mid-2040s due to higher prices in Denmark compared to GB. This leads to less GB thermal generation being dispatched, hence lower emissions.

The impacts that Aminth has on electricity prices in Denmark are less marked. Only in CT does the project lower prices consistently through the modelled period, leading to less thermal generation being dispatched compared to the counterfactual. This is observed especially during the first five years of operation, when thermal generation still represent 15% of the total supply.

Considering that GB has higher thermal capacity installed compared to Denmark, the increase in emissions in GB offset the decrease in Denmark, leading to a net increase in CO_2 emissions between the two countries. Nonetheless, from a European perspective, Aminth has a positive impact contributing to a net decrease in carbon emissions.

Decarbonisation indicators

Except in LW, the increase in CO_2 emissions means that GB energy consumers pay electricity at a higher cost compared to the counterfactual in CT and FS, as more CO_2 allowances have to be bought under the UK ETS. The additional CO_2 also leads to higher societal costs for GB. This is summarised in Table 12 below.

Table 12 - Decarbonisation indicators for Aminth

Indicator	Applies to	Unit	LW	CT	FS
CO_2 reduction (SEW)	GB	£m real 2022 NPV	-7.5	70.8	316.5
CO_2 reduction (Societal value)	GB	£m real 2022 NPV	-24.8	112.2	161.4
Overall decarbonisation	Europe	Mt	-6.8	-11.2	-10.2

3.2.1.5. Security of Supply impacts

As already mentioned, only in LW from 2040 onwards, the energy supply in GB fails to meet demand in periods of system stress, leading to an increase in wholesale prices due to the cost of EENS.

The introduction of Aminth helps reducing the number of USE hours in GB compared to the counterfactual in LW, as shown in Figure 20 below. The project is used to import electricity in periods of system stress, reducing substantially costs for USE energy compared to the counterfactual, for a total of £371.5m.

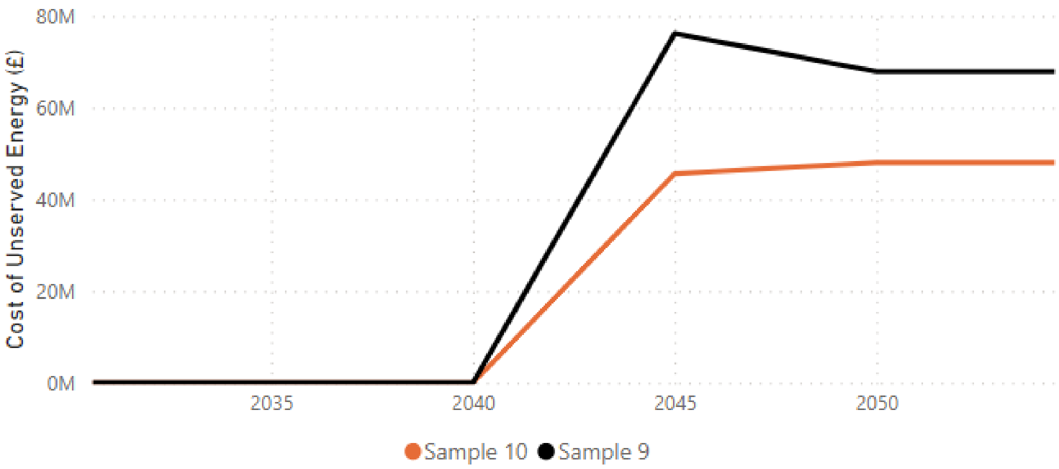


Figure 20 - Cost of EENS in the counterfactual and target case in LW (£, real 2022)

In CT and FS, no USE hours are observed before and after the introduction of the project, meaning that Aminth does not have positive nor negative impacts on SoS in GB.

3.2.2. Aquind

3.2.2.1. Overview and SEW impacts

The Aquind project has been modelled as a 2 GW IC between GB and France, connecting in 2027.

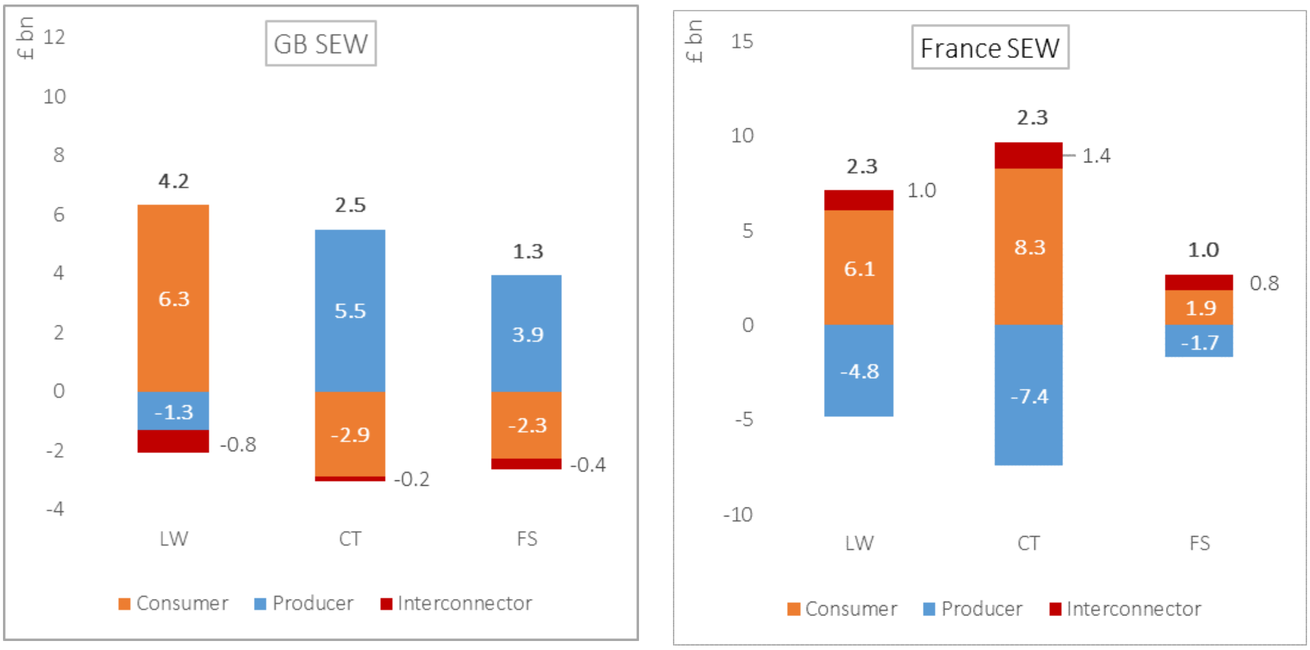


Figure 21 - SEW impacts of Aquind in GB and France (£bn, real 2022, NPV)

The key conclusions from our analysis are:

- **The total SEW impacts in GB are positive in all scenarios,** driven by strong consumers SEW gains in LW and producers SEW gains in CT and FS.
- **In GB, Aquind delivers significantly positive consumers SEW impacts in LW and negative consumers SEW impacts in CT and FS.**

  In **LW**, the project is used at times to import cheaper electricity from France during GB peak hours, when GB prices rise above the French ones. Aquind also contributes to a reduction in the number of USE hours in GB compared to the counterfactual from 2040, lowering the wholesale price and the cost of EENS in GB. Considering the high costs associated to each USE hour, this in turn provides substantial benefits to GB consumers. In **CT and FS,** the project is primarily used to export electricity to France, increasing wholesale prices in GB.
- **IC welfare in GB is negative in all scenarios.** The project earns enough revenue to offset its costs. However, its introduction leads to significant revenue losses for other existing IC and OHA projects, resulting in negative IC SEW overall.
- **In France, Aquind leads to positive SEW in all scenarios.** This is driven largely by positive consumers SEW as the project primarily imports cheaper electricity from GB to France, reducing wholesale market prices. This in turn leads to negative producers SEW. IC SEW is overall positive, as congestion revenue in France are assumed not to be capped as they are in GB through the C&F regime.

3.2.2.2. Economic fundamentals and flows

The key economic and commercial driver for the project is the difference in market prices between GB and France when Aquind is introduced. Figure 22 below shows the 25-years annual average wholesale prices in both countries under LW, CT, and FS. It can be noted that GB has a lower wholesale price compared to France in all scenarios. The price differentials with France average at £7.7 MWh in LW, £13.0 MWh in CT and £5.6 MWh in FS.

The French energy system is characterised by high shares of nuclear generation that often determine the clearing price. GB presents much higher shares of RES generation in all scenarios compared to France, which results in lower wholesale prices on average. In LW, it can be noted that prices increase from 2040 onwards, peaking at £62/MWh in 2045. This is due to a combination of factors such as CCUS CCGTs increasingly setting the market price in a context of growing intermittent generation combined with the highest CO_2 price of the three scenarios.

By 2050, the LW scenario has 4.2 times less BECCS capacity than in the CT scenario and 1.9 times less nuclear capacity than in the CT scenario. Additionally, both technologies have lower SRMC than CCUS Gas. These factors contribute to an increase in annual average wholesale price in LW in the long term.

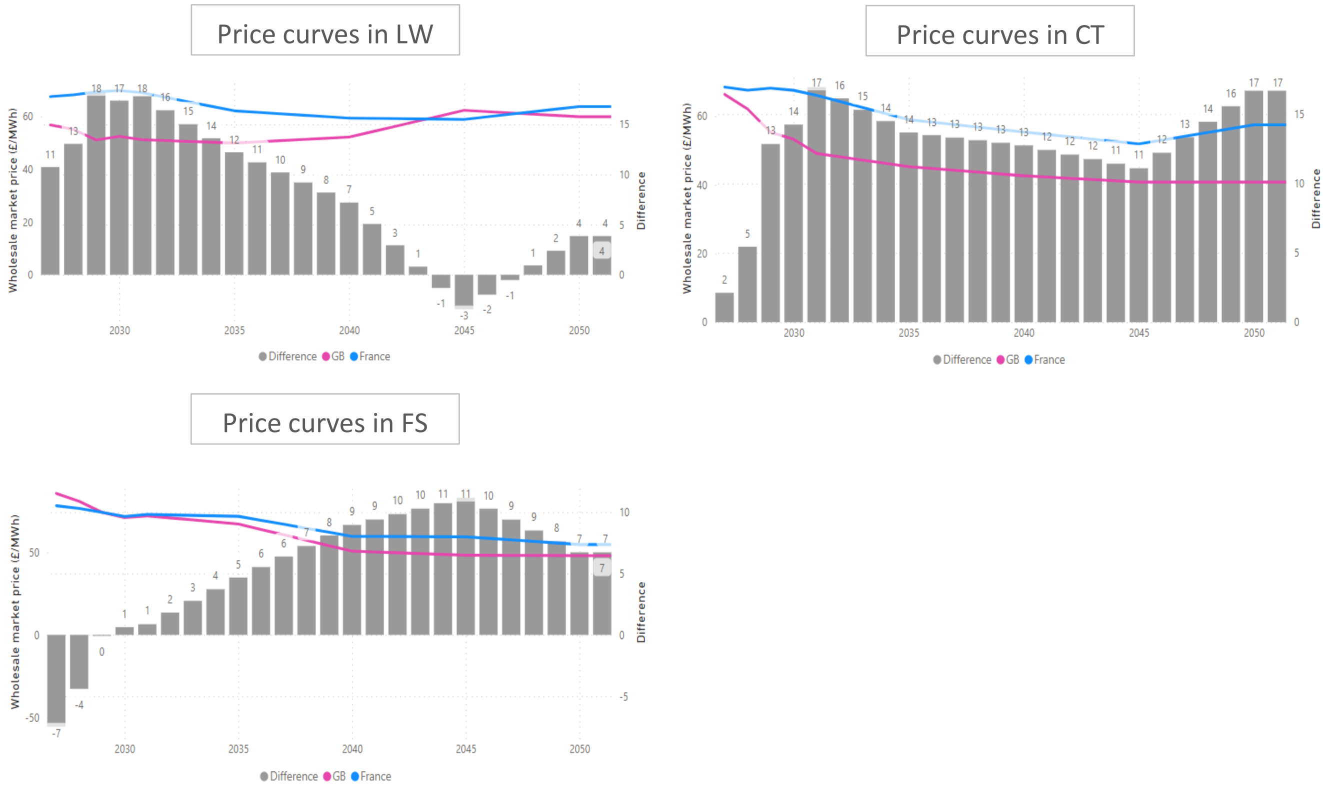


Figure 22 - Price differentials between GB and France (£/MWh)

The price differentials described above largely determine the direction of the electricity flows across the project. These are shown in Figure 23 below.

Aquind is primarily used to export electricity from GB to France, due to the persistent higher prices in France. However, in LW, the increase in GB prices in 2040 leads to an increase in imports from France due to the price delta.

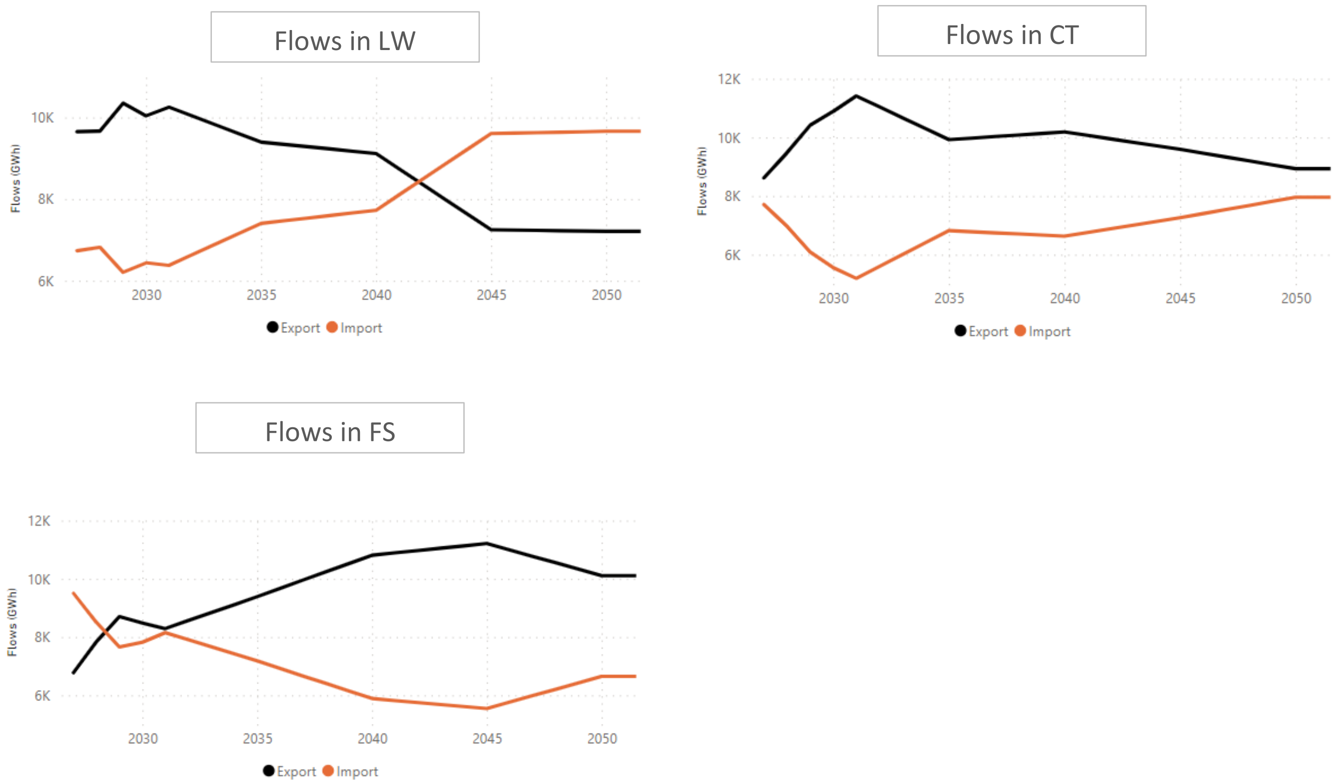
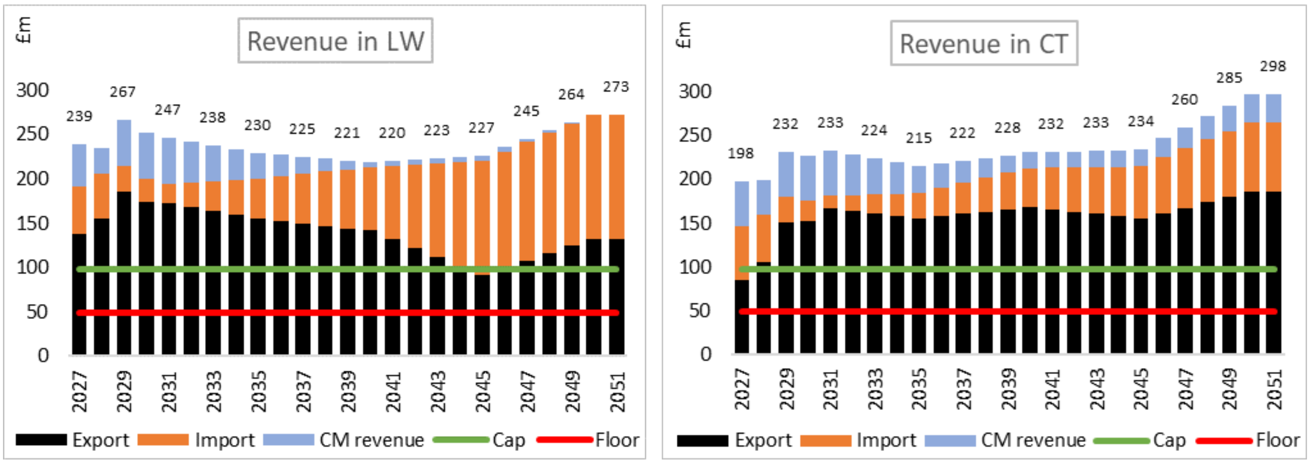


Figure 23 - Electricity flows across Aquind (black line: exports from GB, orange line: imports from France) (GWh)

3.2.2.3. Revenues and impacts on consumers

Figure 24 below shows the GB portion of revenues earned by the project, based on a 50:50 split with the connecting country. Considering the high price differentials and volumes of electricity flows, Aquind earns significant revenue through exports from GB to France, noting that in LW, the share of revenue captured through imports is twice as big compared to the other scenarios. This is due to the price delta between France and GB.

Even without accounting for CM revenues, in all scenarios Aquind is likely not to require floor payments and to provide cap payments.



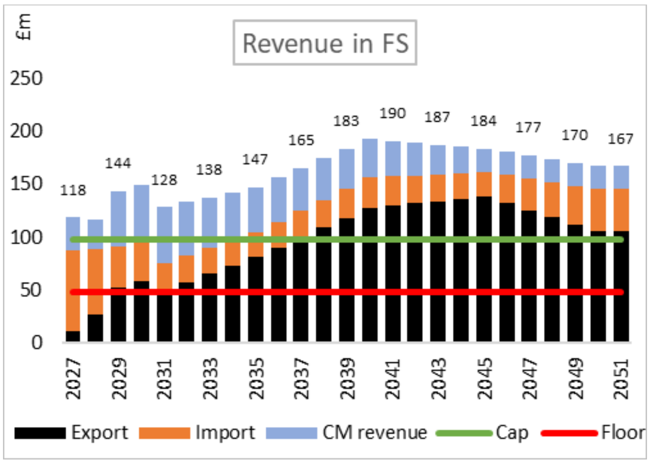


Figure 24 - GB share of revenues earned by Aquind (£m, real 2022)

3.2.2.4. Decarbonisation impacts

Aquind leads to a net decrease in CO_2 emissions in GB, France and across Europe, as shown in Figure 25 below.

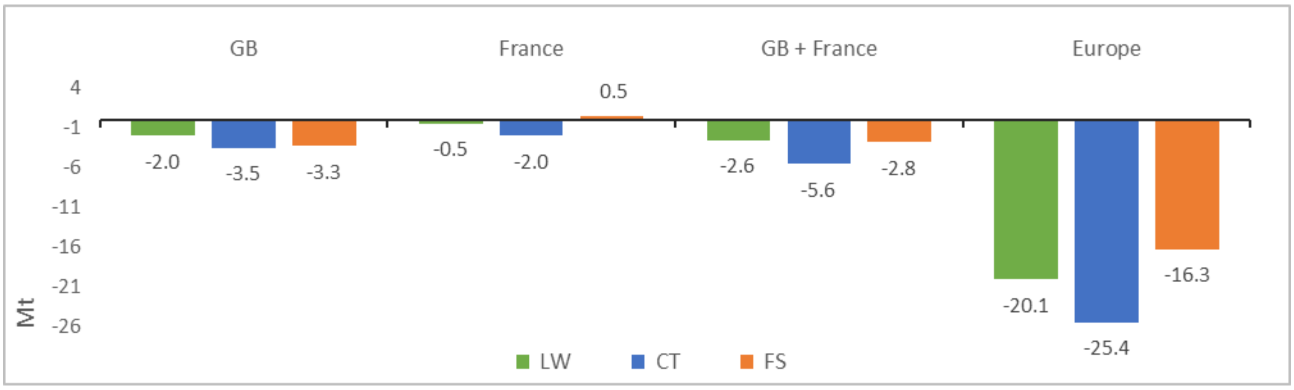


Figure 25 - Changes in CO_2 emissions due to Aquind (Mt)

In France, Aquind is used to import cheaper electricity from GB, leading to lower wholesale prices in LW and CT. Consequently, expensive thermal generation is displaced from the dispatching order, leading to an overall decrease in emissions compared to the counterfactual. In FS, Aquind leads to an increase in wholesale price generating the opposite effect: more expensive thermal generation is dispatched compared to the counterfactual, leading to an increase in emissions.

In GB, a similar reduction in CO_2 emissions can be noted in all scenarios even though GB prices increase due to exporting electricity from GB to France. This apparent oddity can be explained looking at more granular dispatching data.

Despite the fact that Aquind is primarily used for exports, leading to an increase in the annual average price in GB, the project is *also* used to import cheaper electricity from France during peak hours in GB, when prices are higher in GB than in France. In these hours, Aquind contributes to meeting peak electricity demand in GB at a cheaper rate, displacing carbon intensive peaking plants. The net effect is that less thermal generation is dispatched overall compared to the counterfactual.

From a European perspective, the project has a beneficial impact contributing to the overall decarbonisation of other countries.

Decarbonisation indicators

The changes in CO_2 emissions mean that GB energy consumers pay electricity at a lower cost compared to the counterfactual in all scenarios, as less CO_2 allowances have to be bought under the UK ETS. Lower emissions also translated to lower societal costs in GB. This is summarised in Table 13 below.

Table 13 - Decarbonisation indicators for Aquind

Indicator	Applies to	Unit	LW	CT	FS
CO_2 reduction (SEW)	GB	£m real 2022 NPV	-184.4	-302.3	-273.7
CO_2 reduction (Societal value)	GB	£m real 2022 NPV	-561.6	-512.1	-118.1
Overall decarbonisation	Europe	Mt	-20.1	-25.4	-16.3

3.2.2.5. Security of Supply impacts

As already mentioned, only in LW from 2040, energy supply in GB fails to meet demand in periods of system stress, leading to significantly high wholesale prices to cover costs associated with the amount of USE hours observed.

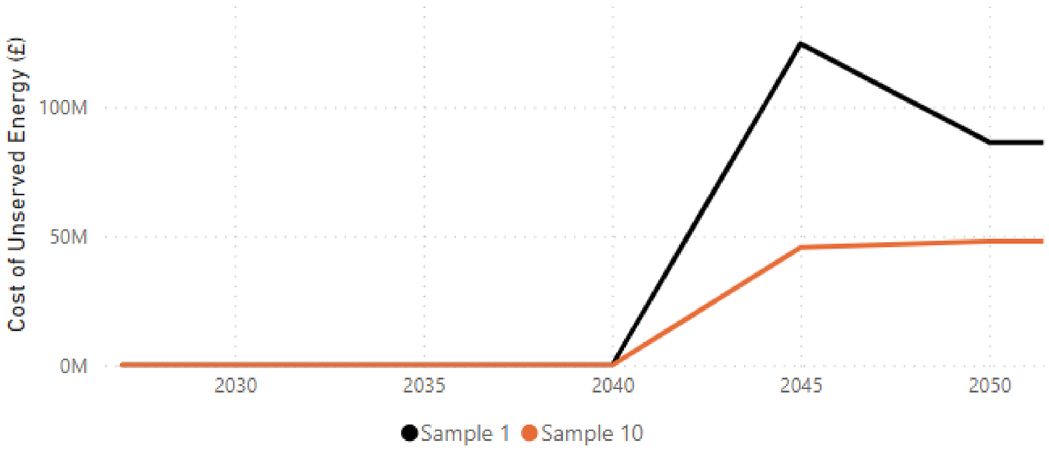


Figure 26 - Cost of EENS in the counterfactual and target case in LW (£, real 2022)

The introduction of Aquind helps reducing the number of USE hours in GB compared to the counterfactual, as shown in Figure 26 above. The project is used to import electricity in periods of system stress, reducing substantially costs of EENS compared to the counterfactual, for a total of £547.9m.

In CT and FS, no USE hours are observed before and after the introduction of the project, meaning that Aquind does not have positive nor negative impacts on SoS in GB.

3.2.3. Cronos

3.2.3.1. Overview and SEW impacts

The Cronos project has been modelled as a 1.4 GW IC between GB and Belgium, connecting towards the end of 2029.

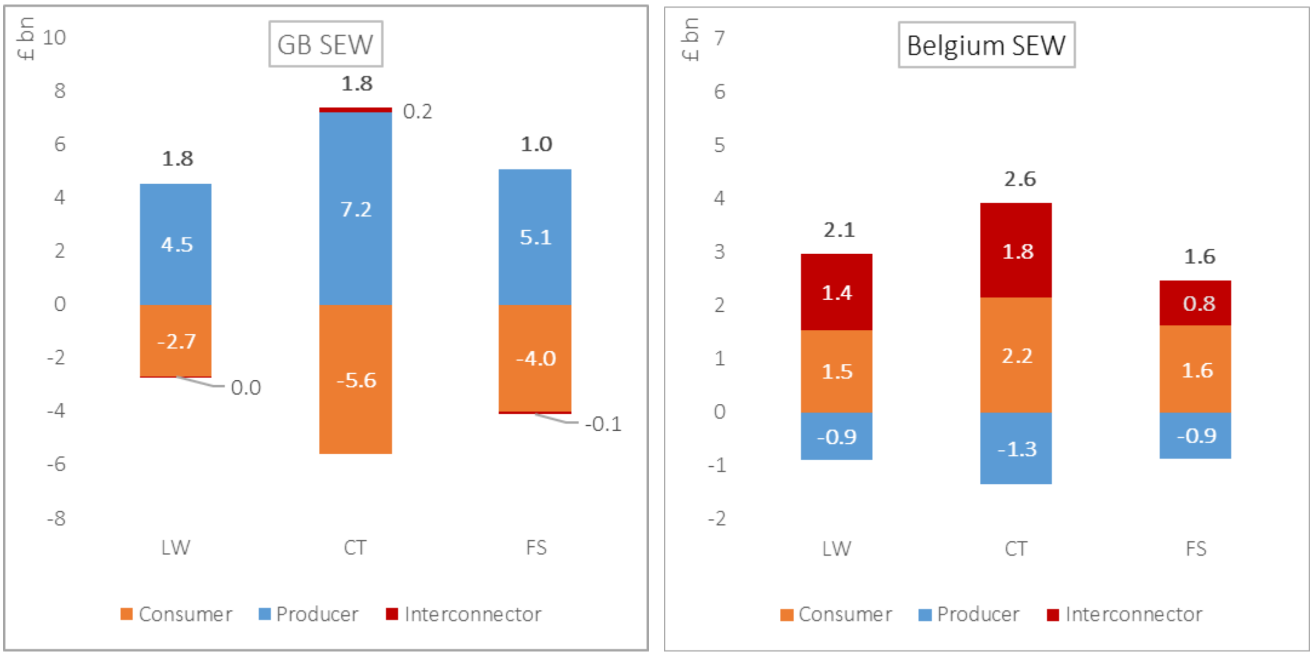


Figure 27 - SEW impacts of Cronos in GB and Belgium (£bn, real 2022, NPV)

The key conclusions from our analysis are:

- **The total SEW impacts in GB are positive in all scenarios,** driven by strong producers SEW.
- **In GB, Cronos delivers negative consumers SEW impacts in all scenarios**, driven by the project largely exporting electricity from GB to Belgium. This in turn drives higher wholesale prices in GB compared to the counterfactual, benefiting GB producers but reducing GB consumers welfare.
- **IC welfare in GB is positive in CT and marginally negative in LW and FS.** Only in CT the project earns enough revenue to offset its costs and mitigate the negative cannibalisation effects on other existing IC and OHAs.
- **In Belgium, Cronos delivers positive SEW in all scenarios.** This is largely driven by positive consumers SEW as the project imports electricity from GB to Belgium, reducing wholesale prices in Belgium.

3.2.3.2. Economic fundamentals and flows

The key economic and commercial driver for the project is the difference in market prices between GB and Belgium when Cronos is introduced. Figure 28 below shows the annual average wholesale prices in both countries under LW, CT, and FS.

In the Belgian power market, nuclear generation capacity is phased out from the system by 2029 in the ST European FES scenario and by 2035 in the CT European FES scenario. Belgium has a high share of renewable generation capacity from the onset of the study horizon at 65% (EU ST) and 70% (EU CT) of the total generation capacity. Solar and wind are the predominant generation technologies within renewable generation capacity. The share of renewable generation capacity increases to 76% and 77% in the EU ST and EU CT scenarios respectively. Conventional gas/biomass-fired generation capacity typically sets the price at the beginning of the study horizon. Towards the end of the modelled period, the price is set more frequently by gas CCS and lower SRMC.

It can be noted that GB has a lower wholesale price compared to Belgium in all scenarios, as the higher share of RES capacity in GB leads to overall cheaper prices compared to its neighbours. In LW, it can be noted that GB prices increase from 2040 onwards, peaking at £62/MWh in 2045. This is due to a combination of factors such as CCUS CCGTs increasingly setting the market price in a context of growing intermittent generation combined with the highest CO_2 price of the three scenarios. By 2050, the LW scenario has 4.2 times less BECCS capacity than in the CT scenario and 1.9 times less nuclear capacity than in the CT scenario. Additionally, both technologies have lower SRMC than CCUS Gas. These factors contribute to an increase in the annual average wholesale price in LW in the long term. The price differentials with Belgium are significant, with an annual average of £12.9 MWh in LW, £19 MWh in CT and £12.1 MWh in FS.

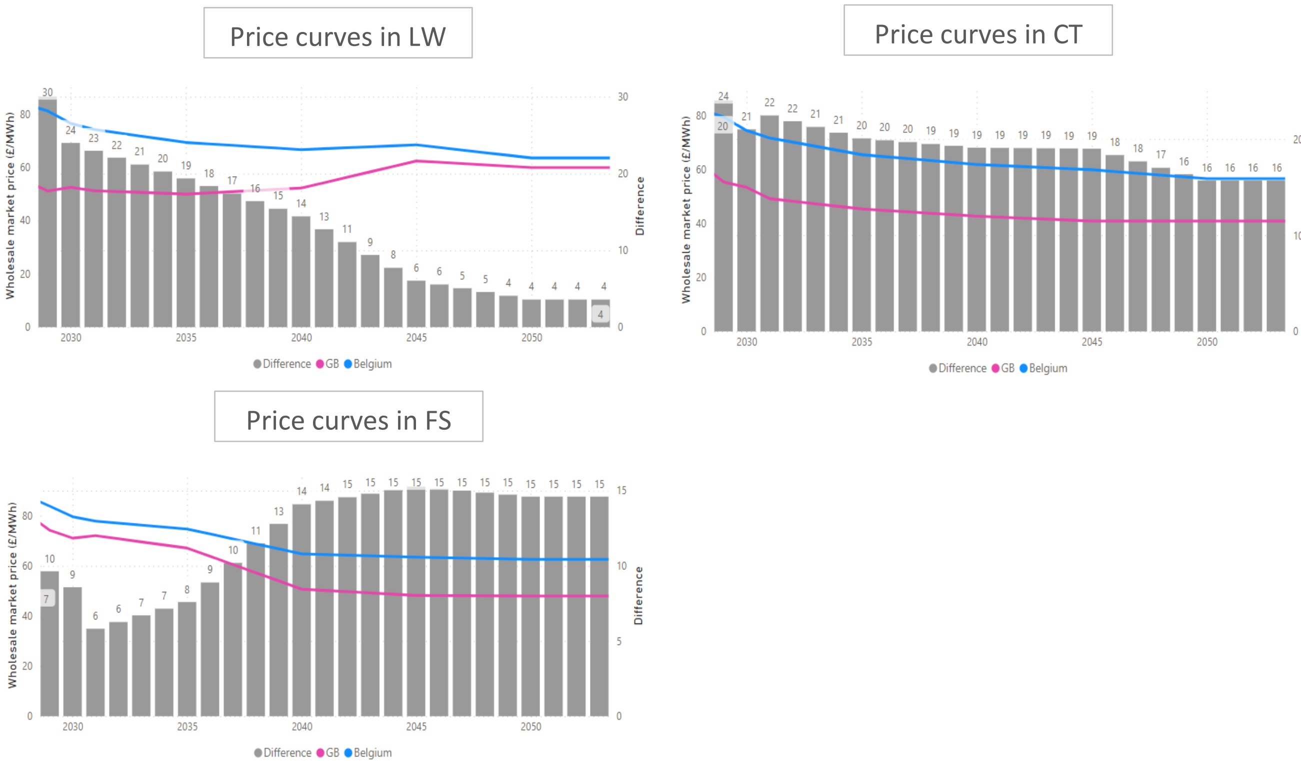


Figure 28 - Price differentials between GB and Belgium (£/MWh)

The price differentials described above largely determine the direction of the electricity flows across the project. These are shown in Figure 29. Cronos is primarily used to export electricity from GB to Belgium, due to the persistent higher prices in Belgium. However, in LW, there is a slight increase in imports as GB price increase and Belgian prices decrease slightly. In the other two scenarios, export and import flows are flatter as the price differentials remain constant.

For clarity, the low volumes of electricity flows in either direction in 2029 are linked to the fact that Cronos is modelled to connect in October of that year, as indicated by the developer. This means that the data for that year cover only three months of operation.

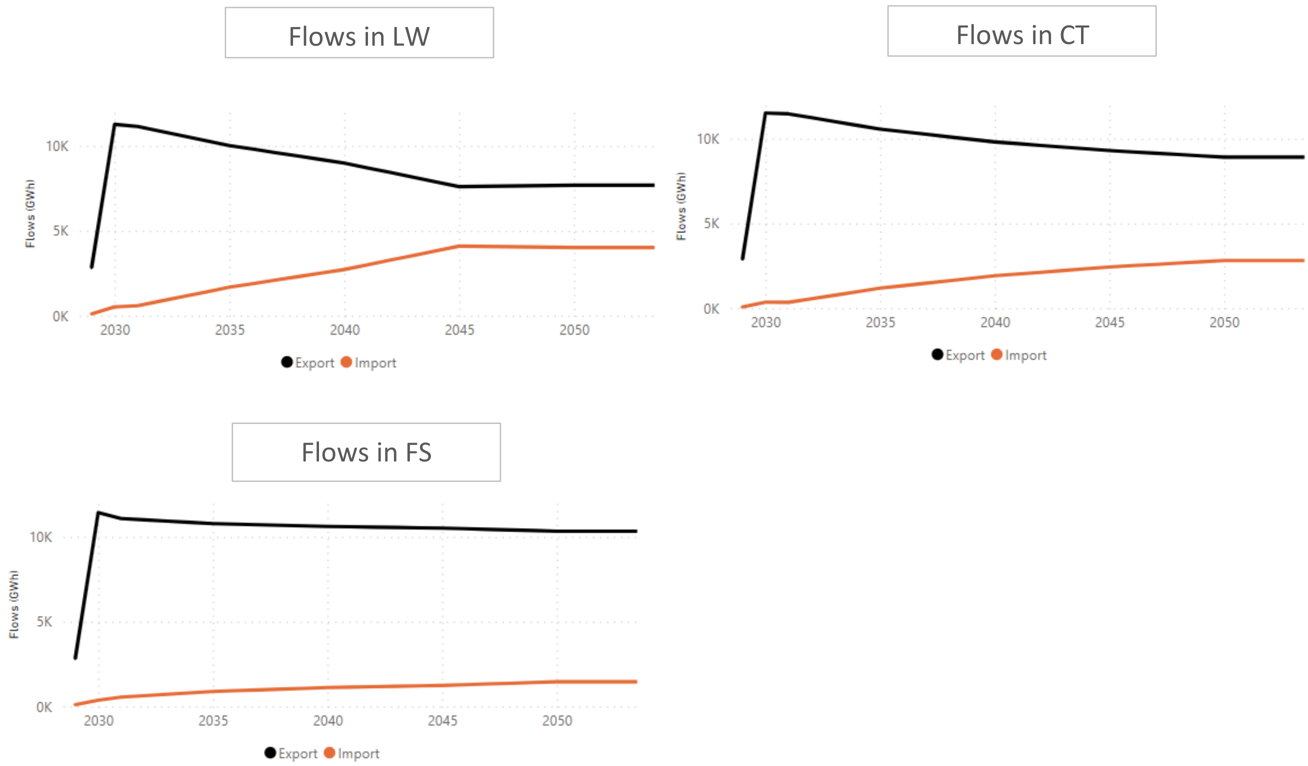
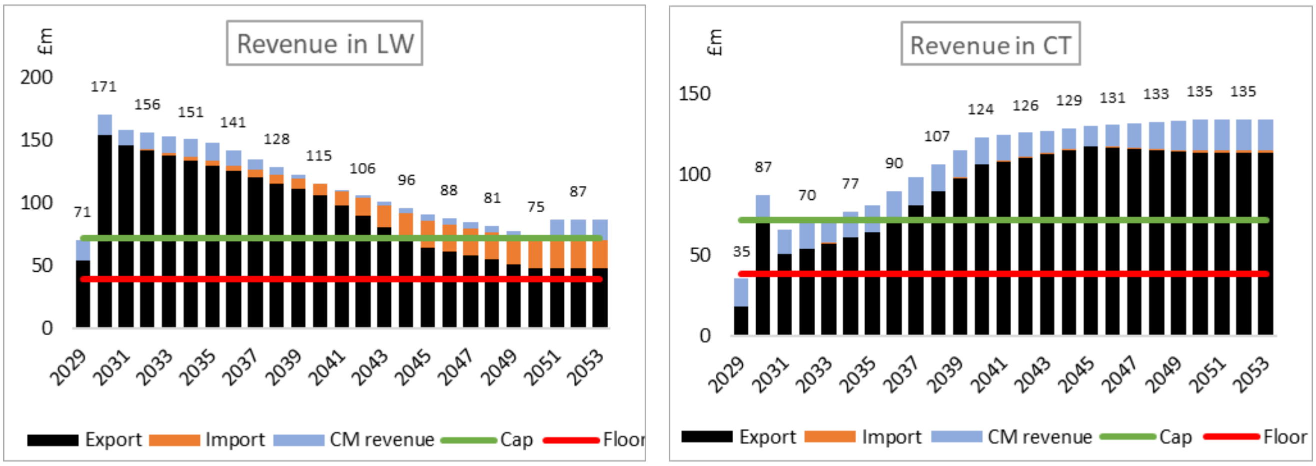


Figure 29 – Electricity flows across Cronos (black line: exports from GB, orange line: imports from Belgium) (GWh)

3.2.3.3. Revenues and impacts on consumers

Considering the high price differentials and volumes of electricity flows, Cronos earns significant revenues.

Figure 30 below shows the GB portion of revenues, based on a 50:50 split with the connecting country. The majority of revenue is earned through exports from GB to Belgium, noting that in LW, the share of revenue captured through imports is larger compared to the other scenarios.



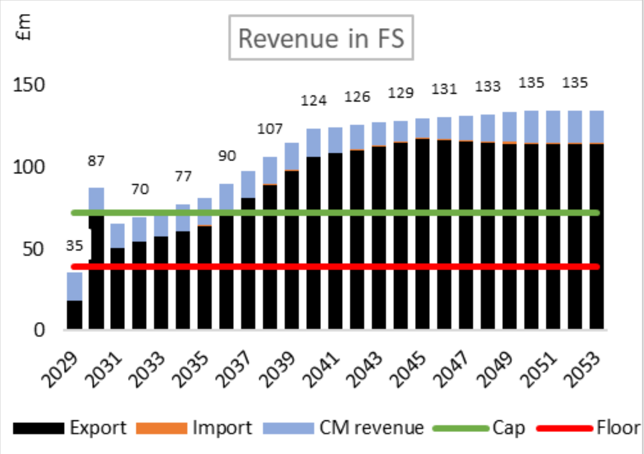


Figure 30 - GB share of revenues earned by Cronos (£m, real 2022)

This is due to the price delta between the interconnected bidding zones. Cronos is likely not to require floor payments, and instead it is likely to provide cap payments to consumers throughout most of the modelled period in all scenarios.

3.2.3.4. Decarbonisation impacts

Cronos leads to a net increase in CO_2 emissions in GB, and a net decrease in Belgium and across Europe, as shown in

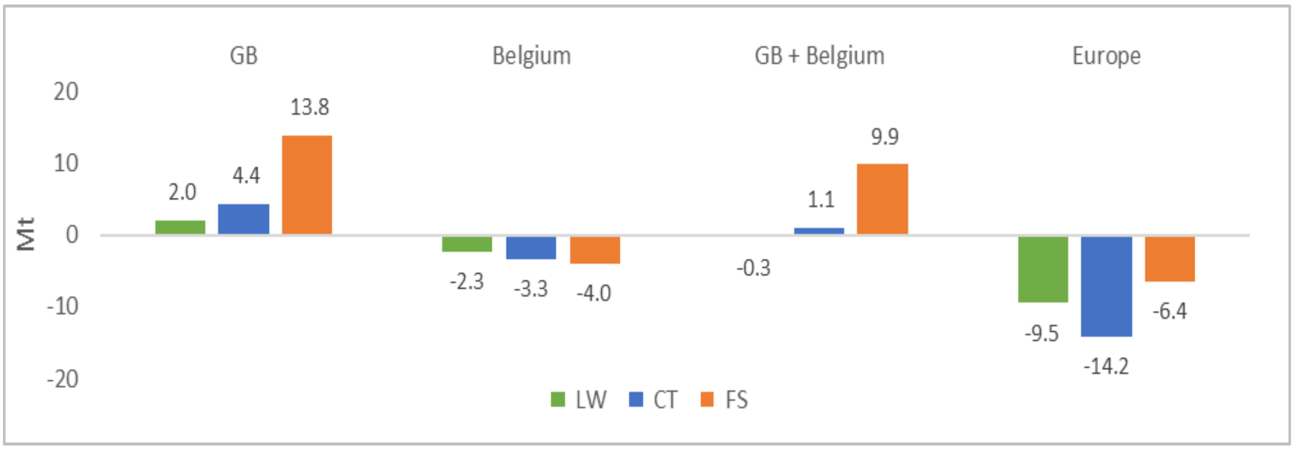


Figure 31 below.

In GB, Cronos is largely used to export electricity to Belgium, leading to higher GB wholesale prices in all scenarios – the only exception being a decrease in GB power prices in LW from 2045. Consequently, more expensive thermal generation is dispatched compared to the counterfactual, leading to an increase in emissions. Conversely, CO_2 emissions decrease in Belgium as Cronos reduces Belgian prices. The decrease in prices displaces expensive thermal generation from the dispatch order, leading to less emissions.

Considering that GB has more thermal capacity installed compared to Belgium, the increase in emissions in GB offset the decrease in Belgium, leading to a net increase in CO_2 emissions between the two countries. Nonetheless, from a European perspective the project has a positive impact contributing to a net decrease in carbon emissions.

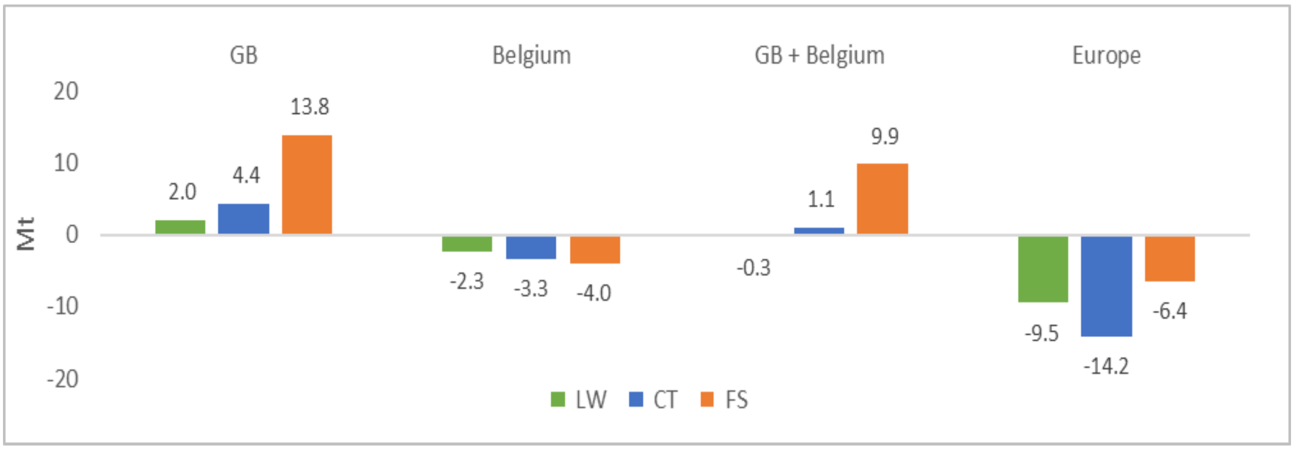


Figure 31 - Changes in CO_2 emissions due to Cronos (Mt)

Decarbonisation indicators

The changes in CO_2 emissions means that GB energy consumers pay electricity at a higher price compared to the counterfactual in all scenarios, as more CO_2 allowances have to be bought under the UK ETS by thermal generators when generating electricity. The additional CO_2 also leads to higher societal costs for GB. This is summarised in Table 14 below.

Table 14 - Decarbonisation indicators for Cronos

Indicator	Applies to	Unit	LW	CT	FS
CO2 reduction (SEW)	GB	£m real 2022 NPV	186.5	378.4	986.6
CO2 reduction (Societal value)	GB	£m real 2022 NPV	526.1	625.4	459.9
Overall decarbonisation	Europe	Mt	-9.5	-14.2	-6.4

3.2.3.5. Security of Supply impacts

As already mentioned, in LW from 2040, energy supply in GB fails to meet demand in periods of system stress, leading to significantly high wholesale prices to cover costs associated with the amount of USE hours observed.

The introduction of Cronos helps reducing the number of USE hours in GB compared to the counterfactual, as shown in Figure 32 below. The project is used to import electricity in periods of system stress, reducing substantially costs for USE energy compared to the counterfactual, for a total of £298.2m.

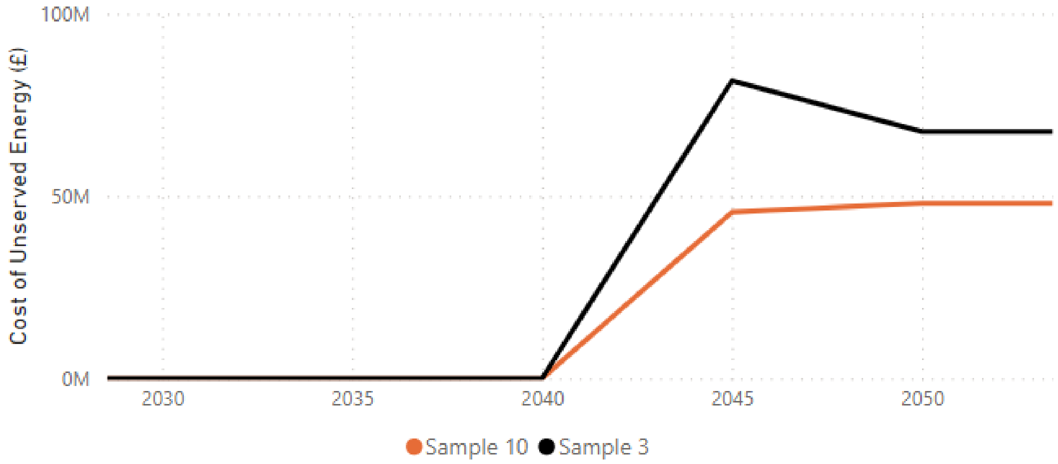


Figure 32 - Cost of EENS in the counterfactual and target case in LW (£, real 2022)

In CT and FS, no USE hours are observed before and after the introduction of the project, meaning that Cronos does not have positive nor negative impacts on SoS in GB.

3.2.4. LirIC

3.2.4.1. Overview and SEW impacts

The LirIC project has been modelled as a 700 MW IC between GB and the island of Ireland connecting in 2030.

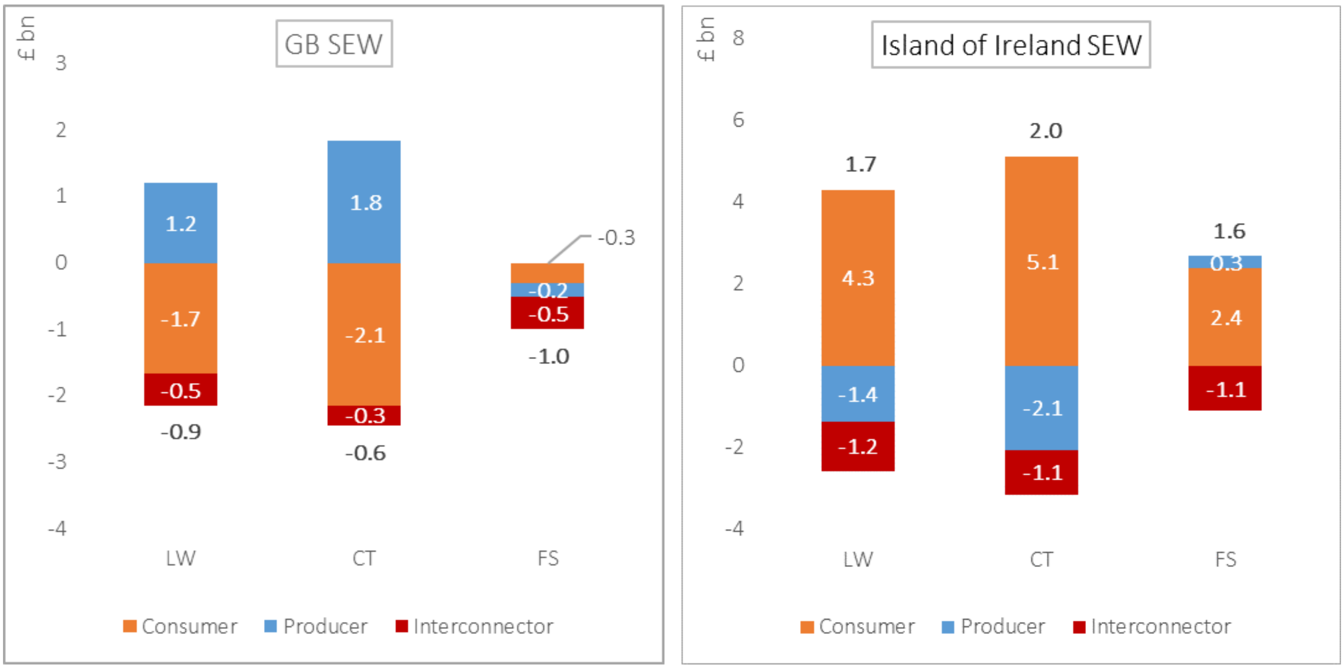


Figure 33 - SEW impacts of LirIC GB (left) and the island of Ireland (right) (£bn, real 2022, NPV)

The key conclusions from our analysis are:

- **The total SEW impacts in GB are negative in all scenarios,** driven by negative consumers and IC SEW.
- **In GB, LirIC delivers negative consumers SEW impacts in all scenarios.** In LW and CT, the project exports electricity from GB to the I-SEM. This drives wholesale prices in GB upwards, to the detriment of GB consumers. In FS, LirIC is initially used also to import electricity leading to early consumers SEW gains. However, these are offset by higher exports from 2040 onwards. The opposite occurs from a producers' perspective. The initial imports lead to a loss in producers SEW which is not fully recouped through higher exports later in the modelled period.
- **IC welfare in GB is negative in all scenarios**. Due to its capacity, LirIC does not fully exploit the price differentials between GB and the I-SEM. Hence, the revenue earned does offset the project costs and the cannibalisation effects on other existing projects.
- **In the island of Ireland, LirIC leads to positive SEW in all scenarios.** This is driven largely by positive consumers SEW as the project imports cheaper electricity from GB to the I-SEM, reducing wholesale market prices. In FS, LirIC is initially used also to export electricity, leading to higher wholesale prices. This generates strong producers SEW gains, which are only partially offset by decreasing prices later on when LirIC imports cheaper electricity from GB. The opposite occurs from a consumer perspective, whereby the early SEW losses due to higher prices are fully recovered thanks to longer periods of imports from GB.

3.2.4.2. Economic fundamentals and flows

The main economic and commercial driver for the project is the difference in market prices between GB and the I-SEM when LirIC is introduced. Figure 34 below shows the price differentials between GB and the I-SEM under LW, CT, and FS.

The I-SEM power market has a high share of renewable generation capacity from the onset of the study horizon at 65% (EU CT) and 62% (EU ST) of the total generation capacity. Wind and solar are the predominant generation technologies within renewable generation capacity. The share of renewable generation capacity increases to 72% in both European FES scenarios. CCGTs typically sets the price at the beginning of the study horizon while towards in the longer term the price is more frequently set by gas CCS and lower SRMC technologies.

It can be noted that GB has a lower wholesale price compared to the I-SEM in all scenarios with an annual average price differentials of £9.2 MWh in LW, £12.8 MWh in CT and £2.0 MWh in FS. GB presents high shares of RES generation, which results in lower wholesale prices on average compared to its neighbours. In LW, GB price picks up gradually from 2040 onwards following an increase in USE hours, as demand is not fully met by supply.

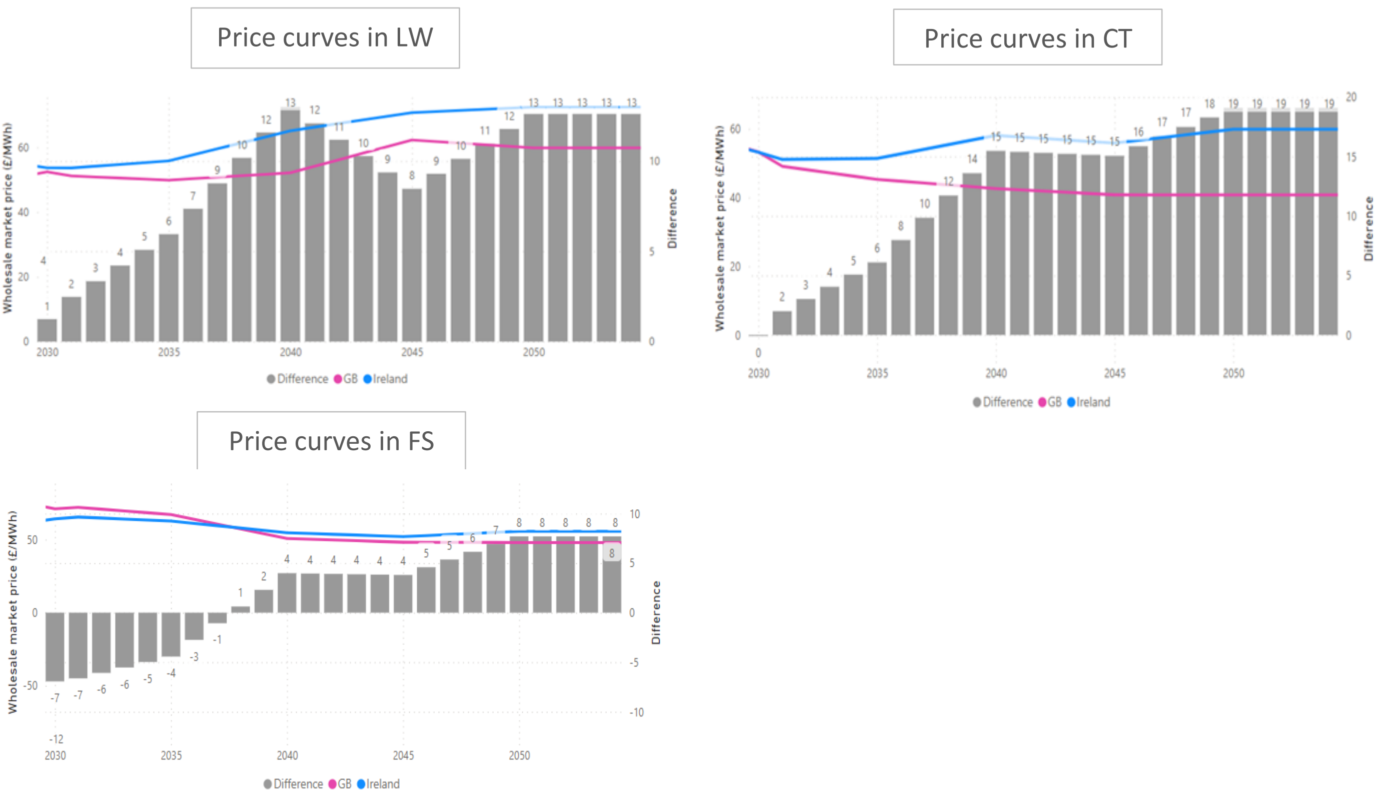


Figure 34 - Price differentials between GB and I-SEM in LW, CT, and FS (£/MWh)

The price differentials described above largely determine the direction of the electricity flows across the project. These are shown in Figure 35 below. LirIC is primarily used to export electricity from GB to the I-SEM, due to the persistent higher Irish prices compared to GB. In LW, there is a gradual decrease in imports from the I-SEM as the difference with Irish prices increases. A similar trend can be observed in CT.

In FS, the project is initially used to import cheaper electricity from the I-SEM until the mid-2030s, when exports overtake imports as GB prices decrease.

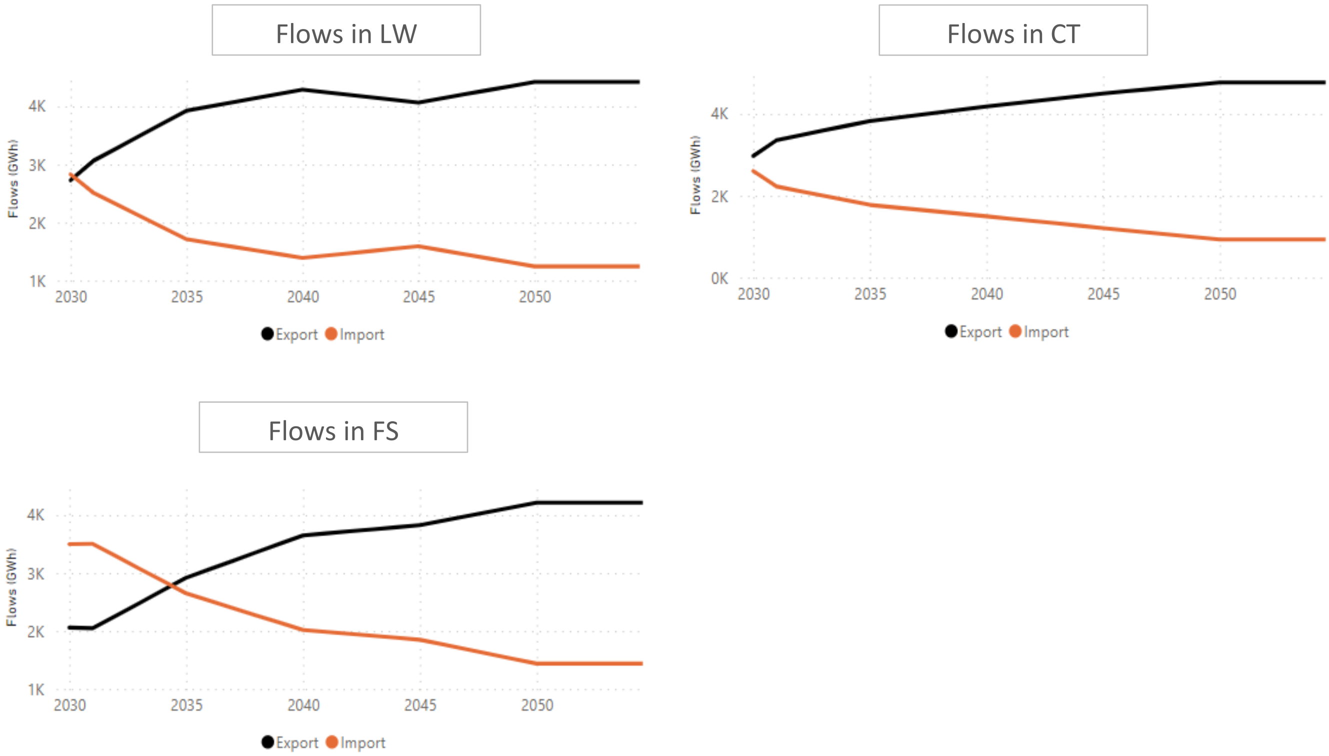


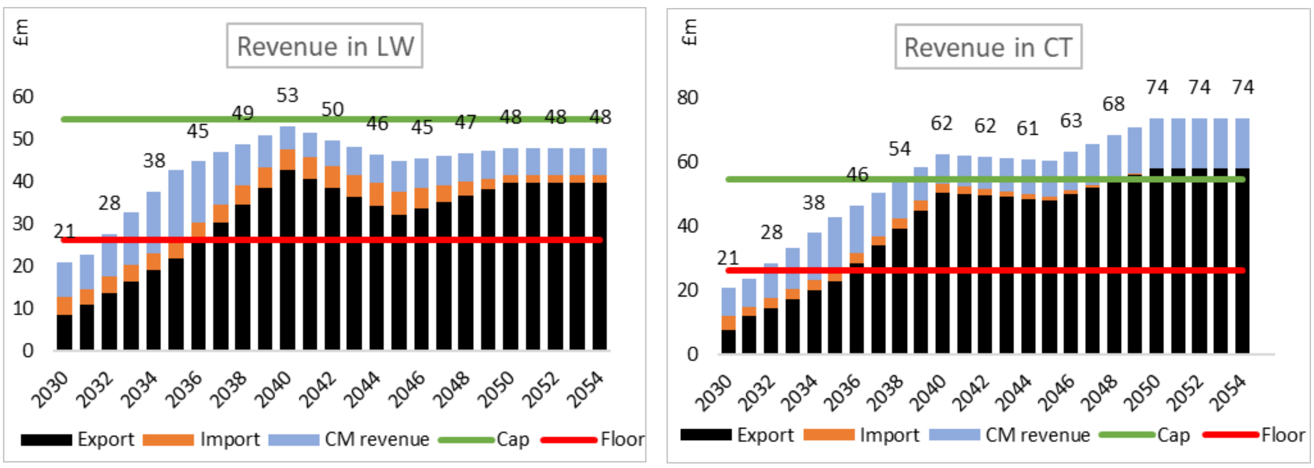
Figure 35 - Electricity exported (black) and imported (orange) by LirIC (GWh)

3.2.4.3. Revenues and impacts on consumers

Figure 36 below shows the GB portion of revenue earned by LirIC, based on a 50:50 split with the connecting country. Despite the relatively high price differentials between GB and the I-SEM, the project does not earn as much as it could due to its relatively small capacity.

The majority of revenue is earned through exports from GB, noting that in FS the share of revenue captured through imports is larger compared to the other scenarios as GB prices are lower than those of the I-SEM.

When CM revenues are considered, LirIC is likely to require very limited floor payments in the early years of operation under LW and CT. Cap payments to consumers could occur in CT, where the price difference between GB and the I-SEM is the biggest leading to higher revenue for the project.



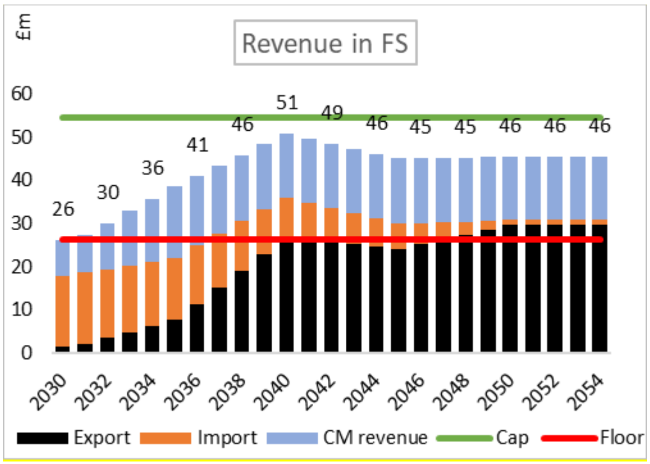


Figure 36 - GB share of revenues earned by LirIC (£m, real 2022)

3.2.4.4. Decarbonisation impacts

LirIC leads to a net decrease in CO2 emissions in GB in LW and FS, and a net decrease in the I-SEM and across Europe in all scenarios, as shown in Figure 37 below.

Figure 37 - Changes in CO_2 emissions due to LirIC (Mt)

LirIC is largely used to export electricity from GB, leading to lower wholesale prices in the I-SEM in all scenarios. Consequently, more expensive thermal generation is displaced compared to the counterfactual, leading to a decrease in emissions.

In GB, the impact of LirIC is more nuanced. In FS, the project is used to import electricity from the I-SEM to GB until the mid-2030s. This applies downward pressure on GB prices early on when the capacity mix still includes significant shares of thermal generation, leading to a decrease of emissions. In LW, despite a marginal increase in prices, CO_2 emissions are lower when LirIC is introduced compared to the counterfactual.

Decarbonisation indicators

The changes in CO_2 emissions means that GB energy consumers pay electricity at a lower price compared to the counterfactual in FS and LW, as less CO_2 allowances have to be bought under the UK ETS. The reduced CO_2 emissions also leads to lower societal carbon costs for GB. This is summarised in Table 15 below.

Table 15 - Decarbonisation indicators for LirIC

Indicator	Applies to	Unit	LW	CT	FS
CO_2 reduction (SEW)	GB	£m real 2022 NPV	-8.5	21.7	-72.9
CO_2 reduction (Societal value)	GB	£m real 2022 NPV	-26.0	32.8	-26.6
Overall decarbonisation	Europe	Mt	-2.9	-5.1	-3.3

3.2.4.5. Security of Supply impacts

As already mentioned, only in LW from 2040, energy supply in GB fails to meet demand in periods of system stress, leading to higher wholesale prices to cover costs associated with the amount of USE hours observed. The introduction of LirIC helps reducing the number of USE hours in GB compared to the counterfactual, as shown in Figure 38 below, although not as much as other projects assessed.

As mentioned in section 3.2.5.2, in this scenario, imports from the I-SEM into GB between 2040 and 2045 do increase, but not significantly. In fact, GB and the island of Ireland are highly correlated in terms of demand and wind generation profile. Considering that they are also located in the same time zone, the two countries present similarly short systems during peak hours. This mean that there is not much excess electricity generated in the I-SEM available for export to meet the higher demand in GB during period of system stress.

Nevertheless, the project does lead to a reduction in the costs of EENS for a total of £64.7m compared to the counterfactual in LW.

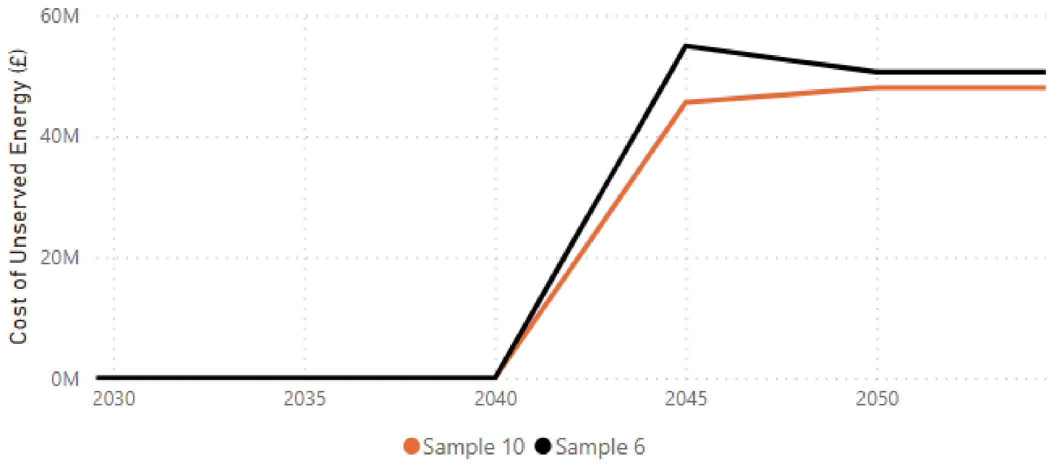


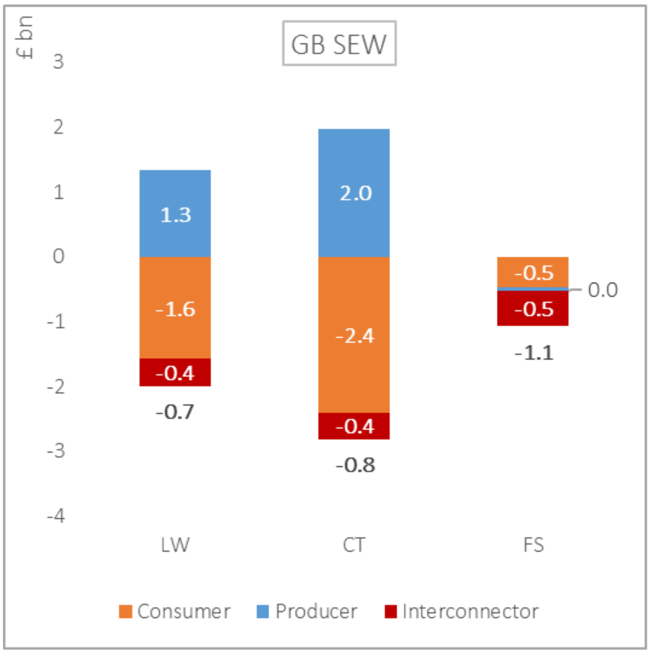
Figure 38 – Cost of EENS in the counterfactual and target case in LW (£, real 2022)

In CT and FS, no USE hours are observed before and after the introduction of the project, meaning that LirIC does not have positive nor negative impacts on SoS in GB.

3.2.5. MaresConnect

3.2.5.1. Overview and SEW impacts

The MaresConnect project has been modelled as a 750 MW IC between GB and the Irish I-SEM, connecting in 2030.



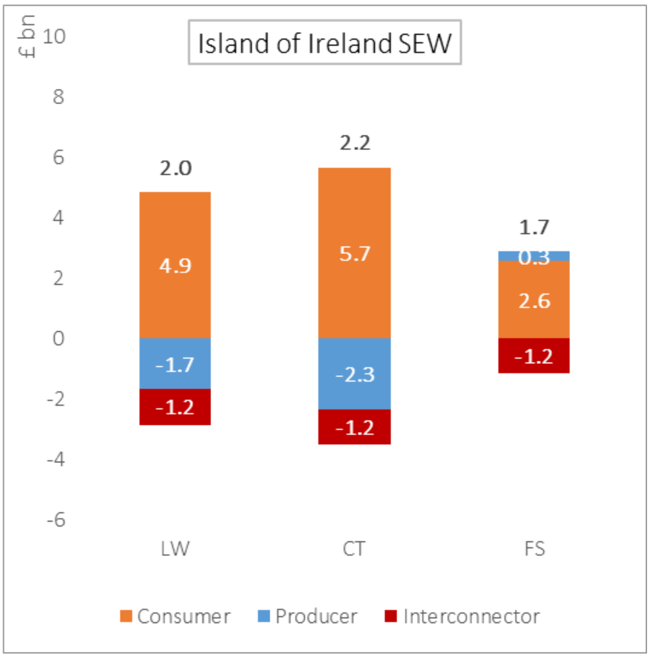


Figure 39 - SEW impacts of MaresConnect in GB and island of Ireland (£bn, real 2022, NPV)

The key conclusions from our analysis are:

- **The total SEW impacts in GB are negative in all scenarios,** driven by negative consumers and IC SEW.
- **In GB, MaresConnect delivers negative consumers SEW impacts in all scenarios.** In LW and CT, the project exports electricity from GB to the I-SEM. This drives wholesale prices in GB upwards, to the detriment of GB consumers. In FS, MaresConnect is initially used to import electricity leading to early consumers SEW gains. However, these are offset by higher exports from 2040 onwards.
- **IC welfare in GB is marginally negative in all scenarios**. Due to its capacity, MaresConnect does not fully exploit the price differentials between GB and the I-SEM. Hence, the revenue earned does not offset the project costs and the cannibalisation effects on other existing projects.
- **In the island of Ireland, MaresConnect leads to positive SEW in all scenarios.** This is driven largely by positive consumers SEW as the project imports cheaper electricity from GB to the I-SEM, reducing wholesale market prices. In FS, the project is used early on to export electricity, leading to higher wholesale prices which in turn translates in strong producers SEW gain. These are only partially offset by decreasing prices later on when MaresConnect imports cheaper electricity from GB. The opposite occurs from a consumer perspective, whereby the early SEW losses due to higher prices are fully recovered thanks to longer periods of imports from GB.

3.2.5.2. Economic fundamentals and flows

The main economic and commercial driver for the project is the difference in market prices between GB and the I-SEM when MaresConnect is introduced. Figure 40 below shows the annual average wholesale prices in both countries under LW, CT, and FS.

The I-SEM power market has a high share of renewable generation capacity from the onset of the study horizon at 65% (EU CT) and 62% (EU ST) of the total generation capacity. Wind and solar are the predominant generation technologies within renewable generation capacity. The share of renewable generation capacity increases to 72% in both European FES scenarios. CCGTs typically sets the price at the beginning of the study horizon while towards in the longer term the price is more frequently set by gas CCS and lower SRMC technologies.

It can be noted that GB has a lower wholesale price compared to the I-SEM in all scenarios with an annual average price differentials over 25 years of £9.2 MWh in LW, £12.8 MWh in CT and £2.0 MWh in FS. GB presents high shares of RES generation, which results in lower wholesale prices on average compared to its neighbours. In LW, it can be noted that GB prices increase from 2040 onwards, peaking at £62/MWh in 2045. This is due to a combination of factors such as CCUS CCGTs increasingly setting the market price in a context of growing intermittent generation combined with the highest CO_2 price of the three scenarios.

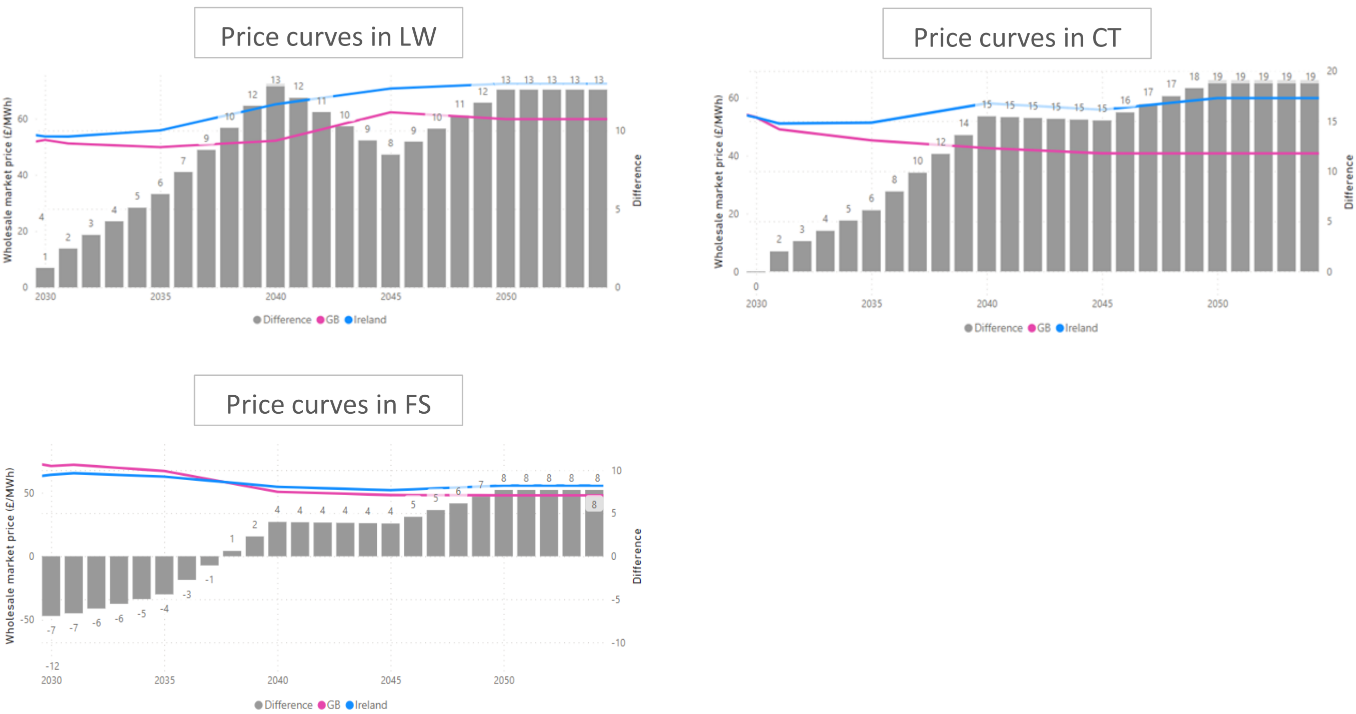


Figure 40 - Price differentials between GB and island of Ireland (£/MWh)

The price differentials described above largely determine the direction of the electricity flows across the project. These are shown in Figure 41below. MaresConnect is primarily used to export electricity from GB to the island of Ireland, due to the persistent higher prices of the I-SEM compared to GB. In LW, there is a gradual decrease in imports of electricity from the island of Ireland and increase in exports from GB as the difference with the I-SEM prices widens.

A similar trend can be observed in CT, whereby exports from GB increase and imports from the island of Ireland decrease as the price difference between the two markets increases. In FS, the project is initially used to import cheaper electricity from the I-SEM, until price curves switch position from mid-2030s. After that, export from GB continue increasing.

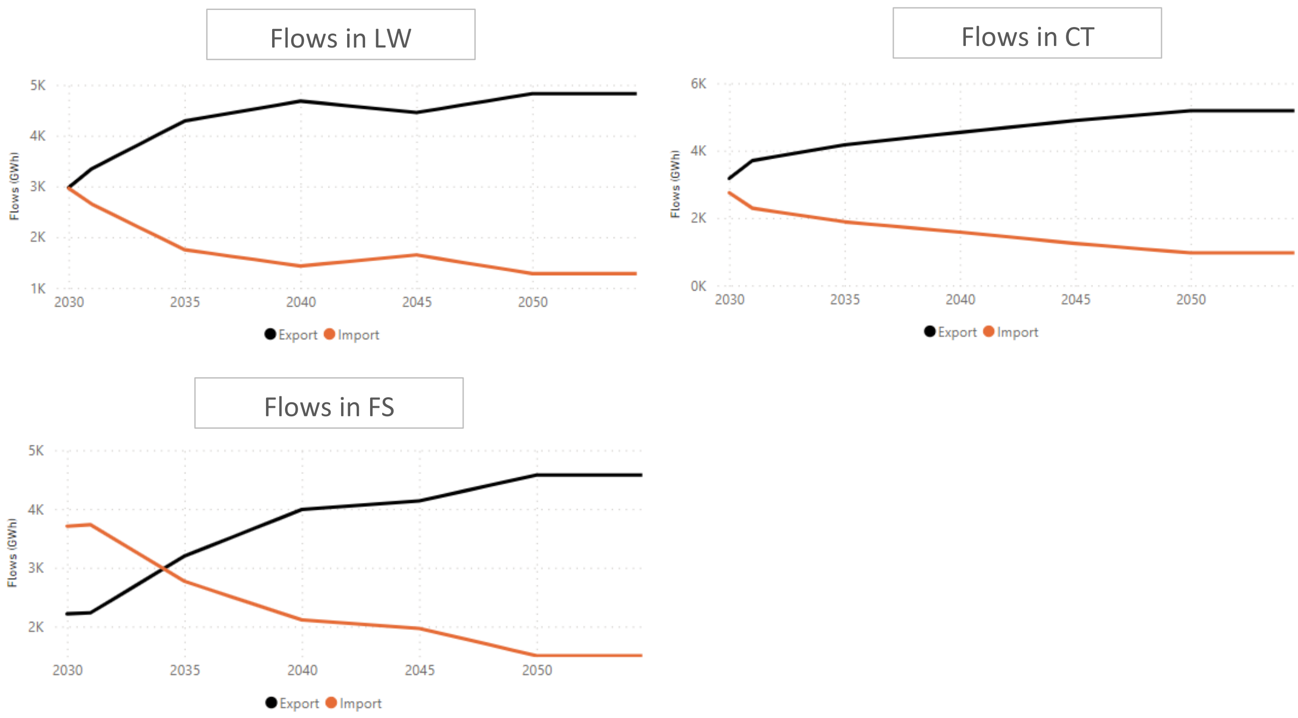


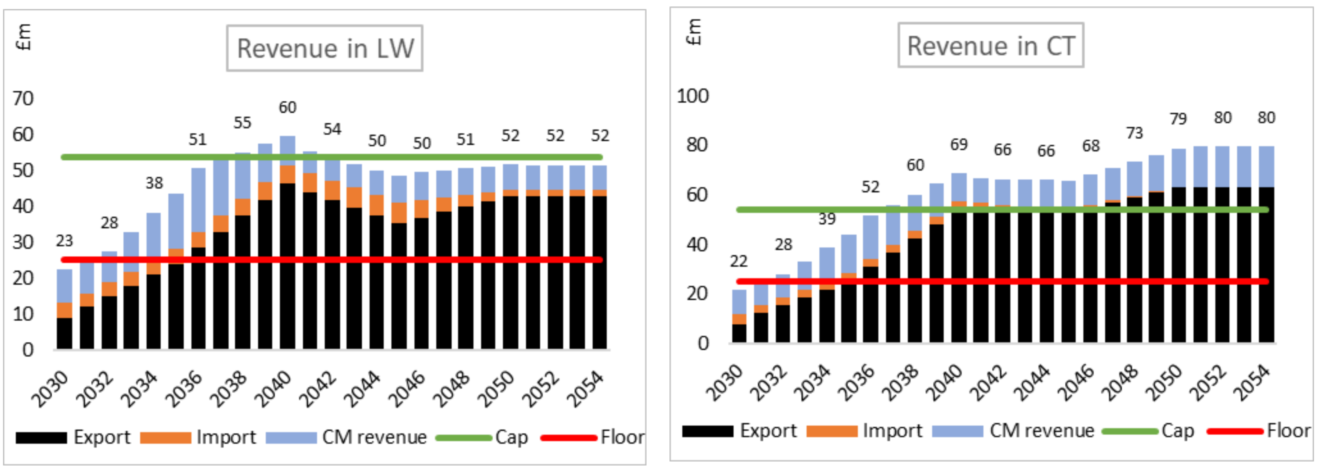
Figure 41 - Electricity flows across MaresConnect (black line: exports from GB, orange line: imports from island of Ireland) (GWh)

3.2.5.3. Revenues and impacts on consumers

Figure 42 below shows the GB portion of revenue earned by MaresConnect, based on a 50:50 split. Despite the relatively high price differentials between GB and the I-SEM, the project does not earn as much as other projects due to its comparatively smaller size.

The majority of revenue is earned through exports from GB, noting that in FS, the share of revenue captured through imports is larger compared to the other scenarios.

When CM revenue is considered, MaresConnect is likely to require minimal floor payments in the early years of operation under LW and CT. Cap payments to consumers are likely to be expected mostly in CT where the price difference between GB and the I-SEM is the biggest.



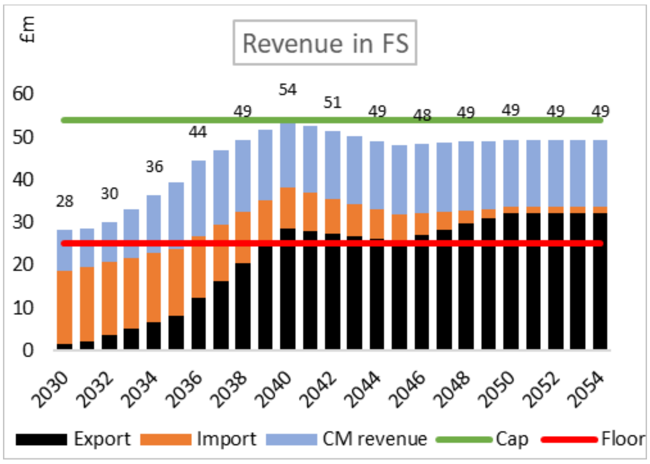


Figure 42 - GB share of revenues earned by MaresConnect (£m, real 2022)

3.2.5.4. Decarbonisation impacts

MaresConnect leads to a net decrease in CO_2 emissions in GB in LW and FS, and a marginal increase in CT. In the island of Ireland and across Europe, the project contributes to a net decrease in emissions in all scenarios, as shown in Figure 43 below.

MaresConnect is largely used to export electricity from GB, leading to lower wholesale prices in all scenarios in the I-SEM. Consequently, more expensive thermal generation is displaced compared to the counterfactual, leading to a decrease in emissions.

In GB, the impact of MaresConnect is more nuanced. In FS, the project is used to import electricity from the I-SEM to GB until the mid-2030s. This applies downward pressure on GB prices early on when the capacity mix still includes significant shares of thermal generation, leading to a decrease of emissions. In LW, despite a marginal increase in prices, CO_2 emissions are lower when MaresConnect is introduced compared to the counterfactual.

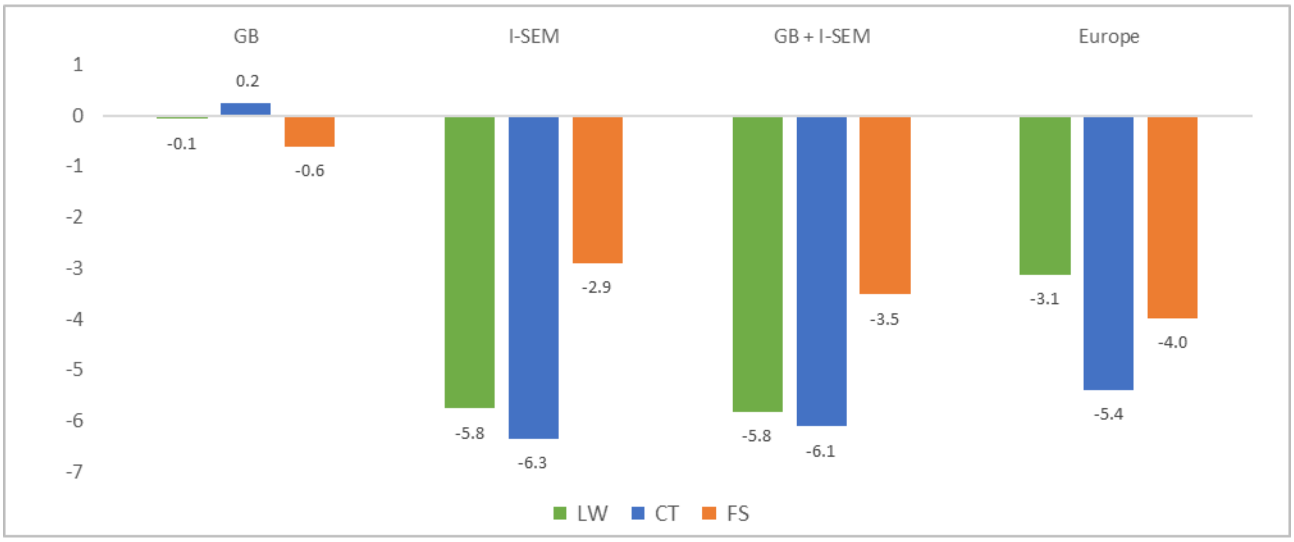


Figure 43 - Changes in CO2 emissions due to MaresConnect (Mt)

Decarbonisation indicators

The changes in CO_2 emissions means that GB energy consumers pay electricity at a lower price compared to the counterfactual in FS and LW, as less CO_2 allowances have to be bought under the UK ETS. The reduced emission of CO_2 also leads to lower societal costs for GB. This is summarised in Table 16 below.

Table 16 - Decarbonisation indicators for MaresConnect

Indicator	Applies to	Unit	LW	CT	FS
CO_2 reduction (SEW)	GB	£m real 2022 NPV	-7.2	16.6	-69.0
CO_2 reduction (Societal value)	GB	£m real 2022 NPV	-22.6	23.8	-24.8
Overall decarbonisation	Europe	Mt	-3.1	-5.4	-4.0

3.2.5.5. Security of Supply impacts

As already mentioned, only in LW from 2040, energy supply in GB fails to meet demand in periods of system stress, leading to significantly high wholesale prices to cover costs associated with the amount of USE hours observed. The introduction of MaresConnect helps reducing the number of USE hours in GB compared to the counterfactual, as shown in

Figure 50 below, although not as much as other projects assessed.

As mentioned in section 3.2.5.2, in LW, imports from the I-SEM Ireland into GB between 2040 and 2045 do increase, but not significantly. In fact, GB and the island of Ireland are highly correlated in terms of demand and wind generation profile. Considering that they are also located in the same time zone, the isles present similarly short systems during peak hours. This means that there is not much electricity generated within the I-SEM available to meet the higher demand in GB during period of system stress.

Nevertheless, the project does lead to a reduction in the costs of EENS for a total of £69.7m compared to the counterfactual.

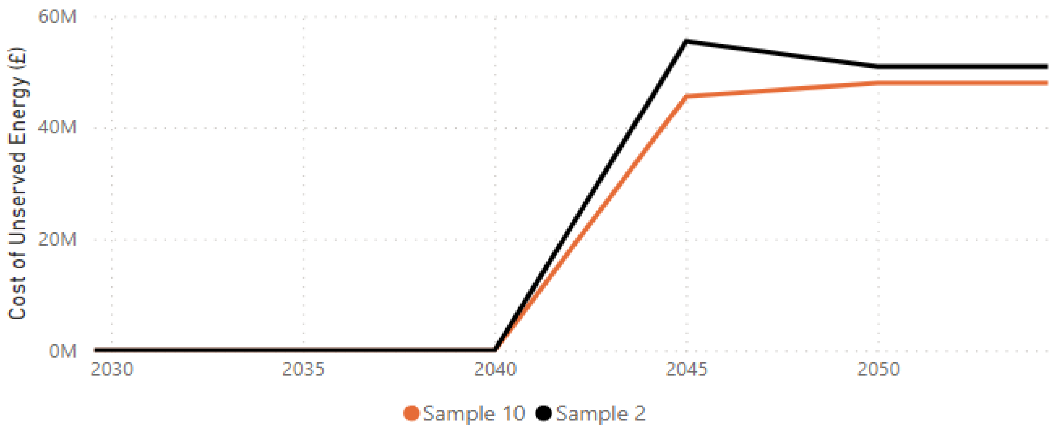


Figure 44 – Cost of EENS in the counterfactual and target case in LW (£, real 2022)

In CT and FS, no USE hours are observed before and after the introduction of the project, meaning that MaresConnect does not have positive nor negative impacts on SoS in GB.

3.2.6. NU-Link

3.2.6.1. Overview and SEW impacts

The NU-Link project has been modelled as a 1.2 GW IC between GB and the Netherlands, connecting in 2031.

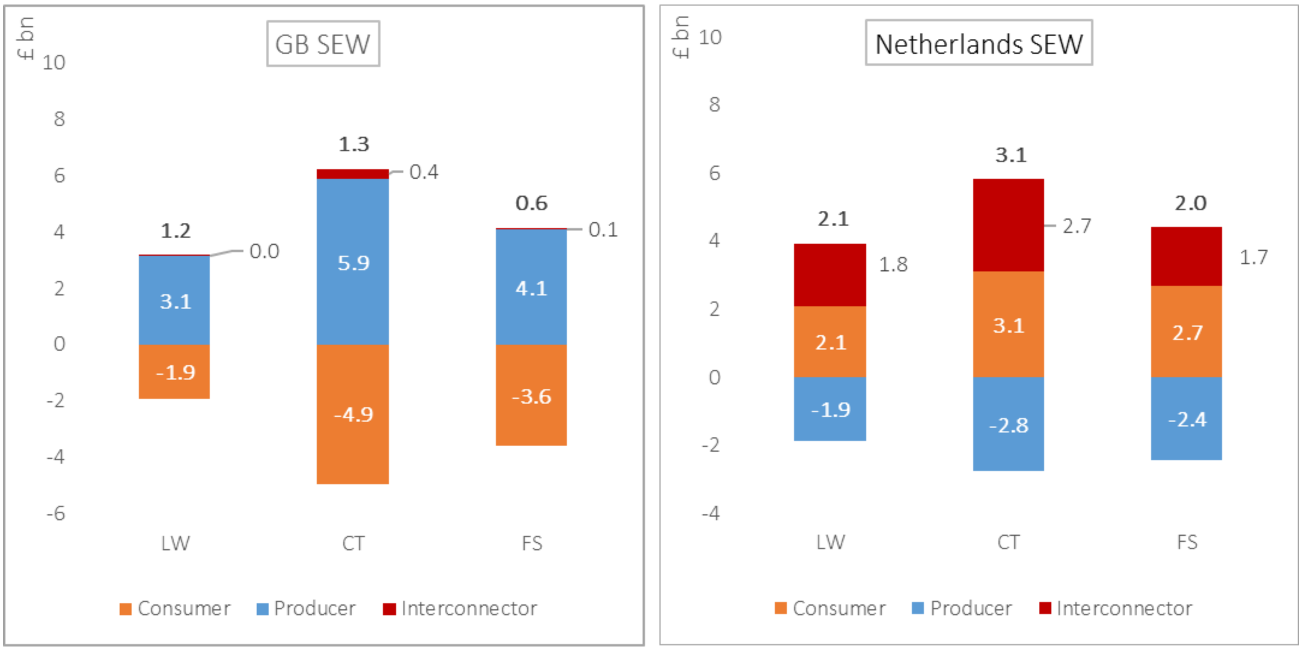


Figure 45 - SEW impacts of NU-Link in GB and the Netherlands (£bn, real 2022, NPV)

The key conclusions from our analysis are:

- **The total SEW impacts in GB are positive in all scenarios,** driven by strong producers SEW and positive IC SEW.
- **In GB, NU-Link delivers negative consumers SEW impacts in all scenarios.** The project largely exports electricity from GB to the Netherlands, driving higher wholesale prices in GB.
- **IC welfare in GB is marginally positive in all scenarios**. NU-Link's revenue offset its costs as well as the cannibalisation effects on other existing projects.
- **In the Netherlands, NU-Link leads to positive SEW in all scenarios.** This is driven largely by positive consumers SEW as the project imports cheaper electricity from GB to the Netherlands, reducing wholesale market prices.

3.2.6.2. Economic fundamentals and flows

The main economic and commercial driver for the project is the significant difference in market prices between GB and the Netherlands when NU-Link is introduced. Figure 46 below shows the annual average wholesale prices in both countries under LW, CT, and FS.

The Dutch power market evolution is characterised by the phasing out of coal and nuclear power plants in all scenarios. Renewable generation capacity grows from 61-63% of total generation in 2027 to above 70% by 2050 in both European FES scenarios, whilst hydrogen-fired and gas-fired generation capacity accounts for circa a quarter of the total generation capacity by 2050 in both European FES scenarios. Conventional gas and biomass typically sets the price at the beginning of the study horizon. Towards the end of the horizon, price is usually set by gas with CCS and lower SRMC technologies. It can be noted that GB has a lower wholesale price compared to the Netherlands in all scenarios. The average annual price differential between these two countries is of £11.1 MWh in LW, £18.8 MWh in CT and £12 MWh in FS.

GB presents high volumes of RES generation capacity, which results in lower wholesale prices on average compared to its neighbours. In LW, it can be noted that GB prices increase from 2040 onwards, peaking at £62/MWh in 2045. This is due to a combination of factors such as CCUS CCGTs increasingly setting the market price in a context of growing intermittent generation combined with the highest CO_2 price of the three scenarios.

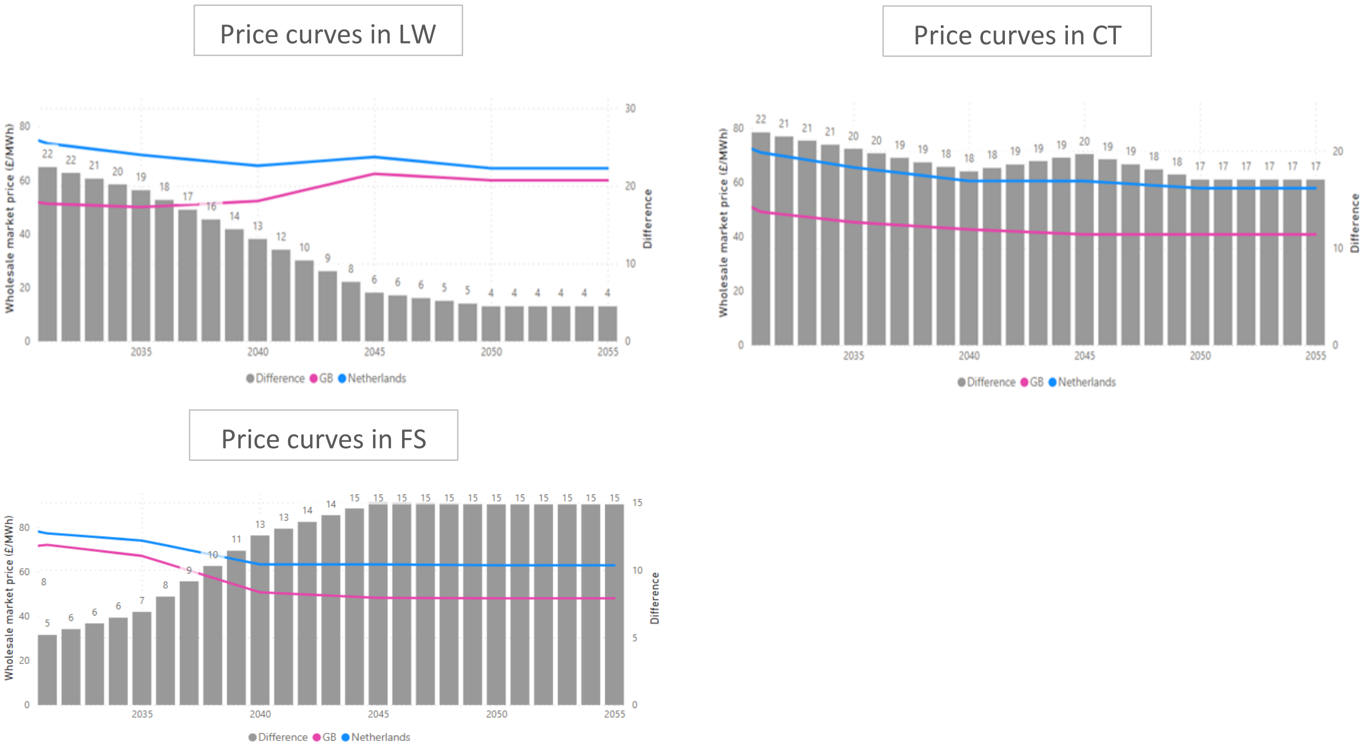


Figure 46 - Price differentials between GB and the Netherlands (£/MWh)

The price differentials described above largely determine the direction of the electricity flows across the project. These are shown in Figure 47 below. NU-Link is primarily used to export electricity from GB to the Netherlands, due to the persistent higher prices compared to GB. In LW, there is a gradual increase in imports as GB prices raise and Dutch prices decrease slightly, narrowing the price differentials. In the other two scenarios, export and import flows are flatter as the price differentials remain constant.

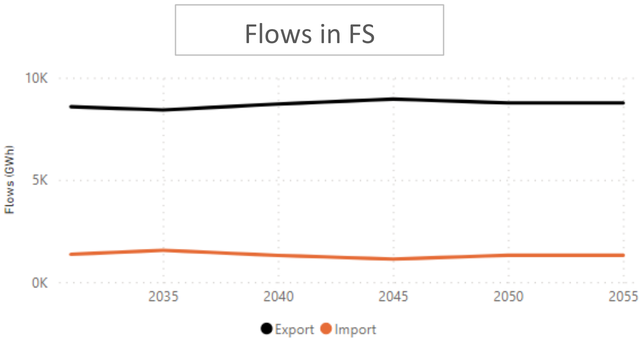


Figure 47 - Electricity flows across NU-Link (black line: exports from GB, orange line: imports from the Netherlands) (GWh)

3.2.6.3. Revenues and impacts on consumers

Figure 48 below shows the GB portion of revenues, based on a 50:50 split with the connecting country. Considering the high price differentials and volumes of electricity flows, NU-Link earns significant revenue through exports from GB to the Netherlands, noting that in LW the share of revenue captured through imports is larger compared to the other scenarios. This is due to the price delta between the interconnected bidding zones.

NU-Link is likely not to require floor payments whilst it could provide cap payments to consumers during the first years of operation in LW, throughout the modelled period in CT, and in the medium term under FS.

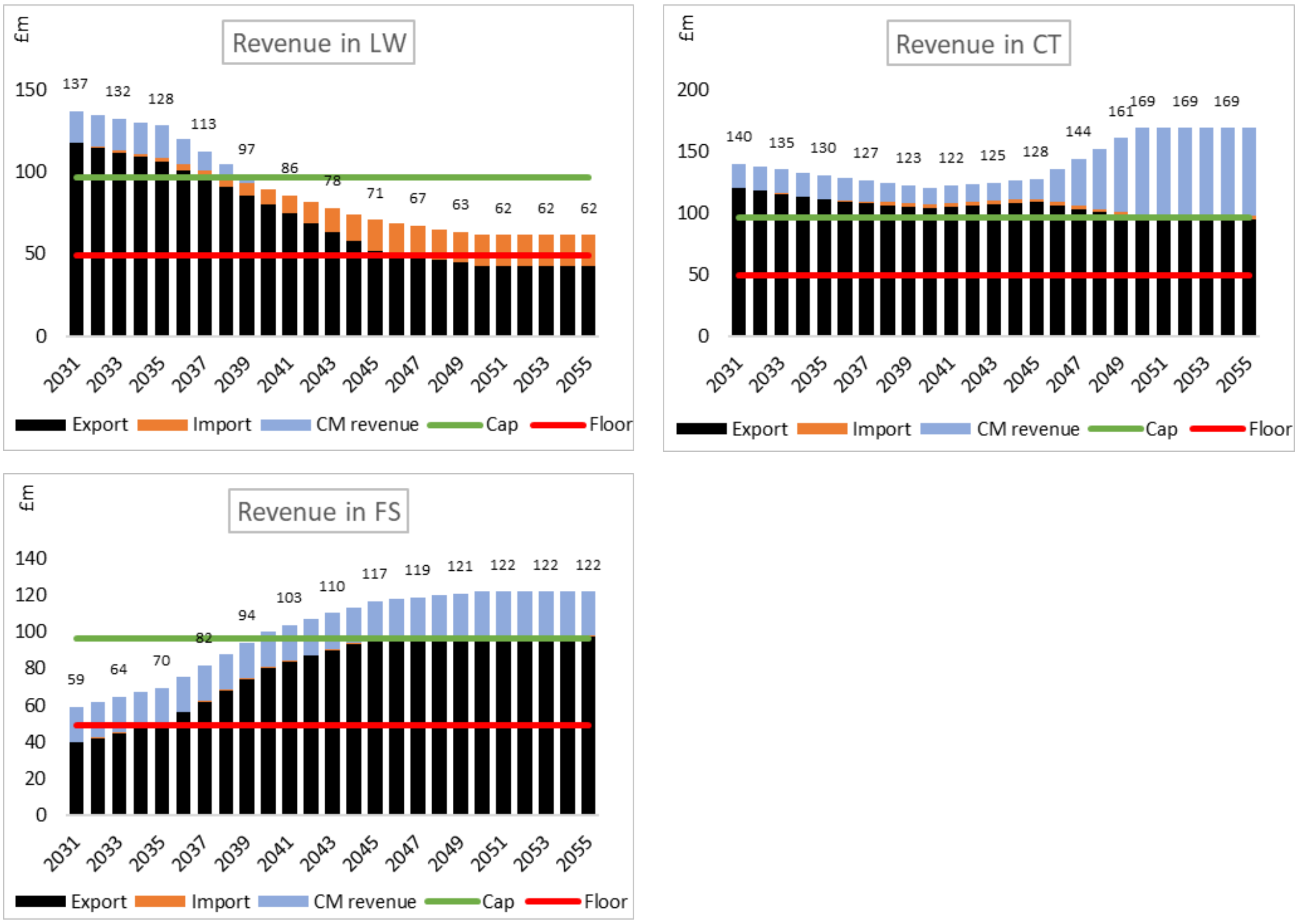


Figure 48 - GB share of revenues earned by NU-Link (£m, real 2022)

3.2.6.4. Decarbonisation impacts

NU-Link leads to a net increase in CO_2 emissions in GB, and a net decrease in Germany and across Europe, as shown in Figure 49 below.

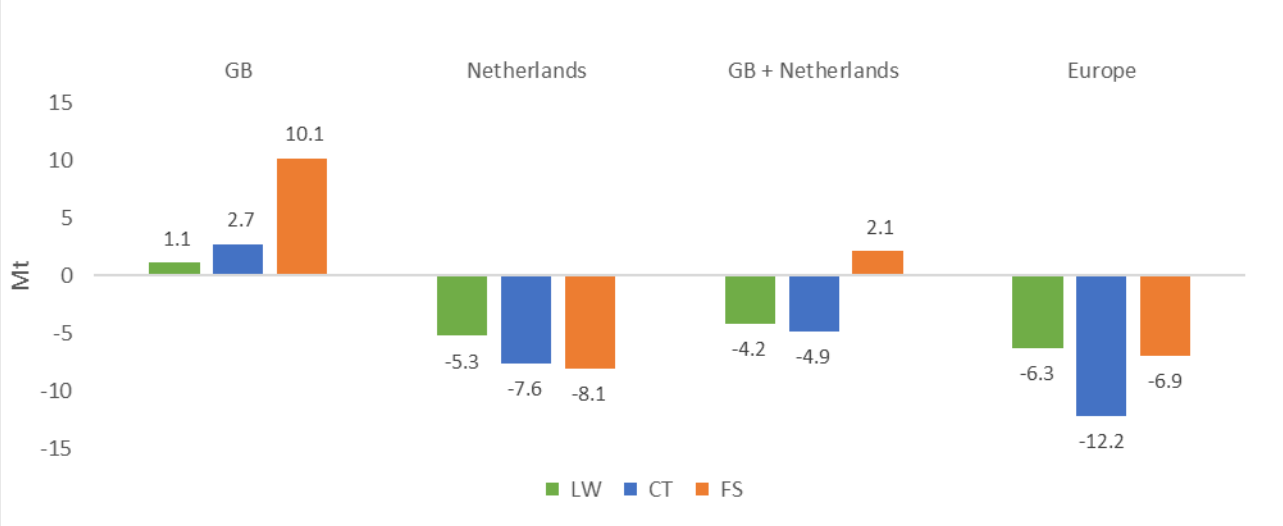


Figure 49 - Changes in CO_2 emissions due to NU-Link (Mt)

NU-Link is largely used to export electricity to the Netherlands, leading to higher GB wholesale prices in all scenarios. Consequently, more expensive thermal generation is dispatched compared to the counterfactual, leading to an increase in emissions.

Conversely, CO_2 emissions decrease in the Netherlands due to the downward impacts that the project has on local prices. As the prices decrease, more expensive thermal generation is displaced from the dispatch order. The share of thermal generation in the Netherlands is 39% of the total in FS, and 25% of the total in CT and LW, respectively. Therefore, the change in the Dutch prices leads to significant reduction in CO_2 emissions that fully offsets the emission increase in GB in CT and LW. In FS, the emissions reduction in the Netherlands does not offset the emissions increase in GB. From a European perspective the project has a positive impact contributing to a net decrease in carbon emissions.

Decarbonisation indicators

The changes in CO_2 emissions means that GB energy consumers pay electricity at a higher price compared to the counterfactual in all scenarios, as more CO_2 allowances have to be bought under the UK ETS. The additional CO_2 also leads to higher societal costs for GB. This is summarised in Table 17 below.

Table 17 - Decarbonisation indicators for NU-Link

Indicator	Applies to	Unit	LW	CT	FS
CO_2 reduction (SEW)	GB	£m real 2022 NPV	96.9	230.5	681.9
CO_2 reduction (Societal value)	GB	£m real 2022 NPV	268.9	370.3	332.7
Overall decarbonisation	Europe	Mt	-6.3	-12.2	-6.9

3.2.6.5. Security of Supply impacts

As already mentioned, only in LW from 2040, energy supply in GB fails to meet demand in periods of system stress, leading to significantly high wholesale prices to cover costs associated with the amount of USE hours observed.

The introduction of NU-Link helps reducing the number of USE hours in GB compared to the counterfactual, as shown in Figure 50 below. The project is used to import electricity in periods of system stress, reducing substantially cost of EENS compared to the counterfactual for a total of £311.6m.

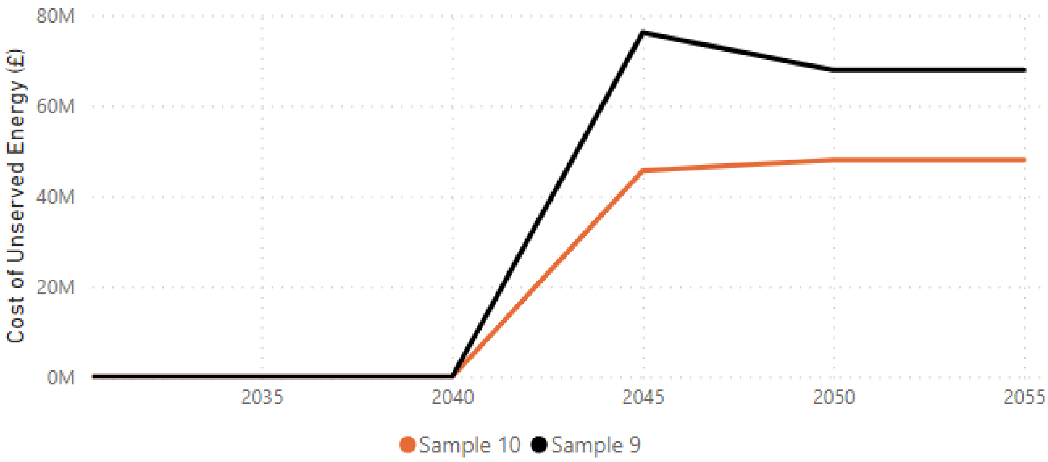


Figure 50 – Cost of EENS in the counterfactual and target case in LW (£, real 2022)

In CT and FS, no USE hours are observed before and after the introduction of the project, meaning that NU-Link does not have positive nor negative impacts on SoS in GB.

3.2.7. Tarchon

3.2.7.1. Overview and SEW impacts

The Tarchon project has been modelled as a 1.4 GW IC between GB and Germany, connecting in 2030.

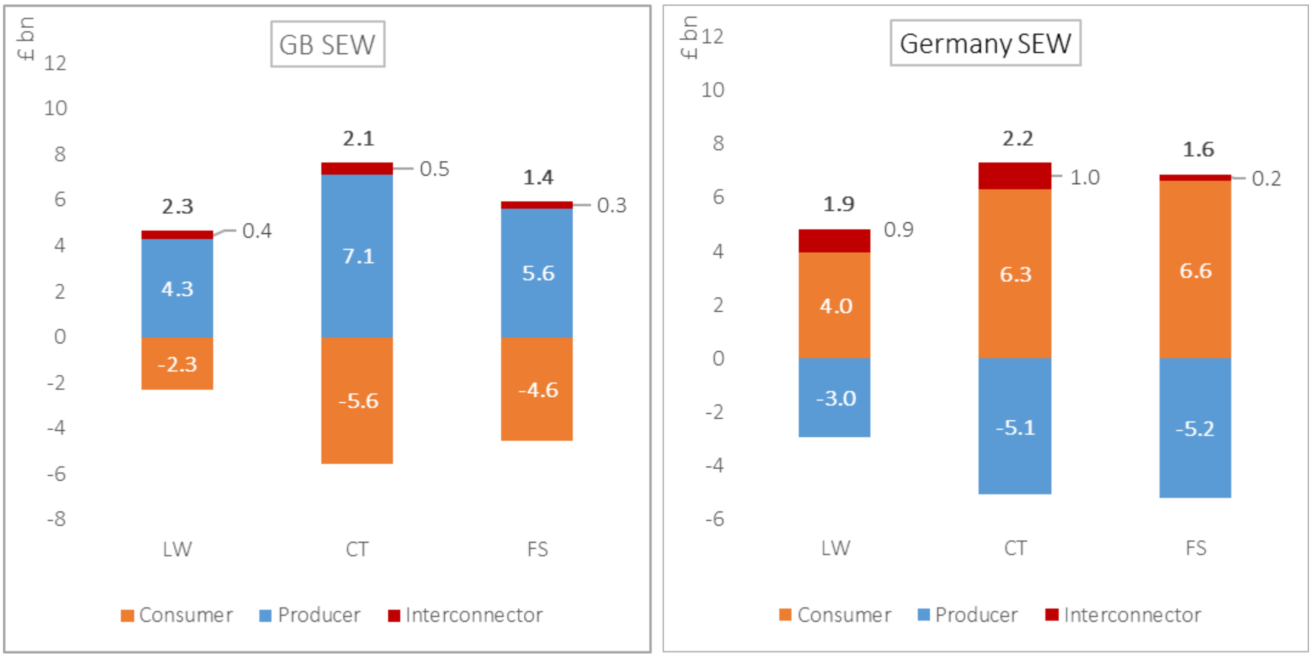


Figure 51 - SEW impacts of Tarchon in GB and Germany (£bn, real 2022, NPV)

The key conclusions from our analysis are:

- **The total SEW impacts in GB are positive in all scenarios,** driven by strong producers SEW and positive IC SEW.
- **In GB, Tarchon delivers negative consumers SEW impacts in all scenarios.** The project largely exports electricity from GB to Germany, driving higher wholesale prices in GB.
- **IC welfare in GB is positive in all scenarios,** as Tarchon's revenue offsets the project costs and cannibalisation effects on existing projects.
- **In Germany, Tarchon leads to positive SEW in all scenarios.** This is driven largely by positive consumers SEW as the project imports cheaper electricity from GB to Germany, reducing wholesale market prices.

3.2.7.2. Economic fundamentals and flows

The main economic and commercial driver for the project is the significant difference in market prices between GB and Germany when Tarchon is introduced. Figure 52 below shows the annual average wholesale prices in both countries under LW, CT, and FS.

In the German power market nuclear generation capacity remains absent of the system in both European FES scenarios. Germany has a high share of renewable generation capacity from the onset of the study horizon at 74% of the total generation capacity. Wind and Solar are the predominant generation technologies within renewable generation capacity. The share of renewable generation capacity increases to 81% and 77% in the EU CT and EU ST scenarios respectively. Coal generation capacity is phased out in all scenarios by 2030.

Conventional gas-fired generation capacity typically sets the price at the beginning of the study horizon whilst towards the end of the horizon, gas CCS and lower SRMC technologies sets more frequently the price in the German market.

It can be noted that GB has a lower wholesale price compared to Germany in all scenarios. The price differentials with Germany are quite high, with an annual average of £13.9 MWh in LW, £22.1 MWh in CT and £15.8 MWh in FS over 25 years. GB presents high volumes of RES generation capacity, which results in lower wholesale prices on average compared to its neighbours. In LW, GB prices increase gradually from 2040 onwards following an increase in USE hours, as demand is not fully met by supply.

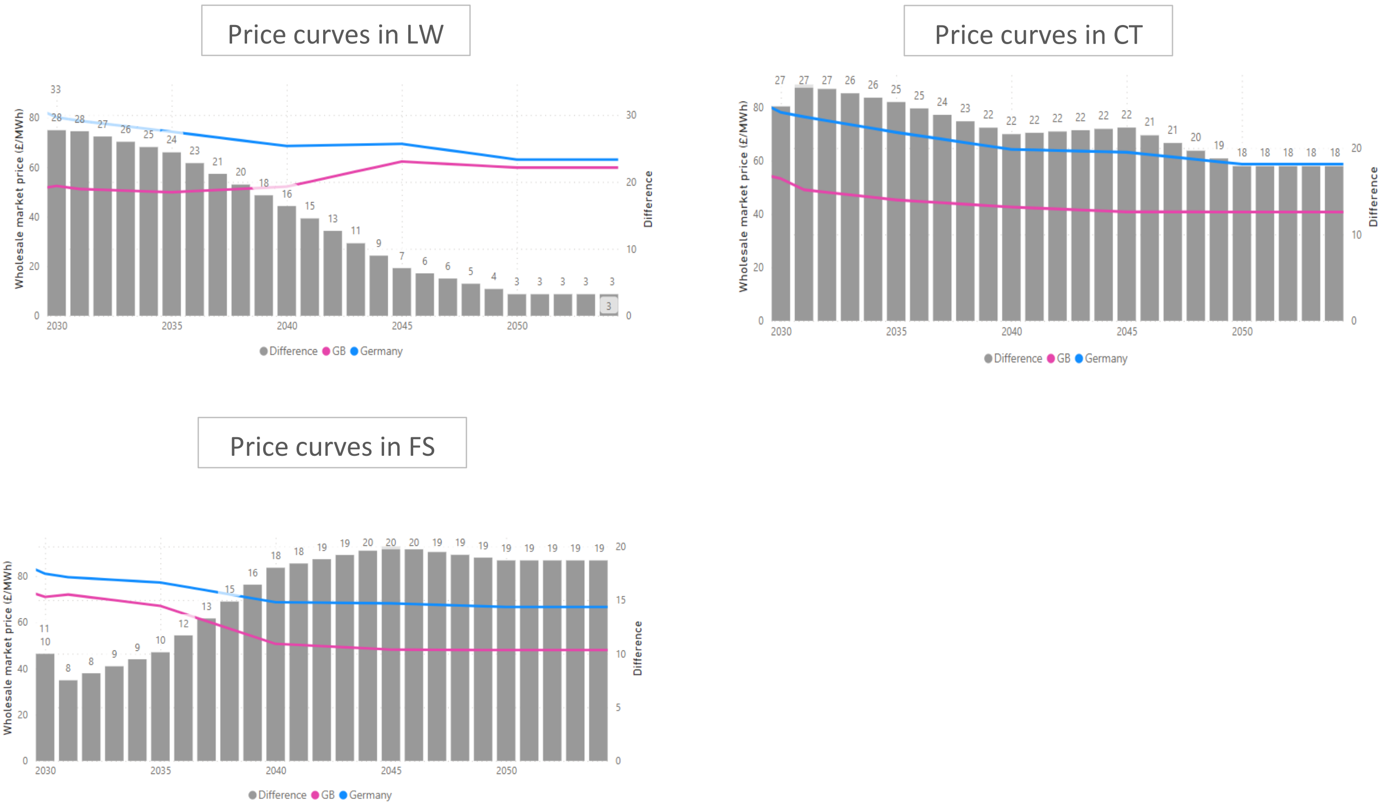
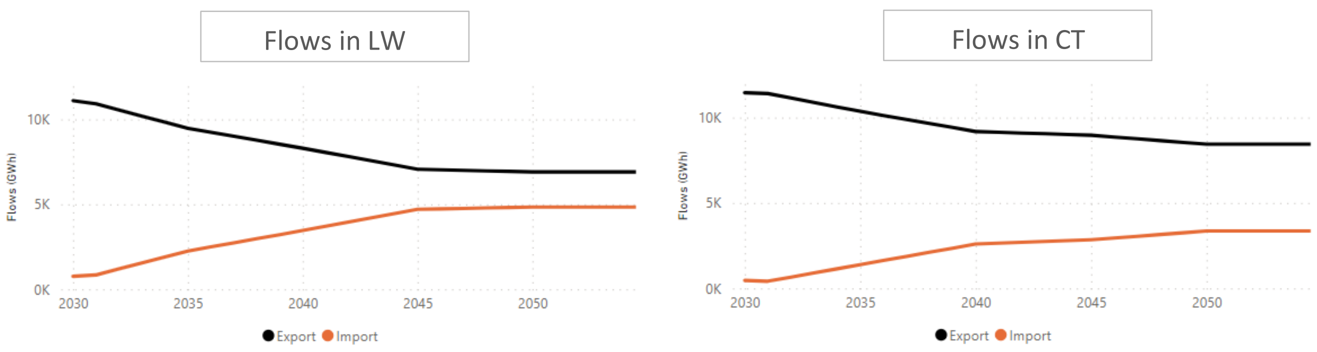


Figure 52 - Price differentials between GB and Germany (£/MWh)

The price differentials described above largely determine the direction of the electricity flows across the project. These are shown in Figure 53. Tarchon is primarily used to export electricity from GB to Germany, due to the persistent higher prices in Germany compared to GB. In LW, there is a gradual increase in imports as GB price raises and German prices decreases slightly, narrowing the price differentials. In the other two scenarios, export and import flows are flatter as the price differentials remain constant.



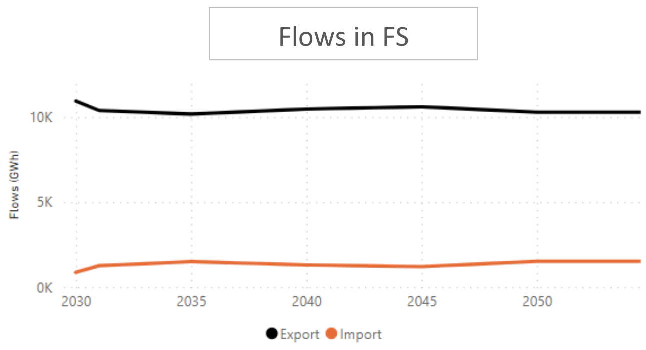
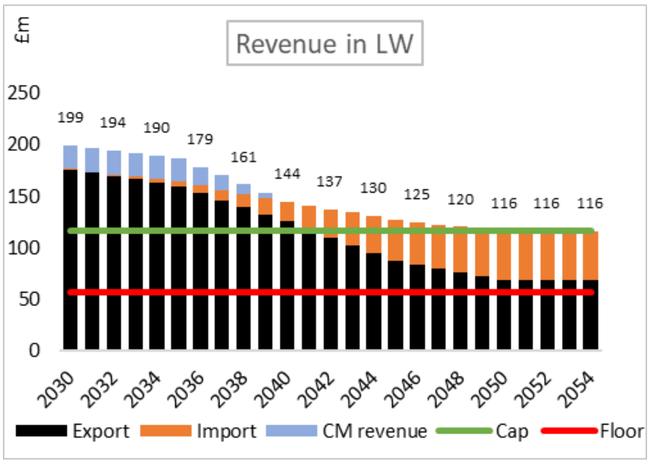


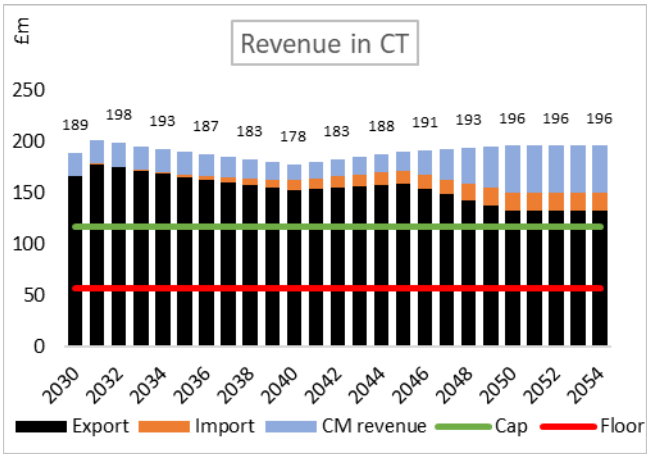
Figure 53 - Electricity flows across Tarchon (black: exports from GB, orange line: imports from Germany) (GWh)

3.2.7.3. Revenues and impacts on consumers

Figure 54 below shows the GB portion of revenues earned by the project, based on a 50:50 split with the connecting country. Considering the high price differentials and volumes of electricity flows, Tarchon earns significant revenue through exports from GB to Germany, noting that in LW the share of revenue captured through imports is larger compared to the other scenarios. This is due the price delta between Germany and GB.

Tarchon is likely not to require floor payments. Instead, it is expected to provide cap payments to consumers throughout the modelled period, except for the early years of operations in FS.





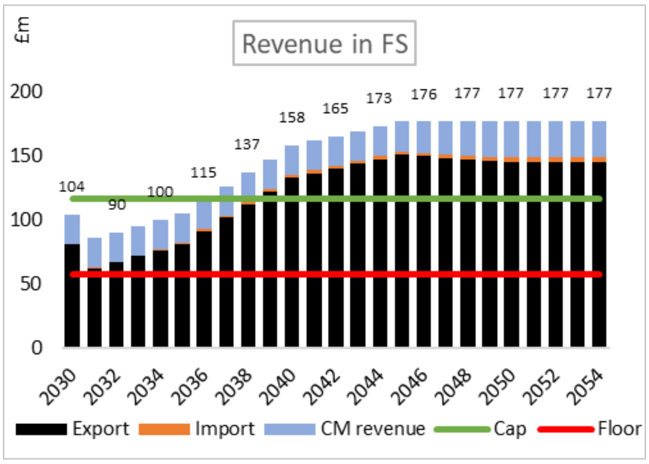


Figure 54 - GB share of revenues earned by Tarchon (£m, real 2022)

3.2.7.4. Decarbonisation impacts

Tarchon leads to a net increase in CO_2 emissions in GB, and a net decrease in Germany and across Europe, as shown in Figure 55 below.

Tarchon is largely used to export electricity to Germany, leading to higher GB wholesale prices in all scenarios. Consequently, more expensive thermal generation is dispatched compared to the counterfactual, leading to an increase in emissions. Conversely, CO_2 emissions decrease in Germany due to the downward impacts that Tarchon has on German prices. As the prices decrease, more expensive thermal generation is displaced from the dispatch order.

Germany's capacity mix includes coal generation until 2030 and growing shares of gas generation between 2030 and 2040. Therefore, the change in the German prices leads to significant reduction in CO_2 emissions that fully offset the emission increase in GB. This leads to a net reduction in CO_2 emissions between the two countries. From a European perspective, the project has a positive impact contributing to a net decrease in carbon emissions.

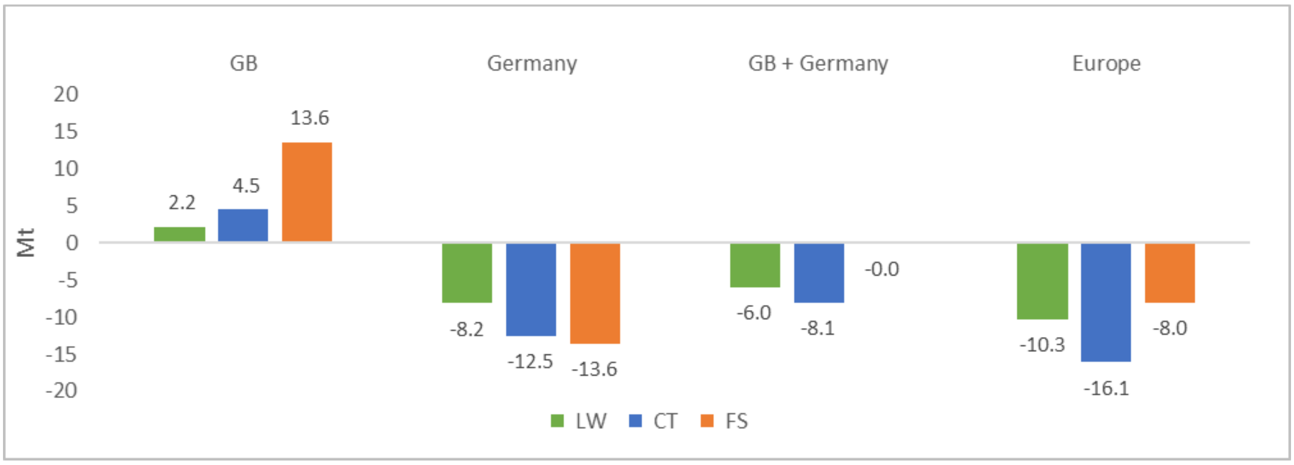


Figure 55 - Changes in CO_2 emissions due to Tarchon (Mt)

Decarbonisation indicators

The changes in CO_2 emissions means that GB energy consumers pay electricity at a higher price compared to the counterfactual in all scenarios, as more CO_2 allowances have to be bought under the UK ETS. The additional CO_2 also leads to higher societal costs for GB. This is summarised in Table 18 below.

Table 18 - Decarbonisation indicators for Tarchon

Indicator	Applies to	Unit	LW	CT	FS
CO_2 reduction (SEW)	GB	£m real 2022 NPV	192.3	380.4	955.7
CO_2 reduction (Societal value)	GB	£m real 2022 NPV	57.4	626.1	449.9
Overall decarbonisation	Europe	Mt	-10.3	-16.1	-8.0

3.2.7.5. Security of Supply impacts

As already mentioned, only in LW from 2040, energy supply in GB fails to meet demand in periods of system stress, leading to significantly high wholesale prices to cover costs associated with the amount of USE hours observed.

The introduction of Tarchon helps reducing the number of USE hours in GB compared to the counterfactual, as shown in Figure 56 below. The project is used to import electricity in periods of system stress, reducing substantially costs of EENS compared to the counterfactual for a total of £347.6m.

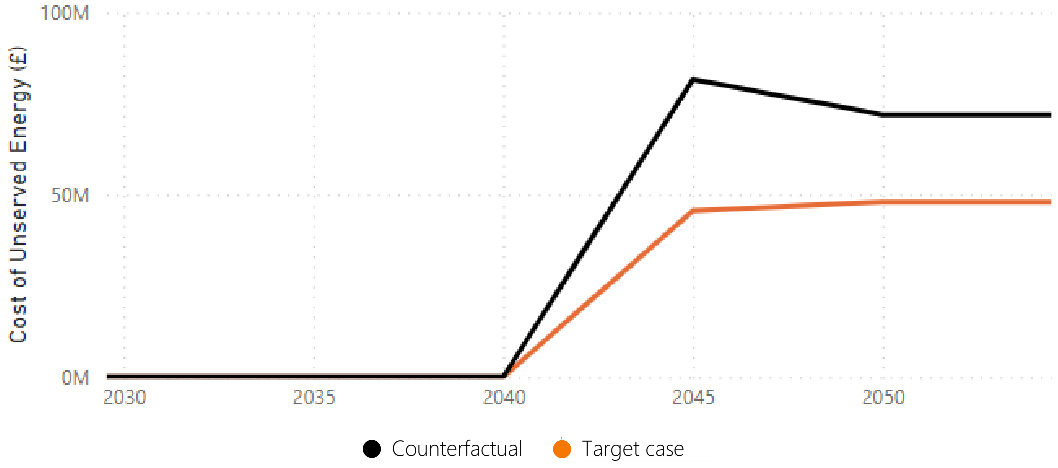


Figure 56 - Cost of EENS in the counterfactual and target case in LW (£, real 2022)

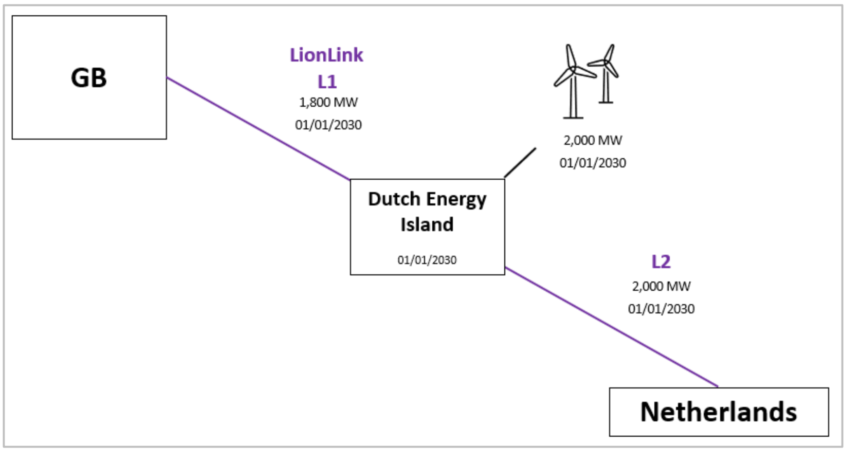
In CT and FS, no USE hours are observed before and after the introduction of the project, meaning that Tarchon does not have positive nor negative impacts on SoS in GB.

3.3. OHA results

3.3.1. LionLink

3.3.1.1. Overview and SEW impacts

The LionLink project has been modelled as a 1.8 GW IC between GB and the energy island currently under development in Dutch national waters (L1). The Dutch energy island is assumed to be operated as an OBZ connected to a 2 GW windfarm and to the Netherlands via a 2 GW line (L2). This is shown in Drawing 7 below.



Drawing 7 - Assumed configuration for LionLink

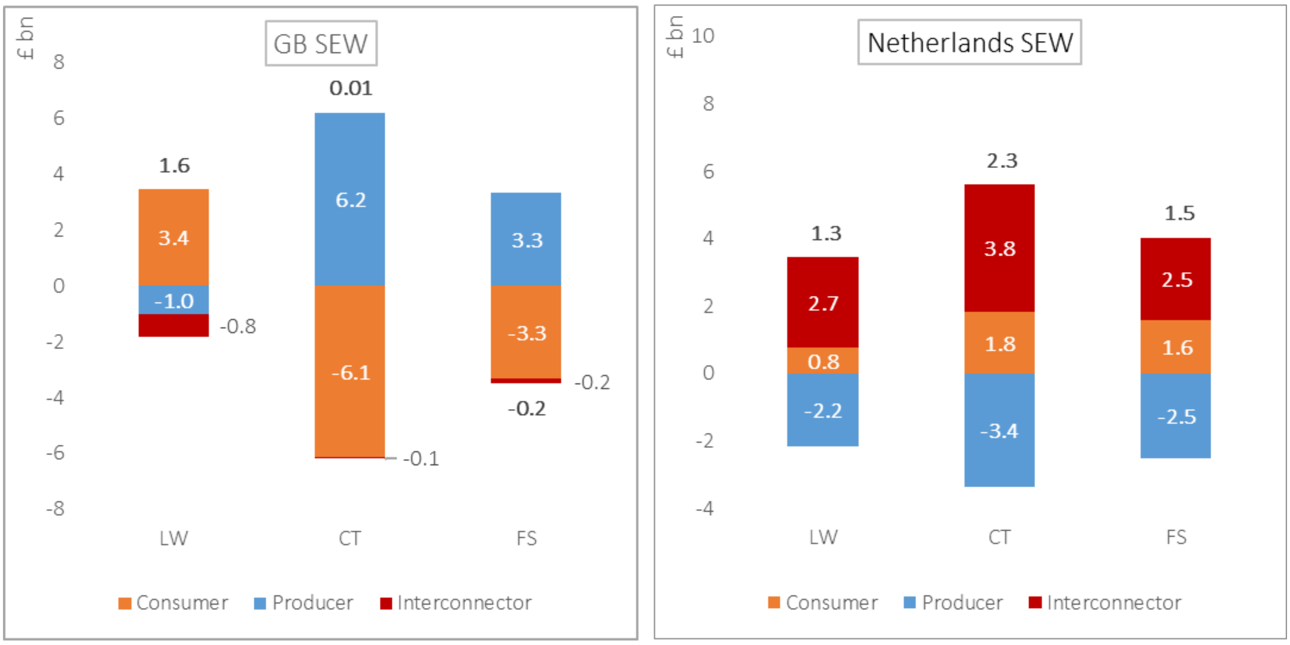


Figure 57 – SEW impacts of LionLink in GB and the Netherlands (£bn, real 2022, NPV)

The key conclusions from our analysis are:

- **The total SEW impacts in GB are positive in LW, marginal in CT and slightly negative in FS.**
- **In GB, LionLink improves consumers SEW in LW**, as the project switches from export to imports from 2040, reducing cost of EENS and consequently the GB wholesale prices compared the counterfactual. **In CT and FS, LionLink decreases consumers benefits**, as the project is mostly used to export electricity which is associated with an increase in GB wholesale prices compared to the counterfactual**.**
- **IC welfare in GB is negative in all scenarios**. The revenue earned by the project does not offset the project costs and the cannibalisation effects on other existing projects. The project is likely to require some floor payments from consumers, particularly in LW.
- **In the Netherlands, LionLink leads to positive total SEW in all scenarios.** The project is used primarily to import cheaper electricity from GB, which in turn reduces the wholesale prices in the Netherlands benefitting consumers. However, these SEW gains are offset by significant losses in producers SEW. IC SEW gains are significant, also thanks to the revenue earned by L2.

3.3.1.2. Economic fundamentals and flows

The key economic and commercial driver for the project is the difference in market prices between GB, the Netherlands, and the Dutch OBZ. Figure 58 below shows the annual average wholesale prices under LW, CT, and FS.

The Dutch power market evolution is characterised by the phasing out of coal and nuclear power plants in all scenarios. Renewable generation capacity grows from 61-63% of total generation in 2027 to above 70% by 2050 in both European FES scenarios, whilst hydrogen-fired and gas-fired generation capacity accounts for circa a quarter of the total generation capacity by 2050 in both European FES scenarios. Conventional gas and biomass typically sets the price at the beginning of the study horizon. Towards the end of the horizon, price is usually set by gas with CCS and lower SRMC technologies.

In all scenarios, the GB prices are lower than those in the Netherlands. GB presents high shares of RES generation, which results in lower wholesale prices on average compared to its neighbours. In LW, it can be noted that GB prices increase from 2040 onwards, peaking at £62/MWh in 2045. This is due to a combination of factors such as CCUS CCGTs increasingly setting the market price in a context of growing intermittent generation combined with the highest CO2 price of the three scenarios. However, it always remains lower than the wholesale price in the Netherlands.

This leads to more frequent exports of electricity from GB towards the Netherlands, as shown later. When the OWF connected to Dutch energy island generates, L2 becomes heavily congested. In order to dispatch the electricity generated over L2 towards the Netherlands, the OBZ price aligns with the cheapest market, i.e., GB.

This leads to low price differentials between GB and the Dutch OBZ, which in turns affect the flows and revenues across LionLink (L1). LW and FS present the lowest average price difference at 0.9 £/MWh, whilst in CT, prices diverge more at 1.88 £/MWh on average.

Figure 58 - Price differentials between GB and the Netherlands and the Dutch energy island (£/MWh)

The price differentials described above largely determine the direction of the electricity flows across LionLink (L1) and L2 project. These are shown in Figure 23 below. As the other projects assessed, LionLink (L1) is primarily used to export electricity from GB with few exceptions.

In LW, imports on LionLink (L1) from the OBZ into GB gradually increase. Export flows from GB towards the OBZ and the Netherlands still occur as the high prices in the latter attracts electricity from the former two. However, in these instances, the price difference between GB and OBZ is extremely low.

In the same scenario, L2 exports primarily towards the Netherlands. Exports decrease gradually whilst imports increase slightly as the price difference between the Dutch OBZ and the Netherlands reduces. A similar trend can be observed in CT and FS. LionLink (L1) and L2 are primarily used to export electricity towards the OBZ and the Netherlands as the high wholesale prices of the latter attract cheaper imports.

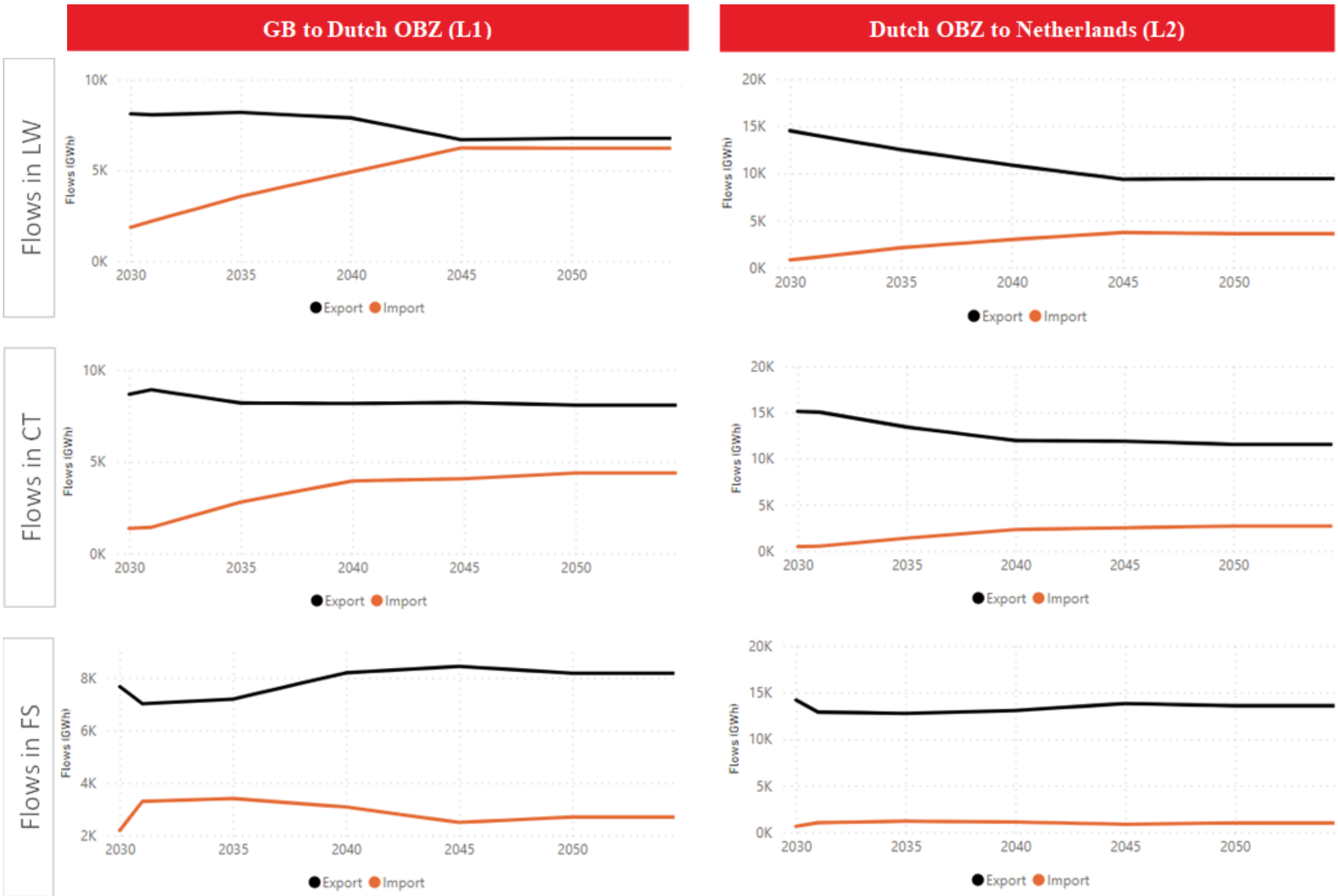


Figure 59 - Electricity flows across LionLink (L1) and L2 (black line: exports, orange line) (GWh)

3.3.1.3. Revenues and impacts on consumers

Figure 60 below shows the GB portion of revenue earned by LionLink (L1), based on a 50:50 split with the connecting country. It also shows the revenues earned over L2.

It can be noted that LionLink (L1) earns significant less congestion revenue than L2. Except for LW, when the project is used to import electricity in GB to curb USE hours, the project is used primarily for export towards the Netherlands. However, the price difference between GB and OBZ is very narrow, leading to limited export revenues earned on L1 despite the considerable export flows. On the contrary, L2 benefits from higher price differentials between the OBZ and the Netherlands, yielding much higher revenues.

Even when CM revenues are considered, the total revenue earned by LionLink (L1) is unlikely to meet the floor throughout the modelled period in LW, requiring consumers top ups. In CT and FS, floor payments are less likely to be required.

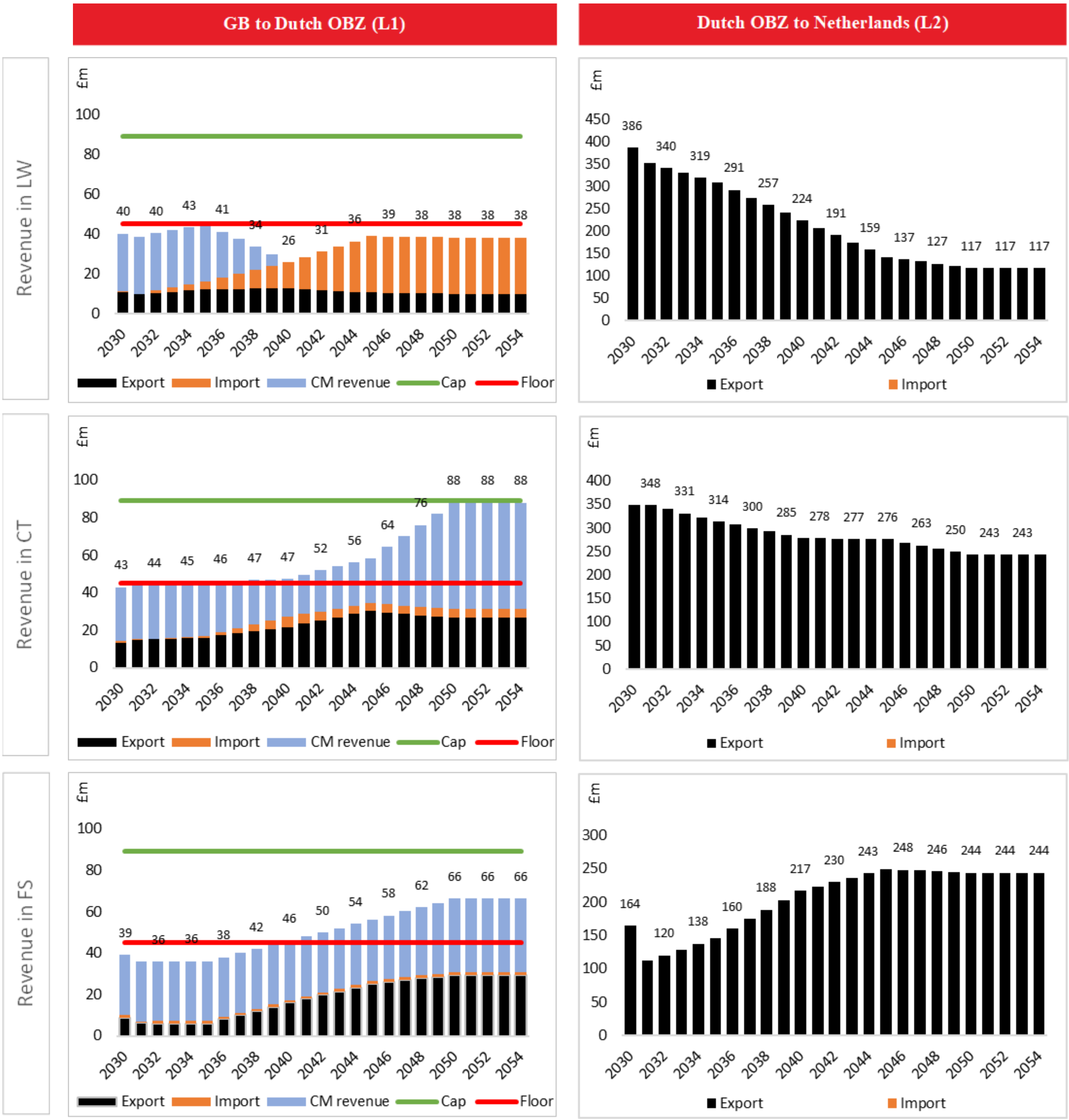


Figure 60 - GB share of revenues earned by LionLink (L1) and L2 (£m, real 2022)

3.3.1.4. Decarbonisation impacts

LionLink leads to a net increase in CO_2 emissions in GB in all scenarios, and a net decrease in the Netherlands and across Europe in all scenarios, as shown in Figure 61 below.

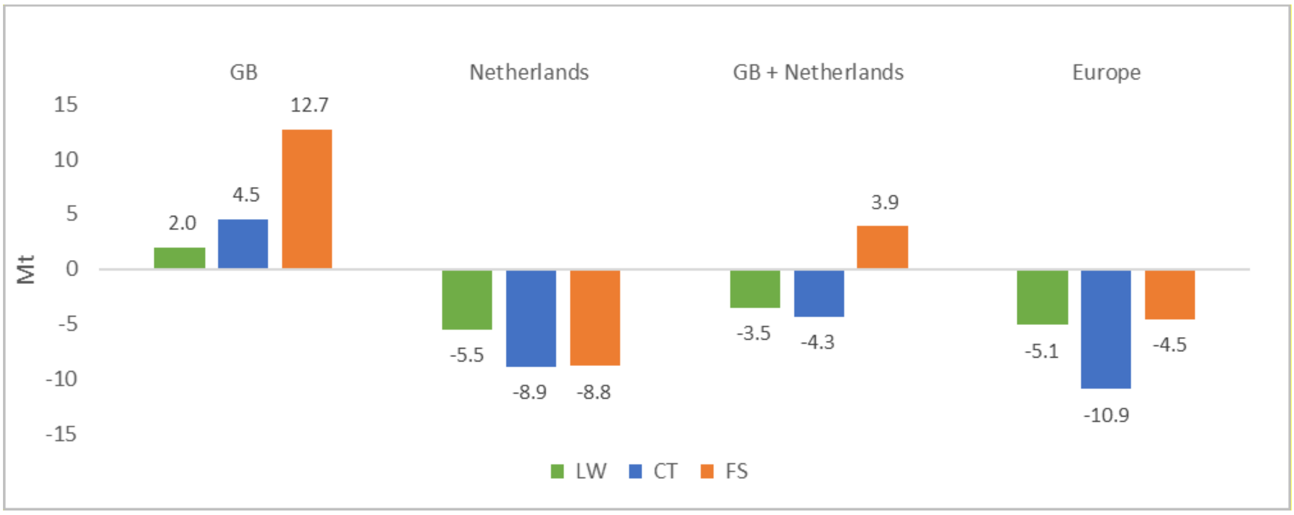


Figure 61 - Changes in CO_2 emissions due to LionLink (Mt)

LionLink is largely used to export electricity from GB to the Netherlands. This leads to an increase in the wholesale market price in GB, which in turn allows for more thermal generation to be dispatched leading to higher emissions compared to the counterfactual. In LW, GB emissions increase despite the high volumes of imports from 2040 onwards, which lead to a decrease in GB prices. This is because the increase in CO2 emissions occurring in the first half of the modelled period is not fully offset by the decrease in the second half, when the capacity mix in GB includes much less thermal generation.

In the Netherlands, LionLink contributes to a reduction the wholesale prices compared to the counterfactual as the project imports cheaper electricity from GB. Considering the shares of thermal generation in the Dutch capacity mix, the change in price leads to substantial emissions savings which almost fully offset the emission increase in GB.

From a European perspective, the project contributes to a faster decarbonisation of the electricity system leading to a reduction in CO_2 emissions in all the scenarios considered.

Decarbonisation indicators

The changes in CO_2 emissions means that GB energy consumers pay electricity at a higher price compared to the counterfactual in all scenarios, as more CO_2 allowances have to be bought under the UK ETS. The higher emissions of CO_2 also leads to higher societal costs for GB compared to the counterfactual. Additionally, LionLink does not lead to the deployment of additional RES capacity in GB.

This is summarised in Table 19 below.

Table 19 - Decarbonisation indicators for LionLink

Indicator	Applies to	Unit	LW	CT	FS
CO_2 reduction (SEW)	GB	£m real 2022 NPV	178.2	384.2	875.4
CO_2 reduction (Societal value)	GB	£m real 2022 NPV	498.3	630.3	418.4
RES integration (additional RES capacity)	GB	MW	0	0	0
Overall decarbonisation	Europe	Mt	-5.1	-10.9	-4.5

3.3.1.5. Security of Supply impacts

As already mentioned, only in LW from 2040, energy supply in GB fails to meet demand in periods of system stress, leading to significantly high wholesale prices to cover costs associated with the amount of USE hours observed. The introduction of LionLink helps reducing the number of USE hours in GB compared to the counterfactual, as shown in Figure 62.

Consequently, the project leads to a reduction in costs of EENS for a total of £223.6m compared to the counterfactual.

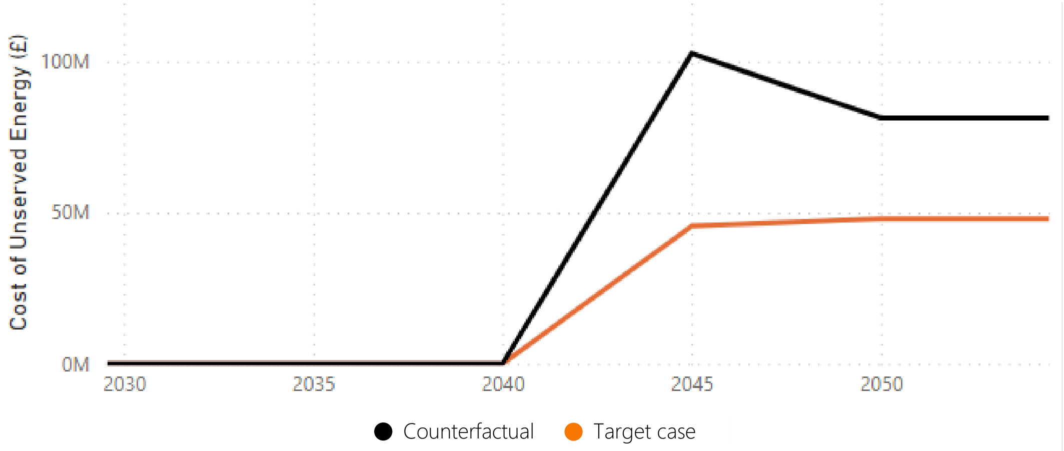


Figure 62 – Cost of EENS in the counterfactual and target case in LW (£, real 2022)

In CT and FS, no USE hours are observed before and after the introduction of the project, meaning that LionLink does not have positive nor negative impacts on SoS in GB.

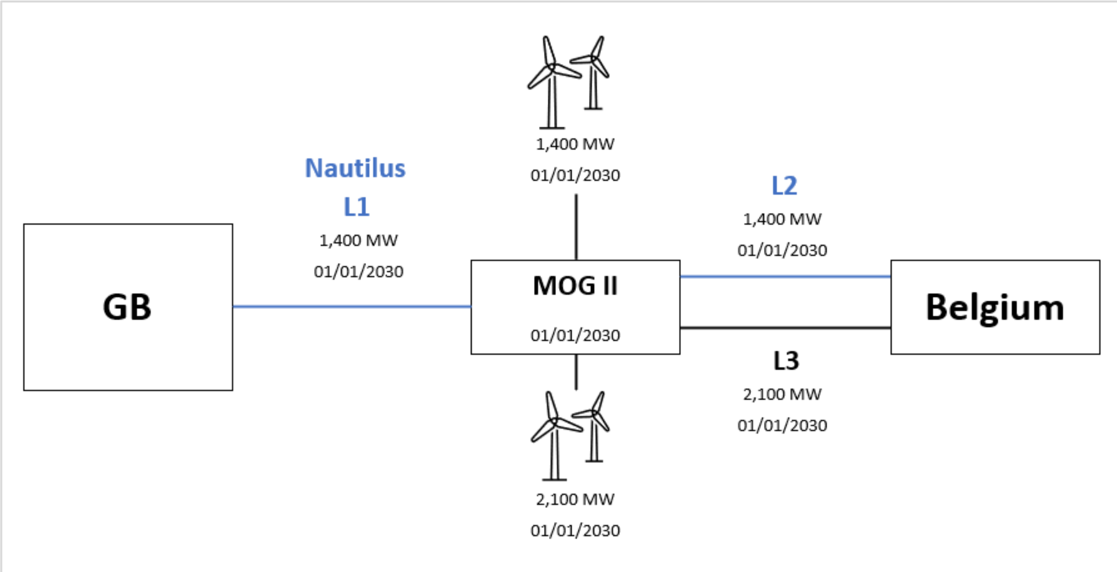
3.3.2. Nautilus

3.3.2.1. Overview and SEW impacts

The Nautilus project has been modelled as a 1.4 GW IC between GB and the Belgian energy island MOG II (L1), currently under development in the Belgian national waters. MOG II is assumed to be operated as an OBZ connected to two OWF of 1.4 GW and 2.1 GW generation capacity. MOG II is then assumed to be connected to Belgium via two transmission lines of 1.4 GW and 2.1 GW. As indicated by the developer in the IPA submission, Arup assumed that MOG II will be configured on a single node basis and that therefore the 2.1GW capacity of L3 will also be available for transmission of power from the energy island, whether that power comes from the two connected windfarms or Nautilus (L1).

This configuration was based on the information provided by the developer in the IPA submission. The configuration of MOG II was also crosschecked with the project sheet from the TYNDP 2022.[37] The assumed configuration is shown below in Drawing 8.

[37] For more information, please visit: https://tyndp2022-project-platform.azurewebsites.net/projectsheets/transmission/120



Drawing 8 - Assumed configurations for the Nautilus project

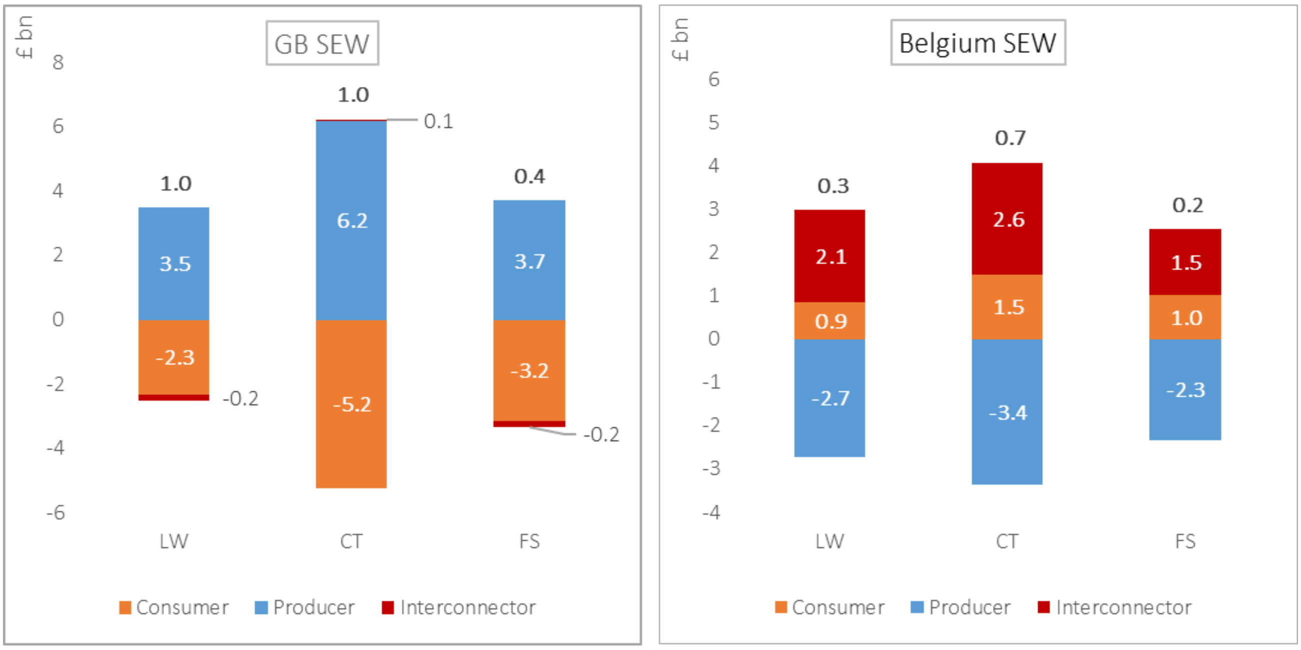


Figure 63 – SEW impacts of Nautilus in GB and Belgium (£bn, real 2022, NPV)

The key conclusions from our analysis are:

- **The total SEW impacts in GB are positive in all scenarios,** driven by a strong increase in producer SEW which offset a decrease in consumer SEW losses.
- **In GB, Nautilus decreases consumers SEW in all scenarios** compared to the counterfactual. The project is primarily used to export cheaper electricity from GB to Belgium. This leads to an increase in wholesale prices in GB, reducing consumers SEW.
- **IC welfare in GB is marginally negative in LW and FS, and marginally positive in CT**. In the first two scenarios, Nautilus does not earn enough revenue to offset the project costs and cannibalisation impacts on existing projects.

- **In Belgium the project leads to positive total SEW impacts in all scenarios.** Nautilus is used primarily to import cheaper electricity from GB, leading to significant producers SEW losses. These are, however, fully offset by the gains in consumers and IC SEW, the latter being driven also by the revenue earned on L2.

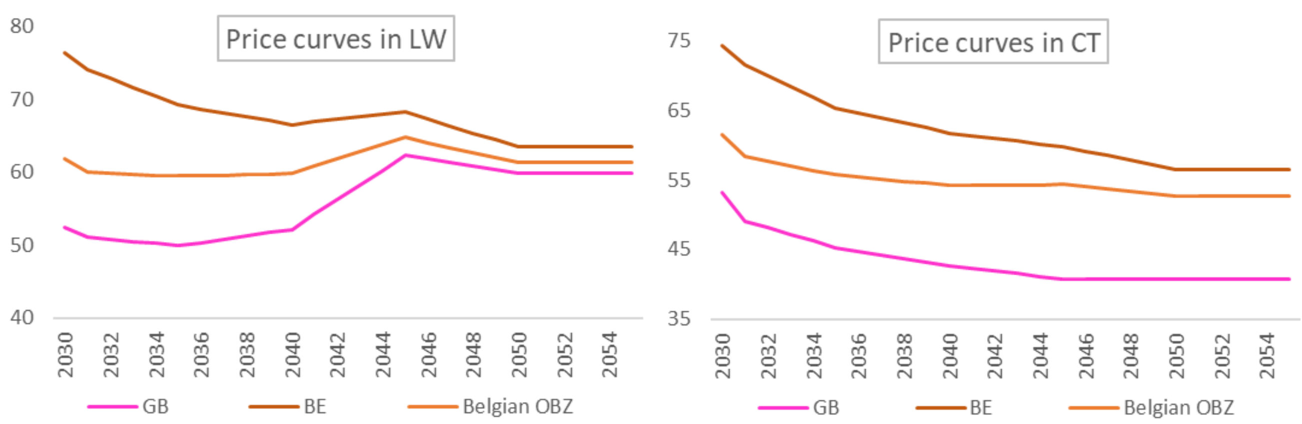
3.3.2.2. Economic fundamentals and flows

The key economic and commercial driver for the project is the difference in market prices between GB, Belgium, and the Belgian OBZ. Figure 64 below shows the annual average wholesale prices under LW, CT and FS.

In the Belgian power market nuclear generation capacity is phased out from the system by 2029 in the ST European FES scenario and by 2035 in the CT European FES scenario. Belgium has a high share of renewable generation capacity from the onset of the study horizon at 65% (EU ST) and 70% (EU CT) of the total generation capacity. Solar and wind are the predominant generation technologies within renewable generation capacity. The share of renewable generation capacity increases to 76% and 77% in the EU ST and EU CT scenarios respectively. Conventional gas/biomass-fired generation capacity typically sets the price at the beginning of the study horizon. Towards the end of the modelled period, the price is set more frequently by gas CCS and lower SRMC.

In all scenarios, the GB prices are lower than those in Belgium and the Belgian OBZ. GB presents high shares of RES generation, which results in lower wholesale prices on average compared to its neighbours. In LW, it can be noted that GB prices increase from 2040 onwards, peaking at £62/MWh in 2045. This is due to a combination of factors such as CCUS CCGTs increasingly setting the market price in a context of growing intermittent generation combined with the highest CO_2 price of the three scenarios.

The high total transmission capacity between the energy island and Belgium (3.5 GW) leads to relative low levels of congestion on L2. As explained in more detail in 0, this leads the price in the OBZ to track that of the neighbouring market with the highest price and available transmission capacity, i.e., Belgium, creating relatively high price differentials between GB and the Belgian OBZ. LW and FS present the lowest average price difference at 5.4 £/MWh and 5.8 £/MWh, whilst in CT prices diverge more at 11.5 £/MWh on average.



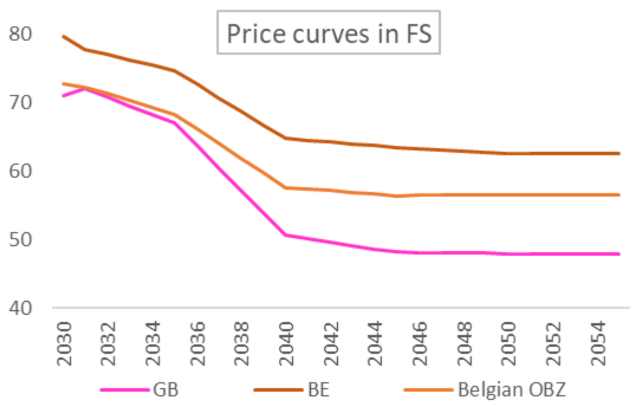


Figure 64 - Price differentials between GB, Belgium and the Belgian OBZ (£/MWh)

The price differentials described above largely determine the direction of the electricity flows across Nautilus (L1) and L2, i.e., from GB to Belgium. These are shown in Figure 65 below.

In all scenarios, Nautilus (L1) is primarily used to export from GB towards the OBZ and Belgium, which has the highest prices. Similarly, L2 is primarily used to dispatch electricity generates by the OWF within the OBZ towards Belgium whilst imports are limited.

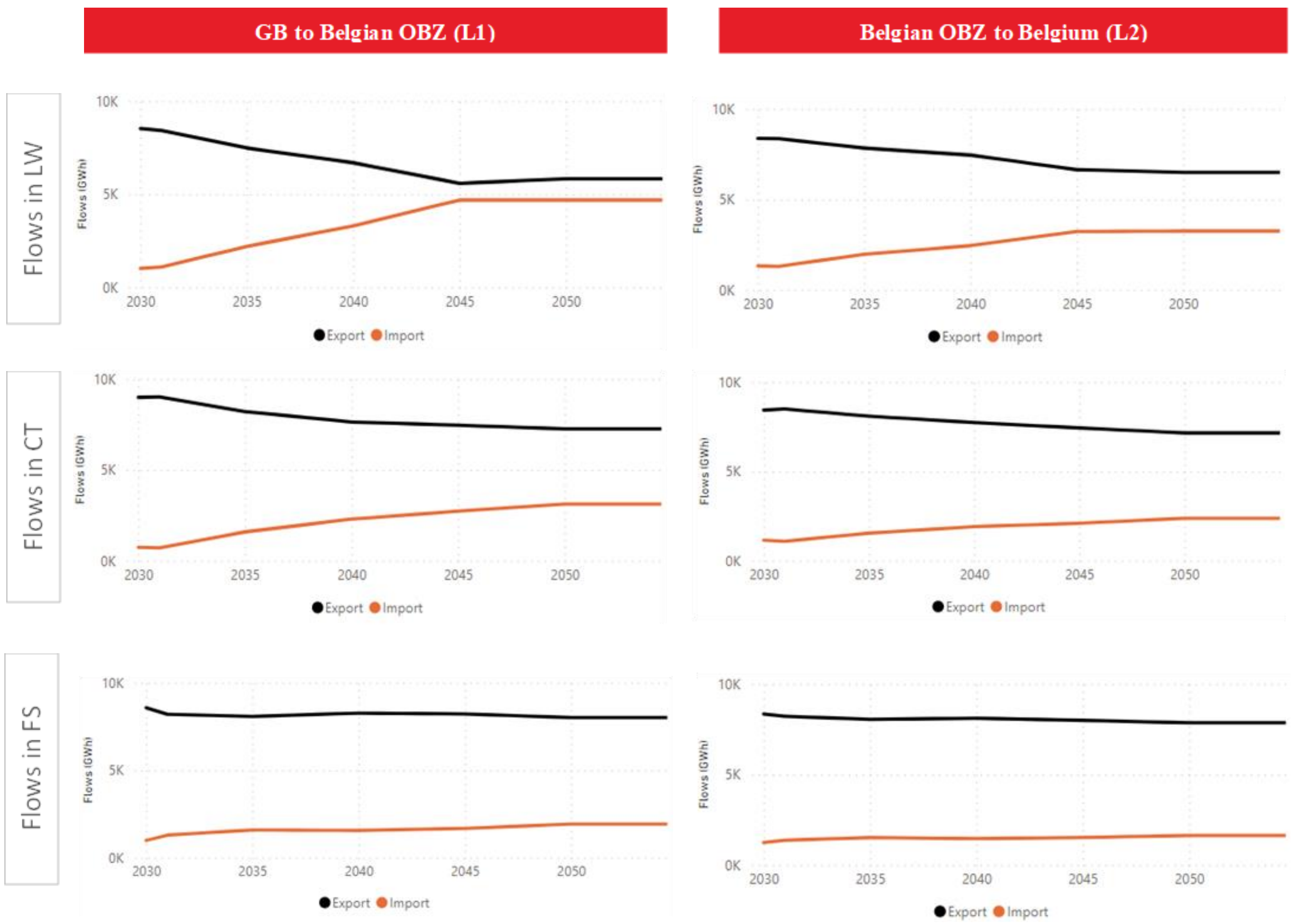


Figure 65 - Electricity flows across Nautilus and L2 (black line: exports, orange line: imports)

Figure 66 shows the GB portion of revenue earned by Nautilus (L1), based on a 50:50 split with the connecting country (left) and the revenues earned over L2 (right).

Considering the high price differentials between GB and the Belgian OBZ, Nautilus (L1) earns most its revenue through exports in all scenarios. Similarly, L2 earns all its revenue exporting electricity from the OBZ to Belgium. These decrease gradually in LW and CT as the price differnetials with Belgium reduce in the longer term. Under all scenarios, the project is unlikely to require floor payments and instead is likely to provide cap payments to GB consumers.

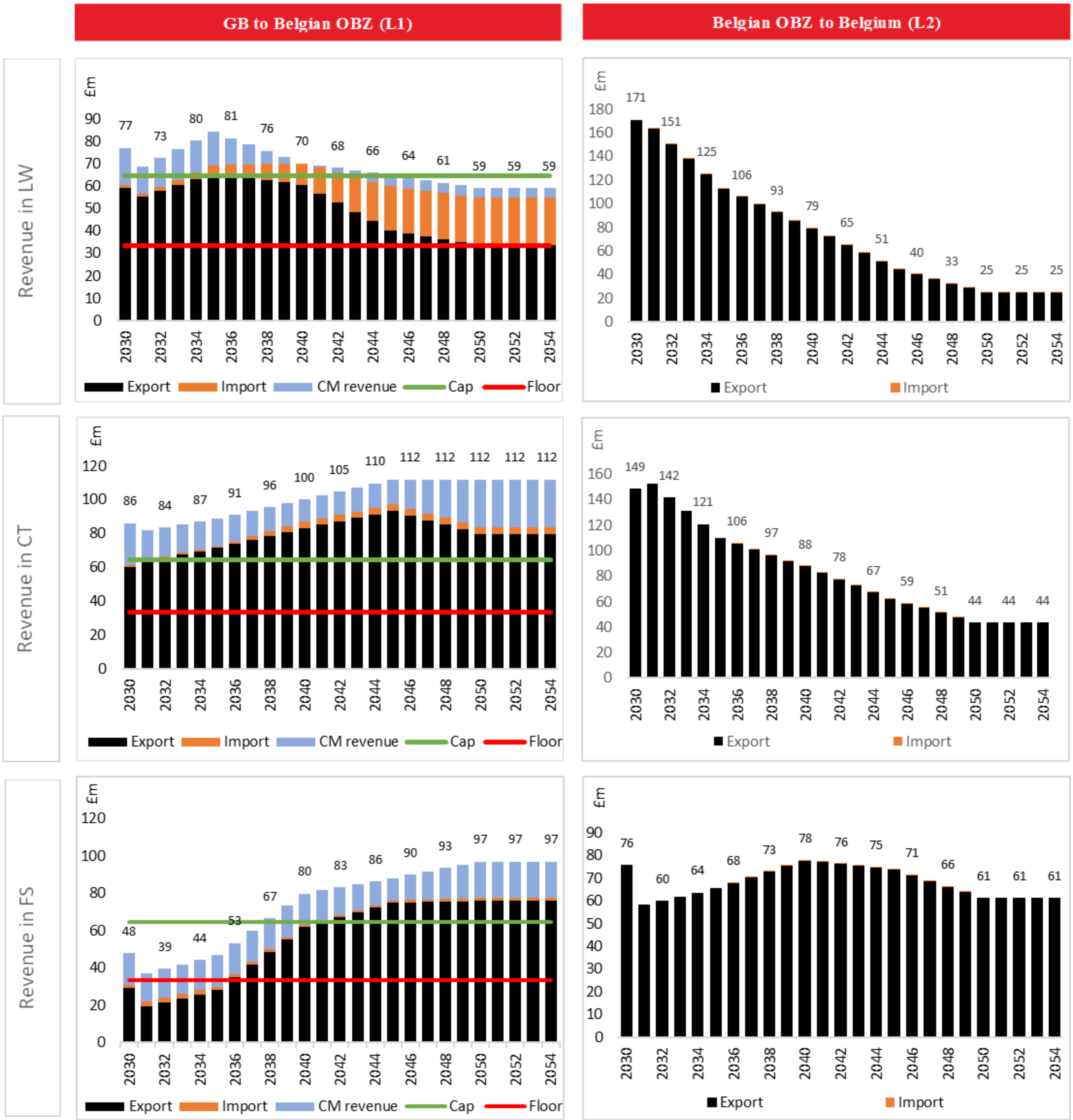


Figure 66 - Revenue earned by Nautilus (L1) and L2 (£m, real 2022)

3.3.2.3. Decarbonisation impacts

Nautilus leads to a net increase in CO_2 emissions in GB and a net decrease in Belgium and across Europe in all scenarios, as shown in Figure 67 below.

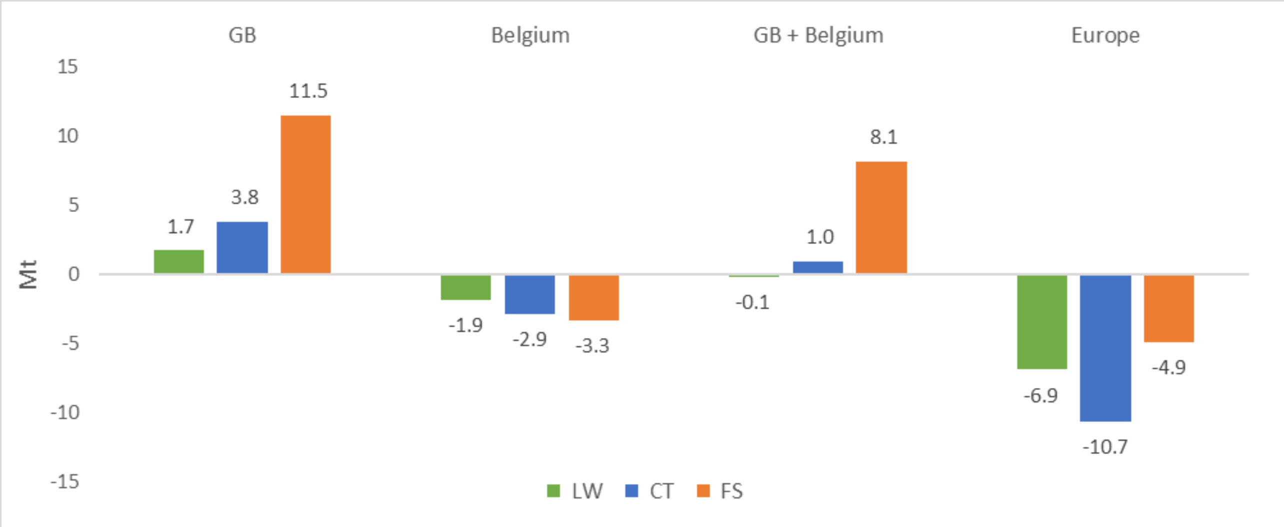


Figure 67 - Changes in CO_2 emissions due to Nautilus (Mt)

Nautilus is largely used to export electricity from GB to Belgium, leading to an increase of the wholesale market price in GB. This in turn allows for more thermal generation to be dispatched compared to the counterfactual. The opposite applies to Belgium. As Nautilus contributes to a marginal reduction the wholesale prices compared to the counterfactual, the project imports cheaper electricity from GB.

The emission reductions in Belgium do not fully offset the increase of CO_2 in GB, leading to a net increase in emissions between the two countries. However, from a European perspective, Nautilus contributes to a faster decarbonisation of the electricity system compared to the counterfactual.

Decarbonisation indicators

The changes in CO_2 emissions mean that GB energy consumers pay electricity at a higher price compared to the counterfactual in all scenarios, as more CO_2 allowances have to be bought under the UK ETS. The higher level of CO_2 also leads to higher societal costs for GB compared to the counterfactual. Additionally, Nautilus does not lead to the deployment of additional RES capacity in GB. This is summarised in Table 20 below.

Table 20 - Decarbonisation indicators for Nautilus

Indicator	Applies to	Unit	LW	CT	FS
CO_2 reduction (SEW)	GB	£m real 2022 NPV	156.2	324.7	791.7
CO_2 reduction (Societal value)	GB	£m real 2022 NPV	436.5	533.8	376.9
RES integration (additional RES capacity)	GB	MW	0	0	0

Indicator	Applies to	Unit	LW	CT	FS
Overall decarbonisation	Europe	Mt	-6.9	-10.7	-4.9

3.3.2.4. Security of Supply impacts

As already mentioned, only in LW from 2040, energy supply in GB fails to meet demand in periods of system stress, leading to significantly high wholesale prices to cover costs associated with the amount of USE hours observed. The introduction of Nautilus helps reducing the number of USE hours in GB in both runs compared to the counterfactual, as shown in Figure 68 below.

Consequently, the project leads to a reduction in costs of EENS for a total of £233.7m in the base run.

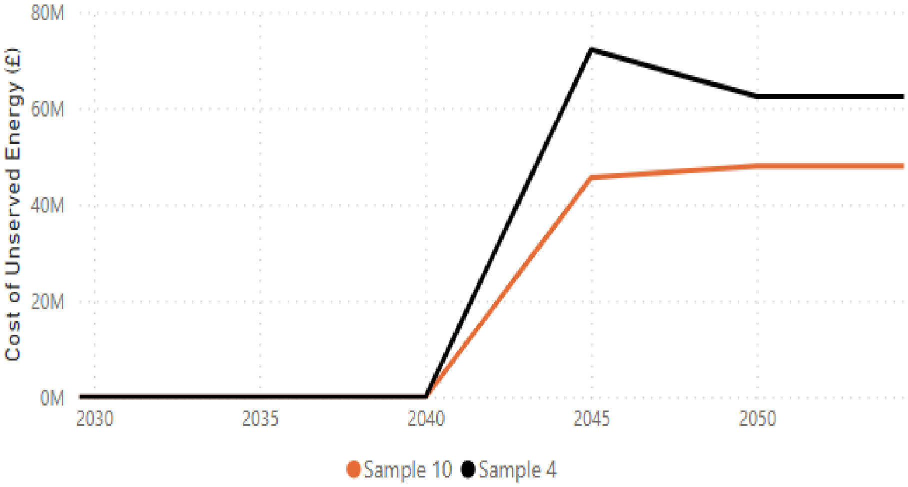


Figure 68 – Cost of EENS in the counterfactual and target case in LW (£, real 2022)

In CT and FS, no USE hours are observed before and after the introduction of the project, meaning that Nautilus does not have positive nor negative impacts on SoS in GB.

4. Summary of results and final conclusions

This section summarises the analysis and considers the performance of the nine candidate projects under the following indicators:

- GB total SEW impacts, or the sum of consumer, producer and IC SEW in GB;
- GB consumers SEW impacts;
- Decarbonisation impacts in GB and Europe; and
- SoS impacts.

As explained in the precious chapter, we present the results for the MA runs.

4.1. GB total SEW impacts

4.1.1. W3 interconnector projects

Figure 69 summarises the impacts on total SEW in GB associated with each new W3 IC project. Total SEW is composed of GB consumer, GB producer and GB IC welfare. The results of the analysis show that:

- **The majority of projects lead to an increase in total SEW in GB in all scenarios compared to the counterfactual.** Due to sustained GB exports and a subsequent increase in GB prices, producer earn more compared to the counterfactual. This increase in producer SEW offset the decrease in consumers SEW.
- **LirIC and MaresConnect leads to negative or marginally negative total SEW in GB.** For each project, the consumers SEW losses are not fully offset by producer and IC SEW gains. Additionally, due to their capacity, these two projects do not fully exploit the high price differentials between GB and the I-SEM. The revenue earned is not enough to offset the cannibalisation impacts on other projects, leading to negative IC SEW. This further reduces total SEW.

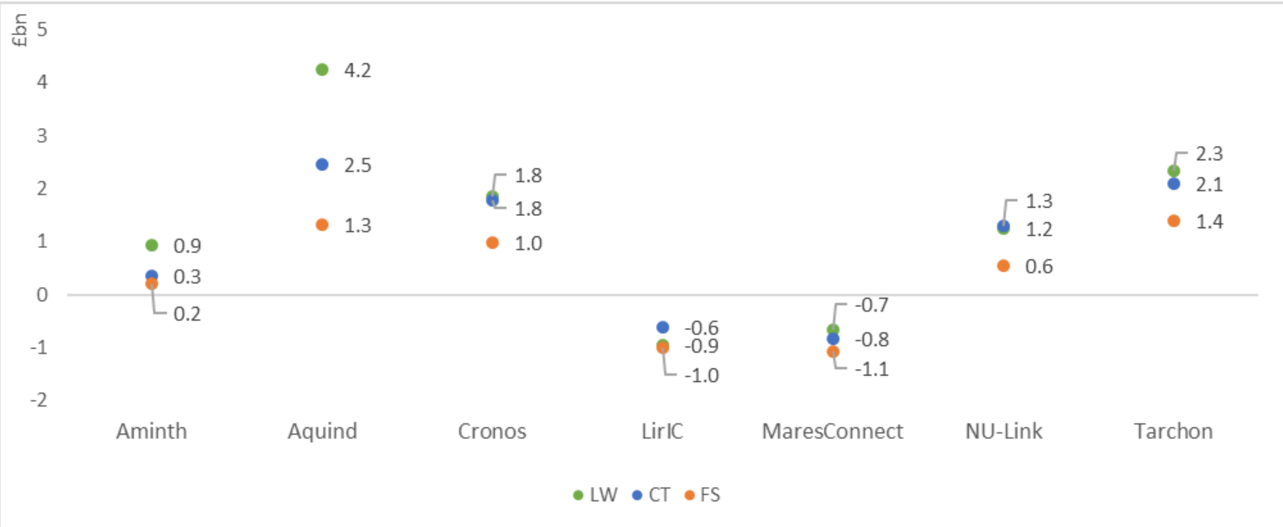


Figure 69 - Change in total SEW in GB after the introduction of a new W3 IC project (NPV, real 2022, £bn)

4.1.2. OHA projects

Figure 70 summarises the impact on total SEW in GB associated with each new OHA project. Total SEW is composed of GB consumer, GB producer and GB IC welfare. The results of the analysis show that:

- **Nautilus leads to an increase in total SEW in GB in all scenarios**, as the decrease in consumers SEW is offset by a significant increase in producers SEW. IC SEW is positive in CT but negative in LW and FS, where the project does not earn enough revenue to offset its costs and revenue losses from existing projects.
- **LionLink generates an increase in total SEW in GB in LW, but only a marginal impact in CT and FS.** In LW, total SEW is driven by strong consumers SEW gains. In the other two scenarios, the consumers SEW losses are offset almost fully by SEW gains. However, because of the narrow price differentials between GB and the Dutch OBZ, the limited revenue earned by the project leads to low IC SEW.

Figure 70 - Change in total SEW in GB after the introduction of a new OHA project (NPV, real 2022, £bn)

4.2. GB consumers SEW impacts

4.2.1. W3 interconnector projects

Figure 71 below summarises the impacts on consumers SEW in GB associated with each new W3 IC project. The analysis shows that:

- **Most of the W3 IC projects assessed lead to a decrease in consumers SEW compared to the counterfactual in almost all scenarios.** This is because the majority of them primarily export electricity from GB to the relevant connecting country, applying upward pressure to GB prices. Consequently, GB consumers pay more for their electricity.
- **From a consumer perspective, CT represents the worst-case scenarios in terms of additional cross-border capacity.** In this scenario, GB prices are consistently lower than those of its neighbouring countries due very high RES generation capacity installed. This in turn favours high and continuous GB exports, putting upwards pressure on GB prices.
- **Aminth and Aquind lead to higher consumers SEW in LW compared to the counterfactual**. These are the two W3 IC projects that import the most electricity in LW compared to other scenarios. Considering the number of USE hours observed in GB in the counterfactual, Aminth and Aquind contribute significantly to reducing USE costs once introduced.

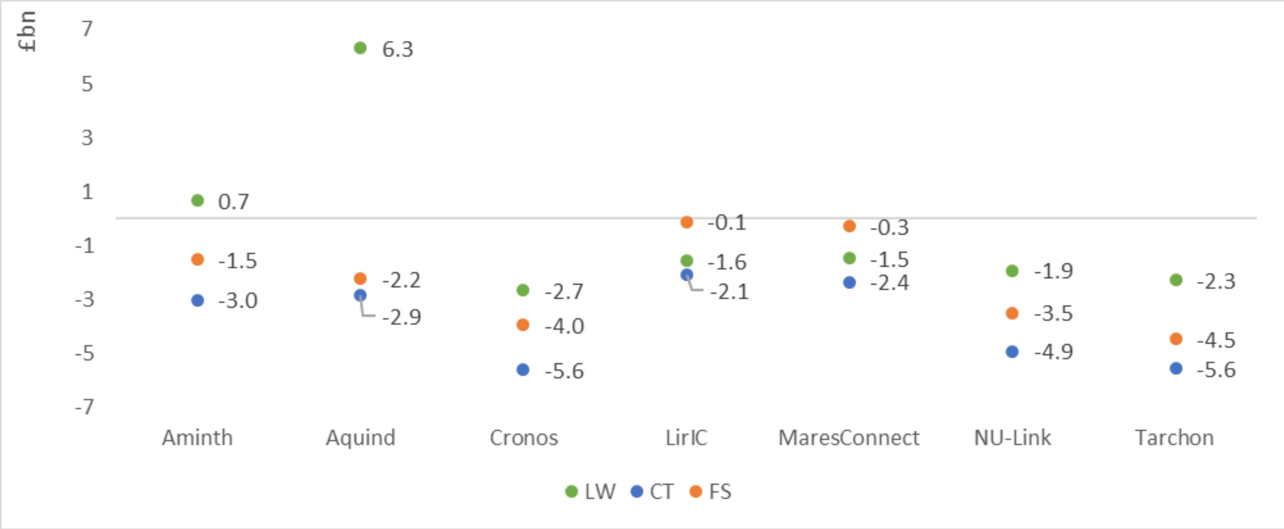


Figure 71 - Change in consumers SEW after the introduction of a new W3 IC project (NPV, real 2022, £bn)

4.2.2. OHA projects

Figure 72 below summarises the impacts on consumers SEW in GB associated with each new OHA project. The analysis shows that:

- **Both OHAs lead to a decrease in consumers SEW compared to the counterfactual in most cases**, as both projects are primarily used to export electricity from GB towards their respective connecting country. This in turn increases GB wholesale prices, to the detriment of consumers. LionLink leads to a decrease in GB prices in LW.
- **Nautilus leads to negative consumer SEW impacts in all scenarios**, as the project is used primarily to export electricity.
- **LionLink is positive for GB consumers only in LW**, as the project contributes significantly to the reduction of USE hours in GB and its associated costs.
- **CT outcomes are the worst case from a consumer perspective**, as in this scenario, GB presents consistently lower prices than its neighbouring countries. This leads to sustained exports from GB and a consequent increase of the wholesale price in GB compared to the counterfactual.

Figure 72 - Change in consumers SEW after the introduction of a new OHA project (NPV, real 2022, £bn)

4.3. Decarbonisation impacts

4.3.1. W3 interconnector projects

Figure 73 shows the change in CO_2 emissions (Mt) in Europe when a new W3 IC project is introduced compared to the counterfactual. The analysis shows that each new project contributes significantly to the decarbonisation of the energy markets across Europe.

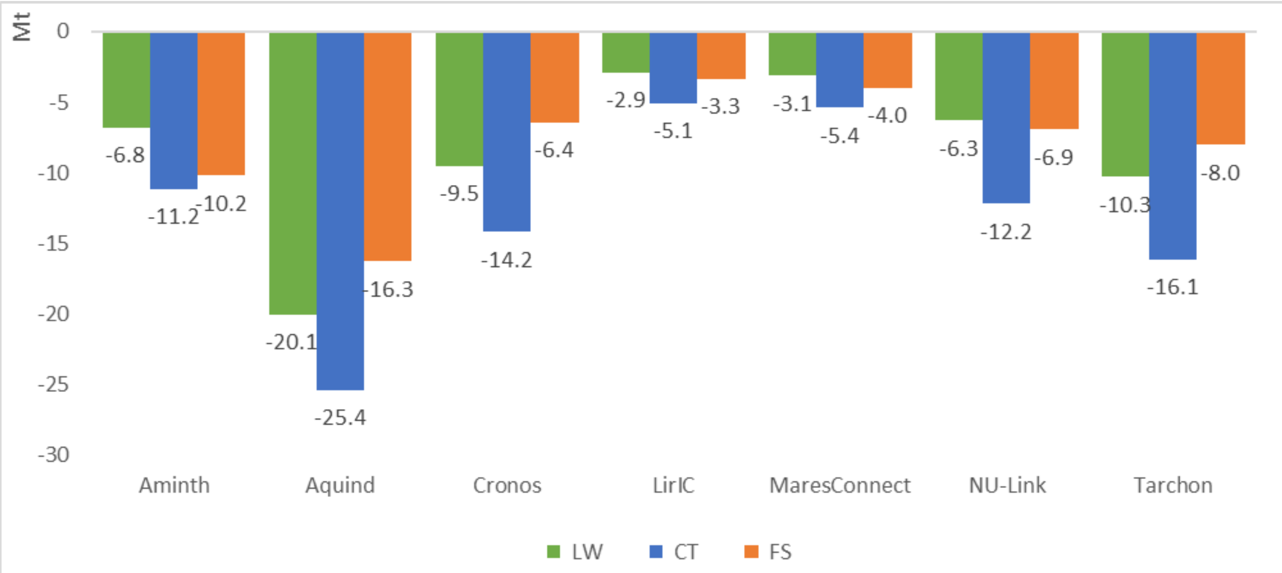


Figure 73 - Change in CO2 emissions in Europe after the introduction of the assessed IC projects (Mt)

Figure 74 below summarises the change in CO_2 emissions (Mt) in GB when a new W3 IC project is introduced compared to the counterfactual. The analysis shows that:

- **Most of the W3 IC projects assessed lead to an increase in CO_2 emissions in GB in all scenarios, compared to the counterfactual**. On average, these projects are used primarily to export electricity from GB to the relevant connecting country, increasing GB wholesale prices compared to the counterfactual. This leads to more thermal generation being dispatched and to higher emissions.

- **Aquind leads to a reduction in CO_2 emissions in GB in all scenarios compared to the counterfactual.** This happens even though on average this project increases GB wholesale prices. In fact, during periods of GB peak demand and high prices, Aquind is used to import cheaper electricity from France that displaces peaking gas plants in GB.
- **LirIC and MaresConnect** have minor changes (either upwards or downwards) to the GB wholesale price due to their smaller capacity. Therefore, the change in CO_2 emission after they are introduced is marginal.
- **All projects significantly contribute to the overall decarbonisation of the European energy system.**

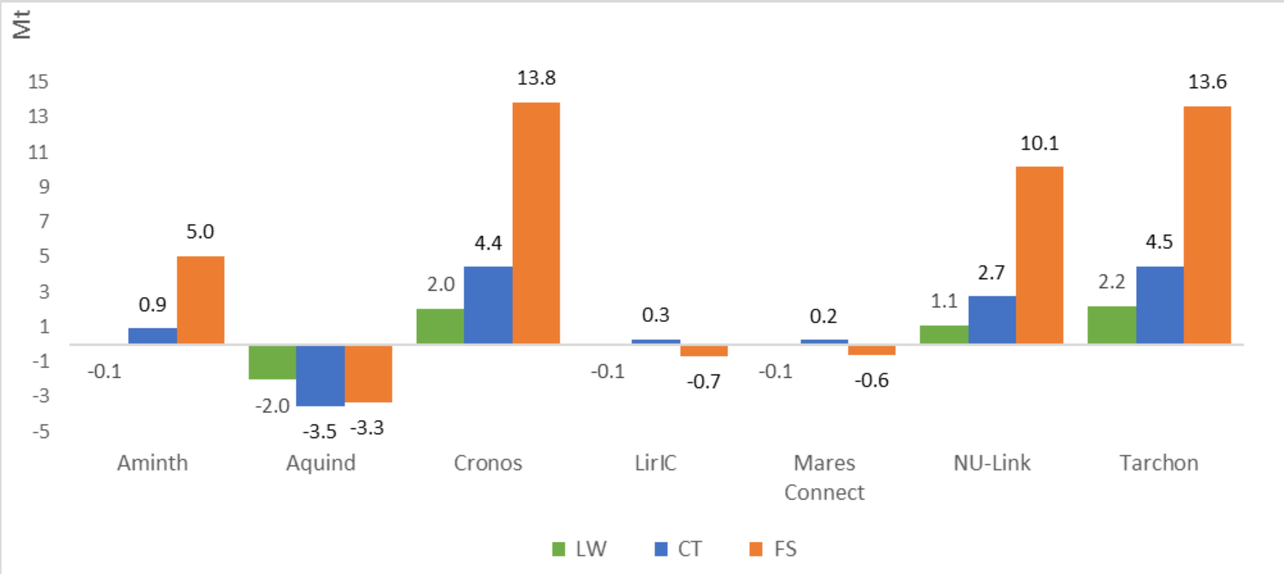


Figure 74 - Change in CO2 emissions in GB after the introduction of the assessed IC projects (Mt)

Decarbonisation indicators

Under the Ofgem MCA framework, the change in CO_2 emissions associated with each IC project has been monetised using the market value of carbon and the societal value of carbon to describe the range of monetary impacts of these changes in GB. These are summarised in Table 21 below.

As a reminder, the impacts described by the indicator 'CO_2 reduction (SEW)' are already factored in in the results of the SEW indicators for consumers, producers, and ICs. The impacts described by the indicator 'CO_2 reduction (Societal value)' are additional to those already captured.

Table 21 - Summary of the monetary impacts associated with the CO2 emission change caused by each IC project in GB (£bn, real 2022), and change in CO2 emission in Europe (Mt)

Project	Scenario	CO_2 reduction (SEW) £bn, real 2022	CO_2 reduction (Societal value) £bn, real 2022	Overall decarbonisation (Europe) Mt
Aminth	LW	-0.01	-0.02	-6.81
Aminth	CT	0.07	0.11	-11.17
Aminth	FS	0.32	0.16	-10.22

Project	Scenario	CO_2 reduction (SEW) £bn, real 2022	CO_2 reduction (Societal value) £bn, real 2022	Overall decarbonisation (Europe) Mt
Aquind	LW	-0.18	-0.56	-20.06
Aquind	CT	-0.3	-0.51	-25.40
Aquind	FS	-0.27	-0.12	-16.28
Cronos	LW	0.18	0.53	-9.50
Cronos	CT	0.38	0.63	-14.19
Cronos	FS	0.99	0.46	-6.42
LirIC	LW	-0.01	-0.03	-2.88
LirIC	CT	0.02	0.03	-5.06
LirIC	FS	-0.07	-0.03	-3.34
Mares Connect	LW	-0.01	-0.02	-3.13
Mares Connect	CT	0.02	0.02	-5.39
Mares Connect	FS	-0.07	-0.02	-3.99
NU-Link	LW	0.10	0.27	-6.28
NU-Link	CT	0.23	0.37	-12.18
NU-Link	FS	0.68	0.33	-6.94
Tarchon	LW	0.19	0.06	-10.29
Tarchon	CT	0.38	0.63	-16.13
Tarchon	FS	0.96	0.45	-8.02

4.3.2. OHA projects

Figure 75 shows the change in CO_2 emissions (Mt) in Europe when a new OHA pilot project is introduced compared to the counterfactual. The analysis shows that each new project contributes significantly to the decarbonisation of the energy markets across Europe.

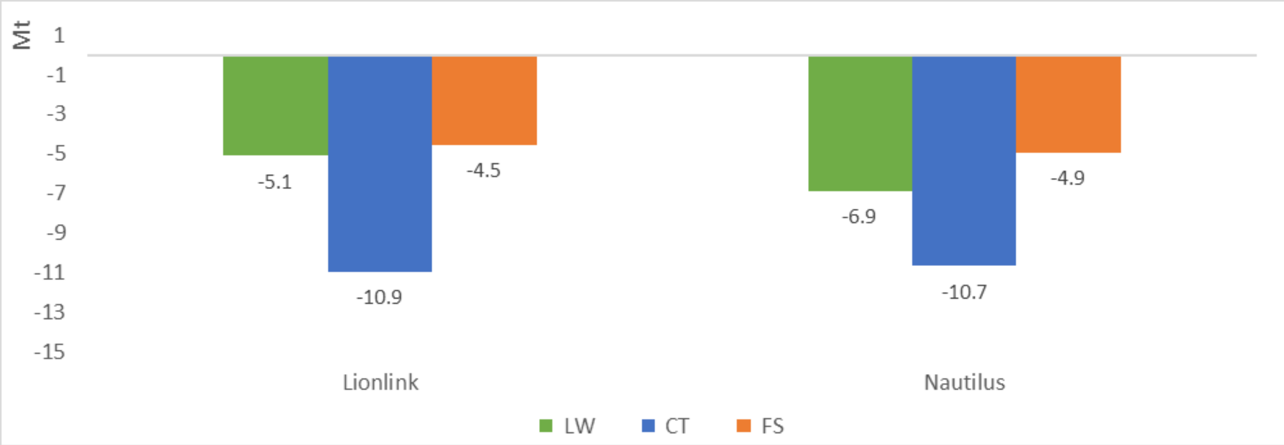


Figure 75 - Change in CO2 emissions in Europe after the introduction of the assessed OHA projects (Mt)

Figure 76 below summarises the change in CO_2 emissions (Mt) in GB when a new OHA is introduced compared to the counterfactual. The analysis shows that:

- **Both OHAs lead to an increase in CO_2 emissions in GB in all scenarios**. On average, these projects are used primarily to export electricity from GB to the relevant connecting country, increasing GB wholesale prices compared to the counterfactual. This leads to more thermal generation being dispatched and to higher emissions.
- **Both OHAs significantly contribute to the overall decarbonisation of the European energy system.**
- **None of the projects directly contribute to the deployment of additional RES generation capacity in GB.**

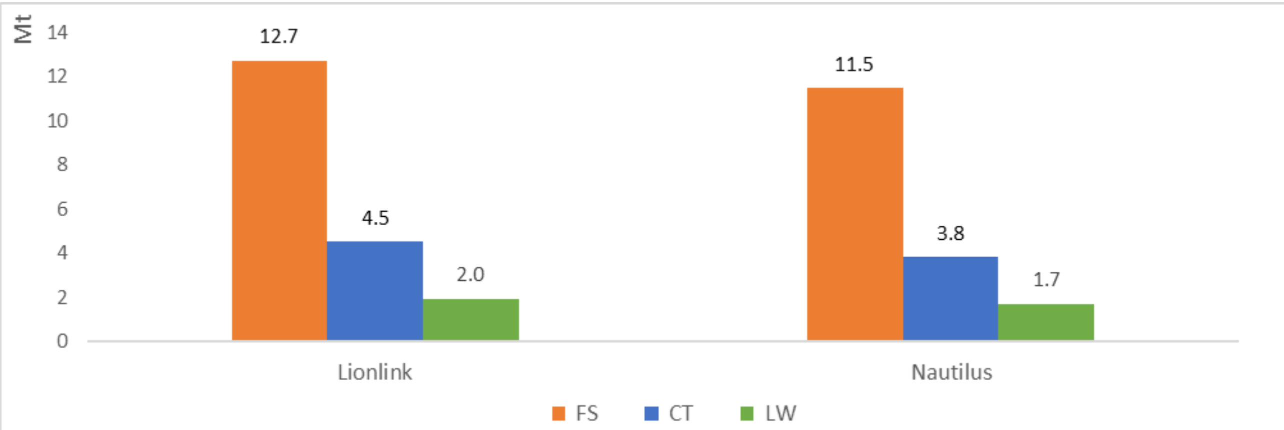


Figure 76 - Change in CO_2 emissions in GB after the introduction of the assessed OHA projects (Mt)

Decarbonisation indicators

Under the Ofgem MCA framework, the change in CO_2 emissions associated with each OHA project has been monetised to describe the monetary impact of these change in GB. These are summarised in Table 22 below.

As a reminder, the impacts described by the indicator 'CO_2 reduction (SEW)' are already factored in the results of the SEW indicators for consumers, producers, and ICs. The impacts described by the indicator 'CO_2 reduction (Societal value)' are additional to those already captured.

Table 22 - Summary of the monetary impacts associated with the CO2 emission change caused by each OHA project in GB (£bn, real 2022), and change in CO2 emission in Europe (Mt)

Project	Scenario	CO_2 reduction (SEW) £bn, real 2022	CO_2 reduction (Societal value) £bn, real 2022	RES integration (additional RES capacity) MW	Overall decarbonisation (Europe) Mt
LionLink	LW	0.18	0.50	0	- 5.10
LionLink	CT	0.38	0.63	0	- 10.94
LionLink	FS	0.88	0.42	0	- 4.55
Nautilus	LW	0.16	0.44	0	- 6.89
Nautilus	CT	0.32	0.53	0	- 10.65
Nautilus	FS	0.79	0.38	0	- 4.92

4.4. SoS impacts

4.4.1. W3 interconnector projects

Table 23 below summarises the impacts that each W3 IC project has in terms of SoS. The analysis shows that:

- **Each project helps reducing costs associated with unserved energy in GB.** This occurs exclusively in LW, as the high levels of RES capacity led to some period of USE hours in the counterfactual runs. Once a new project is introduced, it helps reducing the amount of USE hours and associated costs.
- **The impact that each project has depends on its size, the capacity mix of the country it connects to, and the initial price differentials between GB and the relevant countries.** Bigger projects connecting to countries with significantly different capacity mixes lead to higher cost reductions.

Table 23 - Change in cost of unserved energy in GB following the introduction of a new IC project (£m, real 2022)

Project	LW	CT	FS
Aminth	- 371.5	0	0
Aquind	- 547.9	0	0
Cronos	- 298.2	0	0
LirIC	- 64.7	0	0
MaresConnect	- 69.7	0	0
NU-Link	- 311.6	0	0
Tarchon	- 347.6	0	0

4.4.2. OHA projects

Table 24 below summarises the impacts that each OHA project has in terms of SoS. The analysis shows that:

- **Both OHAs significantly contribute to the reduction of costs associated with unserved energy in GB**. Once again, this occurs only in LW when the GB system presents some USE hours in the counterfactual runs.

Table 24 - Change in cost of unserved energy in GB following the introduction of a new OHA project (£m, real 2022)

Project	LW	CT	FS
LionLink	- 517.9	0	0
Nautilus	- 233.7	0	0

4.5. Conclusions

Considering the results of the analysis conducted, Arup reached the following conclusions:

- **In our analysis, GB decarbonises more rapidly than the other modelled countries, leading to lower wholesale market prices in GB compared to its neighbours**. The impacts associated with each of the projects assessed are primarily determined by this market dynamic.
- **By connecting GB to countries with higher average wholesale prices, all projects generate significant SEW reduction for GB consumers in the vast majority of the assessed scenarios** as they lead to higher electricity prices in GB. Conversely, they often increase producer SEW.
  - CT is the worst-case scenario as GB wholesale prices are consistently the lowest among the relevant countries, due to the high shares of RES generation capacity assumed for GB. This leads to sustained exports throughout the modelled period, increasing GB wholesale prices.
  - In LW and FS, all projects import on average more compared to CT. These imports mitigate the overall increase in GB wholesale prices, and therefore, limit the negative impacts on consumers SEW that most projects have.
  - Only Aminth, Aquind and LionLink deliver consumers SEW gains in LW, as they are projects that import the most, contributing significantly to a reduction in the cost of unserved energy.
- **From a GB perspective, most projects lead to an increase in total SEW.** Only LirIC and MaresConnect deliver negative or marginally negative SEW impacts.
  - Producer SEW gains often fully offset or marginally exceed consumers SEW losses.
  - Projects with higher capacity usually earn more revenue, offsetting almost completely the losses caused on existing projects and avoiding significantly negative IC SEW impacts. They also lead to more cap payments, mitigating consumers SEW losses.
- **In terms of decarbonisation impacts, most projects lead to an increase of CO_2 emissions in GB**. As these projects are primarily used to export electricity from GB, they usually increase its wholesale prices. This allows more thermal generation to be dispatched in GB compared to the counterfactual.
  - Considering the higher volumes of installed thermal generation capacity in FS, this is the scenario where emissions increase the most.
- **Nonetheless, all projects significantly contribute to the decarbonisation of Europe as a whole.** Importing cheap electricity from GB leads to a decrease in the average wholesale prices in the relevant connecting countries. This creates a beneficial ripple effect, whereby downward pressure is then applied to the wholesale electricity prices of their own neighbouring countries, displacing more thermal generation.
- **All projects significantly improve SoS by importing electricity in GB at times of system stress in LW, reducing the number of USE hours in the system**. This translates into substantial cost savings for GB consumers compared to the counterfactual.

Appendix A – W3 interconnector projects results

Aminth

Impact category	Indicator	Unit	FA results			MA results		
			LW	CT	FS	LW	CT	FS
SEW	Consumers SEW	£bn real 2022, NPV	22.44	(2.25)	(2.40)	0.59	(3.14)	(1.67)
SEW	Producers SEW	£bn real 2022, NPV	(16.93)	2.57	2.56	0.22	3.04	1.58
SEW	Interconnectors SEW	£bn real 2022, NPV	(0.34)	0.57	0.58	0.12	0.44	0.29
SEW	Total SEW	£bn real 2022, NPV	5.18	0.88	0.74	0.93	0.34	0.21
Decarbonisation	CO_2 reduction (SEW)	£bn real 2022, NPV	(0.02)	0.04	0.33	(0.01)	0.07	0.32
Decarbonisation	CO_2 reduction (Societal value)	£bn real 2022, NPV	(0.05)	0.07	0.17	(0.02)	0.11	0.16
Decarbonisation	Overall decarbonisation	Mt	(6.90)	(11.80)	(13.10)	(6.81)	(11.17)	(10.22)
Security of Supply	Cost of EENS	£bn real 2022, NPV	(5.04)	(0.11)	-	(0.16)	-	-

Aquind

Impact category	Indicator	Unit	FA results			MA results		
			LW	CT	FS	LW	CT	FS
SEW	Consumers SEW	£bn real 2022, NPV	28.95	(2.12)	(3.73)	6.32	(2.87)	(2.27)
SEW	Producers SEW	£bn real 2022, NPV	(18.70)	5.05	5.93	(1.32)	5.49	3.94
SEW	Interconnectors SEW	£bn real 2022, NPV	(1.54)	(0.19)	(0.27)	(0.76)	(0.17)	(0.36)
SEW	Total SEW	£bn real 2022, NPV	8.71	2.74	1.93	4.24	2.46	1.32
Decarbonisation	CO_2 reduction (SEW)	£bn real 2022, NPV	(0.18)	(0.30)	(0.10)	(0.18)	(0.30)	(0.27)
Decarbonisation	CO_2 reduction (Societal value)	£bn real 2022, NPV	(0.55)	(0.50)	(0.03)	(0.56)	(0.51)	(0.12)
Decarbonisation	Overall decarbonisation	Mt	(20.80)	(29.20)	(18.20)	(20.06)	(25.40)	(16.28)
Security of Supply	Cost of EENS	£bn real 2022, NPV	(5.25)	(0.09)	-	(0.25)	-	-

Cronos

Impact category	Indicator	Unit	FA results			MA results		
			LW	CT	FS	LW	CT	FS
SEW	Consumers SEW	£bn real 2022, NPV	16.37	(5.09)	(5.26)	(2.68)	(5.61)	(4.00)
SEW	Producers SEW	£bn real 2022, NPV	(9.92)	7.24	6.97	4.54	7.20	5.09
SEW	Interconnectors SEW	£bn real 2022, NPV	(0.57)	0.21	0.07	(0.02)	0.18	(0.10)
SEW	Total SEW	£bn real 2022, NPV	5.89	2.37	1.79	1.84	1.77	0.99
Decarbonisation	CO_2 reduction (SEW)	£bn real 2022, NPV	0.24	0.39	1.08	0.19	0.38	0.99
Decarbonisation	CO_2 reduction (Societal value)	£bn real 2022, NPV	0.67	0.64	0.50	0.53	0.63	0.46
Decarbonisation	Overall decarbonisation	Mt	(11.60)	(19.30)	(13.00)	(9.50)	(14.19)	(6.42)
Security of Supply	Cost of EENS	£bn real 2022, NPV	(4.64)	(0.07)	-	(0.13)	-	-

LirIC

Impact category	Indicator	Unit	FA results			MA results		
			LW	CT	FS	LW	CT	FS
SEW	Consumers SEW	£bn real 2022, NPV	(1.04)	(2.52)	(0.77)	(1.68)	(2.15)	(0.30)
SEW	Producers SEW	£bn real 2022, NPV	1.16	2.55	0.63	1.20	1.83	(0.21)
SEW	Interconnectors SEW	£bn real 2022, NPV	(0.51)	(0.48)	(0.27)	(0.47)	(0.31)	(0.49)
SEW	Total SEW	£bn real 2022, NPV	(0.40)	(0.45)	(0.41)	(0.95)	(0.62)	(1.01)
Decarbonisation	CO_2 reduction (SEW)	£bn real 2022, NPV	(0.01)	0.06	0.02	(0.01)	0.02	(0.07)
Decarbonisation	CO_2 reduction (Societal value)	£bn real 2022, NPV	(0.02)	0.09	0.02	(0.03)	0.03	(0.03)
Decarbonisation	Overall decarbonisation	Mt	(9.10)	(8.50)	(4.10)	(2.88)	(5.06)	(3.34)
Security of Supply	Cost of EENS	£bn real 2022, NPV	(1.04)	(0.04)	-	(0.03)	-	-

MaresConnect

Impact category	Indicator	Unit	FA results			MA results		
			LW	CT	FS	LW	CT	FS
SEW	Consumers SEW	£bn real 2022, NPV	(1.35)	(2.46)	(0.77)	(1.57)	(2.40)	(0.48)
SEW	Producers SEW	£bn real 2022, NPV	1.50	2.51	0.64	1.33	1.98	(0.05)
SEW	Interconnectors SEW	£bn real 2022, NPV	(0.53)	(0.48)	(0.31)	(0.42)	(0.41)	(0.55)
SEW	Total SEW	£bn real 2022, NPV	(0.38)	(0.43)	(0.45)	(0.65)	(0.83)	(1.07)
Decarbonisation	CO_2 reduction (SEW)	£bn real 2022, NPV	0.00	0.07	0.02	(0.01)	0.02	(0.07)
Decarbonisation	CO_2 reduction (Societal value)	£bn real 2022, NPV	0.01	0.10	0.02	(0.02)	0.02	(0.02)
Decarbonisation	Overall decarbonisation	Mt	(9.00)	(9.90)	(4.10)	(3.13)	(5.39)	(3.99)
Security of Supply	Cost of EENS	£bn real 2022, NPV	(1.28)	(0.05)	-	(0.03)	-	-

NU-Link

Impact category	Indicator	Unit	FA results			MA results		
			LW	CT	FS	LW	CT	FS
SEW	Consumers SEW	£bn real 2022, NPV	19.50	(4.42)	(4.75)	(1.94)	(4.93)	(3.59)
SEW	Producers SEW	£bn real 2022, NPV	(13.48)	5.73	5.68	3.14	5.86	4.07
SEW	Interconnectors SEW	£bn real 2022, NPV	(0.49)	0.38	0.28	0.04	0.38	0.07
SEW	Total SEW	£bn real 2022, NPV	5.53	1.68	1.20	1.24	1.31	0.55
Decarbonisation	CO_2 reduction (SEW)	£bn real 2022, NPV	0.12	0.22	0.76	0.10	0.23	0.68
Decarbonisation	CO_2 reduction (Societal value)	£bn real 2022, NPV	0.35	0.36	0.37	0.27	0.37	0.33
Decarbonisation	Overall decarbonisation	Mt	(8.50)	(16.00)	(11.50)	(6.28)	(12.18)	(6.94)
Security of Supply	Cost of EENS	£bn real 2022, NPV	(4.41)	(0.09)	-	(0.13)	-	-

Tarchon

Impact category	Indicator	Unit	FA results			MA results		
			LW	CT	FS	LW	CT	FS
SEW	Consumers SEW	£bn real 2022, NPV	13.42	(4.86)	(5.69)	(2.31)	(5.56)	(4.56)
SEW	Producers SEW	£bn real 2022, NPV	(7.65)	6.86	7.12	4.26	7.14	5.64
SEW	Interconnectors SEW	£bn real 2022, NPV	(0.18)	0.55	0.45	0.39	0.51	0.31
SEW	Total SEW	£bn real 2022, NPV	5.58	2.55	1.89	2.34	2.09	1.39
Decarbonisation	CO_2 reduction (SEW)	£bn real 2022, NPV	0.22	0.35	1.04	0.19	0.38	0.96
Decarbonisation	CO_2 reduction (Societal value)	£bn real 2022, NPV	0.62	0.59	0.48	0.06	0.63	0.45
Decarbonisation	Overall decarbonisation	Mt	(12.30)	(20.10)	(14.00)	(10.29)	(16.13)	(8.02)
Security of Supply	Cost of EENS	£bn real 2022, NPV	(4.60)	(0.10)	-	(0.15)	-	-

Appendix B – OHA projects results

LionLink

Impact category	Indicator	Unit	FA results			MA results		
			LW	CT	FS	LW	CT	FS
SEW	Consumers SEW	£bn real 2022, NPV	39.53	(6.01)	(4.75)	3.45	(6.13)	(3.32)
SEW	Producers SEW	£bn real 2022, NPV	(29.79)	6.23	4.83	(1.02)	6.20	3.32
SEW	Interconnectors SEW	£bn real 2022, NPV	(1.55)	0.13	0.02	(0.80)	(0.06)	(0.17)
SEW	Total SEW	£bn real 2022, NPV	8.19	0.36	0.10	1.63	0.01	(0.17)
Decarbonisation	CO_2 reduction (SEW)	£bn real 2022, NPV	0.21	0.36	1.01	0.18	0.38	0.88
Decarbonisation	CO_2 reduction (Societal value)	£bn real 2022, NPV	0.58	0.60	0.48	0.50	0.63	0.42
Decarbonisation	RES integration (additional RES capacity)	MW	0	0	0	0	0	0
Decarbonisation	Overall decarbonisation	Mt	(5.30)	(14.00)	(8.70)	(5.10)	(10.94)	(4.55)
Security of Supply	Cost of EENS	£bn real 2022, NPV	(5.91)	(0.12)	-	(0.22)	-	-

Nautilus

Impact category	Indicator	Unit	FA results			MA results		
			LW	CT	FS	LW	CT	FS
SEW	Consumers SEW	£bn real 2022, NPV	17.97	(4.86)	(4.52)	(2.33)	(5.24)	(3.15)
SEW	Producers SEW	£bn real 2022, NPV	(12.05)	6.15	5.43	3.49	6.17	3.69
SEW	Interconnectors SEW	£bn real 2022, NPV	(0.79)	0.06	0.03	(0.17)	0.06	(0.17)
SEW	Total SEW	£bn real 2022, NPV	5.13	1.35	0.94	0.99	0.99	0.37
Decarbonisation	CO_2 reduction (SEW)	£bn real 2022, NPV	0.21	0.33	0.96	0.16	0.32	0.79
Decarbonisation	CO_2 reduction (Societal value)	£bn real 2022, NPV	0.59	0.54	0.45	0.44	0.53	0.38
Decarbonisation	RES integration (additional RES capacity)	MW	0	0	0	0	0	0
Decarbonisation	Overall decarbonisation	Mt	(8.80)	(15.70)	(10.20)	(6.89)	(10.65)	(4.92)
Security of Supply	Cost of EENS	£bn real 2022, NPV	(4.86)	(0.07)	-	(0.10)	-	-

Appendix C - Key Modelling Decisions

This appendix provides a summary of the key modelling decisions discussed with developers.

Topic	Description	Feedback	Decision	Justification
Presentation of SEW results for the overseas connecting country	Not initially treated	Stakeholders asked how the SEW impacts of a project for the overseas connecting country will be presented	The report will include GB impacts and total SEW impacts	Total SEW impacts will include SEW impacts in GB and the overseas connecting country only. **CHANGE:** Total SEW impacts are defined as the sum of consumer SEW, producer SEW and IC SEW in a given country. The total SEW in GB and in the relevant connecting countries are presented separately in this report.
Revenue streams considered in the CBA	Not initially treated	Two stakeholders asked to clarify which revenue streams will be considered for ICs Where results are presented, stakeholders asked for us to specify what elements are IC revenues (e.g., Ancillary Services (AS) services and Capacity Market (CM)) which can then be used to compare against the forecast C&F levels. A few stakeholders asked for the (CM) de-rating factors assumed for generators and interconnectors to be published.	The IC revenue streams considered will be congestion revenues, CM and AS revenues. The latter two will be calculated outside PLEXOS. These revenue streams will be included in the Interconnector SEW indicator.	CM revenue will rely on CM clearing price forecasts and de-rating factors. **CM De-rating factors**: We are using the de-rating factors provided by developers. **CM Clearing price**: Similarly, to the approach taken in C&F W2, we will assume that new interconnectors will not impact the clearing price. The interconnector displaces higher bids in the auction. It will be assumed that generation capacity will bid up so that the existing clearing price is the same as it would have been without the interconnector. The clearing prices will be derived using new and existing analysis on capacity auction outcomes. This will be based on meeting reliability standards and a missing money approach based on existing and new generators' technical characteristics and costs against the wholesale market prices calculated in each of our scenarios. **AS revenue stream**: NGESO will be calculating the revenue earned by a new project participating in the AS market. This revenue stream is expected to be

Topic	Description	Feedback	Decision	Justification
				very similar across all ICs as they belong to the same technology type and present the same characteristics and capabilities. In addition, we do not expect AS revenues to be material to the analysis. These revenues streams will be presented individually in the final market report to ensure transparency. As a reminder, the wider impacts on system operability and flexibility and the associated benefits on society are captured separately under the System Operability and Flexibility impact categories of the CBA framework. **CHANGE:** Considering the limited impacts that AS revenue would have had on final results, this revenue stream has not been calculated.
Project Cost	Project costs submitted by developers will be quality assured and then utilised to inform the 'Project Costs' indicator	Stakeholders asked to be notified if their cost submission is superseded by Ofgem benchmarking exercise in order to provide feedback	Developers will be informed	Ofgem will run a high-level cost assessment. Arup will be using the figures Ofgem provides. Ofgem will communicate any change to developers.
CO2 reduction (Societal value)	Monetary value to be used to calculate this indicator	Stakeholders asked which value will be used to calculate this indicator. One stakeholder asked whether the GB or EU societal values for CO2 will be used when assessing the CO2 reduction impacts in the connecting country	HMT Green Book Central Scenario for both GB and connected country	We intend to use the same GB societal value in order to define the total impacts of a project (i.e., impacts in GB and the connecting country/countries). More details on the GB societal value of CO2 can be found in the Green Book supplementary guidance: valuation of energy use and greenhouse gas emissions for appraisal. Data tables 1 to 19: supporting the toolkit and the guidance, Table 3. Data tables 1 to 19: supporting the toolkit and the guidance, Table 3. Carbon Value – Central Scenario

Topic	Description	Feedback	Decision	Justification
				For clarity, the market value of CO_2 used to calculate CO_2 reductions (SEW) in GB and the oversea countries are the UK ETS and EU ETS, respectively.
Avoided RES spillage	Value of curtailed energy	One stakeholder asked how Arup is going to monetise RES curtailment.	We will not monetise this indicator. .	In the TYNDP 2022 Implementation Guidelines published in March 2022 (the Match guidelines), ENTSO-E indicates that this indicator can be monetised, highlighting that its value **should not** be considered as an additional benefit to be added to the SEW. Rather, this monetised benefit is already captured in the SEW. In recognition of the above, the ENTSO-E 3rd CBA guidelines published in October 2022 (the October guidelines) clearly state that this indicator should not be monetised. The function of this indicator is to simply provide additional information on how various levels of avoided RES spillage affects changes in generation costs and CO_2 emission, which in turn are captured by the SEW indicators. As the updated CBA framework published in 2022 was based on the October guidelines, we will keep this indicator unmonetized. The MWh value will be indicated in the report.
FA & MA approach	Arup proposed to adopt both the FA & MA approach used by Afry in previous application windows under the C&F regime.	Overall, most stakeholders supported the proposal, noting that the inputs used will have a significant impact on the results under each approach. Two stakeholders disagreed stating that neither of the two approaches recreates realistic scenarios.	Adopt FA & MA approach	This is considered a valid approach to capture a range of potential impacts for each of the projects assessed. It is also aligned with the ENTSO-E CBA guidelines and Ofgem analytical requirements. This approach will be applied to both ICs and OHAs as these two asset types are assessed within the same simulation.

Topic	Description	Feedback	Decision	Justification
MA – connection dates	Two options were considered in relation to the connection dates to use under the MA approach: • Option A: each project assessed connects after all the applicant projects (W1 and W2 approach) • Option B: use connection dates communicated by project developers (staggered approach)	Four stakeholders were in favour of Option B as it was considered less discriminatory. However, it was noted that under this option, the first year of operation of each project should be modelled individually to better capture the impacts of that project. On the contrary, one stakeholder favoured Option A as it would have removed the risk of using over-optimistic connection dates provided by the developers themselves	Adopt Option B	Option A is well suited for W1 and W2 analysis, where all the applicant projects communicated to Ofgem the same connection date. We agree that Option B is less discriminatory towards developers than artificially delay the connection date of the project assessed by several years. We also note that this option simplifies the modelling required, streamlining the entire process. We confirm that the first year of operation of each project assessed will be modelled fully. Please note that Ofgem are running a due diligence on connection date and deliverability generally as part of the wider IPA decision.
Scenarios	Three options were considered: • Option 1: develop completely bespoke scenarios • Option 2: develop hybrid scenarios, modifying and tailoring publicly available data sets • Option 3: use FES 2022 unmodified with NGESO EU assumptions (except for interconnector capacity) Arup's initial proposal was Option 3, selecting the following scenarios: • Low case: Falling Short (FS) • Base case: Consumer Transformation (CT)	Most stakeholders were in favour of Option 3, with reservations. It was flagged that FES 2022 for GB and European countries were not reflective of the most recent energy and climate policies, and market developments. There was also mixed support for the selection of CT as the base case scenarios instead of ST, as the latter had been recently used by Ofgem in a separate study on locational market pricing. It was also noted that FS should have been excluded as it is non-net zero compliant. Some stakeholders also flagged that the criteria underpinning the FES selection might not deliver results aligned with the scenarios, as they are not specifically designed to represent high, base, and low cases for cross border projects. For example, LW might represent the best-case scenario for a project but not for others. This would have implications in the final	Adopt Option 3 No changes to the assumptions Adopt proposed FES selection. The official publication date of the FES 2023 scenarios makes it incompatible with the timeline of this project.	We believe using publicly available information is a fundamental requirement to ensure the transparency, auditability, and replicability of our analysis. The FES scenarios were considered the best source of information as they are a well-known and widely used set of assumptions that undergo a severe scrutiny and review process. Using FES scenarios also ensure analytical compatibility between Arup and NGESO analysis, which is required under the new CBA framework under the C&F regime. For the same reasons, we decided **not** to modify the assumptions in the FES to reflect latest policy and market developments in GB and overseas connecting countries. Doing so would likely undermine the consistency of the scenarios, changing the narrative for which they have been selected. This would also limit the replicability of the results by third parties and delay the publication of the results. The selection of the high, base, and low case scenarios was based on the amount of interconnector capacity assumed in each FES. Acknowledging that the FES scenarios are not specifically designed to assess cross-border projects, this was used as a proxy for price differentials between GB and connected

Topic	Description	Feedback	Decision	Justification
	• High case: Leading the Way (LW)	assessment of a project under the MCA framework. One stakeholder suggested to use the 2023 FES Scenarios. One stakeholder correctly pointed out during the second workshop that the FES workbook does not contain assumptions for DSR or electrolysis for the European zones.		countries, which in turns drives the need for interconnector capacity. CT provided capacity levels much closer to the middle point between FS and LW when compared to ST. As such, CT also includes higher interconnector capacity than ST representing a more favourable base case for project developers.. By the same rationale, FS was selected as the low case for the assessment as it includes the lowest amount of interconnector capacity between GB and connected countries. Whilst we acknowledge that FS is not a Net Zero compliant scenario, it describes a world where significant decarbonisation of the energy system is achieved. Therefore, FS represents a plausible scenario required in our assessment to account for the risk and assess the impact of potentially overdelivering cross-border capacity. This rationale was also supported by NGESO, and a high-level review of the price differentials under the various scenarios corroborates this assumption. We acknowledge the possibility that projects might not perform consistently across the same scenarios, although we do not expect this to happen at aggregate and total SEW levels. We have modified the nature of the MCA decision making process to reflect this possibility (as explained earlier in this table). As per NGESO statement during the stakeholder engagements- provided that there is no confidentiality clause- any data item missing from the FES data workbook required for the modelling will be provided to Arup. **Impact on system margin:** In this answer system margin is meant to mean de-rated system margin. Arup looked into the system margins from the C&F W2 data workbook. The estimated system margins (for the different GB capacity mixes and EU countries) were above the quoted range of 5% to 8%. No system margin re-balancing modifications appear to have been undertaken. Arup also looked into the FES 2022 GB capacity mixes (with no modifications

Topic	Description	Feedback	Decision	Justification
				-including the aggregate interconnector capacity) and there are several instances (scenarios/years) where the system margin was significantly outside 5-8% range. By 2035, the Government has set out a target to be able to run a fully decarbonised electricity power system all of the time. There will be much higher volumes of weather dependent renewables, storage, and more interdependence with neighbouring countries through electricity interconnection. There will be times when weather conditions will lead to very low output from renewable generation. These weather conditions may extend beyond GB affecting neighbouring countries too. There will need to be sufficient additional resources in the resource mix to deliver clean, reliable power at these times i.e., to maintain security of supply and ensure adequacy. The ESO is currently undertaking long-term adequacy studies to assess the potential risks to security of supply and to ensure there are sufficient available resources to meet electricity demand throughout the years out to 2050. The current quoted range system margin range of 5% to 8% may no longer be a suitable measure beyond 2030.
IC baseline	Two options were considered: • Option A: Fixed IC baseline across the forecasting horizon • Option B: Add IC capacity to IC baseline to match FES IC capacity. It was proposed that the IC baseline in GB and overseas connecting countries would consist of project built, under construction and with	Not all stakeholders commented on this proposal, two of which disagreed with the proposed IC baseline definition. Two stakeholders were against the definition. Two were in favour of decommissioning. One stakeholder pointed that Arup should explain in more detail if the system margins with and without the project remain the same in order to compare the two situations on an equal basis (both under the FA and MA approach). Under the MA, there will be an abundance of IC capacity which will	Fixed baseline for GB and EU countries Maintain baseline definition. No decommissioning The EU IC baseline will include all projects build and under construction and those with regulatory approval (the status of Projects of Common Interest (PCIs) was used as a proxy for regulatory approval as agreed with Ofgem)	In order to allow the comparison of projects across all scenarios and sensitivities, the baseline level of GB interconnection (i.e., the amount of interconnection capacity in place before commissioning of any Window 3 projects) has been kept constant over time and equal across scenarios and sensitivities. The approach used to define the baseline capacity for GB (i.e., projects built and under construction + with regulatory approval) will be applied to both the assessment of W3 projects and OHAs projects. This is aligned with the analysis conducted under previous windows.

Topic	Description	Feedback	Decision	Justification
	regulatory approval (i.e., with an IPA in place). It was also considered whether to consider the decommissioning of projects throughout the modelling horizon.	subsequently increase the GB system margins causing a potential decrease in prices and the arbitrage.	Sensitivities on the GB baseline will be explored where there is clear regulatory uncertainty in the overseas country for projects that have already been awarded a C&F in principle but have not demonstrated considerable progress since then.	The same approach will be applied to the EU baseline to maintain methodological consistency. **CHANGE:** in order to maintain as much alignment as possible with NGESO, in agreement with Ofgem Arup utilised the FES EU interconnector assumptions for this analysis. For more details, please see section 2.4.2. It was decided not to include decommissioning as this could not be based on reliable data on the actual useful life of an IC project. Additionally, we understand the interconnector operators have plans in place to refurbish the existing assets and continue their operation over the modelled period. This was considered to be a reasonable simplification benefitting the overall modelling process and timeline. No further ICs are assumed beyond W3 IC, as per previous windows.
Commodity prices		Only two stakeholders addressed this topic, asking Arup to run sensitivities on commodity prices, and suggesting more recent dataset reflecting recent market developments (i.e., FES 2023 commodity prices One stakeholder pointed out that it would be useful to understand if gas prices modelling are subject to any sort of seasonality effect to account for winter/summer supply and demand dynamics.	No	We are using 2022 FES scenarios, which do not include sensitivities on commodities. Variation only on carbon price. Yes, gas prices modelling is subject to seasonality effect to account for winter/summer supply and demand dynamics. We will apply seasonal shape based on historical value

Topic	Description	Feedback	Decision	Justification
Assessment of OHAs and P2P projects together	Not initially treated	Two stakeholders questioned whether OHAs should be assessed alongside the other P2P W3 projects, considering the inherent uncertainty of First of a Kind (FOAK) projects. This would negatively impact the benefits from more certain and deliverable projects, potentially leading to their exclusion from the C&F regime	OHAs and P2P W3 projects will be assessed together	OHAs include a cross border transmission asset in their design. As such, these projects will have direct impacts on all other interconnectors currently applying for regulatory approval, as well as on the existing projects. Therefore, it is necessary to include OHAs in the assessment. Ofgem reserves the right to split IPA decision making timelines if necessary, following the conclusion of the modelling period.
OHAs – generation capacity in factual and counterfactual	Not initially treated	One stakeholder indicated that the analysis should assume that the total offshore wind capacity (for each country) is the same in the factual and counterfactual to properly assess the impact of an OHA project	Agree	Based on the latest information provided by OHA developers, the development of the offshore wind capacity connecting is independent from the delivery of the OHA itself. Therefore, we will assume the same level of generation capacity in both the factual and counterfactual.
OHAs – Same approach as P2P IC candidate	Does the analytical approach differ between P2P ICs and OHAs?	One stakeholder indicated that it was unclear if the approach will be applied to both P2P and MPI. If so, more detailed needed to accommodate 'key economic parameters of MPIs' such as wind farm access	No	Same approach used for both IC and Offshore Hybrid Assets (OHAs)
OHAs – offshore generation curtailment	Not initially treated	One stakeholder asked whether we assume offshore generation connected to an OHA under an OBZ market set up to be curtailed	No	Our understanding is that under an OBZ set up the electricity flows are to be considered as cross zonal and as such the offshore generation connected to an OHAs will not be curtailed
GB Market Arrangements and other EU policies	Future GB Market Arrangements/Other EU Policies	One stakeholder indicated that REMA (Review of Electricity Market Arrangements) outcome should be considered if significant changes are made to the GB energy market. One stakeholder asked if Arup would consider the CBAM (Carbon Border Adjustment Mechanism) regulation	We will not consider REMA and other policy developments.	No formal decision has been made yet on the future market arrangements of the GB power market following the REMA consultation not on the workings of the CBAM.

Topic	Description	Feedback	Decision	Justification
Forecasting horizon	Spot years – Proposed modelling spot years End effects - Past 2050, we would repeat the 2050 values.	Two stakeholders responded - one suggested extending to capture impacts of a project through its useful life. End effects: Two stakeholders explicitly addressed this aspect, agreeing with the proposed approach. Stakeholders noted that end effects can be based on 2050, or on multiple years.	Modelling horizon is 2050. We will model nine spot years as well the first year of operation of each project.	The spot years will be 2027-2031, 2035, 2040, 2045 and 2050. Analysis will be done on a NPV basis. NPV calculations will have 25 data points. We will model specific spot years, then we interpolate in between spot years to end up with 25 data points, for those projects that span over 2050 we will use 2050 values. Extending modelling horizon to asset life: Not possible, too much time, also benefits will be highly discounted and not relevant for the purpose of the C&F regime and Ofgem's decision
Geographical scope	Proposed following the same geographical scope as FES.		We will model the same geographical scope as FES.	This will create alignment and consistency with National Grid's analysis.
Stacked approach	Proposed using a stacked approach when modelling interconnected countries to GB. Under this approach, supply is not modelled at a generator level but rather as technology type (using the categories contained in the FES Data S2 tab) composed by several units.	No feedback received from stakeholders	Use stack approach.	This is required to be fully aligned with NGESO EU assumptions as the ES2 tab does not provide information at a generator level. It will also improve the speed of execution. This is critical given the number of sensitivities that this study required. Finally, it will decrease the risk of human error in the configuration phase when we align to NGESO's assumptions.
Weather years	Proposed modelling 3 weather years; very bad, very good, average from publicly available dataset	Four stakeholders replied. Two agreed, noting. One suggested using stochastic approach to remove degree of subjectivity in picking the weather data used. One stakeholder asked to consider extreme weather events qualitatively	We will use 3 weather years. We will run the model for each weather year, and then average the results. Arup will pick the year with the highest combined load factor in GB (Onshore wind, Offshore wind, and Solar PV) as the High Weather Year and the conversely the low weather year is the lowest combined load factor average.	We believe this is a necessary simplification to ensure thee analysis is delivered within timelines. Difficult to define extreme weather years on a 25y plus horizon, let alone assessing them or understanding their impacts on the projects. Correlations between various sources of RES in GB and connected markets will be considered. Data source for weather years will be taken from ENTSO-E database

Topic	Description	Feedback	Decision	Justification
			Arup will be using ENTSO-E Climate Year Database. 1990: High-RES year 2007: Avg RES year 2010: Low-RES year	
Timeframe	Modelling Timeframe	One stakeholder pointed out that the Day Ahead (DA) timeframe is the key market timeframe looked at in modelling exercise such as the one undertaken by Arup. Another stakeholder stated that more clarity required on ID modelling (e.g., variation produced with stochastic on generation, based on weather variation? How is the price derived?	Arup intend to model also at the ID Timeframe	We are looking at ID too as per Ofgem's updated CBA framework published in 2022. This was in response to stakeholders' feedback highlighting that previous assessments did not properly capture the potential beneficial impacts ICs can have in meeting short term changes in demand and supply, captured in the ID market. Arup's modelling framework simulates a net imbalance volume (NIV) caused by forecast error in the wind and demand. These imbalance volumes forecasts are based on a multivariate regression model calibrated on historical NIV values and considers factors such as the growth in renewable penetration and NIV latency effects. **CHANGE:** ID has not been modelled. For more details, please see section 2.4.8.
Other – CPS support	Not initially treated	One stakeholder asked whether the Carbon Price Support (CPS) in GB will be applied and for how long	No	As per FES assumptions, we are not assuming the CPS to be applied
Other – loss factors and availability	Not initially treated	Few stakeholders asked for loss and availability factors to be published.	Factors will not be published unless developers agree to it.	We will be using the factors provided by developers in their IPA submissions. These will not be published unless developers themselves agree to it, as they consider project-specific factors to be commercially sensitive information.

Topic	Description	Feedback	Decision	Justification
CBA from developers	The developers' CBA will inform the assessment process	Stakeholders required more clarity on this point	To use the developers' CBA as described in the CBA framework published in 2022	Arup used the developers' CBA to corroborate its modelling approach and decisions. The developers' CBA will not be considered directly in the decision-making process by Ofgem.
Welfare transfer calculations	Not initially treated	Not provided	Adopt approach used in W2	Arup believe the conceptual approach adopted in previous assessments to model the relations between revenues and the cap and floor regime is appropriate. The default assumption is that the C&F will be applied to 50% of the asset's costs and revenues. For OHAs, this will be tailored to the project's applications and Ofgem's consideration if necessary. Arup will collaborate closely with Ofgem to correctly apply said approach to OHAs to reflect the different revenue dynamics and arrangements underpinning these assets.
Scenarios	FES 2022 were proposed as the scenarios for the modelling.	It was flagged that FES 2022 for GB and European countries were not reflective of the most recent energy and climate policies, and market developments.	Adopt proposed FES22 selection	The Future Energy Scenarios sets out credible ways that the UK can achieve Net Zero by 2050, as well as the UK Government's commitment to a decarbonised electricity system by 2035. They are based on extensive stakeholder feedback and set out a range of possible pathways to achieving net zero. The scenarios are updated on an annual basis. Broadly speaking, the GB FES scenario framework has remained consistent for several years now. Whilst it is true to say that FES22 may not capture all of the latest policy and market developments, the scenario envelope used for FES22 is sufficiently broad to capture most credible future developments. For example, when comparing FES22 and FES23, there is unlikely to be major differences in the level of capacity for a particular plant type, as the scenario envelope is sufficiently broad to capture most future policy developments. Hence current UK Government targets sit within the range captured within the FES envelope. Similarly for the European element of the scenarios, they represent credible pathways to Net Zero across Europe. So, whilst energy and climate policies

Topic	Description	Feedback	Decision	Justification
				continue to evolve, the scenario envelope should be broad enough to allow for new developments. Although FES23 was published in July 2023, the associated network reinforcements needed for the scenarios to be used to undertake constraint costs analysis will not become available until December 2023. Hence it is not possible to use FES23. The FES22 is used in conjunction with the Network Options Assessment (NOA) 2021/22 Refresh, which integrates the Holistic Network Design (HND) offshore network. The HND provides a recommended offshore and onshore design for a 2030 electricity network, that facilitates the Government's ambition for 50GW of offshore wind in Great Britain by 2050.
CAPEX Costs	The latest available interconnector developer costs will be used as well as the network costs provided by the relevant TO.	Stakeholders questioned how the CAPEX costs will be calculated.	Use Interconnector costs submitted by developers and TO costs submitted within the Connections Infrastructure Options Note (CION) process.	These are the latest costs available. The costs will be scrutinised and checked by Ofgem for consistency and robustness. The costs will be made available, subject to commercial sensitivities.
Constraint Management and Ancillary Services analysis modelling approach	The ESO will undertake the constraint management modelling using its pan European market model (BID3) and use its network modelling software (Power Factory) for some of the Ancillary Services modelling.	Stakeholders highlighted concerns regarding ESO assumptions: e.g., connection locations, ancillary services revenue generated for the interconnector itself also needs to consider the increased competition in the provision of these services. Concern that the ESO elements are not transparent, inconsistent with the CBA and not sufficiently robust. Stakeholders also questioned the robustness of ESO assumptions regarding of batteries on the electricity system.	The ESO will use the FES 22 scenarios and our pan-European market model (BID3) to calculate GB constraint costs and RES spillage. The ESO will use our network modelling software Power Factory for the voltage/reactive power analysis. The ESO will use a range of market data to calculate the potential benefits of interconnection to restoration services and frequency response.	The ESO is fully supportive of Ofgem's ambition to ensure the CBA process is as transparent as possible. The ESO has been working closely with ARUP, to ensure that both parties are using a consistent set of assumptions for their analyses. For example, both ARUP and ESO are using a consistent set of scenarios, FES22, ensuring consistent geographic scope, and demand and supply assumptions. This ensures that there is a single set of input data for ARUP and the ESO. The ESO will publish a detailed methodology document for the elements of the Cap and Floor Window 3 and OHA Pilot work that it is responsible for, providing comprehensive information on how each element has been undertaken, and what underlying assumptions have been used. The ESO has used the methodologies used for C&F W2 as a starting point, but these have then been

Topic	Description	Feedback	Decision	Justification
				revised and updated to reflect current and potential future developments in the provision of ancillary services. The ESO will calculate the benefit to GB consumers from interconnectors providing ancillary services, as well as quantifying ancillary service revenues for interconnectors. The ESO has used its pan-European market model (BID3), populated with FES data to support the annual Network Options Assessment process, as well as all other constraint cost-based cost benefit analyses. It can simulate all European power markets simultaneously from the bottom up, i.e., it can model individual power stations, for example. It includes demand, supply and infrastructure, and balances supply and demand on an hourly basis. It models the hourly generation of all power stations on the system, considering fuel prices, historical weather patterns and operational constraints. As part of the initial testing, the ESO will model a range of weather years to ascertain whether running a single weather year produces comparable results to the average of 1990, 2007 and 2010. **CHANGE:** In line with its general analytical approach, the ESO has used 2013 only for the constraint costs modelling. The ESO consistently uses this weather year in most of its modelling work as it provides good agreement to an average derived from running a range of weather years. BID3 will also be used to calculate RES spillage volumes. Volume of RES curtailment is one of many standard outputs from the model. The ESO will model various spot years for the ancillary services work, as it is currently not possible to do voltage/reactive studies for multiple decades in the future. The Power Factory model will be updated as appropriate to create a robust and credible baseline network which will then be modified to quantify the impact of each interconnector. ESO will calculate

Topic	Description	Feedback	Decision	Justification
				both the value to GB consumers and the revenue generated for each interconnector. The ESO continues to develop its modelling tools and capabilities and recognises that as the newer technologies such as batteries become an increasingly important element of the electricity network, its models must reflect the behaviour of those assets as realistically as possible. This is an ongoing process, and the ESO welcomes all feedback that helps it continue to improve its modelling activities.
Geographical scope	System Operability Cost Efficiencies	Stakeholders noted that ESO analysis will only consider the GB benefits/costs. If the non-GB side of the IC is not to be modelled, it should at least be qualitatively considered to ensure the full impact of the project is taken into account.	Only the GB impacts will be considered	ESO system operability analysis is limited to GB: it is unable to perform detailed system operability analysis on non-GB networks. It is therefore not possible to quantitatively model the impacts of a project on another country's energy system. Where possible, ESO will provide qualitative analysis.

Appendix D – Summary of developers' CBAs

This appendix provides a summary of the key features of developers CBA's.

Table 25 - Summary of W3 Developer CBAs

Topic	Aquind	Aminth	Cronos	LirIC	MaresConnect	Nu-Link	Tarchon
Scenarios	**1. Market Scenario** *Central view on the evolution of European power markets (based on Baringa Summer 2022 core modelling* **2. High Commodities** *Higher oil, gas and coal prices, higher long-term carbon prices & higher demand* **3. Net Zero** *GB capacities based on FES CT. France capacities based on TYNP 2022 Global Ambitions (GA)*	**Consultant reference scenario** *Decarbonisation agenda is pursued across Europe, and Net Zero is achieved by 2050.*	**Consultant reference scenario** *Decarbonisation agenda is pursued across Europe, and Net Zero is achieved by 2050.*	**Base scenario** **GB** projections follow FES 2021 consumer transformation. **I-SEM** projections follow Generation Capacity Statement Central case for 2030, adjusted to meet the Republic of Ireland (RoI) government's 2030 renewable targets, and then Tomorrow Energy Scenario's (TES) Centralised Energy (RoI) and Addressing Climate Change (NI) scenarios through to 2040.	Modelled 3 scenarios which differ by speed of decarbonisation. **1. Steady Decarbonisation** *RES targets met in GB and SEM. GB aligned with FES CT.* **2. Accelerated Decarbonisation** *Net Zero in GB met by 2047. Higher RES capacity, interconnection and flexibility. GB aligned with FES LW.* **3. Slow decarbonisation** *2050 decarbonisation targets not met in GB or SEM. GB aligned with FES FS.*	**Consultant reference scenario** *Decarbonisation agenda is pursued across Europe, and Net Zero is achieved by 2050.*	**Consultant reference scenario** *Decarbonisation agenda is pursued across Europe, and Net Zero is achieved by 2050.*
Sensitivities	1.**Delay to investment** *Project start date delayed to Q4 2028* **2. Cost overrun**	None	None	**1. High I-SEM RES** *increased onshore wind growth rate from 2030. Maintaining pace with GB market to achieve similar RES penetration as a proportion of demand*	**High Gas Prices Sustained Overtime** *Sensitivity on Accelerated Decarbonisation scenario assumes gas prices from 2030 onwards are double*	None	None

Topic	Aquind	Aminth	Cronos	LirIC	MaresConnect	Nu-Link	Tarchon
	Capital and operating costs increase by *10%* **3. High interconnection** *Generic GB-FR capacity introduced in 2045 in market scenario brought forward to 2035.*			**2. North-South capacity not increased** NS *IC capacity between NI and RoI remains 300MW, compared to base scenario where it* increases to 1500MW	*those assumed in the other scenarios.*		
Modelling Timeframe	DA	DA	DA	DA & BM	DA	DA	DA
Spot Years	All years in time horizon from 2027-2052 modelled.	2031, 2035, 2040, 2045, 2050 modelled as spot years, with linear interpolation applied between. Values past 2050 take the simple average of all modelled years.	2030, 2035, 2040, 2045, 2050 modelled as spot years, with linear interpolation applied between. Values past 2050 take the simple average of all modelled years.	Arup assumes that all years have been modelled [2029-2050] as no reference to spot years is made in the document. Method used to derive results from 2051 to 2054 also not indicated.	Modelled 3 spot years; 2040, 2040 and 2050 and interpolated between years. Values past 2050 remain constant.	2030, 2035, 2040, 2045, 2050 modelled as spot years, with linear interpolation applied between. Values past 2050 take the simple average of all modelled years.	2031, 2035, 2040, 2045, 2050 modelled as spot years, with linear interpolation applied between. Values past 2050 take the simple average of all modelled years.
Modelling of Ancillary Services (AS)	Referenced potential for AS revenue but no modelling outlined	Referenced potential for AS revenue but no modelling outlined	Referenced potential for AS revenue but no modelling outlined	Not specified	Quantitative potential for AS revenue but no modelling outlined	Referenced potential for AS revenue but no modelling outlined	Referenced potential for AS revenue but no modelling outlined
Fuel Prices	Forward curve prices inform near term price assumptions. In the long-term, data from the Energy Information Administration (EIA) and International Energy Agency (IEA) World Energy Outlook (WEO) 2022 fuel price projections are used to inform commodity prices	Consultant Reference Scenario – informed by European Energy Exchange (EEX) and Henry Hub prices	Consultant Reference Scenario – informed by EEX and Henry Hub prices	FES 2021	FES *year not specified*	Consultant Reference Scenario – informed by EEX and Henry Hub prices	Consultant Reference Scenario – informed by EEX and Henry Hub prices
Carbon	Unspecified source	Bespoke projections benchmarked against externals, aligning with WEO Announced Pledges scenario by 2050.	Bespoke projections benchmarked against externals, aligning with WEO Announced Pledges scenario by 2050.	FES 2021	FES *year not specified*	Bespoke projections benchmarked against externals, aligning with WEO Announced Pledges scenario by 2050.	Bespoke projections benchmarked against externals, aligning with WEO Announced Pledges scenario by 2050.

Topic	Aquind	Aminth	Cronos	LirIC	MaresConnect	Nu-Link	Tarchon
Interconnection Baseline	Bespoke Interconnector Baseline	Bespoke Interconnector Baseline	Bespoke Interconnector Baseline	Bespoke Interconnector Baseline	Based on: Steady decarbonisation - GB follows FES CT - SEM follows FES CT & TYNDP GA Accelerated decarbonisation - GB follows FES LW - SEM follows FES LW & TYNDP GA Slow decarbonisation - GB follows FES FS - SEM follows FES FS & TYNDP GA	Bespoke Interconnector Baseline	Bespoke Interconnector Baseline

Table 26 - Summary of OHA Developer CBAs

Topic	LionLink	Nautilus
Scenarios	**2 Market Scenarios** derived from FES 2022 for GB and ENTSO-E's TYNDP for neighbouring markets **1. FES22 ST & TYNDP GA** **2. FES22 ST & TYNDP NT** Due to the combination of 2 scenario frameworks, a rebalancing process was conducted by targeted updates to capacity assumptions to obtain regional system margins within an acceptable target range of 5% to 8% in all years modelled.	**2 Market Scenarios** derived from FES 2022 for GB and ENTSO-E's TYNDP for neighbouring markets **1. FES22 ST & TYNDP GA** **2. FES22 ST & TYNDP NT** Due to the combination of 2 scenario frameworks, a rebalancing process was conducted by targeted updates to capacity assumptions to obtain regional system margins within an acceptable target range of 5% to 8% in all years modelled.
Sensitivities	Sensitivity based on the timing of offshore wind deployment in the 2030's based on scenario 1. The 2030 capacity assumption is 30GW instead of 40GW. Thereafter, there is on average 20% less capacity over the 2030s before converging back to the Scenario 1 trajectory from the early 2040s onwards.	Sensitivity based on the timing of offshore wind deployment in the 2030's based on scenario 1. The 2030 capacity assumption is 30GW instead of 40GW. Thereafter, there is on average 20% less capacity over the 2030s before converging back to the Scenario 1 trajectory from the early 2040s onwards.

Topic	LionLink	Nautilus
Modelling Timeframe	DA & BM	DA & BM
Spot Years	2030-2042 single years modelled. Spot years 2045 & 2050. Interpolation between spot years. 2050 results endure for rest of time frame.	2030-2042 single years modelled. Spot years 2045 & 2050. Interpolation between spot years. 2050 results endure for rest of time frame.
Modelling of Ancillary Services	Not specified	Not specified
Fuel Prices	FES 2022	FES 2022
Carbon	FES 2022	FES 2022
Interconnection Baseline	Bespoke Interconnector Baseline Both scenarios assume a strengthening of cross-border capacity with GB; Scenario 1 - from 13GW by 2030 to near 16GW from 2037 onwards Scenario 2 - from near 16GW to 18GW from 2037 onwards	Bespoke Interconnector Baseline Both scenarios assume a strengthening of cross-border capacity with GB; Scenario 1 - from 13GW by 2030 to near 16GW from 2037 onwards Scenario 2 - from near 16GW to 18GW from 2037 onwards

Appendix E – Price formation in an OBZ

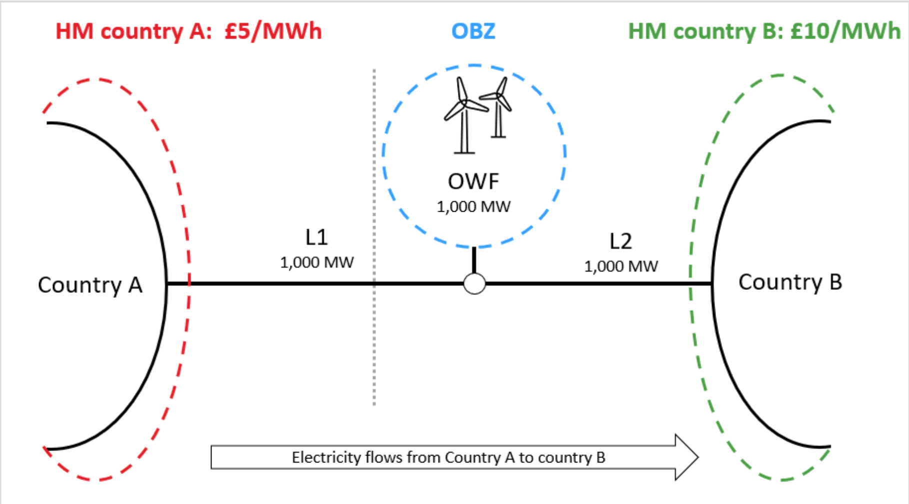
In this appendix, we explain the theory behind the formation of an OBZ price. Please note that the examples made here are a necessary simplification meant to demonstrate the dynamics observed in our modelling.

Price formation considering supply and demand of an OBZ

Let’s assume the following configuration for an OHA project connecting two countries, Country A and Country B:

- L1, with a total transmission capacity of 1,000 MW;
- An OWF with a total generation capacity of 1,000 MW;
- L2, with a total transmission capacity of 1,000 MW.

Let’s also assume that Country A has a wholesale electricity market price lower than Country B, meaning that the OHA project will export electricity from Country A to Country B.



Drawing 9 - Hypothetical OHA configuration

Under this configuration and economic assumptions, **the OWF is a source of supply** in the OBZ, the volume of which is determined by the amount of wind blowing in a given hour. **L1 also represents a source of supply** in the OBZ (i.e., imports from Country A), whilst **L2 represents a source of demand** (i.e., exports to Country B).

This is summarised in the tables below, which shows how supply in OBZ changes depending on whether the OWF is able to generate electricity (i.e., whether or not the wind blows). Here we have assumed a 50% load factor.

The OWF does **NOT** generate

	Supply	Demand
OWF	0 MWh	-
Country A - L1	1,000 MWh	-
Country B - L2	-	1,000 MWh
Total	**1,000 MWh**	**1,000 MWh**

The OWF generates

	Supply	Demand
OWF	500 MWh	-
Country A - L1	1,000 MWh	-
Country B - L2	-	1,000 MWh
Total	**1,500 MWh**	**1,000 MWh**

When the OWF does not generate due to a lack of wind, the electricity provided through L1 by the generators within Country A fully satisfies the demand in the OBZ created by Country B through L2. In this instance, the OBZ price tracks the price of the most expensive market it connects to in order to incentivise enough generators in Country A to meet the demand created by Country B (e.g., £10/MWh).

Things differ when the wind blows. In this case, the OWF is able to generate electricity. This leads to oversupply in the OBZ (1,500 MWh) compared to its demand (1,000 MWh). Because the OWF can generate electricity at virtually no SRMC, the supply within the OBZ meet the demand of Country B through L2 at a lower cost compared to before. This is shown below.

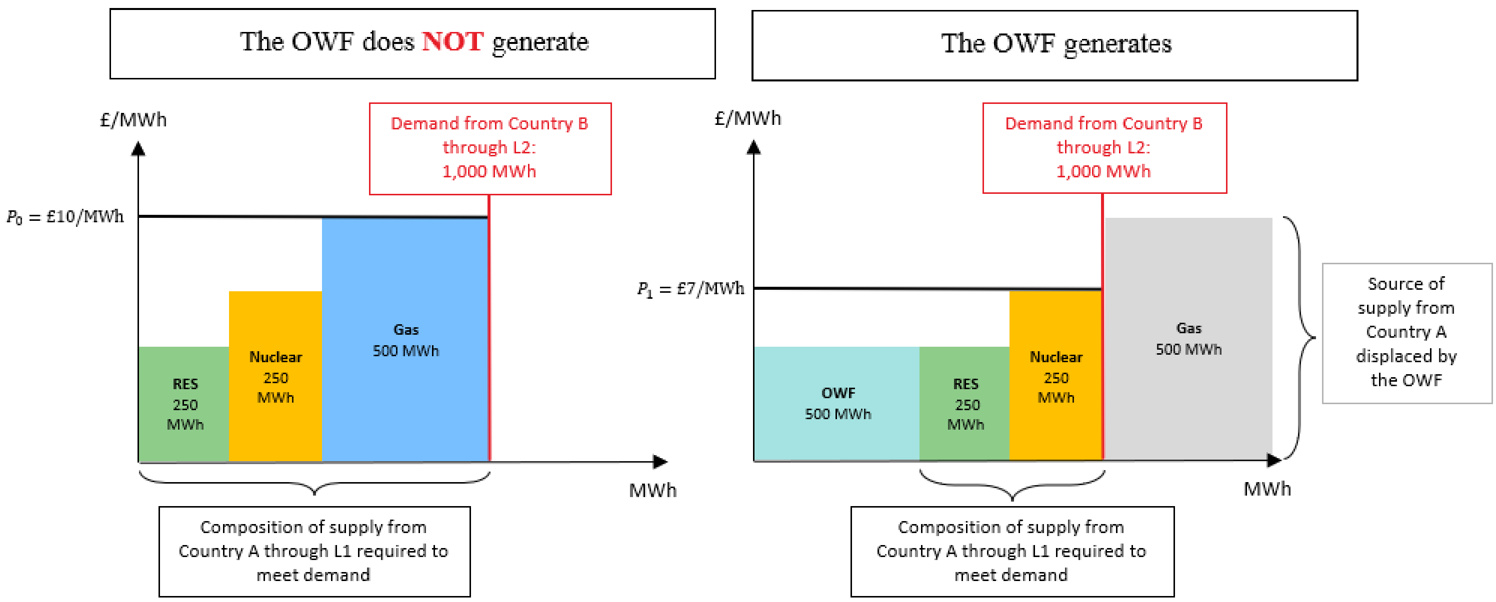


Figure 77 - Change in the OBZ price

Considering that the OWF displaces the most expensive marginal generator from Country A that is willing to provide the last MWh of electricity required by Country B via L2, the price at which the new supply mix in the OBZ can meet the demand is lower than before, for example at £7/MWh.

This means that if the OWF was able to generate enough electricity to fully meet the demand created by Country B via L2, the OBZ price would equal the SRMC of the OWF. Theoretically speaking, these would be close to £0/MWh. However, if the OWF is not able to do so, the OBZ price will be determined by the SRMC of the marginal generator of Country A required to meet the demand in the OBZ.

The exact price of the OBZ will vary each hour. This will be determined by the amount of electricity the OWF is able to generate at any given time as well as the composition of the electricity supply imported in the OBZ. For example, the stronger the wind, the more electricity will be produced by the OWF and the RES assets in the countries the OHA connects. In those instances, the demand in the OBZ will be met primarily by generation assets with the lowest SRMC, which in turn will further push downwards the clearing price in the OBZ.

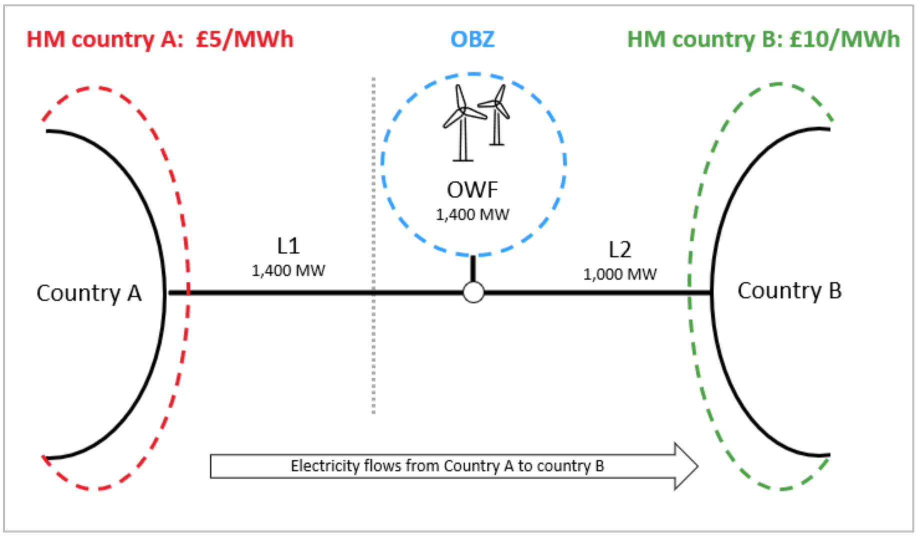
Price formation considering available transmission capacity between the OBZ and other markets

Another way to describe price formation in an OBZ is through the level of congestion across L1 and L2, i.e., the level of available transmission capacity between markets.

Let’s assume an OHA configuration as follows:

- L1, with a total transmission capacity of 1,400 MW;
- An OWF with a total generation capacity of 1,400 MW;
- L2, with a total transmission capacity of 1,000 MW.

Let’s also assume that Country A has a wholesale electricity market price lower than Country B, meaning that the OHA project will export electricity from Country A to Country B.



Drawing 10 - Hypothetical OHA configuration

The price of the OBZ will be determined by the highest price in the neighbouring bidding zone to which transmission capacity is still available. When there is no more transmission capacity available to that zone, the OBZ price will track the second highest price in the neighbouring zone to which capacity is still available.

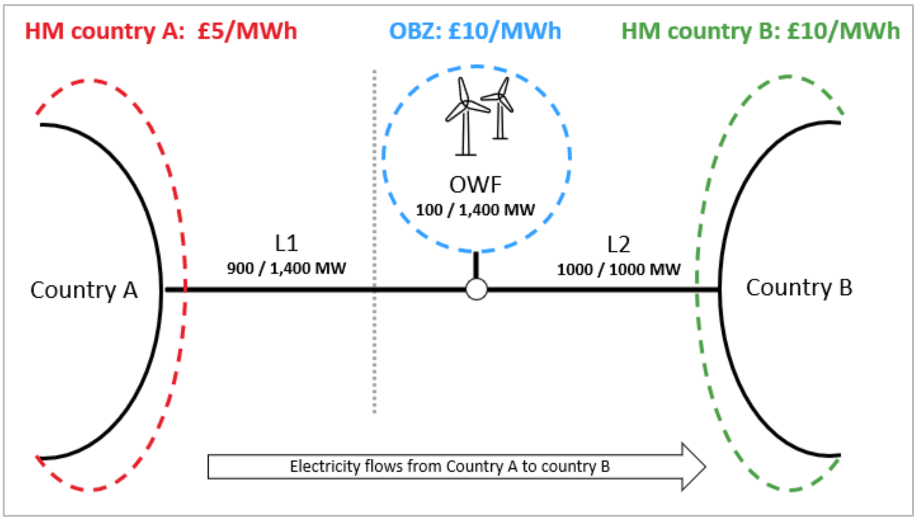
Usually, the transmission lines connecting the bidding zones with the highest prices will be the most congested ones, as generators will try to sell electricity to the highest bidder to maximise profit.

Two key aspects determine the level of congestion across an OHA project, namely:

- The capacity of the lines that compose the OHA, whereby the line with the lowest capacity is the line that determines the volume of electricity flows across the OHA, acting as a bottleneck.

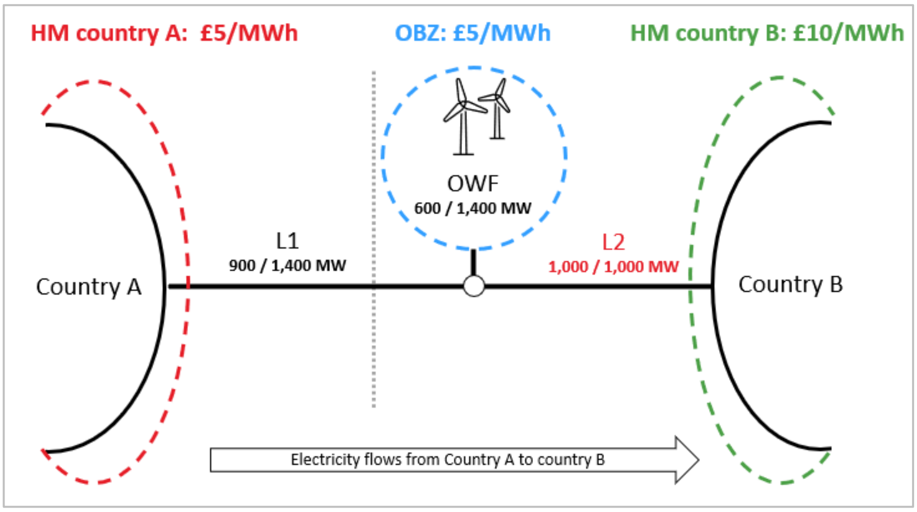
- The amount of electricity generated by the OWF connected to the OHA due to variable weather conditions.

Drawing 11 represents a low wind scenario, whilst Drawing 12 represents a high wind scenario. In a low wind scenario, the OWF will receive the same electricity price of Country B to dispatch the electricity it generates (100 MW), as there still transmission capacity available on L2 after the flow from L1 is taken into account (900 MW from L1 out of a maximum capacity of 1,000 MW on L2).



Drawing 11 – Low wind scenario

In a high wind scenario, L2 becomes increasingly congested. The output of the OWF (600MW) combined with the electricity generate by Country A (900 MW) exceeds the maximum capacity of L2 (1000 MW) after the flow from L1 is taken into account. In this case, the OWF will receive the price of the next zone to which transmission capacity is still available to dispatch the electricity, i.e., Country A.



Drawing 12 – High wind scenario

The two approaches described above can be considered complementary: the higher the level of congestion on L2, the higher is the level of competition between generators in Country A and the OWF (when it can generate) to win the capacity on L2.

Because the OWF has very low SRMC, only the most price-competitive sources of electricity of Country A will be able to secure the capacity on L2 to meet the demand in the OBZ (driven by imports from Country

B). In turn, this leads to an overall low clearing price in the OBZ compared to a situation where the OWF cannot generate electricity. Conversely, the lower is level of congestion on L2, the lower is the level of competition between generators and the OWF, which results in overall higher clearing prices in the OBZ.