GRIDLINK COST BENEFIT ANALYSIS REPORT

A report to GridLink Interconnector Limited

September 2020

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AFRY is an international engineering, design and advisory company. We support our clients to progress in sustainability and digitalisation. We are 17,000 devoted experts within the fields of infrastructure, industry and energy, operating across the world to create sustainable solutions for future generations.

AFRY Management Consulting provides leading-edge consulting and advisory services covering the whole value chain in energy, forest and bio-based industries. Our energy practice is the leading provider of strategic, commercial, regulatory and policy advice to European energy markets. Our energy team of over 250 specialists offers unparalleled expertise in the rapidly changing energy markets across Europe, the Middle East, Asia, Africa and the Americas.

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EXECUTIVE SUMMARY

The GridLink project is a proposed 1.4GW interconnector between France and Great Britain, with commercial operation expected to commence in January 2025. Ahead of this, the GridLink project is seeking regulatory approval for the project. In support of this effort AFRY has carried out an independent Cost Benefit Analysis (CBA) of the project.

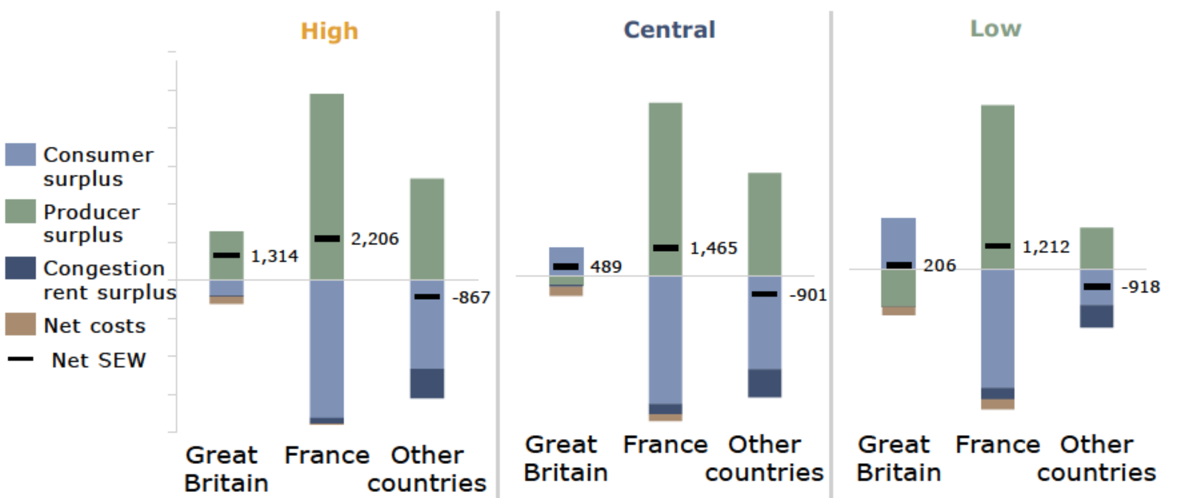
The CBA assesses the socio-economic welfare (SEW) impacts of the GridLink project, informed by market modelling. The assessment is conducted using:

- AFRY modelling, in particular the BID3 power market model, which provides hourly results that include wholesale prices, plant dispatch and interconnector flows, on which the SEW assessment is based; and
- AFRY's latest (Q2 2020) standard High, Central and Low scenarios as the basis, with some refinements to interconnector and thermal capacity build.

GridLink offers net positive socio-economic welfare impact

The modelling results indicate that GridLink offers net positive socio-economic welfare impact in all three scenarios based on the sum of welfare effects in France, Great Britain and other European countries. Focusing on France and Great Britain specifically, welfare effects are positive for both markets in all cases. Summary results are illustrated in Figure 1.

Figure 1 – GridLink SEW impact, (€m, 25yr NPV, 4% discount rate)



Net SEW (m€)	**High**	**Central**	**Low**
Great Britain	1,314	**489**	206
France	2,026	**1,465**	1,212
All Europe[1]	2,653	**1,054**	501

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1 Sum for Great Britain, France and other countries.

In the Central scenario, GridLink improves consumer surplus in Great Britain as the interconnection tends to lower the average wholesale prices in the 'with GridLink' case. In France, producer surplus is positive as GridLink enables French generators to sell electricity into a market which has higher electricity prices. Observations in respect of the wholesale price impacts that are driving the changes in producer and consumer surpluses are discussed below.

Wholesale prices in France and Great Britain converge

As expected, the addition of GridLink means that annual average wholesale prices converge between France and Great Britain, as displayed in Figure 2, which shows the wholesale prices in the 'With GridLink' case compared to the 'Without GridLink'.

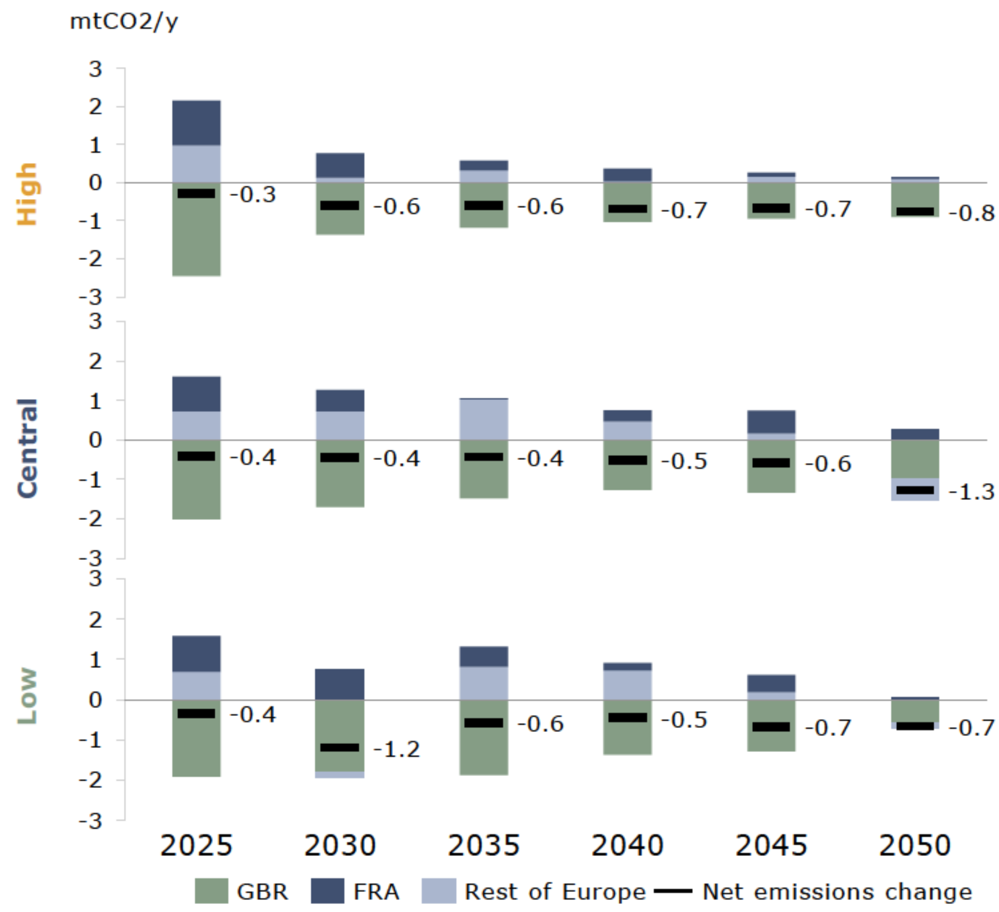
Figure 2 – Baseload wholesale electricity prices 'With GridLink' and 'Without GridLink' (€/MWh, real 2020 money)

[redacted]

GridLink delivers reduction in carbon emissions

Interconnection allows for more efficient operation and dispatch of all generation in general, thereby reducing overall emissions across Europe as a whole in all three scenarios. Figure 3 shows the change in CO_2 emissions per annum from the introduction of GridLink in Great Britain, France and the rest of Europe at 5 yearly intervals. The black bar shows the net carbon emission change across Europe thanks to the introduction of GridLink, negative values representing a reduction in emissions thanks to GridLink. While CO_2 emissions are reduced in Great Britain, French emissions increase slightly due to GridLink's exports to Great Britain. Emissions also tend to slightly increase in the rest of Europe in the 'with GridLink' case, as neighbouring countries rely on comparatively less low carbon imports for France. The combined net decrease in CO_2 emissions across Europe (averaging 0.5 mtCO2 per annum in the Central scenario) represents 1% of total average power sector emissions in Great Britain and France.

Figure 3 – Change in carbon emissions from power sector 'With GridLink' minus 'Without GridLink' case (mtCO_2 /y)



1. INTRODUCTION

1.1 Introduction

The GridLink project is a proposed 1.4GW interconnector between France and Great Britain. GridLink has been designated as an EU Project of Common Interest and has secured a funding grant of up €15.1m from the Connecting Europe Facility. GridLink is being considered within Ofgem's Window 2 assessment in relation to the cap and floor regime.

AFRY has carried out an independent Cost Benefit Analysis (CBA) in relation to the GridLink project to be used in relevant regulatory approvals processes. The results of this assessment are presented in this report.

1.2 Overview of the GridLink Interconnector

GridLink is a 1.4GW interconnector consisting of two High Voltage Direct Current (HVDC) cables under the sea to connect Dunkerque in France and Kingsnorth in Great Britain. Its total subsea route length will be 137km, following the route indicated in Figure 4. The expected Commercial Operations Date for the project is January 2025.

Figure 4 – GridLink cable route and converter station sites

1.3 Cost benefit analysis

The CBA assesses the socio-economic welfare (SEW) impacts of the GridLink project, informed by market modelling. The assessment is conducted using:

- AFRY modelling, in particular the BID3 power market model, which provides hourly results that include wholesale prices, plant dispatch and interconnector flows, on which the SEW assessment is based; and

- AFRY's latest (Q2 2020) standard High, Central and Low scenarios as the basis, with some refinements.

The analysis considers net consumer welfare, net producer welfare and net interconnector welfare changes, based on the NPV of welfare changes, between 'with GridLink' case versus 'without GridLink' case. SEW effects are provided for GB and France and other relevant markets.

1.4 Structure of this report

This report is structured as follows:

- Section 2 sets out the modelling framework and methodology;
- Section 3 provides market background information;
- Section 4 outlines scenarios and sensitivities considered in the CBA;
- Section 5 contains modelling results; and
- Section 6 sets out SEW and CBA results.

1.5 Conventions

- All monetary values quoted in this report are in in real 2020 prices, unless otherwise stated.
- Annual data relates to calendar years running from 1 January to 31 December, unless otherwise identified.
- Plant efficiencies throughout this report are defined at the Higher Heating Value (HHV) basis. Fuel prices are similarly quoted on a gross (HHV) basis.
- Overall SEW is calculated using a 4% (pre-tax, real) discount rate, though see comments on thermal plants in Section 2.2.

1.5.1 Sources

Unless otherwise attributed the source for all tables, figures and charts is AFRY Management Consulting.

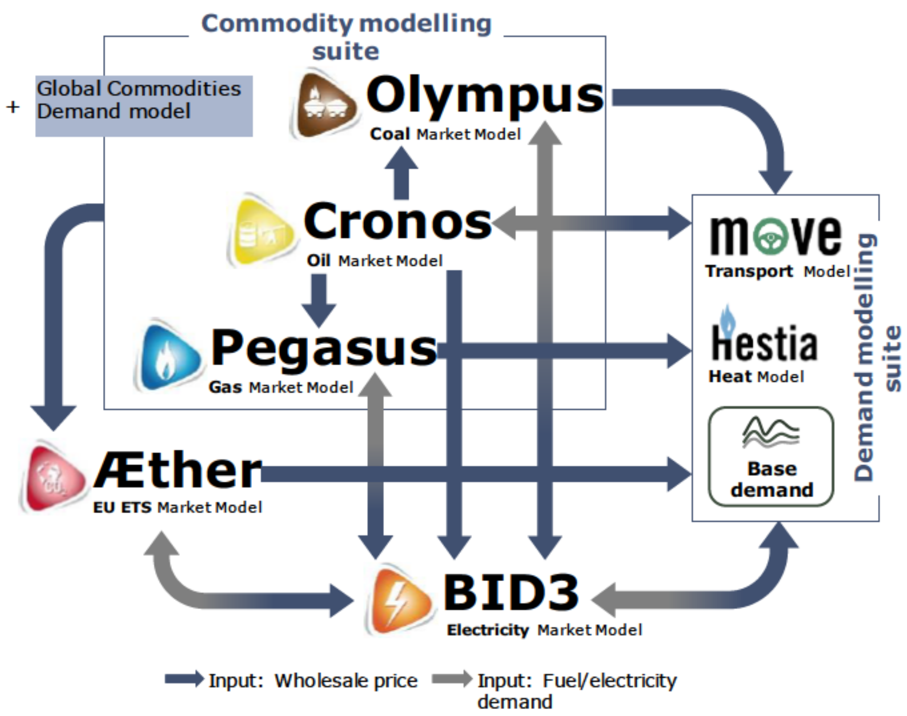
2. MODELLING FRAMEWORK AND METHODOLOGY

2.1 AFRY's pan-European electricity market model

AFRY Management Consulting has been providing energy market participants and lenders with long-term price projections for more than two decades. We produce our projections using a set of in-house market models, running in an interlinked and iterative manner to ensure consistency between related sectors. Accordingly, we have created commodity market models for oil, coal, gas, carbon, and electricity supported by models for demand in the transport and heat sector (Figure 5). These have been created and run based on a unified approach across sectors that ensures correct simulation and optimisation among the markets in terms of demand/supply and price impacts on each other. Running our models in this manner, we ensure our scenarios are internally consistent; with fossil fuels, carbon and electricity reaching a stable equilibrium in terms of price and volume.

Our models are mostly based on linear optimisation, as this has generally proven to be fast accurate and effective. Where needed – for example with unit commitment in small electricity markets – we use mixed integer linear programming (MILP). Where dealing with uncertainty is important, for example hydro dispatch, we use stochastic (dynamic) programming approaches.

Figure 5 – Overview of the AFRY modelling ecosystem

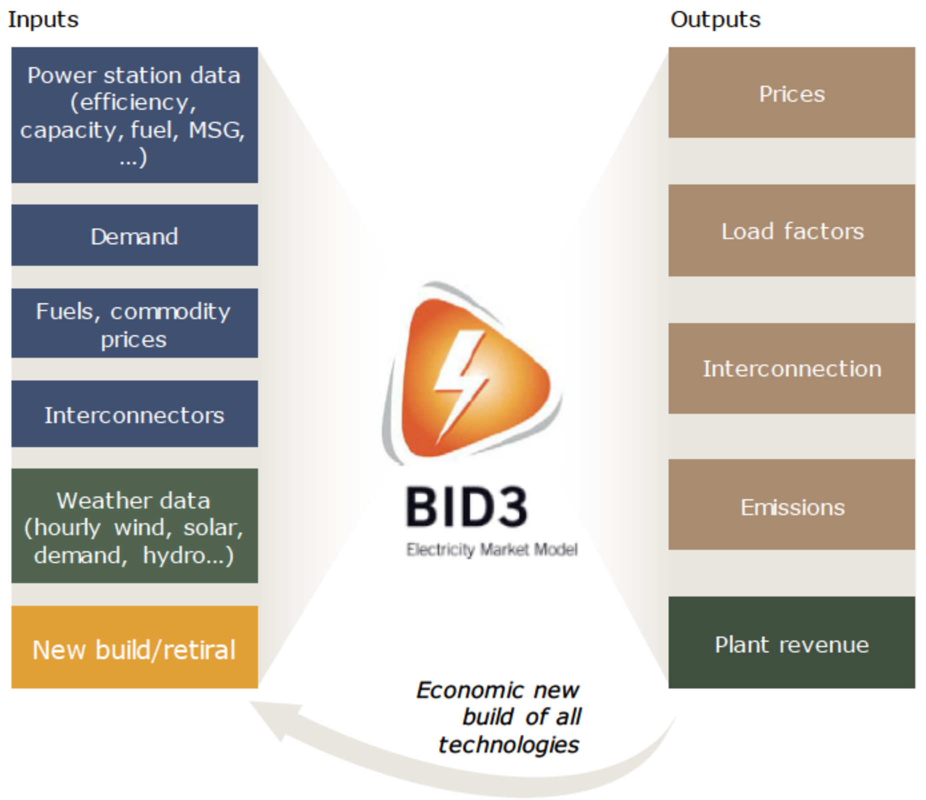


BID3 is our electricity market model, used to simulate the dispatch of all supply and demand in electricity markets as well as the economic new build and retiral decisions by market players. It lies at the heart of our modelling

suite working in an iterative manner with all of the commodity and demand models (Figure 5).

Figure 6 provides an overview of BID3, as an economic dispatch model that simulates the hourly generation of all power stations on the system, taking into account fuel prices and operational constraints such as the cost of starting a plant.

Figure 6 – BID3 Overview



2.1.1 What is the role of BID3 in AFRY's energy system?

BID3 provides a simulation of all the major power market metrics on an hourly basis – day ahead (and for some zones, balancing market) electricity prices, dispatch of power plants and flows across interconnectors. It works in an interactive manner with our commodity market, heat and transport models, receiving the commodity prices, as well as the demand for heat and transport from; and feeding back the power demand for the commodities and the electricity prices to these models.

2.1.2 How does BID3 work?

BID3 is an economic dispatch model based around optimisation. It simulates the hourly generation of all power stations on the system, taking into account fuel prices and operational constraints such as the cost of starting a plant. It accurately models renewable sources of generation such as hydro, reflecting the option value of water, and intermittent sources of generation, such as wind and solar using detailed and consistent historical wind speed and solar radiation. It fully models all sources of flexibility on the system such as pumped storage, batteries and Demand-Side Management, and also new technologies such as electrolysis and hydrogen CCGTs.

The result of this optimisation is an hourly dispatch schedule for all power plants and interconnectors on the system. At the high level, this is equivalent to modelling the market by the intersection between a supply curve and a demand curve for each hour.

2.1.2.1 Demand

There are several tranches of annual electricity demand including:

- electrified transport (largely electric road vehicles (cars, trucks, buses) and rail transport) which comes from the transport sector model called Move;
- electrified heat (predominantly space heating) which comes from the heat sector model called Hestia; and
- residual 'economically sensitive' demand (predominantly driven by GDP growth and assumptions around energy efficiency).

Annual demand is disaggregated into hourly values via a series of demand profiles that take into account historic weather patterns and demand flexibility (in the case of EVs and heating).

2.1.2.2 Supply

There are several factors influencing the supply curve, including (amongst others):

- the existing fleet of thermal assets;
- intermittent renewables;
- hydro;
- interconnection;
- the evolution technology costs; and
- fuel prices.

2.1.2.3 Weather years

We have used five historical years that cover a range of different wind and weather outcomes to capture a wide range of future probable market conditions. This means that for each future year that is modelled, five iterations are carried out, which represent the weather and demand for the historical years. For any given future year, a total of 43,800 prices can be created (8,760 x 5), giving a representation of possible interactions between weather and demand. The modelled prices are the result of the interaction of supply and demand in any given hour. The model also optimises the use of pumped storage, interconnector flow and demand-side management.

Historical weather years used in our modelling influence a large variety of factors that help drive hourly and annual wholesale electricity prices, including electricity demand patterns, hydro inflow patterns and intermittent patterns of renewable generation. For example, a very cold year with low renewable output would lead to high wholesale electricity prices, since the high demand would be covered exclusively by the thermal capacity.

In 2020 Q2 the five weather years used in our energy market modelling are 2012, 2014, 2015, 2017, and 2018.

Existing thermal assets

We maintain an extensive database of all thermal assets across Europe, with information on a range of parameters including (amongst others): fuel types; nameplate capacity; efficiency; co-firing status; start-up costs; and minimum stable generation (MSG).

Intermittent renewables

For intermittent renewables, we estimate hourly load factor profiles on a regional basis (this can be a whole country, a price zone or local regions within a country) and apply these to our projections of installed capacity.

Taking onshore wind as an example (a similar process is used for solar PV), the regional hourly load factor profile is based on: the locations of known wind farms within the region; hourly average wind speeds at each wind farm's location; the hub height of turbines at each wind farm; appropriate aggregate power curves for each wind farm; and the capacity of each wind farm.

New capacity can have different load factors to existing capacity typically as a result of improvements in turbine technology and higher hub heights.

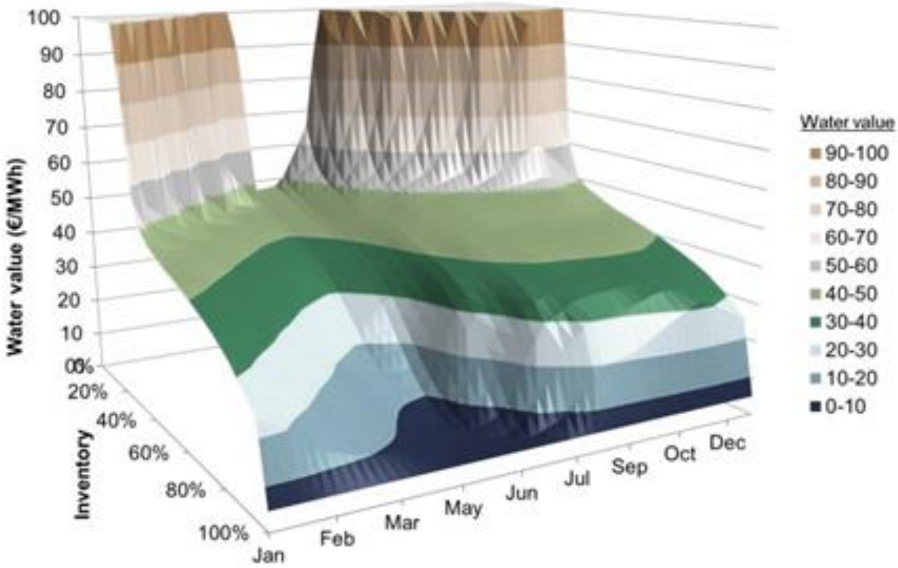
Importantly, we use consistent historical weather and demand profiles (i.e. both from the same historical year) which means we capture any correlations between weather and demand, and can also sample a variety of conditions – for example a particularly windy year, or a cold, high demand, low wind period.

Hydro

For reservoir hydro, the decision regarding how much water to dispatch for power generation and how much to store in the reservoir for later is associated with a high degree of uncertainty. Consequently, BID3 allows reservoir hydro plants to be dispatched using either:

1. A perfect foresight methodology, where each reservoir has a one year of foresight of its natural inflow and the seasonal power price level, and is able to fix the seasonality of its operation in an optimal way. This is used for the thermal-dominated markets in Europe.
2. Or a water value method, where the option value of stored water is calculated using Stochastic Dynamic Programming. This results in a water value curve where the option value of a stored MWh is a function of the filling level of the reservoir, the filling level of competing reservoirs, and the time of year. This is used for the Nordics. Figure 7 shows an example water value curve.

Figure 7 – Water value curve



Interconnection

We model both existing and new interconnection between zones. Interconnectors are assumed to be optimally utilised, i.e. equivalent to a market coupling arrangement.

Technology costs

We model the evolution of costs (capex and opex) for all generation technology types based on: observed data; discussions with our network of industry contacts; and learning rate analyses for battery storage and intermittent renewables.

Fuel prices

Fuel prices are a key determinant of the short-run marginal cost of generation. BID3 takes underlying commodity prices from our suite of commodity models and converts these to input fuel prices using an econometric analysis looking at the historical relationship between underlying commodity prices and input fuel prices.

2.1.3 *What does BID3 provide?*

The key outputs of the model are:

- prices, including:
  - the hourly System Marginal Price (as well as the marginal plant in that hour);
  - hourly levels of scarcity rent; and
  - capacity market clearing prices;

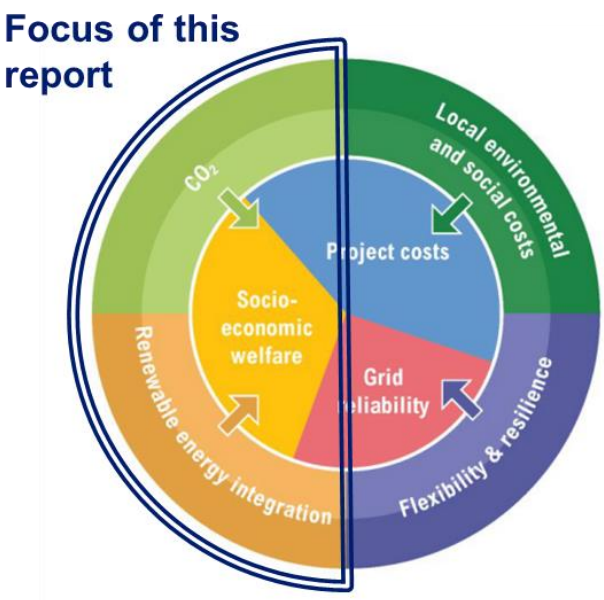
- generation volumes for all types of generation plant (thermal, hydro, intermittent renewables, storage, etc.);
- plant revenues;
- interconnection flows and congestion rents;
- capacity margins;
- new build capacity and retirals of existing assets; and
- emissions down to the plant level.

2.2 AFRY's CBA approach

The assessment of an interconnector can span a wide range of topics, including technical, environmental, market, commercial and financial analysis. In its narrowest sense, the CBA for an interconnector will include the business case for the assessed project, focussing on project returns. This business case is also a part of the socio-economic case, looking at the impact of the project on other market stakeholders, namely consumers, producers and other interconnector owners. There are additional stakeholders affected by interconnectors, the impact on which can often be only qualitatively assessed.

Our CBA methodology is broadly aligned with ENTSO-E's CBA guideline for grid development projects, with a focus on the SEW assessment, as indicated in Figure 3.

Figure 8 – SEW focus within broader ENTSO-E CBA context



To conduct the CBA and inform assessment of SEW impacts of an interconnector asset, AFRY performs market modelling runs using BID3. For a specific market scenario, BID3 runs are conducted for:

- a reference case, which excludes the relevant asset (GridLink in the case of this project); and

- a 'with asset' case, which includes the relevant asset being assessed.

For a given market scenario, all the inputs to these two runs are identical, with two exceptions:

- the addition of the interconnector in the 'with asset' case; and
- a reduction in CCGT or OCGT capacity (either existing or new build) in the 'with asset' case, based on an assessment of the marginal capacity credit[2] of the interconnector in each direction. We think it is important to account for security of supply benefits, and this is one method of doing this.

For each of these runs the following metrics are calculated for each country and year:

- **Short-term consumer surplus**:
  - this is the difference between the Value of Lost Load (VoLL) and the spot electricity price in a given settlement period multiplied by the corresponding demand, and is formulated mathematically as follows:

$$\textbf{Consumer surplus} = \sum_{i} \boldsymbol{VoLL} \times \boldsymbol{D_i} - \sum_{i} \boldsymbol{P_i} \times \boldsymbol{D_i}$$

where

i indicates a settlement period

$VoLL$ is the Value of Lost Load

D_i is the demand in settlement period i

P_i is the spot electricity price in settlement period i

For the purposes of our analysis, we have not considered costs linked to the use of the network, RES subsidies and/or other payments linked to system services.

- **Short-term producer surplus:**
  - this is the sum of difference between the spot electricity price and the short-run cost of operation of each individual production unit (plus storage assets and electrolysers) generating in a given settlement period multiplied by the corresponding output, and is formulated mathematically as follows:

$$\textbf{Producer surplus} = \sum_{\mathbf{i,j}} \mathbf{P_i} \times \mathbf{G_{ij}} - \textbf{Variable Production Costs}$$

where

i indicates a settlement period

j indicates a generating unit

P_i is the spot electricity price in settlement period i

2 Marginal capacity credit is an estimate of how much firm capacity the last MW of addition interconnection would displace, to give the same level of security of supply. This is based on looking at the relative situations in both markets in the tightest periods. For removing CCGT and OCGT capacity we average the capacity credit with and without GridLink.

G_{ij} is the level of output of generating unit j in settlement period i

$Variable\ Production\ Costs$ are the Variable Production Costs across the entire production horizon and include variable costs (such as fuel and CO_2 costs) and quasi-fixed costs such as start-up costs

- **Congestion rent:**
  - this is the income capture by an interconnector owner as a result of the price differential between the connecting price areas, and is mathematically formulated as follows (with half of the congestion rent for a particular interconnector allocated to each of the relevant countries):

$$\textbf{Congestion rent} = \sum_{\boldsymbol{kl,i}} (\boldsymbol{P_k} - \boldsymbol{P_l}) \times \boldsymbol{Flow_{kl,i}}$$

where

i indicates a settlement period

k indicates Price Area k

l indicates Price Area l

P_k is the spot electricity price in Price Area k in settlement period i

P_l is the spot electricity price in Price Area l in settlement period i

$Flow_{kli}$ is the interconnector flow from Price Area k to Price Area l in settlement period i

Taking results for the runs with and without the interconnector asset, we subtract the values in the 'without asset' run from those in the 'with asset' run to derive the net welfare impacts. To this, we then add two further components of the welfare change for country for each year:

- change in interconnector capex/opex (i.e. the Capex and Opex of GridLink in this case); and
- change in CCGT/OCGT capex/opex. Since the interconnector capacity credit varies (in each direction from year to year) it is more appropriate to include capex on a levelised (€/kW/yr) basis. There is some debate about the discount rate that should be using for levelising the capex, whether that be the SEW discount rate (4%) or the commercial rate the generators were assumed to be using (i.e. the value we use for hurdle rates in each scenario, for example 7.5% pre-tax real in the central scenario). These are outlined in an OFGEM paper[3].

These annual changes in each component are then converted to an NPV using the 4% discount rate, and added together to get the overall welfare impact for each market.

3 https://www.ofgem.gov.uk/sites/default/files/docs/2011/10/discounting-for-cost-benefit-analysis-involving-private-investment-but-public-benefit.pdf

2.2.1 Simplifications and distributional impacts

This calculation contains a number of simplifications, which are mainly relevant in terms of distributional impacts:

- We do not consider the impact of CFDs or other forms of generation support. For example, higher electricity prices would mean the generators with CFDs need receive less support, so represent a decrease in producer surplus and corresponding increase in consumer surplus.
- The impact of a change in capacity payments to generation/storage assets is considered (though not expected to be large), but changes in capacity payments to interconnectors are not. This is also distributional since an increase in payments would be a gain for interconnectors and loss for consumers (and vice versa).
- We do not include the change in tax revenues in the EU ETS or GB carbon floor due to a change in interconnectors. For the EU ETS, the case that they should not be included is that if CO_2 is priced correctly, then there is a benefit to the drop in emissions counteracting the potential decrease in EU ETS auction revenues. The case of the GB carbon floor is less clear, as to some extent its effect is to transfer CO_2 emissions from GB to other markets.

3. MARKET BACKGROUND

3.1 Introduction

In this section we describe the main physical characteristics of the electricity markets in Great Britain and France, reviewing historical trends such as electricity demand, generation mix and interconnection as well as describing the key market arrangements in place.

3.2 Great Britain

The wholesale market in Great Britain is one of the longest established competitive electricity markets globally. Since privatisation in the early 1990s it has undergone radical change in terms of generation mix, market players, and electricity market rules.

Large, vertically integrated companies have traditionally dominated the wholesale market. The Big Six, along with Drax, have dominated both generation and supply in recent years. However, market concentration and vertical integration are reducing as the market is becoming more competitive with the entry of alternative wholesale electricity market participants.

The operation of the market is under the British Electricity Trading and Transmission Arrangements (BETTA), which is characterised by a forwards market, power exchanges, the balancing mechanism and a settlement process. A Capacity Market operates alongside the energy market.

Capacity and generation mix in Great Britain have changed significantly over the past decade with capacity historically being commissioned in clusters of periods and technology types. Recent examples include the ‘dash for gas’ period in the 1990s and the recent surge in renewable technology capacity in the 2010s. Supplementing domestic generation, GB also tends to import power from France, Belgium and the Netherlands.

Demand in GB had been growing until the mid-2000s, thereafter it started to descend, driven down by decreases in industrial and domestic demand, especially in the midst of the financial crisis. Demand has slowly declined since with lower industrial demand as well as increases in energy efficiency measures, and the trend is expected to continue due to the impact of COVID-19.

3.2.1 Electricity demand

There are many supply-side issues that are currently attracting attention in the GB market – such as the growth of renewables and the impact of the LCPD and IED directives. However, the demand side is equally important – the pattern of electricity demand in recent years has changed and the outlook is uncertain.

Figure 9 shows historical demand evolution in GB. Up to the mid-2000s, demand growth was stable, with some variance due to various economic drivers. Through the 1990s demand grew at an average rate of 1.8% a year. This level of growth was equivalent to the output from a new 800MW CCGT every year, contributing to the 'dash for gas' of the 1990s. Retail prices and temperature fluctuations have an influence on demand; however, economic growth has been the main driver of electricity demand over the past 30 years.

Figure 10 shows total electricity demand by each sector in the UK. In recent years, decreases in industrial demand and some fall in domestic demand (particularly from energy efficiency improvements) have led to declining total demand.

Figure 9 – Historical demand in Great Britain (TWh)

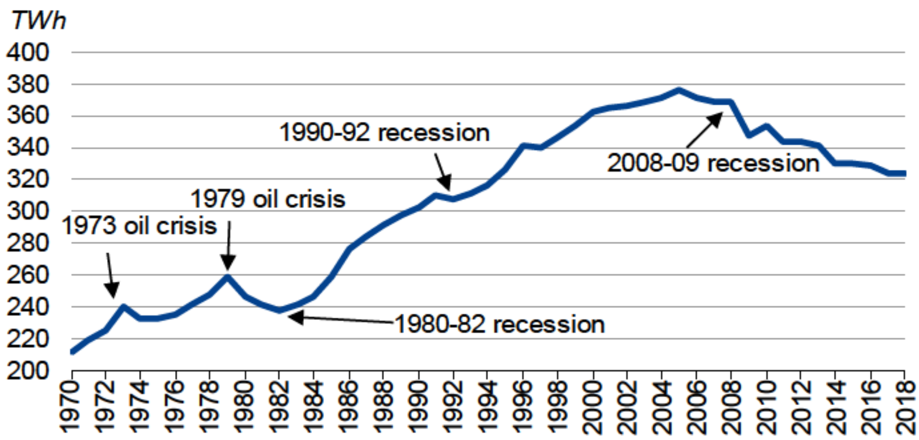
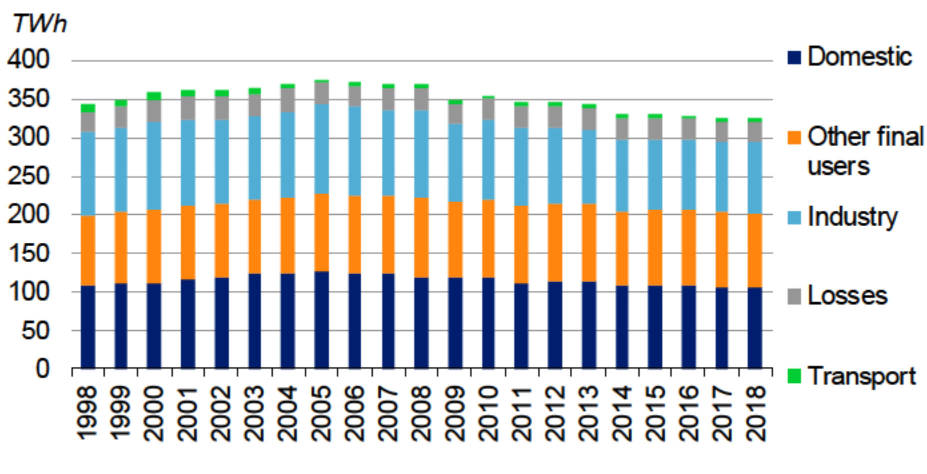


Figure 10 – Electricity consumption by sector in the UK (TWh)



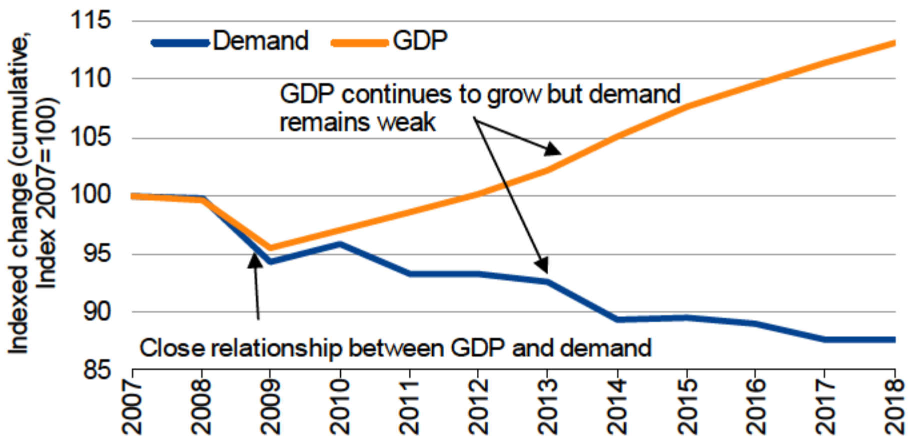
Notes: Includes Northern Ireland (approx. 3% total demand)
Source: BEIS

In contrast to the strong demand growth of the past, between 2003 and 2008 demand growth was relatively flat before falling dramatically (by 5.0%) in 2009. This fall in demand was mainly because of reduced economic activity – with UK GDP dropping by 4.3%. The largest drop in electricity demand in recent years has been in the industrial sector, which has seen around an 18% drop since 2008. Some of this reduction is through outright closures of major industrial sites such as Corus's steel plant in Teesside. However, much of the fall was due to reduced activity levels at industrial sites.

Prior to the financial crisis in 2008, demand growth had already been slowing partly as a result of slower economic growth compared to the late 1990s. Although economic growth was slowing this was unlikely to be the only factor. A greater focus on energy efficiency with initiatives like: the Carbon Emissions Reduction Target (CERT, which places obligations on large suppliers to assist customers in reducing consumption); tighter building regulations; Carbon Trust schemes; and the Carbon Reduction Commitment (CRC) have contributed to the slow down (and eventual reversal) of demand growth.

Figure 11 shows the GDP growth and demand growth since 2007. After a close to 1:1 relation during the financial crisis, the recovery of GDP has not been complemented by a recovery in electricity demand growth. This was also the case in the early 2000s, as growth in energy efficiency measures weakened the correlation between demand growth and GDP growth. It is important to note that just because correlation between growth in electricity demand and GDP growth has weakened in recent years does not mean that the relationship between the two has disappeared. Conflicting drivers are affecting the evolution of demand in GB and the prevailing demand evolution will be a result of the relative strength of these drivers.

Figure 11 – GDP growth vs demand growth since 2007 (% change from 2007 values)



Note: Demand not corrected for weather
Source: ONS, BEIS, Pöyry Management Consulting

3.2.2 *Generation and capacity mix*

3.2.2.1 Historical evolution

Investment in new capacity has generally been clustered, with periods of substantial new build (specifically 1965-1975 and 1990-2005) followed by periods of limited new capacity. In terms of interconnection, the BritNed interconnector was commissioned in 2011, the East-West interconnector with Ireland in 2012 and the latest NEMO interconnector with Belgium came online in 2019.

The change in the capacity fuel mix since vesting can be seen in Figure 12. The vast majority of new developments have been CCGTs, with the 'dash for gas' clearly evident between 1990 and 2000 with gas capacity increasing from around 2GW to 24GW. In more recent years there has been a rapid deployment of renewable capacity driven by government subsidies, with around 30GW of solar, offshore and onshore capacity operating in 2018. In addition, there has been a rise in biomass and waste capacity in recent years (shown in the "Other" category, along with non-pumped hydro), driven by government backed incentives, notably the ROC and CfD subsidy regimes.

A significant drop in coal capacity in 2013 is due to the closure of coal plants under the LCPD. In 2016 the closure of Ferrybridge, Rugeley and Longannet, and the recent conversion to biomass of the Drax and Lynemouth coal units have further reduced the size of the coal generation fleet in GB. Over the next 3-4 years we expect the remaining coal fleet in GB (Drax, Ratcliffe, West Burton) to close. The government has consulted on whether any existing capacity that does not meet carbon emission limits proposed in the EU's Clean Energy for All European's package (coal plants do not) should be allowed to receive capacity payments starting from 1 October 2024. This means coal plants may no longer be eligible for capacity payments starting in the T-4 auction held next year for the delivery year 2024/25 and may, hence, be planning to retire beforehand.

Figure 12 – Electricity installed capacity by fuel (GW)

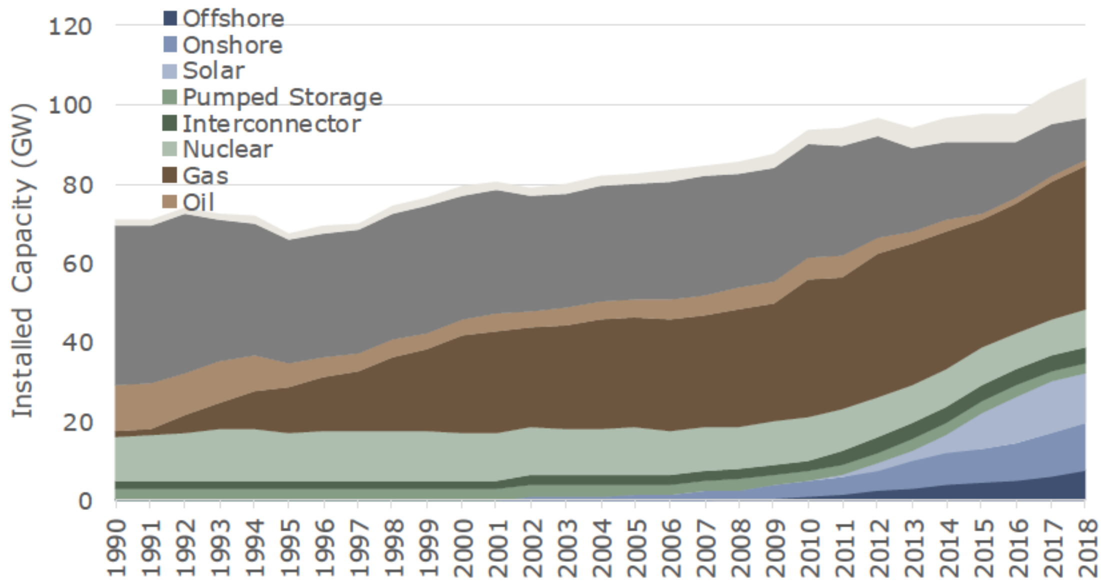


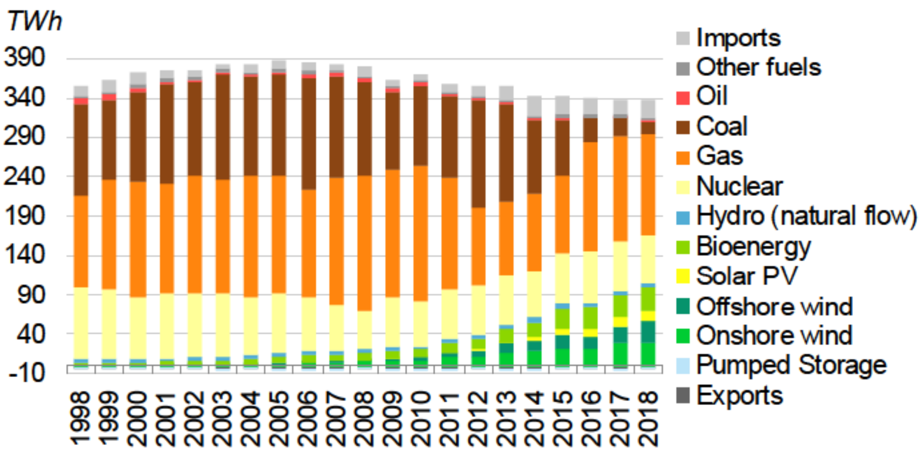
Figure 13 presents a historical overview of electricity generation by fuel in GB from 1998-2018. The generation mix has undergone a radical transformation from the early 2000s. Steadily increasing generation from renewable sources such as solar, wind and bioenergy has eroded the market share of traditional thermal generators. In recent years, political adversity and poor wholesale market economics has forced the closure of several large coal generators dramatically reducing the share of coal in the GB generation mix. A wave of plant closures started in 2015 with several plants closing due to the LCPD and IED directives, poor economics or due to reaching the end of their lifetime (Wylfa). In early 2019, EDF announced it would close Cottam in September

2019 and RWE the closure of Aberthaw in March 2020, leaving just over 5GW of coal capacity online at this time. The role of coal in the generation mix has been rapidly shrinking in recent years.

Falling volumes of coal generation have been replaced by increased generation from gas fired plant. The low levels in gas generation between 2012 and 2015 were caused by growing competition from lower cost coal and higher gas prices which created unfavourable conditions for the less efficient CCGTs on the system. A number of 'less efficient' CCGT units were then mothballed, closed or converted to more flexible operation. Sutton Bridge and Severn Power CCGT are the latest thermal plants facing adverse economics to have to be put in a dormant state in August 2020.

Increasing wind, solar, and bioenergy generation has pressured the contestable demand for thermal plant in recent years. Capacity additions for these technologies to date have mainly been driven by the Renewables Obligation, the small-scale Feed in Tariff, competitively allocated FiT CfDs, and a number of contracts awarded under the FIDeR scheme. The decreasing role of coal generation is well evidence in Figure 13. In recent years, coal generation has been broadly limited to high demand and cold-weather periods (as in March 2018 during the 'Beast from the East').

Figure 13 – Electricity output by fuel (TWh/year)



3.2.3 *Interconnection*

At present, the electricity market of Great Britain is interconnected via 5GW of interconnection capacity with neighbouring countries:

- 2GW with France via IFA (1986);
- 1GW with the Netherlands via Britned (2011);
- 1GW with the Irish Single Electricity Market (SEM) via Moyle (2001) and EWIC (2012); and
- 1GW with Belgium via NEMO (2019).

All existing interconnectors (with the exception of NEMO) were developed as projects on a merchant basis, before the cap and floor regime was introduced in 2014.

The cap and floor regime is the regulated route for electricity interconnector in GB, to incentivise new cross-border infrastructure. Firstly proposed as a regulated regime for the NEMO interconnector, to date two application windows have been held granting a cap and floor regime (in principle) to nine interconnector projects totalling 10.9GW of capacity.

The cap and floor aims at providing long term revenue stability by mitigating revenue exposure through a minimum (floor) and maximum (cap) on the revenues that the interconnector can earn. Where revenues rise above the cap or fall below the floor, payments are made from or to the interconnector respectively to draw-down or top-up to the prescribed cap and floor levels.

With the support of the cap and floor regime, GB has a strong pipeline of interconnection projects which set to increase the significantly the overall level of interconnection over the next decade. 2GW further of interconnection projects with France – via the ElecLink and IFA2 projects – have been under construction and were expected to be commissioned in the summer of 2020 before delays set in. Table 1 shows future interconnection projects under construction and development.

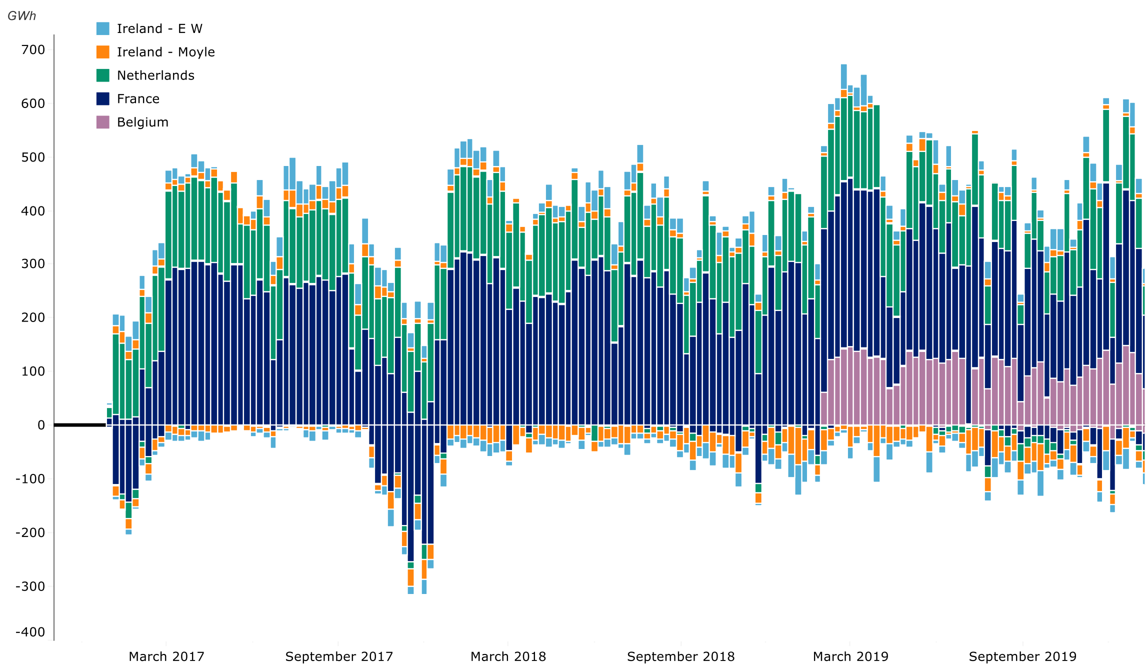
Table 1 – Interconnection projects under construction and development

Project	Capacity (GW)	Connecting country	FID reached	Estimated Delivery date	Route to market
ElecLink	1	France	2016	2020	Merchant
IFA2	1	France	2017	2020	Cap&Floor
NSL	1.4	Norway	2015	2021/22	Cap&Floor
VikingLink	1.4	Denmark	2018	2023	Cap&Floor
FABLink	1.4	France	-	2023	Cap&Floor
Greenlink	0.5	Ireland	2020	2023	Cap&Floor
NorthConnect	1.4	Norway	2020	2023/24	Cap&Floor
Aquind	2	France	-	2022	Merchant
GridLink	1.4	France	-	2024	Cap&Floor
NeuConnect	1.4	Germany	-	2023	Cap&Floor

Figure 14 presents weekly total flows with markets interconnected to the GB market. Great Britain tends to be a net importer from France and the Netherlands due to a price premium in the GB wholesale electricity market over the French and Dutch markets. One of the primary reasons for this premium is the higher costs faced by generators in GB as a result of the

Carbon Price Support mechanism, as well as the charging of BSUoS[4] which are both passed through into higher wholesale prices. This trend temporarily reversed towards the end of 2016 and 2017 as tightness on the continent, principally due to widespread French nuclear outages, meant prices were higher in France and consequently resulted in net flows towards the French market.

Figure 14 – Weekly flows from interconnected markets (GWh per week, gross)



3.2.4 *Trading arrangements*

3.2.4.1 *NETA (March 2001-March 2005) and BETTA (March 2005-present)*

In 2001, the UK introduced a bilateral physical market for electricity through the introduction of the New Electricity Trading Arrangements (NETA). NETA replaced the Pool on 27 March 2001, following the Utilities Act of 2000. Ofgem, the industry regulator, designed NETA with a view to making it resemble other commodity markets as closely as possible. The market-based trading arrangements were based on bilateral trading between generators, suppliers, traders and customers.

In 2000, Ofgem proposed a modified version of the NETA arrangements be implemented in Scotland (as well as England and Wales) in the form of the

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4 BSUoS is under regulatory review in GB. The 2nd BSUoS Task Force has the aim of determining who should pay for BSUoS, its interim report published in July 2020 conclude that 'Final Demand' should pay all Balancing Services charges, therefore removing the charge from generation.

British Electricity Trading and Transmission Arrangements (BETTA). GB-wide arrangements commenced operation in April 2005. BETTA was based on NETA market arrangements in England & Wales, including the Balancing and Settlement Code (BSC).

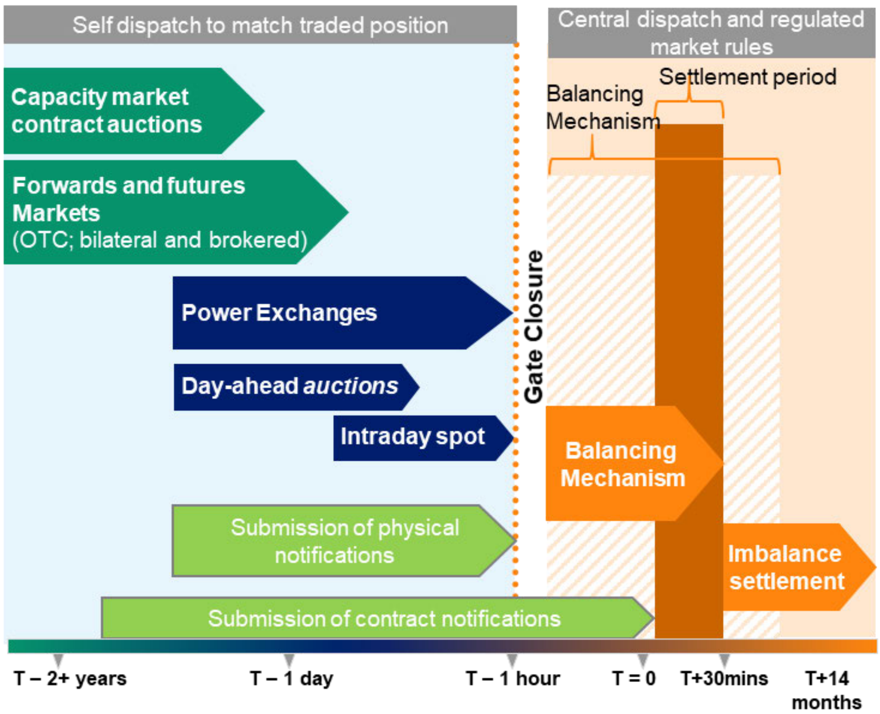
3.2.4.2 Market rules overview

The trading arrangements allow generators to sell their electricity to suppliers, as well as provide a means of managing price risk.

"*competition is achieved through unrestricted bilateral contract trading where the supplier buys the required electricity volume at a price they are willing to pay, and generators in turn sell electricity at a price they are willing to receive for it. The final price reached by negotiation or exchange trading*".

The final responsibility for maintaining a physical balance between generation and demand lies with National Grid Electricity System Operator (ESO), which is achieved through the use of the 'Balancing Mechanism' for the purpose of procuring additional generation or turning plant down if required. Participants that fail to meet their contractual positions face penalties based on the costs incurred by the ESO to balance the system. Figure 15 presents an overview of the current electricity trading and balancing arrangements in GB.

Figure 15 – GB electricity trading arrangements under BETTA



BETTA can be characterised by the following elements:

- Forwards and futures markets that allow contracts for electricity to be struck up to several years ahead.

- Short-term 'spot' power exchanges, enabling participants to 'fine-tune' their physical positions up until Gate Closure (and contract notifications until the delivery period).
- A common scheme for transmission access and charging.
- A Balancing Mechanism, which opens at Gate Closure, in which the ESO accepts offers and bids for electricity to enable it to balance the transmission system.
- A settlement process for charging participants whose contracted positions do not match their metered volumes of electricity, for the settlement of accepted Balancing Mechanism offers and bids, and for recovering the ESO's costs of balancing the system.

A Capacity Market operates alongside the energy market, and is designed to provide (or partially provide) longer-term signals for market entry and exit.

3.2.4.3 Electricity trading

There are different 'routes to market' that a company can take for the power that it generates in Great Britain. Options for realising value include:

- using own retail supply business to access the market;
- selling the power to another party via a Power Purchase Agreement (PPA) or other form of long-term bilateral contract;
- selling the power to another party through a bilateral trade under a Grid Trade Master Agreement (GTMA), which is normally done via a broker;
- selling the power through a power exchange (N2EX, APX-UK or ICE);
- selling the power though the Balancing Mechanism; or
- accepting imbalance ('cash-out') prices for the power.

Historically, the output of the Big Six companies was largely conveyed to market through their own supply business. Many independent players also have PPAs with the Big Six suppliers for portions of their output. A large portion of the physical power in the UK therefore arguably never reached the 'traded segment', which can broadly be considered to be the last four bullets in the above list. Centrica and E.ON have 'spun-out' or sold the majority of their generation assets in recent years. These large suppliers now need to procure more power directly from the market, which could manifest as increased liquidity in the traded segment. Albeit there is still the possibility that the supply businesses of these companies agree long term PPAs with either other members of the Big Six, or with smaller independent power producers.

Bilateral contracts are favoured for trading large volumes of electricity between parties at the season, quarter, or month-ahead stage. Power exchanges are generally favoured for 'fine-tuning' positions closer to real time. Power exchanges can be used for continuous trading to reposition in the case that an unexpected event occurs close to real-time delivery (such as plant outages, or large forecast errors). The majority of the volumes traded on power exchanges are through day-ahead auctions. Participants can submit bids and offers for delivery the following day. Once the day-ahead auction closes, a market clearing algorithm is run centrally to determine prices and positions for delivery the following day.

3.3 France

France is one of the largest electricity markets in Europe and is well interconnected with surrounding countries.

Overall electricity consumption has been stable in France since the 2008-09 economic slowdown as a result of increased energy efficiency measures and limited pick-up in economic activity.

French installed capacity is mainly made of nuclear plants although renewable penetration has increased over the last decade. Evolution of the capacity mix is a politically sensitive issue, especially in terms of nuclear plant lifetime extension. Proposals for closure of nuclear units by 2035 have been submitted.

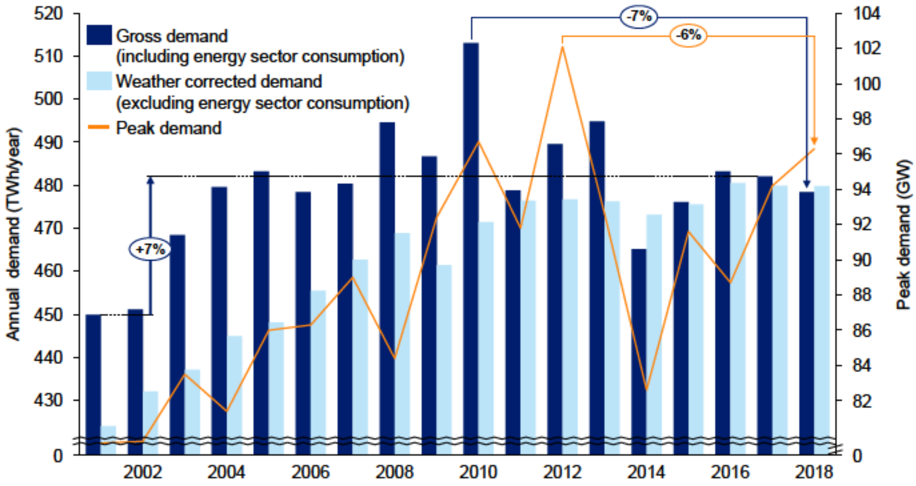
The EDF group dominates the generation mix (sole nuclear owner / operator), has a regulated monopoly in transmission and distribution, and is still a leading supplier but alternative market players have been gaining market shares since retail market liberalisation began in 1999.

3.3.1 Electricity demand

In 2018, total gross (non-weather corrected) electricity consumption in France was 478TWh, relatively stable when compared to 2017 (a 0.8% decrease) due to slightly higher than average temperature in the early and late months of the year, lower economic growth than in 2017 as well as significant social movements (“gilets jaunes”) in the rail transport sector. Peak demand reached 97GW on 28 February 2018 during cold spells; resulting in a 2GW increase (+3%) from 2017 (but still 5GW below the 2012 record level of 102GW).

Figure 16 shows the evolution of the French electricity demand in annual volume and peak since 2001.

Figure 16 – Historical annual (TWh) and peak (GW) electricity demand



Sources: RTE, AFRY Management Consulting

Key points to note with regards to evolution of French electricity demand since 2001 are:

- Gross electricity demand grew in line with economic growth between 2001 and 2007, with peak demand growing at a faster rate than annual volume demand due to higher penetration of electrical heating in the residential and services sectors leading to an increased thermo-sensitivity of electricity demand[5].
- 2010 was an exceptionally cold year (the coldest since 1996), resulting in the only occurrence of annual demand over 500TWh (513TWh). Gross electricity demand has reduced significantly since then (-6%) because of the gradual decommissioning of the Georges Besse uranium enrichment plant (formerly known as EURODIF and permanently closed since June 2012) on the Tricastin nuclear site, replaced by the more efficient Georges Besse II plant. This facility used to consume up to 15TWh per year.
- Slow economic recovery following the 2008-09 economic crisis has resulted in a relatively stable electricity (weather corrected) demand since 2010; reflecting a noticeable change in the evolution of the French electricity demand pattern compared to the early 2000s.
- Due to the large share of electric heating, France is the most thermo-sensitive country in Europe. Analysis conducted by RTE showed that, across Europe, when temperatures are one Celsius degree below seasonal normal, an additional 5.6GW is required to meet demand. Of this additional capacity, 2.4GW are solely for France. Although temperature sensitivity is still likely to remain an important factor in France, its impact is expected to progressively reduce over time due to the implementation of the Thermal Regulation 2012 (RT 2012) in buildings, thus leading to a

5 RTE, 'Bilan Électrique 2018'.

lower share of electric heating in new housings. A new thermal regulation (RT 2020) is being developed.

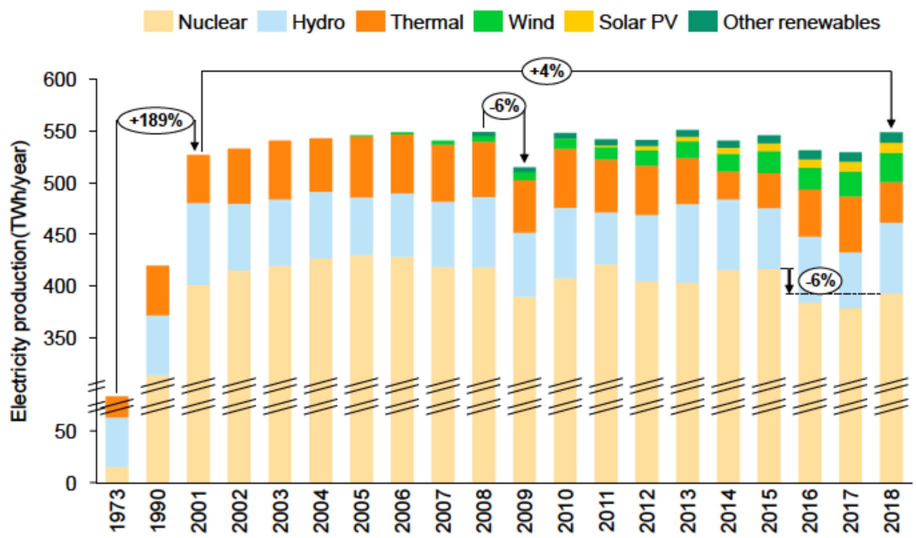
- Increasing energy efficiency measures in the residential and services sectors, developed through regulation (promotion of better housing insulation) and equipment performance, contribute to electricity demand stability despite economic growth and the development of new electric usages (heating and transportation sectors).

3.3.2 Generation and capacity mix

3.3.2.1 Historical evolution

Since the first oil shock of 1973, France has pursued an active policy of achieving energy self-sufficiency, largely through nuclear power (as shown in Figure 17) given its lack of domestic primary energy resources. The impact of the economic crisis in 2008 and lower electricity generation (around -6%) is clearly visible. Since then, electricity production has recovered and reached pre-crisis levels, but growth has been relatively limited. From 2010 onwards, the share of fossil-fuel (gas, coal) and oil-fired thermal technologies has been declining in the generation mix, progressively replaced by renewable energies (wind, solar and biomass).

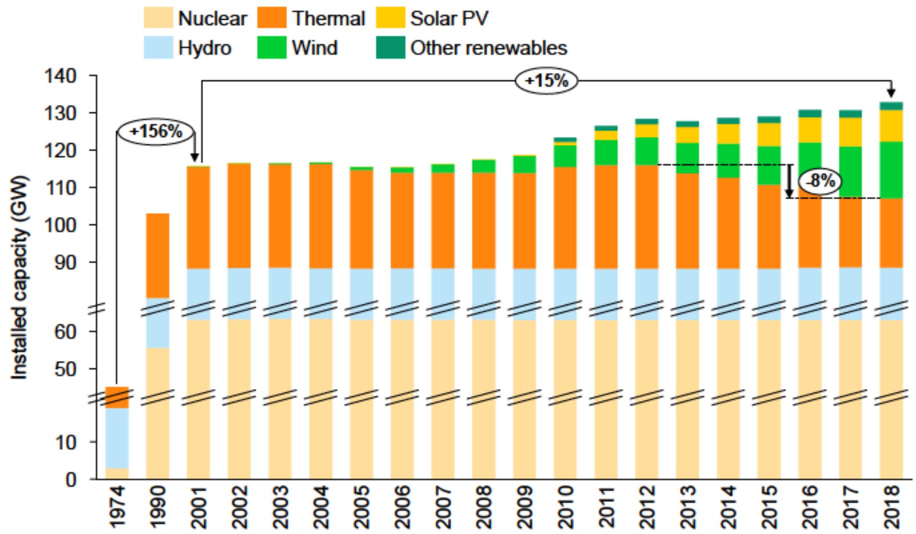
Figure 17 – Electricity production by fuel in France (TWh/year)



In 2016 and 2017, France's total electricity generation dropped to around 530TWh (having remained above 540TWh/year since 2010). This was primarily due to reduced nuclear generation (a 9% reduction from 2015 to 2017) following the temporary closure of several reactors for safety investigation starting in Q4 2016 (and extending into early 2017) and again during Q4 2017. Fossil-fuel (primarily gas) generation stepped up noticeably during this period (as well as imports from surrounding countries – see Figure 21). Nuclear availability returned to higher levels during 2018.

Figure 18 presents the evolution of installed capacity since 1974. Hydro and conventional thermal capacity has remained relatively stable following a growth period until the mid-1980s. Increases in installed capacity were mostly driven by nuclear, beginning at 3GW in 1974 and growing to reach 63GW in the early 2000s (which is the current installed capacity). Since the early 2000s, increases in installed capacity have largely been driven by the development of renewable technologies (mostly onshore wind and solar PV) and a small amount of thermal plants (CCGTs).

Figure 18 – Electricity installed capacity by fuel in France(GW)



In 2018, growth in generation capacity was mainly from renewable technologies (with nearly 2.5 GW of additional capacity), while thermal capacity continued to decrease, following the trend initiated in 2012. This has been driven by the Large Combustion Plant Directive (LCPD) and the Industrial Emission Directive (IED) triggering the closure of several thermal plants unable to fulfil emissions criteria set by these regulations (effective from 2016 and 2024 respectively). These European Directives resulted in EDF announcing:

- the closure of its Aramon oil-fired steam plant (1,370MW) in April 2016;
- its four units at the Porcheville plant (nearly 2,400MW) in May 2017; and
- its two units at the Cordemais plant (nearly 1,400MW) between May 2017 and April 2018 .

All those closures resulted in a reduction of the 2016 installed oil-steam fired capacity (7.1GW) by more than 50%.

At a domestic level, the 2017 Climate Plan called for the phasing out of coal-fired generation (4 plants) in France by 2022 and all fossil-fuel generation by 2040. Although EDF announced that it will close its Le Havre coal plant by 2021[6], there has been no formal closure announcements for EDF Cordemais

[6] L'Usine Nouvelle, 'La fermeture de la centrale à charbon du Havre avancée à 2021', 7 June 2019.

site nor for the EPH plants (formerly owned by Uniper). However, it is expected both operators will comply. This would tend to be supported by experimentations being made EDF on biomass co-firing ("Ecocombust" test on the Cordemais site) and Uniper having launched a call for initiatives to help supporting the development of new industrial activities on its two coal sites[7]. In December 2019, EDF announced its intention to keep the Cordemais plant operating until 2026 and submitted a plant to the government for the biomass conversion[8].

3.3.3 Nuclear capacity

The development of nuclear capacity in France started after the first oil shock in 1973 and progressed quickly between the 1980s and the mid-1990s. As of 2018, French nuclear fleet consisted of 58 reactors distributed over 19 locations (for a capacity of 63GW). Whilst the French nuclear plants were built with an anticipated 40-year nominal lifetime, the Nuclear Safety Authority ('Autorité de Sureté Nucléaire' – ASN) is responsible for overseeing their safety. It does so through decennial inspection of each reactor upon which a 10-year operating licence is granted.

Following the discovery of inconsistencies in certification documents in an Areva factory[9], the ASN launched an investigation and requested further analysis to re-assess the quality of nuclear plants components provided to EDF. Along with planned maintenance schedules, this led to around a third (22GW) of the French nuclear fleet being offline during October 2016. All 15 reactors under review were gradually authorized to go back online from November 2016 to January 2017[10]. In September 2017, the ASN required the closure of the four Tricastin reactors (3.7GW) for new maintenance works against seismic risks[11]. They were authorized to restart on 5 December 2017. In September 2019, EDF informed the ASN of its investigation into 16 operating steam generators with deviation from technical standards in relation with post-weld treatment process. The review process is ongoing from the ASN, EDF and its subsidiary Framatome[12].

3.3.3.1 Future of French nuclear

The future of nuclear capacity in France, both in terms of lifetimes and new build, is a very sensitive and controversial topic. The current PPE out to 2023 did not envisage specific nuclear plant closures. Since 2018, the French

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7 Le Point, 'En France, la délicate fermeture des centrales à charbon', 24 August 2018.

8 Montel, 'EDF to keep Cordemais power plant open to 2024', 10 December 2019.

9 Le Monde, 'Un tiers du parc nucléaire d'EDF est à l'arrêt', 18 October 2016.

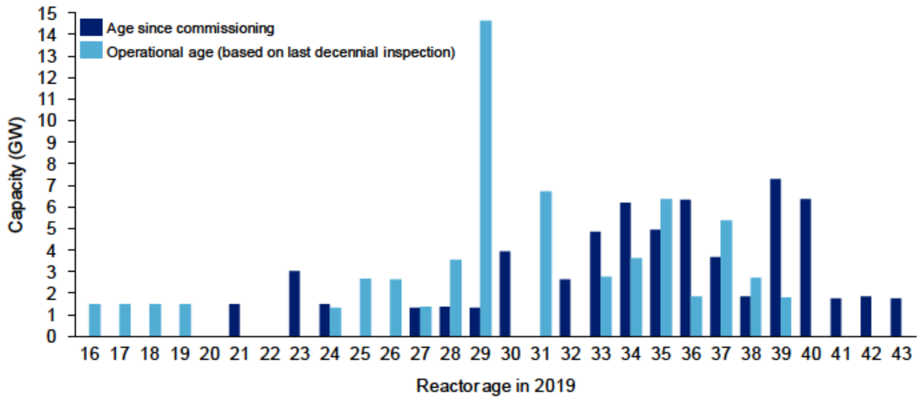
10 Le Monde, 'Redémarrage de neuf réacteurs nucléaires d'EDF autorisé', 13 January 2017.

11 EDF, 'Mise à l'arrêt provisoires des quatres unités de production de la centrale nucléaire de Tricastin', September 2017.

12 EDF, 'Point sur l'écart relatif au référentiel technique de fabrication de composants de réacteurs nucléaires par Framatome', September 2019.

government has been working on establishing the next PPE out to 2028 and on January 2019 outlined its ambitions for France's energy policy for the coming decade (final version to be adopted in Parliament by the end of 2019).

Figure 19 – Capacity weighted age distribution of nuclear plants in France

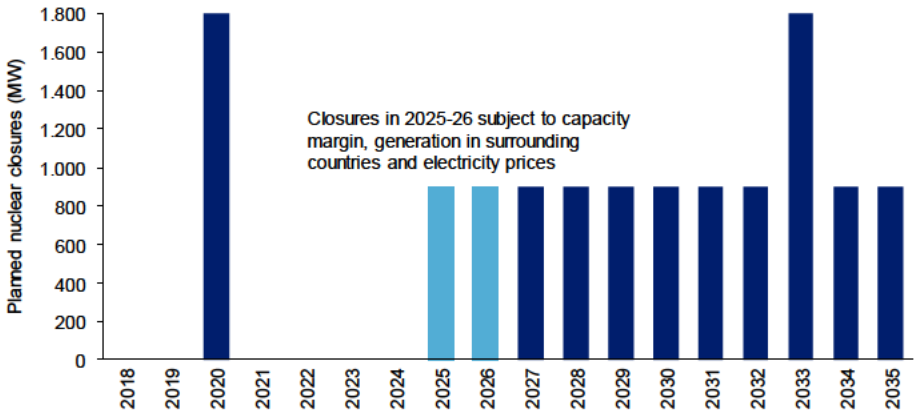


Sources: ASN, AFRY Management Consulting

Of relevance to nuclear, 14 nuclear reactors (900MW each) are considered and planned for closure by 2035. Of those, two will be closed in 2020 (Fessenheim), 4 to 6 additional units by 2030 and the remaining by 2035 as part of their fifth decennial inspection (Figure 20). As part of this preferred trajectory, the construction of new nuclear units remains an option as part of guaranteeing security of supply in the long-term, subject to EDF submitting a plan by mid-2021 outlining how new nuclear capacity would be a viable option (industrial capacity, economic optimization, nuclear waste storage, financing, regulatory and legal aspects) compared to alternatives such as batteries, hydrogen, power-to-gas and demand side management. In a letter leaked in October 2019, the government asked EDF to size its nuclear capacity plan on the assumption of 3 pairs of new EPR reactors with 4 years between each pair and 18 months between two reactors in a pair by 2035[13]. The target date for bringing the share of nuclear to 50% in electricity production has been set to 2035 in the proposed 2023-2028 PPE.

13 Le Monde, 'Nucléaire : comment le gouvernement travaille en catimini à la construction de six nouveaux EPR', 15 October 2019.

Figure 20 – Proposed trajectory for nuclear closure in the 2023-2028 PPE



Source: Ministère de la Transition Ecologique et Solidaire

3.3.4 *Interconnection*

Owing to the large amount of generation from nuclear power plants on the system and its low marginal cost, France is the largest exporter of electricity in Europe and was a net electricity exporter (on a contractual basis) to all neighbouring countries except Germany in 2018. France mainly exports baseload power and imports during peak time due to higher generating costs in such periods in France compared to neighbouring countries given that the French capacity mix has limited mid-merit plants before resorting to expensive domestic oil-fired steam units.

As illustrated in Figure 21, whilst France remained a net exporter, its import and export patterns have varied over time:

- Between 2007 and 2010, exports decreased, and imports increased because of low nuclear availability. The lowest level of net exports was reached in October 2009 when France became a net importer from Belgium for a whole month (the first time in 27 years at that time) following unexpected nuclear outages and cold weather driving up electricity demand. This exceptional need for imports was fulfilled by an increase of contractual import flows from both Belgium and Great Britain[14].
- Between 2011 and 2013, the combination of higher nuclear availability and changes in German nuclear policy (Energiewende) led to a reverse in the trend, with flows reaching their pre-2008-09 economic crisis levels.
- In 2014-2015, net exports rose thanks to high nuclear and hydro generation, as well as a new interconnection being commissioned with Spain.
- In 2016-2017, net flows dropped to their lowest level since 2010 due to sustained reduction in exports between June 2016 and February 2017 following low nuclear availability.

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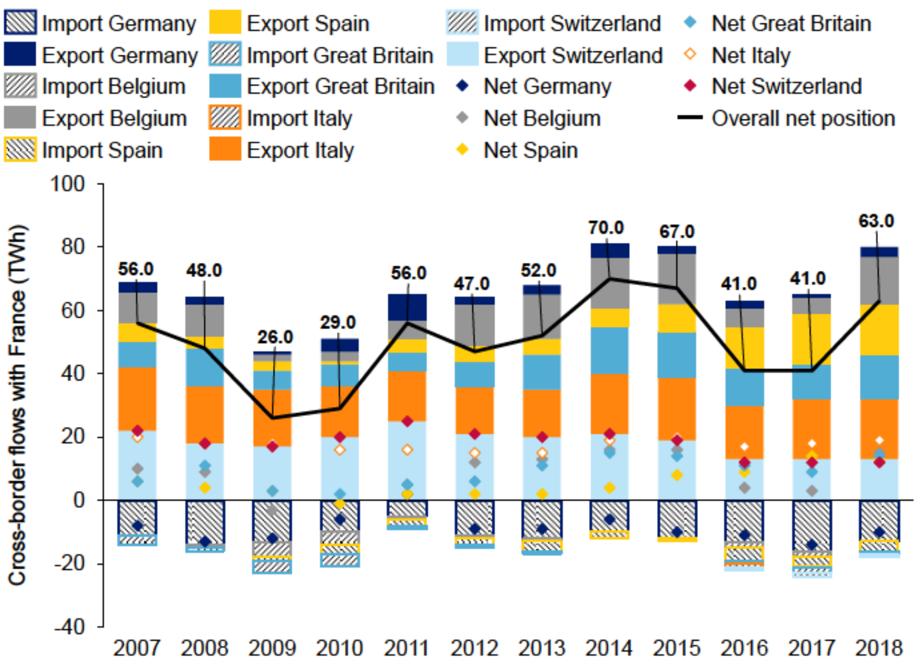
14 RTE, 'L'énergie électrique en France', January 2009.

- In 2018, export flows recovered to their 2014-2015 levels due to higher nuclear availability.

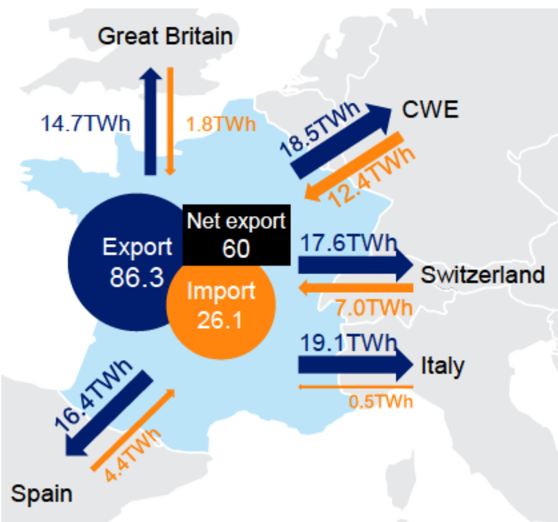
Figure 21 – Evolution of physical flows 2007-2018 (TWh/year)



Sources: RTE, Pöyry Management Consulting

Figure 22 presents the French commercial flows with its surrounding countries in 2018. The notable difference between reported physical flows (which is calculated as the sum of daily flows) in Figure 21 is due to certain transactions such as intraday exchanges, exchanges conducted under the Balancing Mechanism or mutual back-up contracts, as well as ex-post corrections.

Figure 22 – Overview of commercial flows in 2018 (TWh)

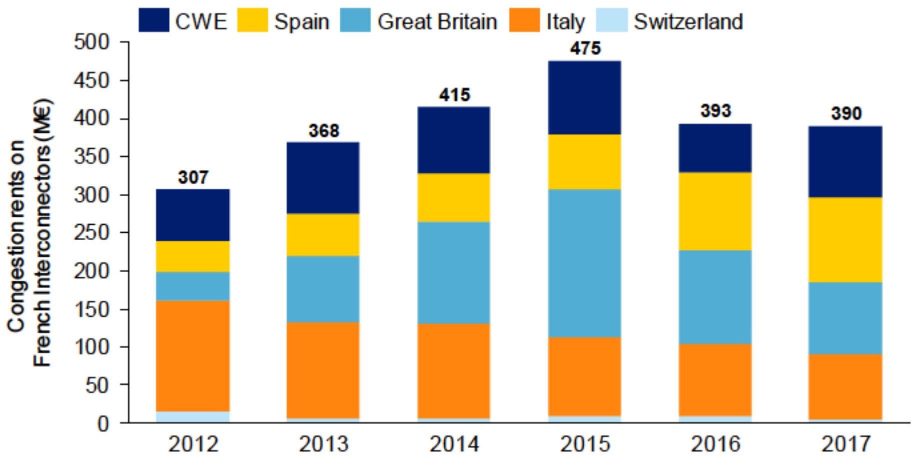


The physical flows represent the actual flow of electricity across borders whereas the commercial flows represent the electricity sold between countries. For example, France can sell electricity to Belgium, but power may physically first go through Germany

Congestion rents appear as a result of insufficient interconnection capacity between two price zones and reflects the price differentials between the zones concerned.

Figure 23 shows the total congestion rent revenues shared across TSOs with links to France between 2012 and 2017. Revenues from congestion rents increased by more than 50% over 2012-2015 and were primarily due to larger price differentials with Great-Britain and French exports in 2015[15]. In 2016 and 2017, congestion rents returned to 2013-2014 levels although distribution per interconnector evolved: cross-borders exchanges with Spain increased due to the Baixas Santa-Llogaia interconnection starting its operation in 2015, while price differential to Italy and Great Britain reduced.

Figure 23 – Total annual congestion rents at the day-ahead stage (2012-2017, million euros, nominal money)



3.3.5 *Trading arrangements*

The French electricity market design is based on a set of decentralised arrangements for financial and physical electricity trading, complemented by a centralised dispatch system based on bids submitted at the day-ahead stage, which is managed by the TSO for balancing purposes.

Electricity can be traded across various timeframes, from several years ahead, up to five minutes prior to delivery. Those trades can either be through an organised power exchange platform or Over The Counter.

Arrangements for cross-border interconnection capacity are on an implicit basis for coupled markets, which means the price of using the interconnection is included in the energy price.

Demand participation is increasing; from load shedding in day-ahead markets to contracted reserve in the balancing market.

15 Partly as a result of the introduction of the Carbon Price Floor in GB in 2013.

Deviations between commercial and physical positions are settled through the balancing mechanism. The balancing mechanism is a tool at the disposal of the TSO to manage security of system.

Figure 24 – Timescale for electricity trading

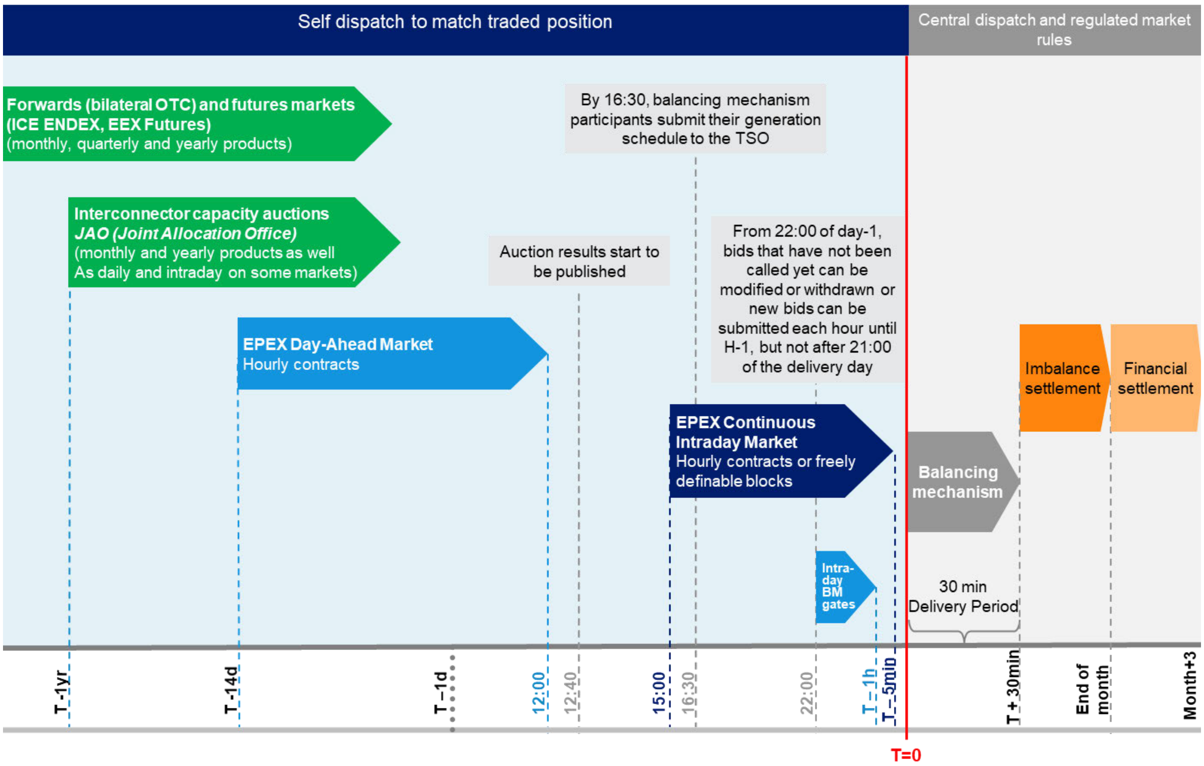


Figure 24 provides a simplified overview of the different time horizons and markets, which are available for trading power in France and bordering countries. When trading power for delivery in a certain time-window, not all markets are available.

The key markets shown in this diagram are as follows:

- Forwards and futures markets, allowing market participants and traders to strike contracts (for physical delivery or not) up to several years ahead.
- Interconnection capacity auctions are operated by the Joint Allocation Office (JAO), these are yearly and monthly auctions for interconnector capacity with every surrounding country. The JAO also manages daily auctions with Switzerland and intraday auctions with Italy.
- The Day-Ahead Market is operated by EPEX Spot as an auction for the next day and setting 24 hourly prices. Selling and buying orders are aggregated to determine the clearing price and volume (intersection of offer and demand curves). The clearing works on an all-or-none basis, meaning that a block order is only executed for its full quantity. Orders can be sent until 12:00 and auction results are published at 12:40.
- The Continuous Intraday Market operated by EPEX SPOT France is a continuous trading market operating all day long. At 15:00 each day,

hourly blocks or hours for the following day become available to trade and can be traded up to 5 minutes before delivery (if trade and delivery are within France). Due to intraday cross zonal interconnection capacity timing constraints, lead time for intraday transaction is 60 minutes if cross-border delivery within coupled markets where this market operates (Belgium, Germany and Switzerland in the case of France).

- Balancing Mechanism used by the French TSO (RTE) to balance the system.
- Settlement process for charging participants whose contracted positions do not match their metered volumes of production/consumption, for the settlement of accepted bids and offers in the Balancing Mechanism.

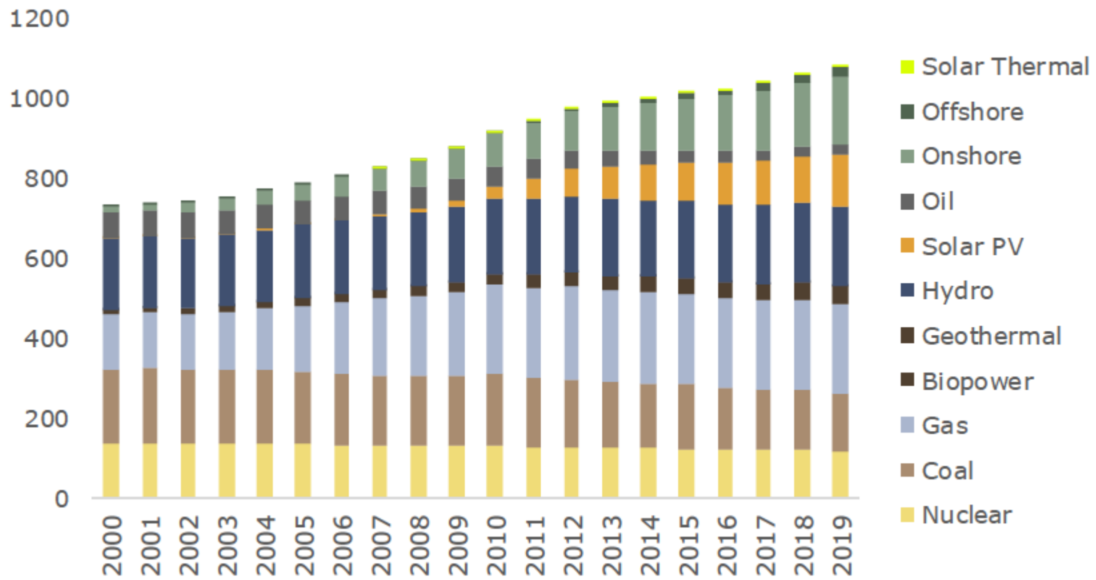
3.4 European market overview

Figure 25 and Figure 26 present a snapshot of the electricity market in Europe with an overview of electricity installed capacity and generation according to different energy sources.

Overall capacity has been growing partly driven by the steady increase in renewable energy plants that with relatively low load factors compared to fossil-fuelled generation, which means that more capacity is required to meet demand. Renewable energy power plants continue to be added at an increasing pace, supported by the EU’s evolving climate and clean energy policy agenda (i.e. the EU 2020 and 2030 targets), government subsidies and a rising price for EUAs.

At the opposite end of the spectrum, fossil-fuelled and thermal power plants have been declining in recent years as they face adverse economic and regulatory environment in many EU countries, accelerating the closures of end-of-life assets and curbing investment in new plants as low levels of wholesale electricity prices provide little incentive for investment in particular for coal-fired power plants.

Figure 25 – Electricity installed capacity by fuel in Europe (GW)

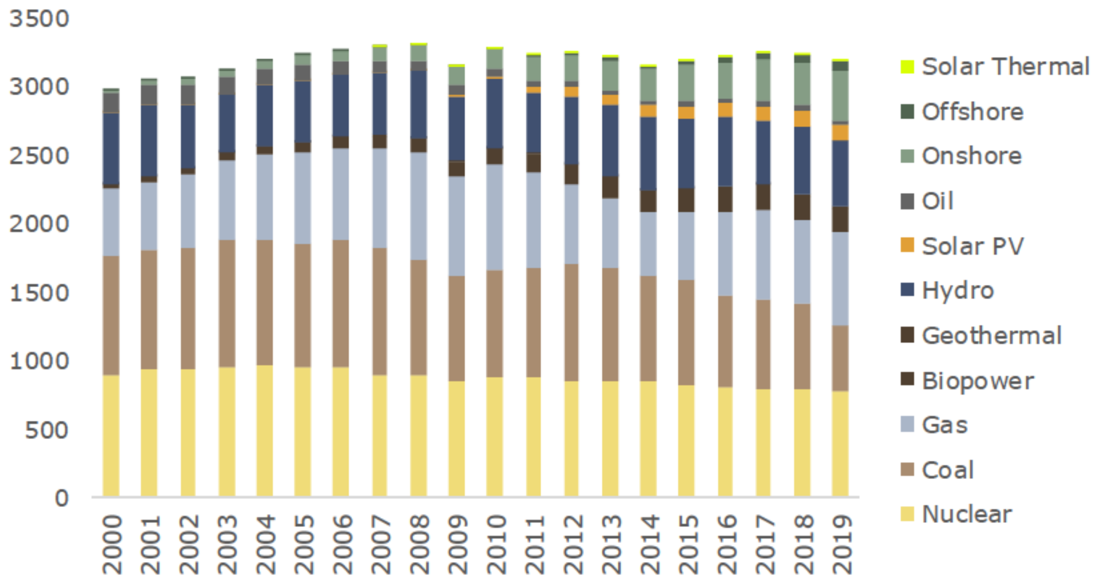


Notes: Includes data for Austria, Belgium, Bulgaria, Croatia, Czech Republic, Denmark, Finland, France, Greece, Germany, Ireland, Italy, Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Spain, Sweden, Switzerland, United Kingdom
Source: Global Data

Total annual electricity generation in the EU has been at relatively stable levels in recent years, reflecting energy efficiency gains and growing electrification of segments of the economy. Historically, close to half of the net electricity generated in the EU has been from fossil fuelled generation (natural gas, coal, oil), although this has been trending down. In 2019, fossil fuel generation provided around 40% of total generation, while close to a quarter came from nuclear power plants. Among renewable energy sources, the highest share of net electricity generation in 2019 was from wind followed by hydropower plants (which includes pumped hydro and therefore not necessary of renewable origin) and solar power. As with installed capacity, the generation from renewable energy sources has been growing in significance in recent years with the proportion of electricity generated from wind and solar increasing the most.

Germany remains the highest electricity generator among the EU Member States, ahead of France, Italy and the UK.

Figure 26 – Electricity generation by fuel in Europe (TWh)



Notes: Includes data for Austria, Belgium, Bulgaria, Croatia, Czech Republic, Denmark, Finland, France, Greece, Germany, Ireland, Italy, Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Spain, Sweden, Switzerland, United Kingdom
Source: Global Data

3.5 Market coupling

3.5.1 Overview of EU Target Model and market coupling process

To capture the benefits of interconnection for end-consumers, the EU 'Target Model' aims to create a framework for efficient cross-border flows of electricity across Europe, with market coupling central to the design. At a high level, the requirements of the EU Target Model are:

- (mostly) decentralised markets with bilateral trading and self-dispatch;
- physical forward, day-ahead, continuous intraday and balancing markets;
- national/zonal pricing for bilateral/exchange trading;
- full market-coupling across Europe for short-term trading timeframes; and
- standard balancing products.

Figure 27 demonstrates the three fundamental aspects of the EU Target Model, which are:

- **The determination of how much cross-zonal capacity is available for allocation in each timeframe** (top 3 orange blocks in Figure 27): The EU Target Model is built around the concept of bidding (or pricing) zones, which may be sub-national or may stretch across national borders. Therefore, the capacity allocation rules in the EU Target Model apply to transmission capacity between zones ('cross-zonal capacity') rather than 'interconnection' capacity, which is typically defined as transmission capacity between different countries[16].
- **The mechanisms and rules for allocating cross-zonal capacity in each timeframe** (middle grey row of 3 navy blocks in Figure 27): These determine whether market participants can buy capacity as a separate product through an explicit auction (as is the case in the forward timescale); or whether cross-zonal flows are determined as part of the process of matching energy trades in different zones through an implicit auction.
- **The harmonisation of balancing and imbalance arrangements** (bottom row of 3 green blocks in Figure 27): This includes the development of mechanisms for market participants to provide balancing reserve and/or energy to a TSO in another country, as well as harmonisation of the arrangements by which each TSO recovers the cost of balancing supply and demand on its system.

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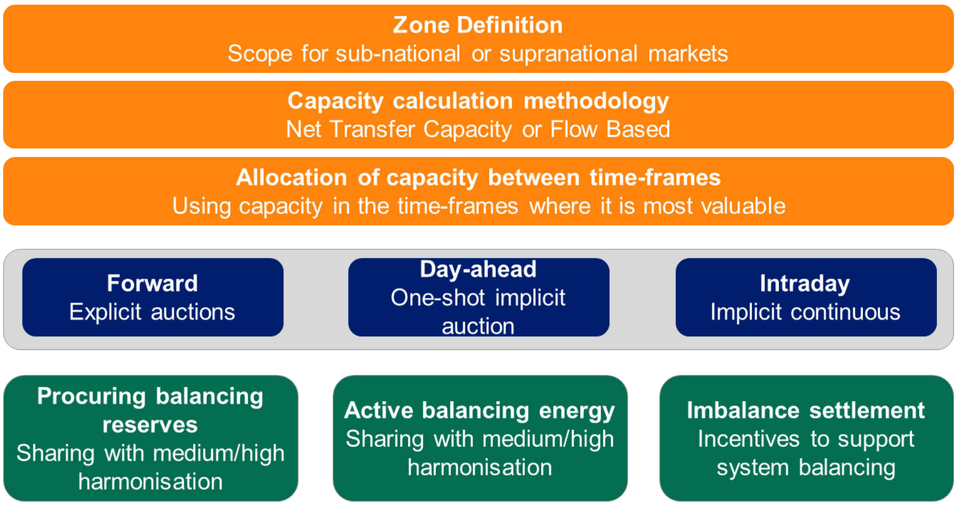
16 Some national wholesale electricity markets in the EU (e.g. Italy, Norway, Sweden, Denmark) are already split into multiple, smaller zones. The Irish electricity market is an example of a supra-national market covering the Republic of Ireland and Northern Ireland (which is part of the UK). However, most countries still have only one zone covering the whole country, and hence in practice, there is currently little difference between 'cross-zonal' capacity and 'interconnection' capacity for most of Europe.

Figure 27 – Building blocks of EU Target Model



At present, the electricity flows across GB's cross border interconnectors are governed by common EU rules (Network Codes) and GB has access to single, pan-European arrangements for day-ahead and intraday market coupling (as governed by the CACM Regulation, EU 2015/1222). However, the ongoing Brexit process may have implications for cross border exchange arrangements, depending upon how it unfolds. However, following the UK's exit from the EU and the end of the transitional arrangements on 31 January 2020[17], (subject to further negotiations):

- electricity arrangements may remain broadly as they are today, and the framework for cross-border exchanges therefore remain the same; or
- the UK may no longer be a part of the Internal Energy Market (IEM) from 2021, and therefore there will be a need for alternative contingency cross border trading arrangements to be developed to maintain the benefits of market coupling for market efficiency and consumers. If possible, the objective is for the contingency arrangements to maintain implicit cross border trading functionality with flows driven by commercial signals.

The situation in Switzerland is a relevant reference point in the context of post-Brexit future scenario. As a non-EU member state, market coupling arrangements applied in much of the rest of Europe do not automatically apply in Switzerland. As of the end of 2014, technical and operational readiness was secured in order to meet the requirements for the Swiss-European coupling process. However, this implementation can only be finalized after the

17 Under the Withdrawal Agreement, an implementation period will run until 31/12/2020, during which time there will be a negotiation on the future arrangement. No details are available for the future arrangement but at present it seems unlikely that GB could continue to enjoy membership of the IEM.

conclusion of a political agreement between Switzerland and the European Commission[18].

Pending any political agreement, the trade in cross-border transmission rights in Switzerland is currently conducted by means of explicit auctions separately from energy traded on the energy exchanges. Turning attention back to the UK post-Brexit, it is possible that arrangements could revolve around explicit auction for GB-EU interconnection capacities, rather than implicit allocation through market coupling.

3.5.2 *Forward capacity allocation*

Forward cross zonal capacity allocation (FCA) enables market participants to hedge price risk between price zones. This is an important part of the creation of an integrated EU electricity market, as it supports the management of the risk of fluctuations in the spread between market prices between zones. Failure to have an effective and efficient forward capacity allocation mechanism could lead to more risks being carried by market participants, with consequent impact on the potential for market participants to enter into cross-zonal forward transactions. The FCA is regulated via the Network Code on Forward Capacity Allocation - (EU) 2016/1719[19]. The FCA objectives are:

- promoting effective long-term cross-zonal trade with long-term cross-zonal hedging opportunities for market participants;
- optimising the calculation and allocation of long-term cross-zonal capacity;
- providing non-discriminatory access to long-term cross-zonal capacity;
- ensuring fair and non-discriminatory treatment of TSOs, ACER, regulatory authorities and market participants;
- respecting the need for a fair and orderly forward capacity allocation and orderly price formation;
- ensuring and enhancing the transparency and reliability of information on forward capacity allocation; and
- contributing to the efficient long-term operation and development of the electricity transmission system and electricity sector in the EU.

All TSOs that issue long-term transmission rights shall offer long-term cross-zonal capacity through a single allocation platform (Joint Allocation Office (JAO)[20]) for at least annual and monthly time frames[21]. Harmonised Allocation Rules (HARs) for long-term transmission rights define the procedures of the

18 https://www.swissgrid.ch/swissgrid/en/home/reliability/power_market/market_coupling.html

19 https://www.entsoe.eu/network_codes/fca/

20 In October 2018, JAO was appointed as the single allocation platform for all European TSOs and started operation in January 2019.

21 All TSOs in each capacity calculation region may jointly propose to offer long-term cross-zonal capacity on additional time frames.

allocation process, types of products offered, minimum requirements for participation (such as provision of collateral), nomination rules and other relevant rules by taking into account the general principles, goals and other methodologies set out in the Network Code on FCA.

Long-term transmission rights can be in the form of:

- Physical Transmission Rights (PTRs) sold on a Use-It-Or-Sell-It (UIOSI) basis. The UIOSI principle ensures that any annual or monthly capacities not used to nominate flows are made available for the daily auctions in the market coupling process. Rights holders who do not nominate flows to (fully) use their long-term access rights receive compensation based on the price difference between the connected markets for unused capacity if this price difference is positive for the flow direction of the access rights.
- Financial Transmission Rights (FTRs), which can either by in the form of an option or an obligation, and do not require accommodation of interconnector flow nominations. Like a PTR with UIOSI, an FTR option provides the holder with the price difference between the connected markets if this difference is positive for the flow direction of the access rights. Holders of FTR obligations are exposed to both positive and negative price differences, receiving the difference if positive and paying it if negative.

At present, all long-term transmission rights under the governance of the FCA take the form of either PTRs or FTR options.

3.5.3 *Single day-ahead coupling (SDAC)*

Historically, day-ahead markets in each country in Europe were operated independently and interconnection capacities were allocated via bilateral auctions between each neighbour. To increase liquidity in day-ahead trading and to make optimal use of the interconnection between the European countries, market coupling has been introduced over time with the aim of creating a single European market. As such, market coupling is both a mechanism for matching orders between markets and an implicit cross-border capacity allocation mechanism.

The current SDAC arrangements originate from the Price Coupling of Regions (PCR) project, run by a collection of European power exchanges[22]. The PCR process led to the development of the common day-ahead price coupling algorithm, PCR Euphemia[23] or simply Euphemia. Euphemia calculates electricity prices and implicitly allocates cross-border capacity in a way that maximises welfare.

The coupling process involves market participants, power exchanges and TSOs in the coupled markets and the 'central market coupler'. As illustrated in Figure 28, the coupler:

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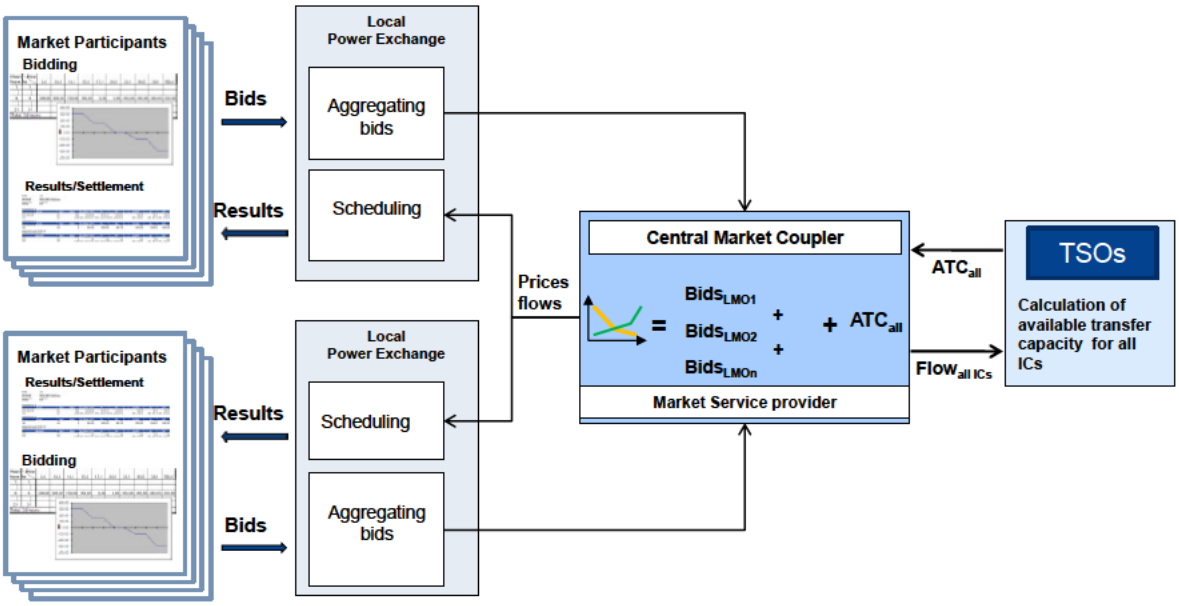
22 EPEX SPOT, GME, Nord Pool, OMIE, OPCOM, OTE and TGE.

23 Euphemia stands for: EU + Pan-European Hybrid Electricity Market Integration Algorithm.

- aggregates at an hourly resolution all the bids/offers submitted by gate closure (12h00 D-1 CET) to active power exchanges in different zones and ranks them according to price;
- matches these bids/offers, subject to the available cross-border capacities, to maximize social welfare by running Euphemia; and
- informs the markets on the resulting prices, flows and the allocated network capacities to support these flows.

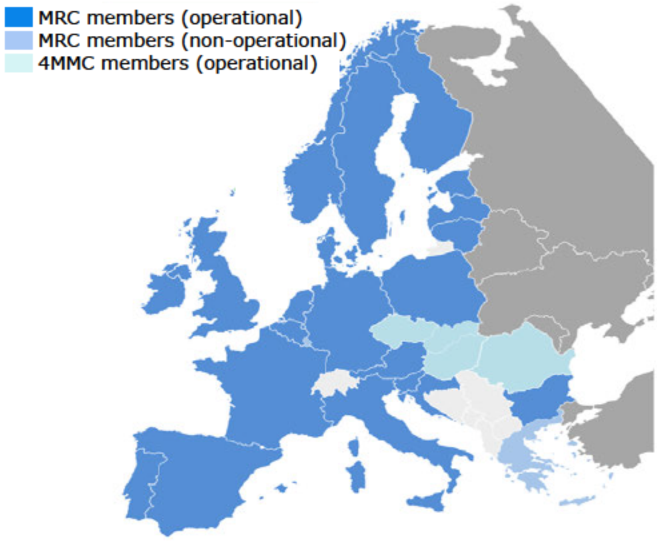
When there is insufficient interconnection capacity to ensure price equality across the markets, the markets de-couple and more than one price emerges.

Figure 28 – Market coupling process



The operation of the SDAC arrangements and the Euphemia algorithm currently spans the regions shown in Figure 29.

Figure 29 – Single day-ahead coupling coverage



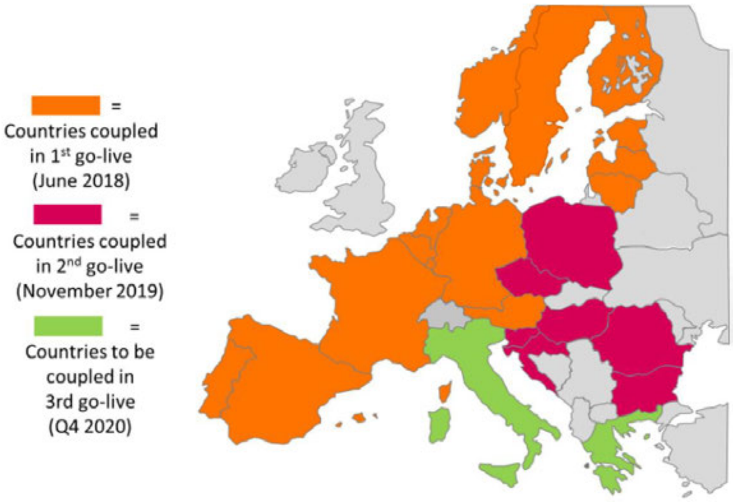
Source: ENTSO-E

3.5.4 *Single Intraday Coupling (SIDC)*

In intraday timeframes, pan-European Single Intraday Coupling (SIDC) arrangements are in place for many markets, as shown in Figure 30. SIDC enables continuous cross-border trading via a shared order book, a single capacity management module and a single shipping module. These allow for orders entered by market participants in one bidding zone to be matched by orders submitted by market participants in any other bidding zone, as long as transmission capacity is available. The solution is delivered through a common IT system called XBID.

As highlighted by Figure 30, the XBID based coupling solution is not currently in place in GB. Arrangements for GB coupling are awaiting clarity on Brexit, and so it is, therefore, not a part of the 3rd wave yet.

Figure 30 – Single intraday coupling coverage



Source: ENTSO-E
Note: Luxembourg is part of the Amprion Delivery Area. Market participants in Luxembourg have access to the SDIC through Amprion Delivery Area

4. SCENARIOS AND SENSITIVITIES

4.1 Scenario Overview

Our three AFRY Independent Market Report scenarios, the High, Central and Low, are constructed to cover (in our opinion) a reasonable and internally consistent set of outcomes in wholesale prices over the timeframe to 2060.

They are designed to illustrate the future electricity prices projected to result from internally consistent combinations of assumptions and drivers:

- Our High scenario reflects a combination of drivers that consistently result in electricity prices towards the upper limit of plausible expectations.
- Our Central scenario presents our best view of future electricity prices.
- Our Low scenario reflects a combination of drivers that consistently result in electricity prices towards the lower limit of plausible expectations.

We use scenario levers to set the framework under which the drivers of electricity prices determine the scenario outcome and achieve internal consistency within our scenarios by using a suite of models to capture the complex and dynamic interactions between the drivers.

Our scenario framework reflects the most important drivers of the energy transition, including those within the heat and transport sectors which we model alongside the power sector in a 'whole energy system' approach.

Figure 31 gives an overview of our three scenarios, including a summary of the four key drivers for each scenario.

Our projections are for sustainable long term price levels and the range of outcomes do not cover spikes caused by random, unpredictable or short term events. All three scenarios are market scenarios that do not allow for market failure. Scenarios should be seen as offering descriptions of what could transpire – plausible pathways for the future and useful insights along the way.

Figure 31 – AFRY's scenario matrix

Scenar o	High	Central	Low
Price outcome	Electricity pr ces towards the **upper** lim t of plausible expectations	Our **best view** of future electric ty prices	Electr c ty pr ces towards the **lower** limit of plausible expectat ons
Scenar o Drivers			
Econom c growth	Strong **2.2%** per annum for Europe	Moderate **1.2%** per annum	Weak **0.2%** per annum
Technology costs	High end of current estimates, w th a less rapid decline	Central starting point, with a moderate rate of decline	Low end of current estimates, w th a more rap d decline
Decarbonisa t on	Higher ambit on (**-95%** on 1990 economy-w de levels by 2050)	Central amb t on (**-85%** on 1990 economy-w de levels by 2050)	Lower ambit on (**-75%** on 1990 economy-wide levels by 2050)
Heat and transport	High uptake of electric heating and veh cles, w th more rap d deployment	Central uptake, with moderate deployment rates	Lower uptake, with less rapid deployment and more hydrogen

4.1.1 Scenario decarbonisation targets for 2050 and 2060

Decarbonisation in Europe is being driven by a number of factors, including:

- **European decarbonisation targets**: the EU currently has a decarbonisation target to achieve an 80% to 95% reduction in economy-wide greenhouse gas emissions by 2050 (compared to 1990) with an ambition to enshrine a 2050 net-zero emissions target into law as soon as possible (proposal published on 4 March 2020[24]).
- **Falling costs for renewables and storage**: recent years have seen a rapid decline in the costs of renewable technologies and grid-scale storage. Electric vehicles and the associated infrastructure have started to deploy at scale.
- **New technological innovations**: the potential large scale rollout of CCS technology, electrolysis and hydrogen-fired power plants makes long term decarbonisation more plausible.

The decarbonisation agenda in Europe is set to drive fundamental changes occurring in European wholesale electricity markets. For example decarbonisation is likely to put upward pressure on future electricity demand growth as electrification of heat and transport accelerate and it is also set to drive a fundamental change in the capacity mix favouring low carbon generators over traditional fossil fuel fired thermal plants.

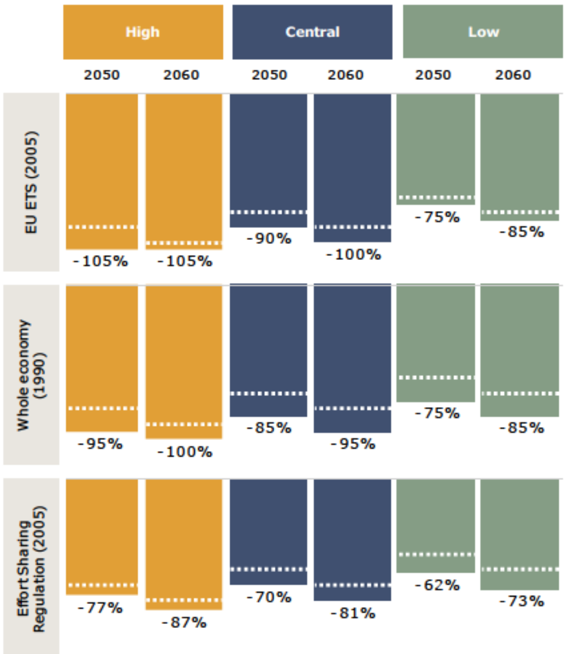
24 European Climate Law , European Commission, 4 March 2020.

Decarbonisation targets in our scenarios are summarised in Figure 32 which shows the assumed level of decarbonisation that is achieved in different sectors for 2050 and 2060 in each scenario. These are carefully selected to reflect a range of possible future policy outcomes that are internally consistent with our other key scenario drivers, as follows:

- our Central scenario reflects our belief that ambition is increasing in policy discussions while acknowledging that to reach net-zero by 2050 would be an enormous challenge; and
- our High and Low scenarios represent the likely range of achievable targets that could be backed by industry and business as well as policy-makers.

However, this only represents a subset of the plausible outcomes. At one extreme, net-zero could be achieved economy wide by 2050. At the other extreme, there could be a rapid slowing of the ambition in Europe over time, as the high costs of decarbonising heat and other sectors becomes apparent, leading the focus of actions (and capital) to move to other parts of the world to decarbonise China and India.

Figure 32 – Scenario decarbonisation targets by 2050 and 2060



4.2 Description of scenarios

We have assessed the socio-economic welfare impact of the GridLink interconnector project in three market scenarios that are primarily based on our Q2 2020 internal pan-European electricity market modelling scenarios, incorporating some internal views from GridLink on certain elements in different scenarios. Key aspects of the scenarios assessed are set out in the following Sections.

4.2.1 Interconnector build

For the purpose of GridLink CBA assessment, interconnection deployment in AFRY High, Central and Low scenarios was refined based on assessment of project economics. The approach taken was to assess the profitability of new interconnection post 2030 and to build new interconnection capacity when deemed profitable. Table 2 outlines the costs assumptions used for DC interconnection.

Table 2 – Interconnector costs assumptions, €/kW real 2020

[redacted]

Figure 33 and Figure 35 give an overview of the assumed total interconnection capacity in Great Britain and France respectively.

Figure 33 – Total interconnection capacity in Great Britain including GridLink (GW)

[redacted]

Figure 34 shows the new interconnectors with Great Britain assumed to go ahead in each of the scenarios.

Figure 34 – New interconnection capacity in Great Britain including GridLink (GW)

[redacted]

Table 3 provides the details of the interconnectors project with Great Britain assumed to go ahead in the Central scenario in a table format.

Table 3 – New interconnection capacity in Great Britain – Central scenario (MW)

[redacted]

Figure 35 – Total interconnection capacity in France including GridLink (GW)

[redacted]

4.2.2 *Generation capacity mix*

Our outlook for capacity is driven by a combination of existing capacity and units under construction, plant closures, plus the build out of new generic capacity.

Once technical and/or policy constraints are accounted for (e.g. mandated nuclear decommissioning, or closure of thermal units not compliant with legislated environmental requirements), both the decommissioning and the new build of generation units are driven by an economic test. New build capacity across all key technologies – in particular, thermal, renewables, grid-scale battery storage and interconnectors – only proceeds if new units receive, in our judgement, an adequate return on investment.

In this process, we also take account of import capacity from neighbouring countries, which may change over time, and reduce (or increase) the requirements in new capacity in a specific market.

Figure 36 summarises our Q2 2020 installed capacities by technology type in 5 year time intervals in Great Britain and France.

Figure 36 – Installed capacity in Great Britain and France (TWh)

[redacted]

The generation capacity mix in Great Britain is dominated by offshore and onshore wind and CCGT capacity. This is expected to persist over the modelled period, with wind capacity (onshore and offshore) continuing to increase at over 1900MW per year in the Central scenario. The overall trend is a growth in total capacity but with a reduction in thermal capacity as portion of the mix, as new capacity deployment is primarily driven by renewables. This particularly consists of onshore and offshore wind and merchant solar PV in the long term.

In France, nuclear provides the largest share of generation early in the modelled period (around 35% of total installed capacity in 2025 in the Central scenario). The share of nuclear in the installed capacity is projected to decrease over time as solar PV and wind enjoy continued strong growth. In the Central scenario, fossil-fuel thermal new builds do not happen before 2030 in compliance with the announced ban on new thermal capacity, but is required in the medium-term to support with system adequacy. In the High scenario, strong demand drives thermal capacity increase earlier, with expectations of the announced ban of new fossil-fuel thermal to be amended.

4.2.3 *Supply and demand balance*

To illustrate the adequacy between installed capacity and peak demand, Figure 37 shows the de-rated installed capacity against the peak demand during winter evenings (average across weather years). The installed capacity has been de-rated based on its contribution during the 40 tightest hours of the year.

Figure 37 – De-rated installed capacity vs. peak demand in Great Britain and France in the Central scenario (GW)

[redacted]

4.2.4 *Other scenario specific assumptions*

More details on the assumptions in AFRY's scenarios can be found in Annex A.

4.3 Sensitivities

In addition to the High Central and Low scenarios introduced above, the assessment considered the following sensitivities:

- an increase of GridLink capex by 5%;
- an increase of GridLink opex by 5%;
- a decrease of GridLink capex by 5%;
- a decrease of GridLink opex by 5%; and
- a reduction of 1.4GW of interconnection capacity between GB and France in 2040.

5. MODELLING RESULTS FOR GRIDLINK

5.1 Emissions and generation output

GridLink delivers reduction in carbon emissions across Europe in all three scenarios. Interconnection allows for more efficient operation and dispatch of all generation in general, thereby reducing overall emissions. Figure 38 shows the change in CO_2 emissions per annum from the introduction of GridLink in Great Britain, France and the rest of Europe at 5 yearly intervals. The black bar shows the net carbon emission change across Europe thanks to the introduction of GridLink, negative values representing a reduction in emissions thanks to GridLink. While CO_2 emissions are reduced in Great Britain, French emissions increase slightly due to GridLink's exports to Great Britain. Emissions also tend to slightly increase in the rest of Europe in the 'with GridLink' case, as neighbouring countries rely on comparatively less low carbon imports for France. The combined net decrease in CO_2 emissions across Europe (averaging 0.5 $mtCO_2$ per annum in the Central scenario) represents 1% of total average power sector emissions in Great Britain and France.

Figure 38 – Change in carbon emissions from power sector 'With GridLink' minus 'Without GridLink' case ($mtCO_2/y$)

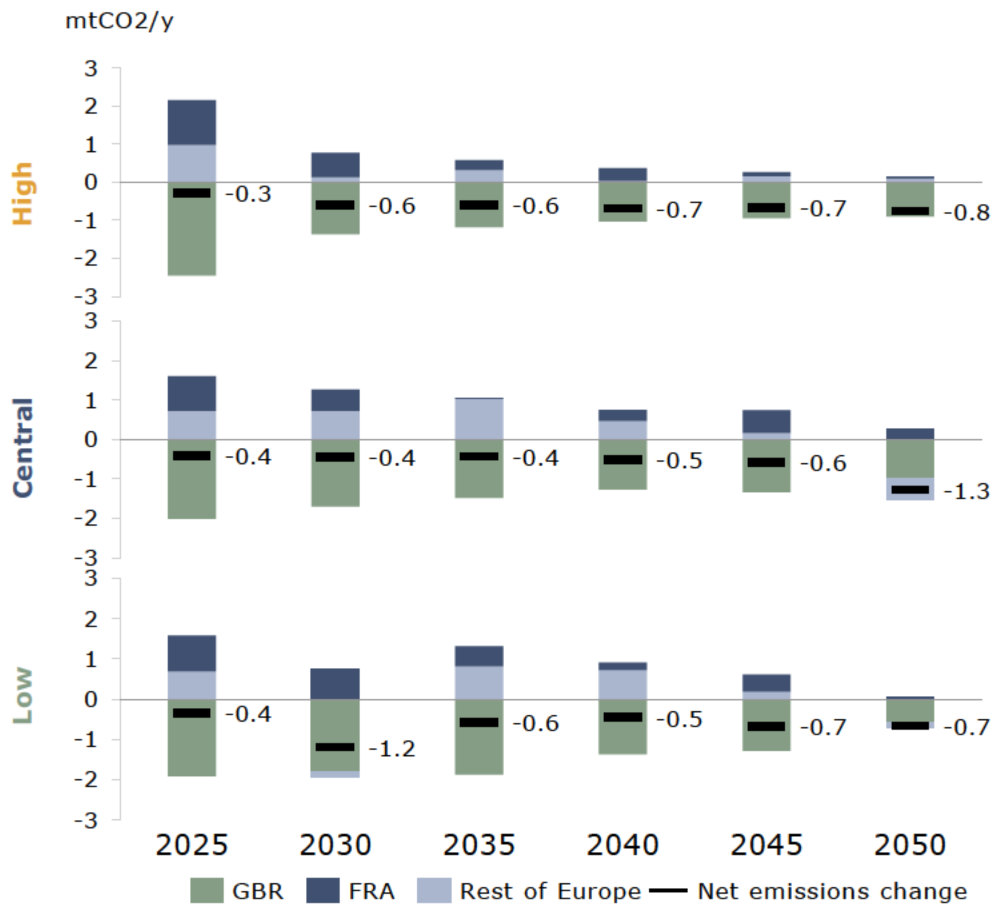


Figure 39 shows the outturn generation by technology type in Great Britain and France in all scenarios.

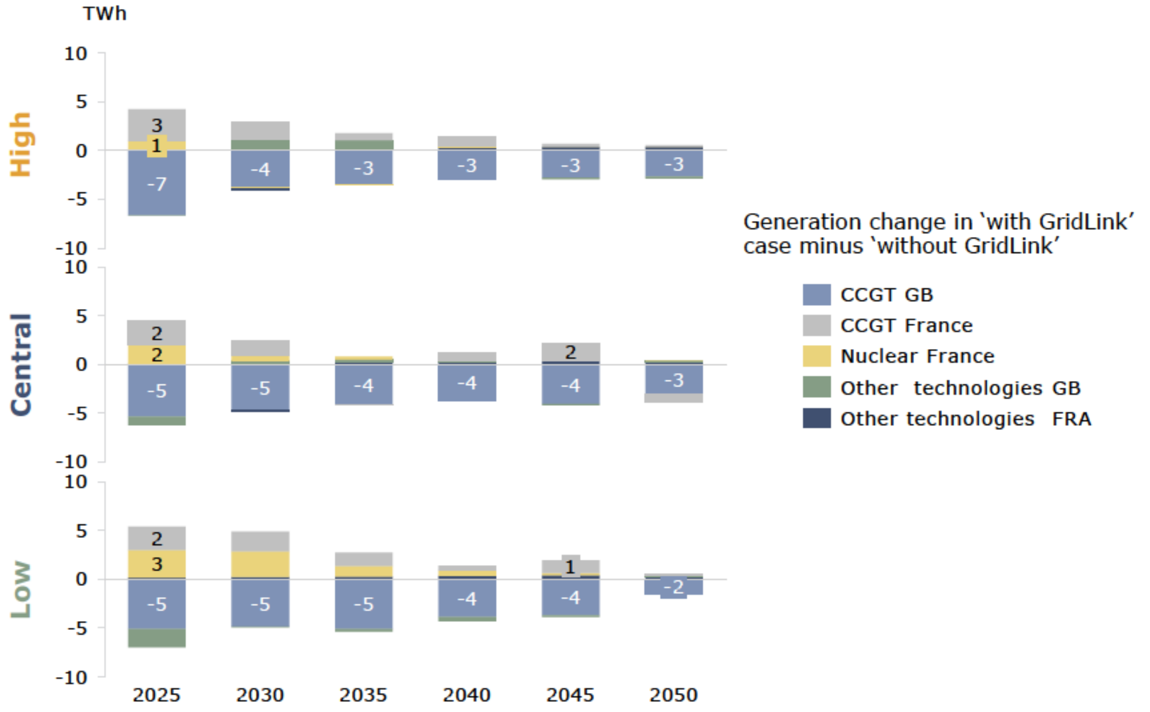
Figure 39 – Generation by technology in Great Britain and France (TWh)

[redacted]

In both markets, the overall trend is a growth in total generation, with a reduction in thermal generation as portion of the mix and an increase in renewable generation both in absolute terms and as a proportion of the mix. In the Central scenario in France, the share of nuclear in the total generation drops below 50% around 2037, which is two years after the target outlined in the latest 'Plan pluriannuel de l'énergie'.

Figure 40 shows the net impact of GridLink on the generation mix in Great Britain and France. In the 'with GridLink' case, generation from CCGT is lower in Great Britain, while generation from nuclear and CCGT increases in France.

Figure 40 – Generation change in 'with GridLink' case compared to 'without GridLink' in Great Britain and France (TWh)



5.2 Market prices

Our results for annual baseload wholesale electricity prices in both markets are presented for all three scenarios in Figure 41. Absolute price levels are highest in the High scenario and lowest in the Low scenario.

In both markets, the evolution of gas and carbon prices tends to put upward pressure on the wholesale baseload prices, while the increasing penetration of renewables and other low carbon technologies has a dampening effect on prices.

Price differentials between markets are the greatest in the first years of operation of GridLink, around 10€/MWh across scenarios. The price differential reduces over time as the prices between Great Britain and France converge. The main drivers for the prices to move closer are:

- the increasing interconnection capacity between the two markets; and
- alignment of carbon prices in the two markets after the EU ETS price rises above the GB carbon support price (see Annex A).

These levels and differentials give an indication of the direction of flow and potential revenues, although both could vary substantially from hour to hour.

Figure 41 – Baseload wholesale electricity prices (€/MWh, real 2020 money)

[redacted]

Figure 42 shows the difference in wholesale prices in the 'With GridLink' case compared to the 'Without GridLink'. It illustrates the impact of GridLink on baseload prices. Wholesale electricity prices on an annual average basis converge with increased available interconnection capacity between the two markets. In the long term in the Central scenario, there is a slight price increase in both markets, due to less low priced periods (e.g. GB can export more when it is windy in GB and France when it is windy/sunny in France).

Figure 42 – Baseload wholesale electricity prices 'With GridLink' and 'Without GridLink' (€/MWh, real 2020 money)

[redacted]

Figure 43 shows the evolution of price difference curves between 2025 and 2040. It can be seen that, in 2025, GB has a higher wholesale price in almost all periods, whereas in 2040 this is a more even split.

Figure 43 – Price difference duration curves in 2025 and 2040 (€/MWh, real 2020 money)

[redacted]

Prices are initially characterised by baseload price differential. As the carbon prices align, and more GB-FR interconnection is built, annual baseload prices tend to converge (in all scenarios, slower in the Low).

Later in the period, price differentials increasingly vary during the year, as well as within day, as presented for 2040 in Figure 44. This is mainly driven by more low prices periods due to renewable generation in one or the other market (in general solar PV in France, and wind in GB).

On the left, the monthly price shape shows comparatively lower prices in France in summer months and lower prices in GB in winter. On the right, the within day shape for the month of May also illustrate the strong price effect during the day. The lower prices are primarily driven by more solar in France, as well as additional nuclear and interconnection with countries with high solar deployment (Spain, Germany, Italy).

Figure 44 – Monthly and daily price shape in 2040 – Central (€/MWh, real 2020 money)

[redacted]

5.3 Arbitrage flows and revenues

Figure 45 presents our modelling results for flows on the GridLink interconnector in both directions. The total utilisation rate (i.e. the sum of flows in both directions) is in the range of [redacted] in the three scenarios. The high utilisation is in part a consequence of GridLink having lower losses than other GB-France interconnectors, though many of these hourly have little or no congestion rent.

Figure 45 – GridLink utilisation rates and flows by direction of flow (% and TWh)

[redacted]

Figure 46 shows our projections for GridLink's arbitrage revenues in all scenarios. In the Central scenario, revenues from electricity arbitrage are around [redacted] on average. In the Central and Low scenarios, most of that value arises from import flows into Great Britain from France, while the source of value by flow direction is more balanced in the High scenario. In all scenarios, the share of value arising from flows from Great Britain to France increases over time, as the average wholesale prices converge. The source of the income gradually shifts from baseload price differential to flows during periods of low prices due to renewable generation in one or the other market (in general solar PV in France and wind in GB).

Figure 46 – GridLink congestion rent by direction of flow (m€/annum, real 2020 money)

[redacted]

5.4 Capacity Market Revenue

Our modelling of the GB and France capacity mechanisms assumes that new entrants receive long-term contracts and, therefore, they would only set the auction clearing price in their year of entry. The clearing price in other years is set by existing capacity, which is assumed to receive an annual contract. The combination of long term contracts for new capacity and annual contracts for existing capacity results in significant variation in the capacity price over time. Figure 47 shows capacity price projections in GB and France for each of the three scenarios.

The future capacity markets market structure is uncertain, especially regarding the applied derating factor for interconnectors. We model the capacity markets according to our best view of the evolution of the capacity mechanisms. In particular we assumed that interconnectors would receive capacity payment based on their marginal derating in both markets, which is more conservative than the current levels of derating factors applied for interconnectors, but less conservative than assuming the money going directly to power plants in interconnected markets, with nothing for interconnectors.

Changes in capacity market prices between the 'without' and 'with GridLink' cases are neutral in term of welfare as capacity payments are effectively a transfer from consumer surplus to producer surplus.

Figure 47 – CM clearing prices in Great Britain and France (€/kW available, real 2020 money)

[redacted]

Figure 48 shows the potential capacity revenues from the British and French capacity markets that could be obtained by GridLink. GridLink's revenue from the two capacity markets is projected to be around [redacted] on average per year in our Central scenario. Our modelling shows that a non-negligible proportion of revenues could result from participation in the GB and France capacity markets. However, there is a material level of uncertainty for these revenues, which results from market conditions as well as regulatory decisions. In particular these values are quite sensitive to the volume of interconnection.

Figure 48 – Revenues from the GB and France Capacity Markets (m€/annum, real 2020 money)

[redacted]

6. SOCIAL WELFARE AND CBA RESULTS

6.1 Introduction to CBA results

To conduct the CBA and inform assessment of SEW impacts of GridLink interconnector, AFRY performed market modelling runs using BID3 for:

- a reference case without GridLink; and
- a 'with GridLink' case, which includes GridLink interconnector.

As explained in Section 2.2, for a given market scenario, all the inputs to these two runs are identical, with two exceptions; the addition of GridLink and adjustment of CCGT or OCGT capacity in the 'with GridLink' case.

For each of these runs the following metrics are calculated for each country and year, as introduced previously in Section 2.2:

- short-term consumer surplus;
- short-term producer surplus; and
- congestion rent.

In the 'with GridLink' case, net costs are calculated for France and Great as follows:

- avoided cost of thermal capacity that would have been otherwise built in the 'without GridLink' case to ensure adequate supply for consumers; minus
- costs incurred by the project during construction (capital costs) and operation. The interconnector costs are assumed to be equally shared between Great Britain and France

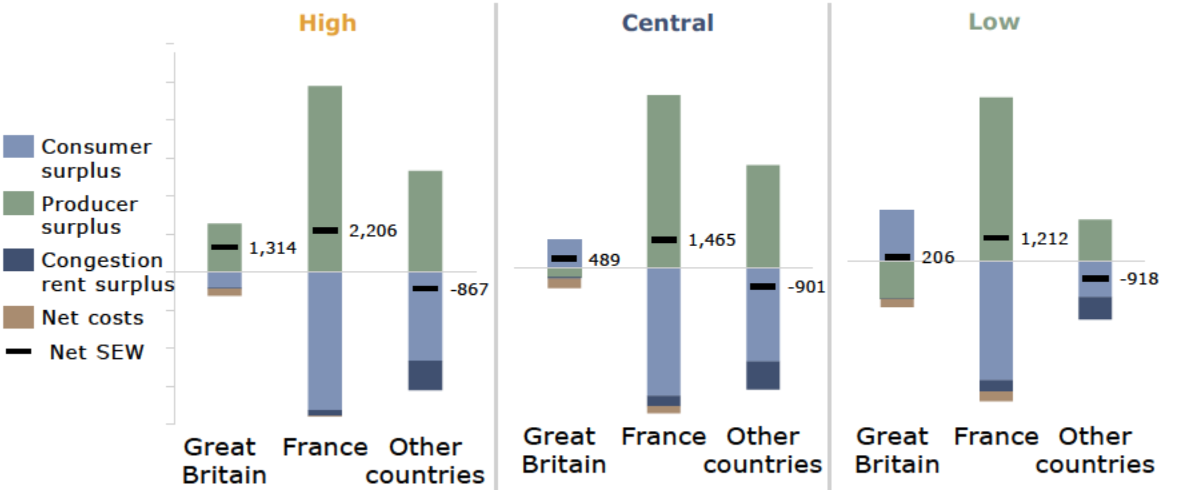
The net present value of the annual difference between the different metrics is calculated assuming a 4% discount factor.

6.2 Summary of results

Our model results for GridLink's impact on socio-economic welfare in Great Britain, France and other European countries are presented in Figure 49.

Summing up British, French and other countries welfare effects, GridLink offers net positive socio-economic welfare impact in all three scenarios.

Figure 49 – GridLink socio-economic welfare impact, (€m, 25yr NPV, 4% discount rate)



Net SEW (m€)	High	Central	Low
Great Britain	1,314	**489**	206
France	2,026	**1,465**	1,212
All Europe[25]	2,653	**1,054**	501

Under the Central scenario, GridLink delivers net positive SEW impacts of:

- €1,054m for all of Europe;
- €489m for Great Britain; and
- €1,465m for France.

In the Central and Low scenarios, GridLink increases consumer surplus in Great Britain as the interconnection tends to lower the average wholesale prices in the 'with GridLink' case. Conversely, the producer surplus is positive in France because the wholesale prices are higher in the 'with GridLink' case.

In the High scenario, producer surplus is increased in Great Britain. While the average wholesale prices in the 'with GridLink' case are initially lower compared to the 'without GridLink' case, the situation reverses over time in this scenario, resulting in positive present value for the producer surplus. The higher wholesale prices, on average, in Great Britain in the 'with GridLink' case in the High scenario are mainly driven by the reduction of low priced periods during high renewable generation (in particular wind generation). The additional interconnector allows for more exports to France during high wind generation periods, lifting GB prices in these periods.

25 Sum for Great Britain, France and other countries.

6.3 Breakdown of SEW by country

Figure 50 shows the detailed breakdown of the socio-economic welfare impact of GridLink by country. Given its reliance on nuclear, France tends to be a net exporter to most of the interconnected countries. As France is a significant net exporter, the increase in wholesale prices in the 'with GridLink' case is more positive to producers than it is negative to consumers, due to generation being higher than demand.

As average wholesale electricity prices are higher in the 'with GridLink' case compared to 'without GridLink' in France, owners of interconnectors to countries for which France is a net exporter capture less congestion rent revenues. It results in a negative impact on congestion rent surplus in these countries, but a positive impact on producer surplus as higher wholesale prices mean higher margins for generation.

The capex and opex incurred by GridLink are shared equally between Great Britain and France. The avoided cost of thermal capacity that would have been otherwise built in the 'without GridLink' case to ensure adequate supply for consumers varies by scenario. In which country (between Great Britain and France) the new thermal capacity can be avoided in the 'with GridLink' is quite sensitive to the capacity mix in each country.

Figure 50 – GridLink socio-economic welfare impact in all countries, (€m, 25yr NPV, 4% discount rate)

High

m€	Consumer surplus	Producer surplus	Congestion rent surplus	Gridlink costs	Avoided costs of thermal capacity	Net SEW	Share of postive SEW
[redacted]							
Total SEW						**2653**	
Total positive SEW						3933	

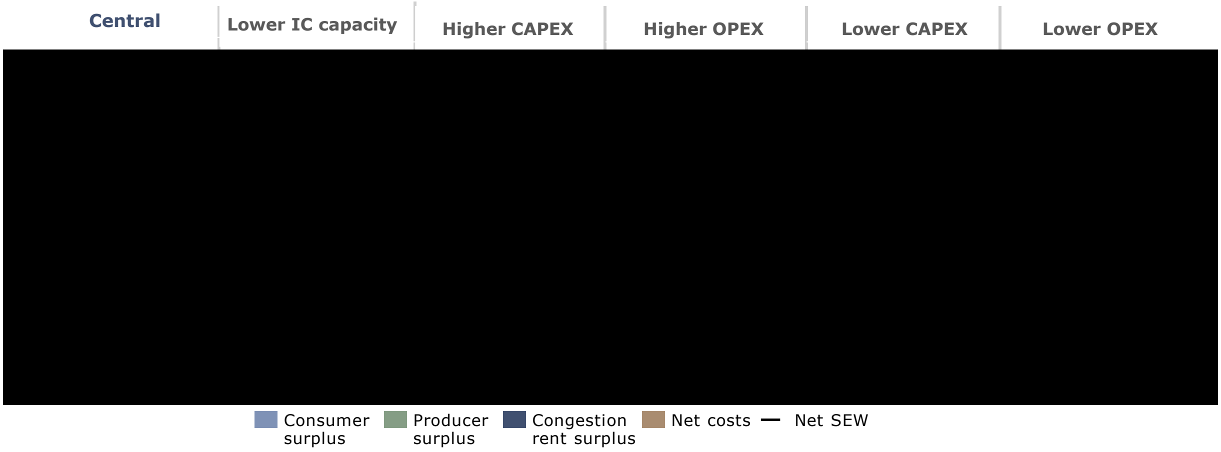
Central							
m€	Consumer surplus	Producer surplus	Congestion rent surplus	Gridlink costs	Avoided costs of thermal capacity	Net SEW	Share of postive SEW
[redacted]							
Total SEW						**1054**	
Total positive SEW						2128	

Low							
m€	Consumer surplus	Producer surplus	Congestion rent surplus	Gridlink costs	Avoided costs of thermal capacity	Net SEW	Share of postive SEW
[redacted]							
Total SEW						**501**	
Total positive SEW						1481	

6.4 Sensitivity results

Figure 51 presents the welfare results in the Base Case and the considered sensitivities.

Figure 51 – GridLink socio-economic welfare impact in sensitivities, (€m, 25yr NPV, 4% discount rate)



Net SEW (m€)	Central	Reduction of IC capacity in 2040	Higher CAPEX	Higher OPEX	Lower CAPEX	Lower OPEX
Great Britain	[redacted]					
France						
All Europe[26]						

Net change in SEW compared to Central (m€)	Central	Reduction of IC capacity in 2040	Higher CAPEX	Higher OPEX	Lower CAPEX	Lower OPEX
Great Britain	[redacted]					
France						
All Europe[27]						

The overall welfare is higher in the 'Lower interconnection' sensitivity, mainly driven by higher (less negative) congestion rent surplus in GB and France.

The producer and consumer surplus evolve in the same way as Central, with a greater welfare change in the sensitivity case. The total GB-France interconnection capacity being lower in the sensitivity, the impact of adding

26 Sum for Great Britain, France and other countries.

27 Sum for Great Britain, France and other countries.

GridLink has a greater impact on prices and welfare between the ‘with’ and ‘without GridLink’ cases.

The costs sensitivities show higher overall welfare when the project costs are assumed to be lower and the opposite when costs are assumed to be higher. The 5% change in capex has a greater impact on the welfare compared to the 5% change in opex.

6.5 Hard to quantify benefits

As a supplement to the quantitative CBA results, we identify the following hard to monetise benefits, taking categories from Ofgem’s initial project assessment of GridLink as the basis:

- Connecting new providers of balancing services:
  - In line with Ofgem’s initial project assessment, the expectation is that GridLink can provide benefits through potential provision of ancillary services. Benefits can potentially be realised by the TSOs in both France and GB by increasing the pool of potential providers of balancing services.
- Providing alternative solutions to increase security of supply:
  - Presence of the link provides potential security of supply benefits to GB and France directly and to the region more broadly. Despite potential correlation of stress periods, the link still has a positive capacity credit in both markets, which is reflected in the modelling and welfare.
- Supporting decarbonisation of energy supplies:
  - The link is expected to facilitate flows of low carbon generation between GB and France and to support lower carbon dispatch across the markets and wider region.
- Strategic and sustainability framework areas:
  - In line with Ofgem’s initial project assessment, generally positive:
    - mid-term stress and security implications expected based on positive impact on security of supply, reduced potential for extreme prices and volatility, lower net combined carbon output through less carbon-intensive electricity imports; and
    - long-term sustainability implications as an increasingly meshed transmission network has greater ability to cope with a range of future pathways and energy system developments and the development of interconnectors might be less environmentally disruptive than alternative options for electricity supply.

ANNEX A – SCENARIO ASSUMPTIONS

A.1 Commodity and carbon price assumptions

A.1.1 Oil price projections

The current oil market is strongly oversupplied, our scenarios reflect this situation and contain assumptions as to how quickly the overhang will dissipate. In the longer-term, we do not attempt to predict the investment cycle and our projections are of sustainable long-term levels of investment. Outputs from the Cronos model are therefore smoothed in later years.

Cronos uses economic fundamentals to produce projections for the price of Brent. However, price fluctuations can often be driven by a range of factors not necessarily explainable by fundamentals. Therefore, we use the Brent forward curve as an input to determine a projection for the average price over the full the current year. After that, we move emphasis from the forward price to our model's demand-supply balance. This is because analysis shows that forward markets, beyond the year ahead, are limited predictors of future prices, because of three key reasons:

- the open interest (the number of contracts remaining open at the end of the trading day) for future products beyond the year ahead, reduces to zero; this indicates that there is limited interest in opening or closing contracts for the specific future product;
- the number of transactions and volume traded drops significantly past the first year, hence the forward price is based on a smaller number of views on the market position; and
- the forward price tends to follow recent market trends.

These reasons highlight that forward prices are not necessarily indicative of actual market expectations, hence we reduce the forward curve's impact on the Central scenario price projections after the first year.

Figure 52 summarises our AIMR scenario assumptions relating to our Q2 2020 Brent crude oil price projections, which are presented in Figure 53.

Figure 52 – Scenario framework for oil price projections

High	Strong global GDP growth, a decrease in OPEC market share and an increase in production in more expensive non-OPEC regions, as well as high production costs. These assumptions lead to a strong price growth in the short term, peaking in the late 2020s. After 2027, prices begin to decline due to ambitious decarbonisation targets and rapid electrification of transport, resulting in declining demand. Oil price decline below $90/barrel by 2060.
Central	OPEC maintains market share, production costs remain at current levels, and the global economy grows in line with historical levels. Prices rise to a level that supports new investments. We expect that the extension of the production cuts by OPEC and non-OPEC countries will result in a price increase in the short term, bringing price around $81/barrel in 2026. In the long term, demand begins to decline after peaking in mid 2030s. This causes prices to decrease post 2040, mainly driven by decarbonisation and electrification targets in the transport sector.
Low	Global GDP growth is below historical levels. Production costs decrease and OPEC expands its market share, reducing the required production from non-OPEC regions. The price falls in the short-term, before a recovery to a stable price level around $45/barrel until 2060. Drive to decarbonise in the 2040s results in gently declining demand, mainly from the electrification of transport. The impact is offset by gradual increase in production costs as cheaper sources are depleted.

Figure 53 – Projections of Brent Crude Oil prices ($/Barrel, real 2020 money)

[redacted]

A.1.1.1 Crude oil market model

The global crude oil market is extremely complex with tens of thousands of fields in production, each containing crude oil with a unique composition. Constructing a detailed field-level model of the entire market would be a difficult task, which would not necessarily lead to accurate projections. Therefore our crude oil market model Cronos is (as with any model) a simplification. However we believe that Cronos considers an appropriate level of detail which allows the production of robust projections of crude oil prices based on the scenario assumptions described in detail below.

The main output from Cronos is the price of light sweet crude in the North Sea on a Free On Board (FOB) basis. This can be taken to represent the Brent crude benchmark.

Cronos projects crude oil prices by analysing the global supply and demand for crude oil. The following bullet points describe this process in more detail:

- demand is determined by global GDP growth and the level of future technological progress (for example the development of electric vehicles);
- OPEC supply is an exogenous assumption across the different scenarios (it is difficult to construct an economic model of the behaviour of OPEC Member States, as their actions are often driven by political factors);
- other sources of supply, such as biofuels, coal-to-liquids and gas-to-liquids and processing gain are included as exogenous assumptions as well;
- the depletion of existing non-OPEC supply is based on data from the IEA; and
- new non-OPEC supply is determined by price developments, based on a detailed supply curve of potential non-OPEC fields.

We have created three scenarios, which span a reasonable range of outcomes and uncertainty in Brent crude oil prices. The main assumptions behind the three scenarios are summarised in Table 4.

The assumptions in the High and Low scenarios have been selected so as to examine the credible long-term range of future crude oil prices. Critical to this is the assumed future access to non-OPEC reserves. In the Low scenario, we assume cheaper reserves are developed at a faster rate than in the Central scenario, and therefore balance demand at a lower marginal price. In the High scenario, we assume cheaper reserves are developed more slowly than in the Central scenario, which requires more expensive reserves to be developed to balance demand, thus leading to a higher marginal price.

Table 4 – Overview of scenario specific assumptions

	High	Central	Low
Access to non-OPEC reserves	Low	Central	High
OPEC 2030 production capacity	Low	Central	High
US light tight oil (LTO) production	High	Central	Low
Production costs	High	Central	Low
Natural Gas Liquids expansion	Low	Central	High
Reduction in demand elasticity	Low	Central	High
Long-term global GDP growth	4.8%	3.8%	2.9%

A.1.2 Gas price projections

A.1.2.1 Long-term drivers of gas prices

Out to 2040, we project that gas prices will rise in Europe for three primary reasons:

- declining indigenous reserves;
- growing global competition; and
- more expensive gas sources.

Post 2040, prices stabilise as more ambitious decarbonisation drive causes gas demand to decline.

Declining indigenous reserves

- Indigenous reserves and production in Europe have declined rapidly in recent years and this trend is projected to continue**.**
- Production from the UK continental shelf (UKCS) is expected to continue its decline, despite new production wells coming online in recent years.
- In the Netherlands, the national government has decided to reduce production from the large Groningen field to zero by 2022, following multiple earth tremors in the surrounding area.
- Norwegian gas production is also projected to decline after the mid-2020s, once the Troll field and other prolific fields in the North and Norwegian Seas start to decline, despite an expected new production centre further north in the Barents Sea.

Much of the decline in indigenous and Norwegian supplies to Europe are likely to be met by growing imports of LNG, as can be seen in AFRY's projections for Europe's supply mix in Exhibit A.3. Therefore, Europe will have to increasingly compete on the global market for its gas, and it is the cost of delivering LNG to Europe that will determine future gas prices.

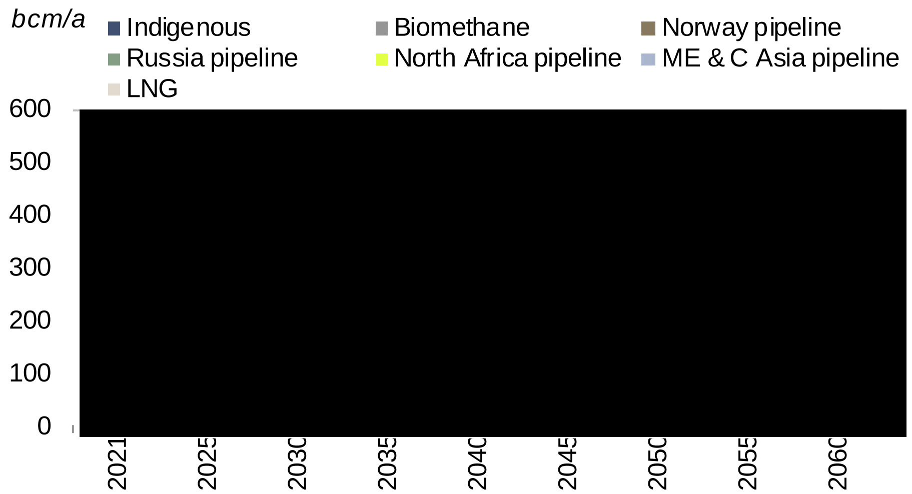
Growing global competition

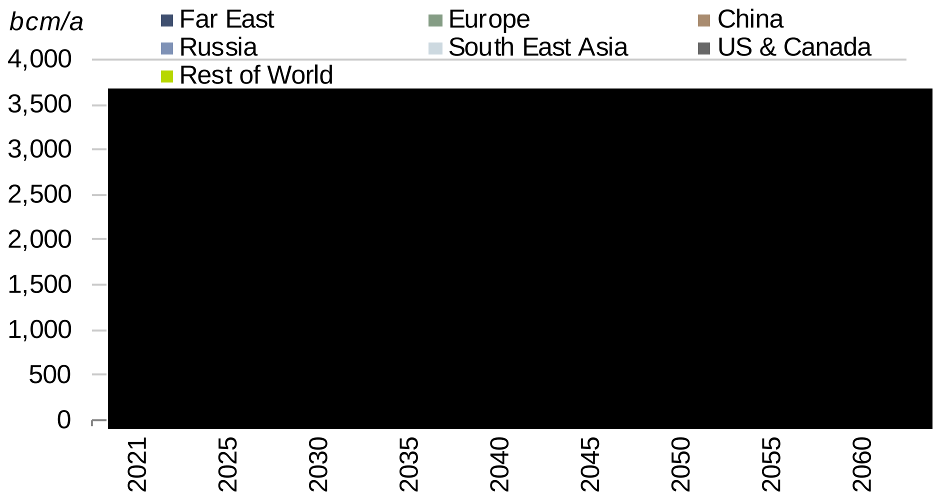
AFRY projects global gas demand to increase by 22% between 2021 and 2050, largely driven by growth in the emerging economies as shown in Exhibit A.4. Demand growth will in turn increase the requirement for LNG imports into non-traditional markets, led by China and India. In addition, increasing demand for gas from traditional exporting regions such as the Middle East and South East Asia will further intensify competition for global gas supplies out to 2050. As Europe competes for additional LNG (including the still significant levels of oil-indexed LNG supplied to Asia) it will be increasingly exposed to the rising prices of the global LNG market.

After 2050, global gas demand is projected to decline by 10% by 2060, driven by decarbonisation appropriate for each scenario, especially in Europe, but also part of North America and reductions in China and Russia. The reduction loosens global competition for LNG resources, resulting in plateauing prices.

We project gas prices[28] using our gas model, Pegasus 3, which examines the interaction between supply and demand worldwide on a daily basis. Three scenarios examine the effect on prices of a number of key drivers. In our quarterly updates, we factor in the latest developments in upstream production, infrastructure, and long-term contracts to reflect the complex situation in the gas market. For our price projections to 2060, we assume a seasonal normal demand based on the average over the last 10 years.

Figure 54 – Projected EU supply mix (top) and global demand for gas (bottom) in bcm/a for the Central scenario





28 The gas prices that we report are traded prices for delivery at a notional balancing point: they are market prices for marginal supplies and reflect the interactions between oil-indexed contracts and uncontracted gas; they do not represent average costs of gas for companies with significant contract volumes in their portfolios.

More expensive gas sources

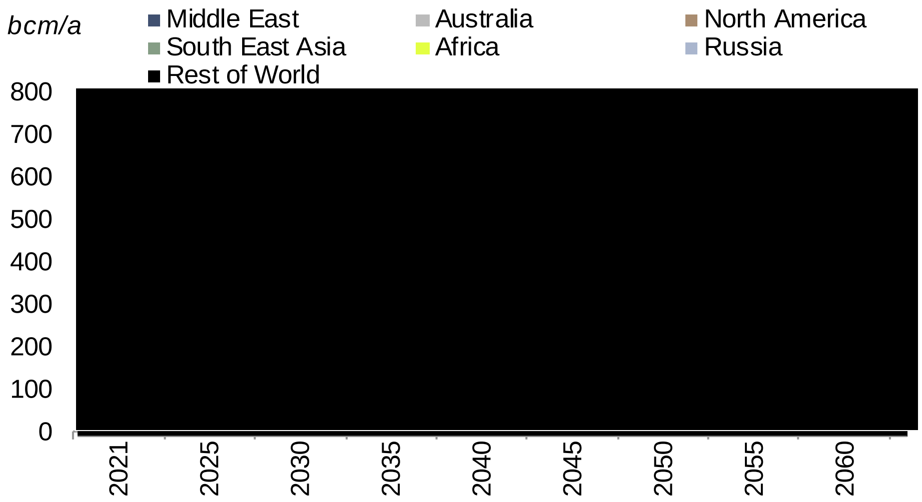
European gas prices are projected to remain low over the next few years, as the gas supply in storage and in the global market remains high. A significant number of new LNG liquefaction plants have also commenced operations in recent years, most notably in the United States and Australia. It is expected that this new capacity will keep an overhang in supply in the LNG market, leading to a buyers' market for LNG in the near term, and potentially resulting in LNG sellers being unable to recover their full cost (as is the case for US LNG off-takers selling into the European market, as shown in Exhibit A.5). The glut in LNG supply capacity is projected to gradually unwind in the early 2020s.

Notwithstanding the short-term LNG glut, in order to meet rising global demand growth from the mid-2020s onwards, gas from new and more remote sources will need to be exploited and transported to Europe. Exhibit A.6 shows significant new supplies of LNG from North America, Africa and Russia will be required to meet growing global demand for gas. In order to warrant investment in these sources, the price of gas will have to match the long run marginal cost (LRMC) of these developments, including upstream production, liquefaction and shipping costs. In addition, given that the construction period for a liquefaction terminal is typically five years, there is a requirement for new capacity to reach final investment decision (FID) by the turn of the decade to meet the supply-demand shortfall.

Figure 55 – Cost of supply to EU from difference sources (Central scenario) (€/MWh left, $/MMBTU right, real2020)

[redacted]

Figure 56 – Global LNG exports by region (including intra-regional trade) (Central scenario) (bcm/a)



A number of major players in the LNG market have identified the supply-demand gap expected from the mid-2020s, most notably Qatar, the world's largest producer of LNG. In 2017, the Qatari government lifted its moratorium on development of the giant North Field, which has been in place since 2005, and has since introduced plans to expand liquefaction capacity to 150bcm/a by 2025. In addition, US LNG developers Qatar Petroleum and Exxon-Mobil have taken FID for their 21 bcm/a Golden Pass LNG facility. Several others have been expected to follow suit over the next year; however, the current COVID-19 pandemic and potential global recession are likely to suspend many of these projects. The existing cost-competitive supply will serve to dampen the rise in gas prices during the 2020s, but also force the delay of new production from more expensive greenfield sites in Australia, North America and East Africa, as they would ideally build to flow during a higher price environment.

Influence of oil prices on gas prices

Historically, long term gas contracts were indexed to a time-lagged oil price. In recent years, we have seen differing regional trends in pricing gas contracts. In Europe, low hub prices have encouraged buyers to press for long term contracts for pipeline imports from Russia to be re-negotiated to include more pricing from spot markets. Gazprom's launch of its new electronic sales platform has been successful and more Russian gas is being sold under short-term contracts at close to European hub prices. All Norwegian imports to North-West Europe are now hub-priced.

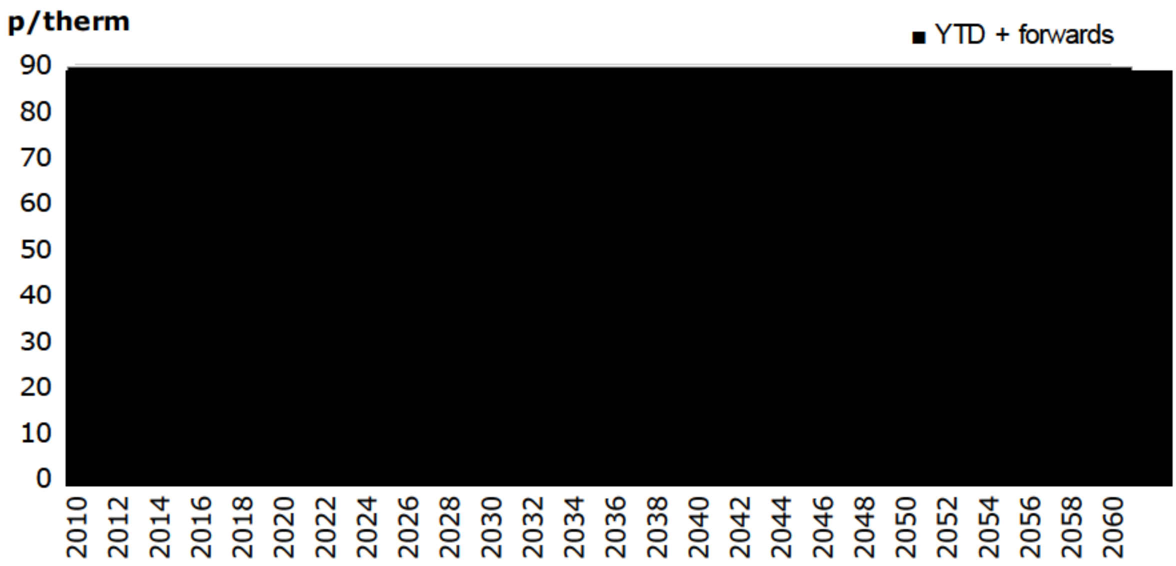
Nonetheless, oil-indexation remains a contributing factor to European gas prices. Firstly, the recent low oil prices have led gas deliveries under long-term contracts to be competitive with gas priced at North-West European hubs, resulting in buyers maximising their contracted nominations under these oil-indexed contracts. In Southern European countries, where there remains a reliance on a limited number of suppliers, pipeline supplies (from Russia and North Africa) are still very much oil-indexed. In addition to this, global LNG prices are influenced by the still significant levels of gas sold on oil-indexed contracts, particularly in the Pacific Basin, meaning that the oil price continues to have an influence on gas prices. The linkage between oil and gas has been weakening, and is expected to weaken further going forward; but as European hubs are relatively well interconnected, any influence of oil prices will still influence hubs across Europe.

A.1.2.2 Gas price projections

We summarise below our AIMR scenario assumptions relating to our Q2 2020 gas price projections, which are shown on a seasonal normal demand basis in Great Britain at the NBP hub in Figure 57.

High	Strong global GDP growth drives higher global gas demand, which leads to a need to exploit much more expensive sources of gas. Higher demand leads to greater producer power, which is reflected in the persistence of oil-indexed pricing in gas contracts. Combined with higher oil prices, this contributes to higher gas prices. In the late 2030s, ambitious decarbonisation targets drive global gas demand to plateau and decline after 2040.
Central	Moderate GDP growth and declining European gas reserves lead to a need for more expensive gas sources being imported into Europe. Oil-indexed pricing is in decline, especially in Northern Europe. There is a gradual de-linking between gas and oil prices, with oil-indexed pricing in Northern Europe phased out more quickly than in Southern Europe and the Asian LNG market. As a result, oil has only a minor influence on hub prices by 2040. In the 2050s, global gas demand begins to decline due to decarbonisation ambitions replacing gas in power generation, heating, and through energy efficiency gains.
Low	Regulatory pressure and low demand lead to the market being well supplied across the modelled period, meaning few major gas sources are needed. The healthy supply market also drives more quickly a full delinking from oil prices within the next few years. Post 2045, prices start to rise despite fairly flat demand, as cheaper Russian and Norwegian supplies have to be replaced by more expensive sources, including LNG.

Figure 57 – Annual gas price projections at NBP for Great Britain (p/therm, real 2020 money)



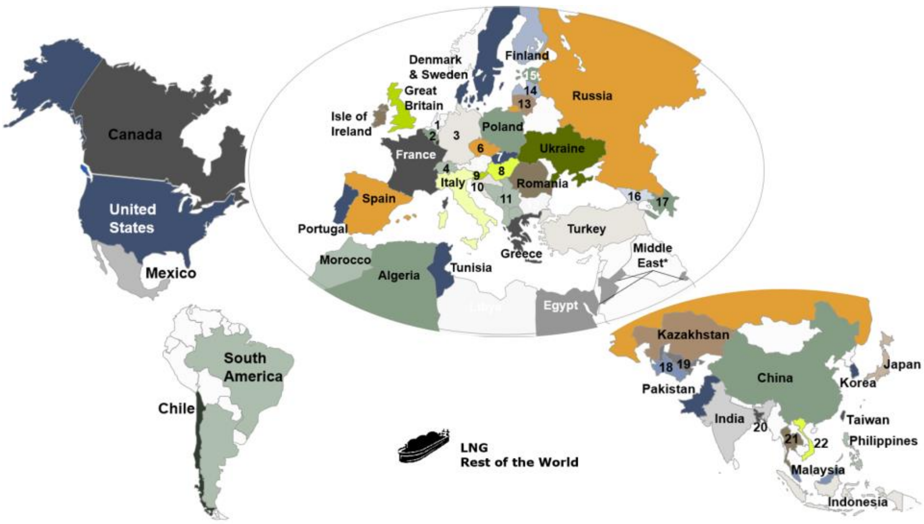
Notes: Historical and Forward prices on 1 May 2020
Source: Historical and Forward prices – Refinitiv; Projections – AFRY

A.1.2.3 Gas market modelling

Gas prices are projected using our gas model, Pegasus 3. The model examines global supply and demand on a daily basis. Pipeline imports from Norway, Russia, the Middle East and North Africa, alongside LNG imports interacting with the global market and indigenous production are all modelled against daily power and non-power demand across Europe. Interconnection flows within the European states as well as LNG terminals and pipes providing flows into Europe are all modelled in detail.

Examining daily supply and demand across these markets gives a high degree of resolution, allowing the model to examine weekday/weekend differences, flows through interconnectors and storage usage in detail. Figure 58 shows the modelled zones in Pegasus 3.

Figure 58 – Gas market zones in Pegasus 3



1 Netherlands
2 Belgium & Luxembourg
3 Germany
4 Switzerland
5 Austria
6 Czechia
7 Slovakia
8 Hungary
9 Slovenia
10 Croatia
11 South-East Europe
12 Bulgaria
13 Lithuania
14 Latvia
15 Estonia
16 Georgia
17 Azerbaijan
18 Turkmenistan
19 Uzbekistan
20 Bangladesh
21 Thailand
22 Vietnam
*Middle East includes Bahrain, Jordan, Kuwait and UAE

Notes: Gas demands in 60 geographical regions are modelled in Pegasus 3, aggregated into 59 H-gas and L-gas demand zones. The remaining 'Rest of the World' zone includes all other LNG terminals

As a core part of our modelling, we take gas demand from power generation sources from our electricity model, BID3, to understand the effect of changes in gas price on demand for gas, and changes in demand for gas on price. This iteration between the two models ensures that our assumptions on gas prices and gas demand remain realistic and reflects the elasticity of gas demand. Further details of our gas modelling methodology and assumptions may be found in our Western Europe & Global Gas Supply Study.

A.1.3 Coal price projections

The projections are determined using our coal model, Olympus, as part of our overall commodity price modelling suite. The model reflects the prices required to support sufficient investment in mining and transport capacity to meet worldwide coal demand in each scenario. Our scenarios for coal prices are described in more detail below.

High	▪ Strong GDP growth outweighing higher decarbonisation targets, resulting in growth in coal demand in the short and medium-term. ▪ Higher demand growth leading to new mine developments further away from established infrastructure, resulting in rising production costs and increasing investment costs. ▪ Higher coal transportation costs driven by higher oil prices. ▪ Post-2030, prices begin to fall as decarbonisation and new technologies reduce coal requirements.
Central	▪ Moderate economic growth combined with the decarbonisation policies in industrialised countries leading to modest coal demand growth. ▪ An adequate supply of coal being ensured by extra production in major exporting countries. ▪ Post 2030, prices follow a slight downward trend.
Low	▪ Weak global economic growth leading to lower demand for coal. ▪ Large quantities of low cost coal being available for export. ▪ Productivity gains in coal production ensuring costs reduction. ▪ Prices follow a slow downward trend to 2040 and remain at a low level in the long term.

The AFRY steam coal price projections are based on the fundamentals of supply and demand. However it can often take many years for the international coal market to respond to price signals and adjust available supply. Therefore, short-term prices are based on the API2 Argus/McCloskey forward curve, as reported by Refinitiv. The near-term prices are then interpolated with our long-term projections to calculate the current AFRY price projections.

Figure 59 presents our Q2 2020 global coal imports projections broken down by main sources across all three AFRY Independent Market Report (AIMR) scenarios (High, Central and Low).

Across all scenarios, coal imports remain stable in the short- to medium-term driven by the robust demand in India and other countries (mainly the non-OECD economies) offsetting the drop in the coal consumption in OECD coal importing countries and China. Post 2030, global coal imports reduce as India halts building new coal plants. Imports by OECD countries and China continue to decrease (especially in the Central scenario), as a result of prevailing decarbonisation policies.

Figure 59 – Global steam coal imports by destination (million tonnes)

a
■ China

[redacted]

2050 2060

In the Low scenario, coal imports drop across the whole modelling time frame mainly due to sluggish GDP growth in China (with China even being a coal exporter in the long-term) and weak GDP growth in OECD coal importing countries. The increase in coal imports in India and other emerging economies is not high enough to offset the drop in the rest of the world.

A.1.3.1 ARA steam coal price projections

Figure 60 shows the AFRY coal price projections alongside a comparison with a recent forward curve.

Figure 60 – Coal price (CIF ARA) projections ($/tonne, real 2020 money)

$/tonne

■ YTD + forwards

140
120
100
80
60
40
20
0

[redacted]

2010 2012 2014 2016 2018 2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040 2042 2044 2046 2048 2050 2052 2054 2056 2058 2060

A.1.3.2 Coal market modelling

The AFRY steam coal price projections are based on the fundamentals of supply and demand and long-run marginal costs using Olympus, our worldwide coal model.

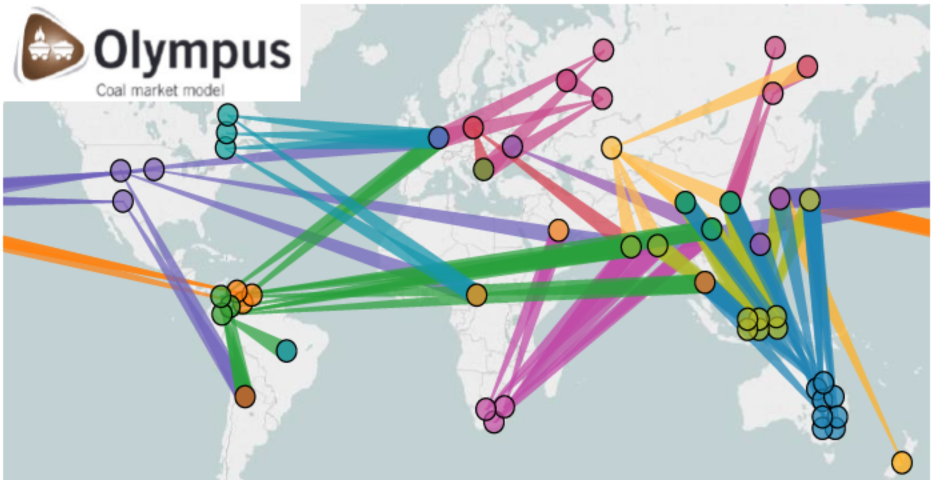
Olympus is a linear programming model dividing the world into individual zones. The model projects yearly coal trade and international prices to 2060, by notionally transporting coal from zones with an excess of supply over demand to zones with an excess of demand over supply, until all world demand for steam coal has been satisfied.

The model takes the following into account:

- the cost of production of coal (including future expansion) in each zone;
- the availability of coal in each zone;
- the demand for coal in each zone;
- the cost of transporting coal from where it is available to where it is needed; and
- an assumption of coal calorific value in each region.

This model produces an annual coal merit order for each importing zone (see Figure 61). The model is solved to satisfy coal demand at least cost, with the final ARA coal price calculated from the Western European coal supply curve. The model works on an annual basis and gives results for coal of an average calorific value of 6,000kcal/kg NAR.

Figure 61 – Representative coal flows in AFRY Olympus model



We develop coal cost information for exporting regions using data provided by the IEA Clean Coal Centre together with our own assumptions (Figure 62). Estimates of mine investment costs are based on various mining company reports. Shipping costs take into account capex, opex and fuel costs. Demand projections are also developed based on IEA assumptions.

Figure 62 – Indicative supply curve in AFRY Olympus model - Central

[redacted]

The AFRY steam coal price projections are based on the fundamentals of supply and demand. However as has been discussed, it can often take many years for the international coal market to respond to price signals and provide increased supply. Therefore short-term prices are based on the prevailing forward curve.

A.1.4 Carbon price projections

A.1.4.1 Drivers of carbon prices

Using our carbon model, called Aether, we project that carbon prices will increase over time due to:

- **The tightening cap.** The tightening cap causes the supply of allowances to be restricted over time, creating a significant increase in the demand for abatement relative to abatement achieved to date. In addition, supply-side policy interventions in the form of back-loading and the Market Stability Reserve (MSR) effectively increase demand for abatement throughout the 2020s.
- **The increasing cost of additional sources of abatement.** Cheap abatement (e.g. in the form of industrial energy efficiency) will tend to be used up first. As the cap tightens, participants are gradually forced to invest in more expensive abatement technologies.

Counteracting these drivers are the impacts of overlapping policies (e.g. coal phase out, renewable subsidies, energy efficiency policies), the offshoring of industrial emissions outside of Europe, and decreasing low-carbon technology costs. In the absence of these mitigating drivers, carbon prices would be considerably higher.

Our approach to modelling EUA prices is based on long-term fundamental analysis of the economics of reducing carbon emissions within the EU ETS traded sectors:

- Demand for abatement is driven by the difference in emissions under a business-as-usual (BAU) baseline versus the supply of allowances (EU ETS cap plus offsets).
- Supply of abatement (i.e. carbon reduction measures) primarily comes through fuel switching, low carbon investment in the power sector, and industrial abatement. The cost of abatement varies considerably among the individual sources of abatement amongst these broad categories.

The carbon price is determined by the marginal cost of the abatement source required to meet the demand for carbon allowances.

Demand for abatement

Demand for abatement is calculated as the projected difference between:

- a business-as-usual (BAU) emissions baseline; and
- the supply of allowances into the market, which is determined by the EU ETS cap plus international offsets, and adjustments made through back-loading and the MSR.

BAU baseline

The baseline comprises emissions from power generation, industry, and aviation. Baseline power emissions are calculated based on electricity demand under our three electricity price scenarios from BID3 assuming a static emissions intensity at today's levels. All structural changes to the power sector are therefore accounted for in the supply of abatement. Emissions from the industrial sectors are calculated based on AFRY's assessment of industry sector growth rates. These assumptions are linked to historical and short-, medium- and long-term European GDP projections, as well as the Industrial Production Index (IPI). Aviation is included from 2012 together with other additional sectors included from the start of Phase III in 2013. The aviation sector projections follow passenger distance estimates from the European Organisation for the Safety of Air Navigation. We assume the scope of aviation continues to only cover domestic EU flights and does not revert back to full scope.

Emissions cap

The methodology for calculating the overall EU ETS cap on emissions is set out by the European Commission.

Over Phase III (2013-2020) it declines linearly each year by 1.74% relative to a fixed reference value . This is consistent with the target to reduce GHG emissions in the stationary segment of the EU ETS by 21% by 2020 and is the pathway adopted across our EUA price scenarios. The aviation sector cap is set at the legislated 5% reduction across Phase III.

For Phase IV (2021-2030), in our Low scenario we apply the agreed linear reduction factor of 2.20% to the stationary and aviation sectors for the subsequent ten-year period, resulting in a 42% reduction by 2030. In our Central scenario we assume the linear reduction factor increases to 2.7% in 2024 to reach an EU ETS target of a 45% reduction by 2030. In our High scenario we assume the linear reduction factor increases to 3.43% in 2024, in expectation of a ratcheting up of European climate ambition as part of the global stocktake under the Paris Agreement for the ETS to reach a 50% reduction by 2030.

After Phase IV (2031 to 2060) where no binding EU ETS cap has been set, we assume the cap continues to tighten and is consistent with a 90% emission reduction by 2050, broadly in line with the EU's 2011 objective of reducing greenhouse gas emissions by 80-95% by 2050 . Our High and Low scenarios diverge to 2050 to test plausible ranges around this level as shown in Exhibit A.4.

We note that the net negative position in the High scenario is necessary to reach our 95% economy wide decarbonisation by 2050 target, as sectors outside the EU ETS are significantly harder to decarbonise and hence have their emissions partly offset by net negative emissions from the EU ETS sector.

Table 5 – Emissions cap reduction under the EU ETS (% relative to 2005 level)

	High	Central	Low
2020	-21%	-21%	-21%
2030	-50%	-45%	-42%
2050	-105%	-90%	-75%

In all scenarios we model the MSR in line with the proposed rules which state that:

- If the surplus in the previous year is greater than 833Mt, then 24% of the surplus is withheld from the market and placed into the reserve in the current year.
- If the surplus in the previous year is less than 400Mt, then 100Mt is returned to the market in current year from the reserve (assuming the reserve contains permits).

The surplus, legally referred to as the Total Number of Allowances in Circulation (TNAC), is defined as[29]:

TNAC = (Allocation + Offset credits) – Verified emissions

Additionally, as per the legislation (Section A1.2), we assume that:

- the aviation sector is currently excluded from this calculation;
- the 900 million backloaded allowances are transferred directly into the reserve; and
- from 2023, allowances in the MSR above the total number of allowances auctioned in the previous year are invalidated.

Due to the increasing impact of excluding aviation from the TNAC calculation, we assume that the rules are modified to include aviation from 2024.

We also assume the phase-out of German coal and lignite plants by 2038 and that the EU cancels the half of the equivalent volume of EUAs from our projected supply of allowances. Not doing so would result in a €3-6/tCO2 price reduction from mid to late 2020s relative to our latest projections.

[29] In this equation TNAC refers to the surplus since 2008; specifically, 'allocation' includes (i) allowances banked from Phase II (2008-12), (ii) allowances auctioned between 1/1/2013 and 31/12/2016, (iii) allowances allocated for free between 1/1/2013 and 31/12/2016, including EUAs allocated from the New Entrants' Reserve (NER), and (iv) allowances monetised by the European Investment Bank for the purposes of the 'NER300' programme. Meanwhile 'verified emissions' consists of verified emissions since 2008, minus any invalidated allowances, minus allowances currently in the MSR.

A.1.4.2 Carbon price projections

We summarise our AIMR scenario assumptions for the Q2 2020 carbon price projections, while Figure 63 shows these carbon price projections.

Figure 63 – EUA price projections (t/CO_2, real 2020 money)

[redacted]

High	Characterised by high electricity demand growth, high fossil fuel prices and high decarbonisation policy ambition. The emissions cap achieves a reduction of 50% by 2030 and 90% by 2050. We have reflected recent market developments by assuming two-thirds of the surplus is currently price unresponsive. Prices rise quickly which helps support investment in low carbon generation, such as bioenergy with CCS (BECCS) and renewables.
Central	The emissions cap achieves a reduction of 21% by 2020 and 45% by 2030, consistent with the increasing ambition for the EU ETS. Beyond 2030, we assume the cap continues to tighten and is consistent with a 90% emissions reduction by 2050. The current market is above the price derived from fundamentals meaning our projections for early years sit below the forward price. We use the forward prices to trend from the current 2020 price to the 2023 modelled price. From 2030 prices rise as the supply-demand balance tightens. Abatement from the power sector grows from around 2050 as BECCS is deployed.
Low	Characterised by low electricity demand growth, low fossil fuel prices and low decarbonisation policy ambition. It has an emissions cap that reaches 42% by 2030 and 75% by 2050. A loose supply-demand balance results in weak long-term price. MSR activity combined with a tightening cap eventually tightens the market, resulting in slowly rising prices from 2030.

A.1.4.3 The UK carbon price

The total carbon price (the effective carbon price) applicable in GB is made of two components: the price of the EUAs and the Carbon Price Support (CPS).

In the modelling of this update we continued to assume the £18/tonne (nominal) cap to remain on the Carbon Price Support until FYE 2022 (as announced in Budget 2020). The government retains the freedom to adjust the CPS rates beyond FYE 2022 depending on market conditions.

The government has also put forward proposals for a domestic carbon ETS to come in to place once the UK leaves the EU ETS at the end of the transition period. In our modelling we assume a future UK ETS to be swiftly linked to the EU ETS and therefore, continue to assume the price of EUAs as a component of the effective carbon price.

Figure 64 – Effective carbon prices (£/tCO2), real 2020 money

[redacted]

In our carbon modelling we have implemented the CPS cap at £18/tonne in nominal terms in all scenarios until 2020/21. We assume that the cap is uprated by inflation of 2% from 2021/22 in all scenarios, whereupon assumptions around the effective carbon price in GB diverge. The CPS element falls away once the EUA price rises above the assumed carbon price floor trajectory.

High	The carbon price floor trajectory is assumed to continue indefinitely while being uprated for inflation from 2022/23 onwards. The increase in the price of EUA results in the effective carbon price being capped at the assumed trajectory level in the early 2030s. In the late 2030s EUA prices increase beyond the assumed carbon price floor trajectory, bringing the effective carbon price in line with the EUA price.
Central	In the central scenario, our view remains aligned with the government's legislated carbon price support until 2021/22, thereafter we keep the effective carbon price flat in real terms until 2025 (the year in which the last domestic coal generator is closed in our Central scenario). This means the carbon price floor trajectory reduces as the EUA price rises. After 2025 the carbon price floor is kept constant at 2025 levels, allowing the effective carbon price to rise to a long-term target level (£30 in real 2009 money) as EUA prices increase over time. In the early 2030s, the EUA prices increase beyond the assumed carbon price floor trajectory, bringing the effective carbon price in line with the EUA price.
Low	We believe that a carbon price floor significantly above the EUA price would be untenable in the Low scenario. However, as a floor may be needed in the future to provide certainty for low carbon generators, we hold the carbon price floor trajectory constant from 2022 onwards in real terms. In the late 2030s, the EUA prices increase beyond the assumed carbon price floor trajectory, bringing the effective carbon price in line with the EUA price.

A.2 Electricity demand assumptions

Our electricity demand projections represent net demand, including transmission losses. We define net demand as the demand that has to be met by plants connected to the grid (transmission and distribution), as measured at the station gate.

We use our demand modelling suite which is made up of three models:

- **Econometric base demand** which produces projections for the base demand and also combines them with transport and heat to obtain total electricity demand projections;
- **Move** which models the decarbonisation of the transport sector; and
- **Hestia** which models the decarbonisation on the heat sector.

The design of the demand scenarios is an integral part of the three AFRY Independent Market Report scenarios whose main drivers consist of differing levels of sector decarbonisation, economic and population change; and energy efficiency measures:

- **High scenario** reflects a combination of drivers that consistently result in electricity prices towards the upper limit of plausible expectations. This scenario foresees high electricity demand driven by high GDP growth and strong commitment towards decarbonisation and electrification
- **Central scenario** presents our best view of future electricity prices with moderate demand growth driven by lower GDP growth compared to the high scenario, decarbonisation commitment to reach net zero by 2070 and high electrification which is partially offset by other decarbonisation methods such as hydrogen.
- **Low scenario** reflects a combination of drivers that consistently result in electricity prices towards the lower limit of plausible expectations. Demand

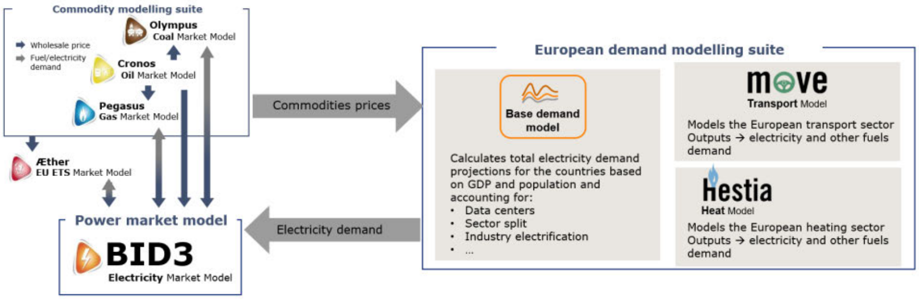
is this scenario remains flatter and grows in the medium/long term as a result of the need to decarbonise. GDP growth tends to 0% in 2060 and the development of other decarbonisation methods results in lower electrification.

A.2.1 The demand modelling within AFRY's modelling approach

The demand modelling suite is part of the wider AFRY's modelling environment and closely interacts with the other models receiving inputs such as fuel prices and technology costs and producing outputs (annual demand figures) that are used by BID3 for the power markets modelling.

Figure 65 shows how the demand modelling suite fits in our modelling environment.

Figure 65 – AFRY modelling environment



The modelling suite combines the different demand components to get annual figures of total electricity demand providing the inputs that are used by BID3. The various demand components of the power market model are:

- **Base demand** – which groups the sectorial demands (residential, commercial, industrial and agricultural), it includes cooling but excludes any electric demand coming from the heating and transport sectors.
- **Flat demand** – represent demand components which are modelled with a flat hourly profile such as data centers and oil-field electrification in Norway:
  - **EV demand** – represent electricity demand required by the transport sector, and it is further split into two three components:
    - **BEV** → Battery Electric Vehicles, with a specific profile that takes into account the ability to charge flexibly[30].
    - **HEV** → Hybrid Electric vehicles, with a specific profile that accounts for flexibility of hybrids vehicles.

30 We do not actually model BEV and HEV fully flexibly because of computational difficulties. However, the hourly profiles associated with these types of vehicles have been built running the model in a fully flexible set up. The resulting profiles are then used as a fixed input in the EMQA standard runs.

  - **Non-responsive EV** → representing electric vehicles which despite being electric do not act flexibly.
- **Heat demand** – represents electricity demand required for heating and it is further split into:
  - **Existing heating** → represents the share of heat demand as of today which is mainly made up by resistive heating.
  - **New heating** → represents the electricity demand coming from the heat sectors in the future on top of the existing one to capture the effect of heat pumps on the hourly profile.

A.2.2 2020 Q2 outlook in Great Britain

In this section we present our projections for total system and peak electricity demand out to 2060 in Great Britain (Figure 66), while Figure 67 shows the build-up of demand by the different categories of demand.

High	In the short-term, we project a rapid recovery from the COVID-19 situation driven by a reduced schedule of months under lockdown while robust GDP growth drive up industrial and residential demand. In the medium to long-term we project strong electrification of the transport and heat, driven by the strong decarbonisation ambition in this scenario. Improvements in energy efficiency partially counteract demand growth until the 2030s.
Central	We assume a moderate impact from COVID-19 which results in partial lockdown measures in the short-term until 2022. Electricity demand follows a steady recovery from today's levels to reach pre-COVID-19 electricity demand by 2025. Improvements in energy efficiency are realised in the short to medium-term, providing downward pressure on demand growth. In the medium to long-term the electrification of transport and heat is projected to increase significantly, being the primary factor behind the overall growth of demand for electricity.
Low	We assume a severe long-lasting impact from COVID-19, in which the current situation intensifies taking longer to recover in the short-term. The period of low economic growth prolongs in the medium term behind weak macroeconomic growth factors coupling with energy efficiency improvements and limited electrification of the economy, resulting in falling demand until 2030, and insufficient demand growth to recover to pre-COVID-19 levels until 2040. In the long-term the high rates of electrification of transport and heat sectors increase overall demand.

Figure 66 – Total (TWh) and Peak (GW) electricity demand projections including electrolysis

[redacted]

Figure 67 shows the evolution of the different demand components over time.

Figure 68 provides an overview of the key metrics used for the demand modelling.

Figure 67 – Demand breakdown for Great Britain

[redacted]

Figure 68 – Key electricity demand metrics for Great Britain

		High	Central	Low
GDP Growth (annual rate)	2030	2.4%	1.4%	0.3%
	2040	2.2%	1.2%	0.1%
	2060	1.8%	0.8%	0.0%
Energy efficiency (annual improvement rate)	2030	0.6%	0.4%	0.2%
	2040	0.9%	0.6%	0.3%
	2060	2.0%	1.2%	0.6%
Electric heating (share of heat production)	2030	9%	7%	6%
	2040	31%	17%	12%
	2060	54%	44%	33%
EVs (share of total vehicles, incl. hybrids)	2030	43%	20%	12%
	2040	86%	70%	44%
	2060	99%	98%	68%

A.2.3 2020 Q2 outlook in France

In this section we present our projections for total system and peak electricity demand out to 2060 in France (Figure 69), while Figure 70 shows the build-up of demand by the different categories of demand.

High	A stronger increase in GDP and a faster uptake of EVs and heat pumps create a large increase in both total and peak electricity demand.
Central	A moderate increase in GDP and a reasonable uptake of EVs are balanced by energy efficiency gains, leading to relatively stable total and peak electricity demand up to 2030. Post 2030, the fast uptake of EVs and heat pumps leads to an increasing demand.

Low	Up to 2030, both total and peak electricity demand slightly decrease as an increase in energy efficiency more than offsets a low economic growth and a slow uptake of EVs. Post 2030, the uptake of EVs and heat pumps leads to a more stable then increasing demand.

Figure 69 – Total (TWh) and Peak (GW) electricity demand projections including electrolysis

[redacted]

Figure 70 shows the evolution of the different demand components over time. Figure 71 provides an overview of the key metrics used for the demand modelling.

Figure 70 – Demand breakdown for France

[redacted]

Figure 71 – Key electricity demand metrics for France

		High	Central	Low
GDP Growth (annual rate)	2030	2.3%	1.3%	0.2%
	2040	2.1%	1.1%	0.1%
	2060	1.8%	0.8%	0.0%
Energy efficiency (annual improvement rate)	2030	1.6%	1.1%	0.7%
	2040	1.4%	1.0%	0.4%
	2060	1.1%	0.7%	0.1%
Electric heating (share of heat production)	2030	16%	15%	15%
	2040	46%	36%	35%
	2060	65%	57%	59%
EVs (share of total vehicles, incl. hybrids)	2030	44%	18%	13%
	2040	85%	58%	40%
	2060	99%	98%	80%

A.3 Comparison of AFRY and TYNDP assumptions

This Section presents a comparison between AFRY's scenarios assumptions and the scenarios from ENTSO-E TYNDP 2018.

Figure 72 presents a comparison of demand assumptions between AFRY scenarios and TYNDP 2018 scenarios. TYNDP assumptions for demand in GB and France are generally in line with AFRY assumptions. AFRY assumes somewhat higher demand in France in 2040 in High and Central compared to TYNDP.

Figure 72 – Demand assumptions in AFRY and TYNDP scenarios (TWh)

[redacted]

Figure 73 shows the comparison in solar PV, onshore and offshore wind deployment in AFRY scenarios compared to TYNDP 2018 scenarios. In general, TYNDP assumptions for renewable deployment in GB and France are comparable with AFRY assumptions. TYNPD Distributed Energy assumes more solar PV in GB and more onshore wind in France in 2040 compared to the range of AFRY scenarios.

Figure 73 – RES deployment in AFRY and TYNDP scenarios (GW)

[redacted]

Figure 74 shows the interconnection capacity in GB and France in AFRY and TYNDP scenarios. TNYDP tends to assume higher interconnection with GB in 2040 compared to AFRY's scenarios, driven by interconnection with the Netherlands and Norway.

Figure 74 – Interconnection capacities in GB and France in AFRY and TYNDP scenarios (GW)

[redacted]

A.4 Supply curves

Figure 75 shows indicative supply curves for GB and France in 2025 and 2040 in the Central scenario.

Figure 75 – Supply curves for January and July 2025 and 2040

[redacted]

France - 2040

[redacted]

A.5 LCOE/ costs assumptions

This section details the cost assumptions we use in assessing the economic viability of new generic power plants in Europe. These assumptions draw upon:

- a wide range of published sources;
- AFRY's knowledge of actual projects; and
- the expertise and experience of engineers within AFRY.

The minimum required internal rate of return (IRR), also often called the hurdle rate, used in our modelling is based on pre-tax, real project returns. The hurdle rates are used to assess whether new capacity is economically viable. If, given a certain set of market prices and other economic assumptions, a new plant would have an IRR equal to or greater than the pre-defined hurdle rate then the plant is commissioned, otherwise it is not .

The lifetime cost of power plants consists of three main components:

- the capital expenditure ('capex'), which represents the initial cost of building and putting the plant into operation;
- the operational expenditure ('opex'), which represents the annual fixed cost of running the plant throughout its lifetime; and
- any variable costs, for example fuel costs for a CCGT.

The Levelised Cost of Electricity (LCOE, €/MWh) is the net present value of the total lifetime costs of the power plant, averaged over lifetime energy production. It can be seen as a proxy for the minimum captured wholesale price that must be obtained by the plant in order to reach its hurdle rate. It is most meaningful for technologies that run at close to their availability, such as wind, solar and nuclear. In other cases the comparison would be between the captured price and the levelised cost of the plant given the load factor it achieves, which is generally not known in advance of running BID3.

A.5.1 Thermal generation

Table 6 and Table 7 detail the cost assumptions we use in assessing the economic viability of new generic thermal plants in Europe. The tables show costs and efficiencies for a generic new build thermal plant starting operations in the Netherlands in years 2020 and 2030. Capex costs are very similar across Europe, while CCGT and GT opex costs vary across different countries, mainly driven by differences in gas transmission charges (fixed component).

In the medium to long term, capex and opex costs of most thermal technologies are expected to remain stable in all our scenarios. The increased competiveness of fossil fuel plants over time is mainly derived from increases in plant efficiencies. Our efficiencies are HHV, full load, lifetime average efficiencies.

Table 6 – New entry cost assumptions for thermal generators (real 2020 money)

[redacted]

Table 7 – New entry efficiency assumptions for thermal generators

[redacted]

A.5.2 Renewable generation

Table 8, Table 9 and Table 10 outline assumptions employed for renewables across Europe. With a limited number of exceptions, capital costs for solar and wind generation (for each hub height classification) are uniform across Europe, though there is a little more variation in hurdle rates. The projected cost of new entrants drops across all our scenarios over time.

Table 8 – New entry assumptions for generic European renewable generators (real 2020 money) – Capex and Opex

[redacted]

Table 9 – New entry assumptions for generic European renewable generators - hurdle rates

[redacted]

Table 10 – New entry assumptions for generic European renewable generators – financial lifetime

[redacted]

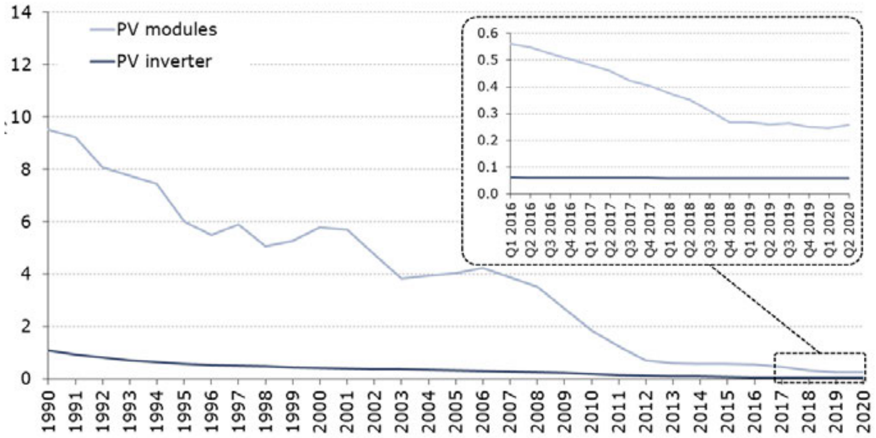
A.5.2.1 Solar PV

Capital costs of a typical ground-mounted utility scale PV system can be split into three main cost components:

- photovoltaic modules;
- photovoltaic central inverters; and
- Balance-of-System (BoS) components.

PV system costs have been rapidly declining for the past 30 years, mainly due to the exponential drop in the price of PV modules, represented in Figure 76. While modules used to account for over 70% of system costs only 10 years ago, nowadays their share is typically around 40-45% for fixed-tilt systems and 35-40% for single axis tracker systems.

Figure 76 – Evolution of the EU wholesale market price for Solar PV components (€/W, real 2020 money)



Source: Fraunhofer ISE, IRENA, pvXchange and AFRY analysis.

The European price of PV modules used to be kept artificially high due to import duties on solar panels and cells imported from China, Taiwan and Malaysia, which were imposed by the European Commission in 2013. The anti-dumping Minimum-Import-Price (EU MIP) for Asian PV modules was terminated in September 2018, as represented in Figure 77. EU modules are still trading at a premium, but arbitrage is projected to force modules in Europe to drop to global pricing levels.

One of the main trends of the global solar market that started in 2019 and is expected to continue in 2020 is bifacial solar panels. These types of modules, which can absorb sunlight from both sides, have higher investment costs, but can also help achieving higher load factors. Considering the competitiveness that this technology is projected to have in the near future, almost all main manufacturers are starting to propose a bifacial option.

Another global trend that is expected to strongly affect the PV industry in the following years is the shift from muiti- to monocrystalline modules. BNEF expects monocrystalline silicon cells to increase global market share from 42% at the end of 2018 to 64% at the end of 2021[31].

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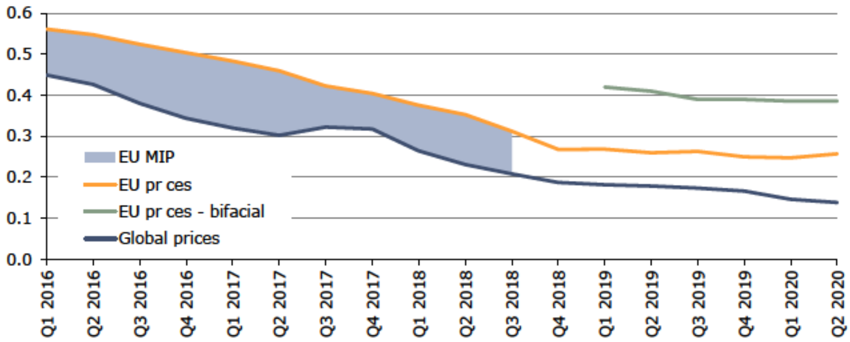
31 Bloomberg New Energy Finance, 'Global solar investment report', 2019.

Figure 77 – Recent evolution of the EU and global wholesale market price for Solar PV modules (€/W, real 2020 money)



Source: pvXchange and PVinsight
Note: Comparisons with other sources show that on a global level the premium of bifacial panels over monocrystalline is often small

As shown in Figure 76, inverter costs have also decreased significantly since the 1990s, contributing (although to a lesser extent) to the downward pressure on PV system prices. Inverter efficiencies for the best-in-class products are close to 100%, but further cost reductions are expected thanks to hardware changes allowing for higher bus DC, production delocalisation and economies of scale[32].

BoS components include, among others, cabling, grid connection[33], electrical and mechanical installation, permitting and financing costs. BoS cost currently amounts to about 50% of the aggregate cost of a PV system. Although BoS costs have been declining along with the cost of PV modules and inverters, the downward trajectory has varied significantly depending on the country or region.

While the cost of labour and other macroeconomic factors play a role, the development of a local solar market and its competitiveness are often major drivers of BoS price reductions.

We expect PV systems costs to reduce over time in all three scenarios. A rapidly expanding global demand is likely to be met by further drops in module and inverter costs, while BoS savings will be generated by a convergence towards best practice project development, increases in module efficiencies leading to project's improved use of space, policy making, automation in the installation phase and aggressive BoS vendor pricing.

The integration of digital monitoring and management of PV systems offers scope for significant O&M and servicing savings. This is mainly driven by the adoption of predictive, rather than reactive, maintenance practices, allowing access to higher quality data and advanced analysis tools to improve both output and reliability, and optimisation of load integration into the grid.

32 IRENA, 'The power to change: solar and wind cost reduction potential to 2025', June 2016.

33 Grid connection costs vary by market.

Figure 78 presents our projections of the LCOE for a fixed-tilt PV system for typical European high, average and low solar load factors. Historical figures are also presented to show the extent of the drop in LCOE since 2014 due to technologic improvements.

Figure 78 – LCOE Projections for fixed tilt Solar PV (€/MWh, real 2020 money)

[redacted]

Trackers however have larger capex and opex costs than fixed-tilt systems, mainly due to: more expensive procurement and installation, larger land use and higher operation and maintenance (O&M) costs.

Moreover, tracking system development can be hindered by site dependent conditions such as terrain, wind loads and soil conditions.

While careful evaluation of all the aforementioned factors is required in order to make a sound investment decision, aggressive improvements in system design and in predictive maintenance are behind the recent significant increase in market share of tracking solar devices, which are becoming the PV technology choice in several regions of Europe and the Americas.

Figure 79 presents our projections of the LCOE for a PV system with single-axis tracker for typical European high, average and low solar load factors.

[34] ‘Current and future costs of photovoltaics’, 2015 and ‘Levelized Cost Of Electricity Renewable Energy Technologies’, 2018.

Figure 79 – LCOE projections for single-axis tracker Solar PV (€/MWh, real 2020 money)

[redacted]

A.5.2.2 Onshore wind

Capital costs for a typical onshore wind power system can be split into four main cost items:

- wind turbine (including rotor, blades, towers, electrical components, transportation and installation costs);
- grid connection;
- civil works; and
- other capital costs (licensing and permitting costs, consultancy, financing, development and engineering costs, and monitoring systems).

Wind turbines are the most cost intensive item of a wind farm, with a share of almost 65%-85% of system costs[35]. A local peak in turbine costs occurred in 2008, due to a significant increase in commodity prices such as steel and copper. This was followed by a sharp drop in prices to the current level, with a decrease in turbine costs of up to 30%-40%[36]. This occurred due to significant improvements in the wind turbine technology and due to increasing nameplate capacity.

As viable high wind speed sites are becoming increasingly rare in Europe, taller towers and longer blades are enabling investments in lower wind speed sites.

In order to capture the wide range of wind turbines, and their effect on the cost of onshore wind development, we use three different types of hub heights in our cost modelling[37]:

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35 Agora Energiewende, 'Future cost of onshore wind. Recent auction results, long-term outlook and implications for upcoming German auctions', April 2017; IRENA, 'The power to change: solar and wind cost reduction potential to 2025', June 2016; World Energy Council, 'World energy resources 2016', October 2016.

36 IRENA, 'Renewable power generation costs in 2014', January 2015.

37 In producing the wind generation profiles in BID3, a less generic approach is used.

- • low hub (below 115 metres);
- • medium hub (between 115 metres and 135 metres); and
- • high hub (above 135 metres).

Typically, the higher the hub and the greater the rotor diameter (for a given output capacity), the higher the capital cost required to develop a wind farm. This is due to increased transportation, foundation and installation costs. Moreover, for hubs higher than 130-140 metres, steel towers pose more logistical challenges and become less economic, forcing developers to look at cement or hybrid solutions, such as in-situ concrete towers or precast concrete elements[38]. The increase in capital costs caused by taller and larger turbines is detailed in Table 9.

The additional cost sustained for higher hubs and larger swept areas, is often, however, more than compensated by the financial returns derived from the increased capacity factors for a given wind resource.

Based on our data, the average wind speeds at 100m and 50m differ by between 4% and 28% depending on location. High wind locations with high wind gradients include much of Scandinavia, Portugal and smaller areas of other European countries.

Although hub height partly determines the turbine that can be used, it is reasonable to estimate, using a typical Vestas V90 2MW power curve, that a 20% increase in wind speed is equivalent to a growth of ten percentage points in the load factor, without considering that higher winds are often also steadier. However, in recent years there has been a large expansion in the number of turbines designed for low/moderate wind locations, and picking suitable turbines for a site can reduce the dependence of load factor on wind speeds. China is a market where both Chinese and international wind turbine manufacturers have been and are targeting low wind areas.

Given the large role played by capital costs on the LCOE, Figure 80 below outline the effect of different hub heights on LCOEs for different load factors.

Looking forward, grid connection, civil works and BoS best practices should allow further cost efficiency improvements. LCOE savings are also likely to be found as a result of the on-going innovation in design and in the materials used for towers and blades, manufacturers' economies of scale, and extended plant lifetime.

In addition, the increase in wind turbine reliability has been and is projected to remain another driver of LCOE reduction. In May 2019, TÜV NORD issued the

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38 This is rapidly changing as cement or hybrid solutions for medium and high hub towers are increasingly challenged by steel hubs. Manufacturers have made significant progress in making steel towers economically viable. Vestas's Large Diameter Steel Tower (LDST) allows tower height for 5.6 MW turbines to surpass 165 meters. GE Renewable Energy has introduced a two-piece blade design, which enables turbines with a rotor diameter of 158 meters to be mounted on 160-meter steel towers in a cost efficient way.

first Design Evaluation Conformity Statement for a lifetime of forty years, which is twice the standard period. The certification covers the GE Renewable Energy's 2.7-116 onshore wind turbine.

The steady scaling in turbine heights and rotor diameters is expected to continue in the coming years, impacting the ratio of generator size to rotor swept area, and reducing the development cost per-kilowatt.

Lastly, similarly to solar PV plants, the increasing integration of digitalisation in wind systems' O&M and asset management offers scope for further LCOE savings.

Figure 80 – LCOE projections for Onshore wind – High (top), Medium (middle) and Low (bottom) Hub height (€/MWh, real 2020 money)

[redacted]

A.5.2.3 Offshore wind

Excluding financing and decommissioning costs, the costs of transmission[39], construction and foundation typically account for about 60%-70% of the total capital costs for an offshore wind project. The turbine share is typically between 30%-40% of the capex[40], while electrical infrastructure, foundation and installation costs and project planning account for the rest.

Sharply decreasing bids in recent offshore wind auctions in Denmark, the Netherlands, Germany and Great Britain suggest that capital costs for offshore development are rapidly decreasing. A major driver behind the low offshore wind bids recently witnessed in Europe is certainly the structure of the auctioned projects that allows a significant portion of development risk to be stripped away from the project, thanks to procuring authorities often covering the provision of the location, consents, any required transmission network reinforcement, and connection to the electricity grid[41].

Cheap financing, driven both by the current economic climate and by the lower development risk carried by the recent auction winners, is also playing a central role in this price movement, given the significant impact of financing costs on the overall project LCOE[42].

Lastly, the trend in technical improvements in offshore wind turbines has been similar to that for onshore wind in terms of moving to larger capacities, larger rotors, and to a lesser extent higher hub heights. This factor, combined with increasing pressure on supply chain margins, has also contributed in the significant LCOE savings achieved by offshore wind projects.

The largest offshore wind turbine close to getting a Type Certification is General Electric's 12MW Haliade-X. With a 220-metre rotor, 260-metre tip height and 12MW nameplate capacity, it is the world's biggest, most powerful offshore wind turbine at this stage of commercialisation.

The 12MW-turbine was first announced in March 2018 and has generated first power at the end of 2019 through a prototype installed in Dutch waters. GE expects to begin serial production in the second half of 2021 ahead of project commissioning in 2022[43].

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39 In our modelling, the cost of connecting an offshore wind plant to the coast is part of the opex.

40 IEA, World Energy Outlook, 2019.

41 This only partially applies to Great Britain, where the auction system has a different structure.

42 In some cases, this also reflects that winning an auction may not represent a final investment decision.

43 https://www.windpowermonthly.com/article/1665071/ges-12mw-haliade-x-produces-first-power

In May 2020, Siemens-Gamesa announced the SG 14-222 DD, a 14-MW offshore wind turbine that when available will become the largest on record[44].

Going forward, further capital cost reductions are expected to be attained thanks to improvements in jacket foundation and manufacturing, tower design and higher voltage array cables. Recent project data suggests that this process is already in action, as supply chain margins are shrinking and EPC costs are dropping significantly. Capacity factor increases and greater nameplate capacities are also set to play a role in future LCOE reduction, as they are set to improve output and BoS costs per MW respectively.

Projected capital costs can be seen in Table 9, while Figure 81 below illustrates the projected LCOE for offshore wind.

Figure 81 – LCOE projections for Offshore wind (€/MWh, real 2020 money)

[redacted]

A.5.3 Electrochemical energy storage

The main battery technologies for utility-scale applications are advanced-lead, sodium-sulphur and lithium-ion (Li-ion) batteries. It is expected that Li-ion batteries will outperform the other two technologies on cost in the near future. This feature, along with their versatility and their prevalent position in the market at the moment, are the reasons why we focus our analysis of cost assumptions on Li-ion batteries only.

We are also monitoring the evolution of flow batteries, which suit use cases requiring many hours of storage. These batteries can be divided in two main sub-categories: redox and hybrid, depending on whether all reactants are products in solution (redox) or not (hybrid). The latter category includes zinc-air batteries that have been subject to particular attention recently. Zinc8, a Canadian zinc-air battery developer, has already agreed to build three pilot

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44 https://www.siemensgamesa.com/en-int/newsroom/2020/05/200519-siemens-gamesa-turbine-14-222-dd

projects by 2022 and claim that their technology is significantly cheaper than lithium-ion for storage capacities of more than eight hours[45].

However, flow batteries are still at an experimental stage, and currently there is a lack of transparency on their costs. For these reasons, this technology is not considered in our modelling.

Other storage technologies such as liquid air storage, compressed air storage and gravity storage are also being developed but similarly, these are also not included in our modelling.

A.5.3.1 Lithium-Ion (Li-ion) battery

Li-ion has proven to be the most versatile battery option for systems in the 1MW to 50MW range, since the variety of chemistries results in batteries with different characteristics in terms of safety, replacement cycles, efficiency, stability and other factors. The market has yet to converge on one or more 'optimum' chemistries for grid-scale applications.

Li-ion batteries started being commercialised in 1990s, after an intensive research and development period in 1980s, mainly by Japanese firms. The first applications were in consumer electronics and particularly in high-end products. A few years later, in the mid-2000s, Chinese and South Korean companies also started producing Li-ion batteries. From the late 2000s onwards, the electric vehicle and storage battery markets started ramping up.

While raw lithium prices have almost doubled since 2016, lithium is not rare, and as the supply base expands and adapts to meet the growing demand, prices are expected to retrace back to the historical mean in the short to mid-term. The steep rise in lithium prices that occurred in 2018 has not significantly affected the downward trajectory of the automotive Li-ion battery pack price, as shown in Figure 82. Since beginning of 2019, the lithium prices have been falling along with battery pack prices.

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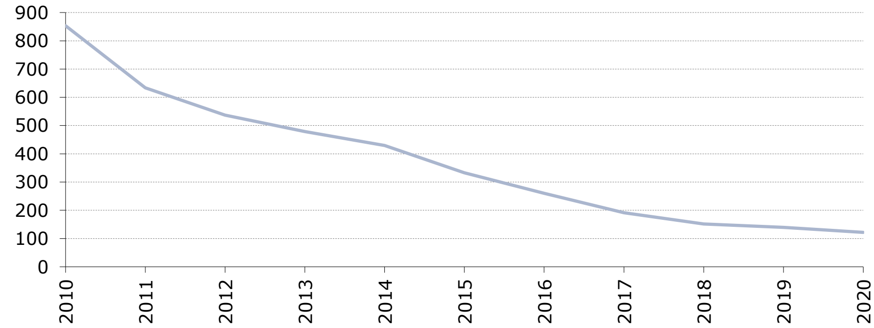
45 https://www.rechargenews.com/transition/new-zinc-air-battery-is-cheaper-safer-and-far-longer-lasting-than-lithium-ion/2-1-812068

Figure 82 – Historical price evolution in automotive lithium ion battery packs (€/kWh, real 2020 money)



Source: Bloomberg New Energy Finance and AFRY analysis.
Note: The 2020 figure is a projection.

In our modelling we consider three types of grid-scale battery, depending on their storage capacity:

- 2 hours storage;
- 4 hours storage; and
- 6 hours storage.

Their technical assumptions are detailed in Table 11.

Table 11 – Technical characteristics of modelled batteries

[redacted]

Capex cost assumptions

The battery installed system capital cost (BISCC) comprises the cost of four elements:

- Battery – the battery pack itself.
- Power Conditioning System (PCS) – the system that includes the inverter, which turns the DC voltage into a 3-phase AC voltage. This also includes other filter components that improve power quality before it steps up to the utility grid.
- Controls – the power electronics system (other than PCS) which is responsible for battery management. More precisely, it is responsible for protecting the battery from operating outside its Safe Operating Area,

monitoring its state, calculating secondary data, reporting that data and controlling the environment.

- Balance of Plant (BOP) – other infrastructure and facilities costs.

Apart from BISCC, capex includes the cost of the equipment for the connection to the grid (transformer, cables, protection equipment, etc). Other capex costs include fees for permitting the construction of an industrial facility and the engineering, procurement and construction (EPC) cost of the contractor who builds the plant (labour costs are included here), and the developer's overhead. Finally, capex includes the cost of land where the plant will be based.

Figure 83 shows our view on battery capital costs. 2, 4 and 6 hour battery capex costs are assumed to decrease sharply in the short and mid-term, driven by a rapidly expanding global battery market , which creates significant room for economies of scale, raising competition among suppliers and increasing investment in Research & Development (R&D). Prices flatten out at the end of the curve due to learning rates gradually reducing over time.

Figure 83 – Projected battery capital costs (€/kW, real 2020 money)

[redacted]

Opex cost components

Opex is divided into fixed costs (expressed in €/kW/year) and variable costs (expressed in €/kWh of energy charged or discharged). Fixed costs are independent of battery operation (e.g. wages of permanent personnel), in contrast to variable costs which depend on how much the battery is actually used (e.g. maintenance costs). Opex also includes yearly insurance costs.

Equipment replacement costs fall (at least in part) into the opex category. Battery cells, the inverter and power electronics within the control systems all potentially require replacement during the lifetime of the installation. We assume that all the battery cell replacement costs are considered in the variable costs given the dependence of replacement costs/intervals on how much the battery is utilised. The approach we use to quantify the battery replacement variable costs is augmentation-based: it considers the investment in new battery cells to cover the reduced storage due to degradation.

Figure 84 below shows our projections for battery operating costs up to 2040. Again, costs are projected to fall faster at the near end of the curve and flatten in the long term, as the market reaches maturity.

Figure 84 – Projected battery operational costs (€/kW/year, real 2020 money)

[redacted]

A.5.4 Hydrogen and CCS technologies

As part of the extension of our scenarios to 2060, we have started to model more in detail the hydrogen economy and thermal technologies coupled with CCS[46].

The main technologies appearing in the late part of the modelling period are: hydrogen production technologies (e.g. steam methane reforming with CCS and electrolysis) and quasi carbon neutral technologies in the power sector (e.g. Hydrogen CCGTs, CCS Gas and CCS Biomass).

A.5.4.1 Hydrogen production

The technologies involved in the hydrogen production are used in our modelling to determine the hydrogen prices that feed into our power, heat and transport modelling. The only two technologies considered are SMR CCS and electrolysis.

In Table 12, the main investment assumptions for a generic new build hydrogen production technology in 2050 are presented[47].

Steam methane reforming (or SMR) is a technology that uses natural gas to produce hydrogen through a series of chemical processes. The main by-product of this technology is carbon dioxide. SMR is currently the most diffused technology involved in the hydrogen production, consisting of more than 95% of the total generation. This technology in our modelling is assumed to be coupled with carbon capture and storage, which despite increasing costs allows abatement of up to 95% of the total CO2 emissions.

Electrolysis is a cleaner option for hydrogen production that relies only on water and electricity to produce hydrogen. This technology is currently expensive, but its capital costs are projected to more than halve in the next decades.

In our modelling, the hydrogen price is most of the time set by SMR CCS, as SMR is a baseload technology, whose variable costs are only function of gas and carbon prices, which do not change on an hourly basis.

The hydrogen price is assumed to be set by electrolysis only if the variable costs of producing hydrogen via this technology are lower than via SMR CCS. In other words, we would build electrolysis when the electricity prices drop below a certain threshold that is function of commodity prices, though the hydrogen price continues to be set by SMR CCS unless enough electrolysis is built to cover the full hydrogen demand, consisting of transport, heat and power generation (hydrogen CCGTs and potentially OCGTs).

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46 Carbon capture and storage.

47 Considering that here are several processes comparable to SMR that can be used to produce hydrogen (e.g. Autothermal reforming or ATR), when showing investment assumptions for SMR all the possible developments in these similar technologies are also considered.

Table 12 – New entry assumptions for a generic hydrogen production technology (real 2020 money)

[redacted]

A.5.4.2 Thermal generation (CCS and hydrogen)

The main technologies involved in the decarbonisation of the power sector are CCS Gas, CCS Biomass and hydrogen CCGTs.

The first two technologies consist of a CCGT and a biomass plant respectively coupled with post-combustion capture and storage. Therefore, the investment assumptions for these technologies consist of the sum of the standard thermal plants plus the cost of the capture and storage of the carbon dioxide.

The Hydrogen CCGT investment costs are modelled as a function of CCGT costs; the capex for this technology is assumed to be 10%, 7.5% and 5% higher than for a conventional CCGT in the High, Central and Low scenarios respectively.

In Table 13 and Table 14, the main investment assumptions and efficiencies for a generic new build CCS and hydrogen-fuelled power plant in the Netherlands in 2050 are presented[48].

Table 13 – New entry efficiency assumptions for a generic CCS and hydrogen fuelled power plant

[redacted]

Our efficiencies are HHV, full load, lifetime average efficiencies.

48 Considering that here are several processes comparable to SMR that can be used to produce hydrogen (e.g. Autothermal reforming or ATR), when showing investment assumptions for SMR all the possible developments in these similar technologies are considered.

Table 14 – New entry cost assumptions for a generic CCS and hydrogen fuelled power plant (real 2020 money)

[redacted]

A.6 Exchange rate assumptions

This section outlines the methodology for our economic assumptions, the Bloomberg dataset behind them, and provides the economic assumptions for our scenarios.

Our real exchange rates are derived from projections of nominal exchange rates and inflation[49]. Within our modelling, the real exchange rates are used to convert dollar-denominated oil and coal price projections into the currency used for our electricity price projections, which is the euro for all markets except the UK.

A.6.1 Methodology

We apply different methodologies for short-term and long-term exchange rates.

Long-term exchange rates are held stable from quarter to quarter unless significant evidence emerges that they should be changed. While these exchange rates are regularly monitored, the expectation is that the rates set in Q2 each year (when we update the money base of our projections) will not be altered throughout the remainder of the year unless forecasts deviate outside an acceptable range. These assumptions apply from 2025 onwards and are based on the financial institution forecasts from Bloomberg, taking into account the distribution, range, and trends over time within this dataset.

Reviewing the exchange rates in the Q2 2020 update, we have updated the long-term dollar per euro rate to 1.15 and we have kept the pound per euro rate constant at 0.85 (as set in 2019 Q2), reflecting the consensus view of the financial institutions' mid-term forecasts.

Short term exchange rates for 2020 to 2023 are based on the median Bloomberg forecast from up to 50 financial institutions. The nominal exchange rates in 2023 and 2024 trend between the 2022 values and the nominal exchange rates in 2025.

Inflation rates for 2020 to 2022 have been derived using the median Consumer Price Index (CPI) forecast from Bloomberg. In 2023, the inflation rate trends between the 2022 value and the long-term (from 2024 onwards) assumption of 2% in all three economic areas.

A.6.1.1 Nominal exchange rate forecasts from financial institutions

Bloomberg polls of financial institution forecasts for nominal exchange rates are used to derive our real exchange rate assumptions. The median of the dataset is our main input for the 2020-2022 nominal exchange rates, however we also assess the whole dataset of forecasts in terms of distribution, range and trends over time to inform our long-term exchange rate assumptions.

Bloomberg provides the exchange rate forecasts from each contributor financial institution individually for each future year, including the date on which each forecast was made. This allows us to remove any out of date financial institution forecasts to concentrate on more recent views from the

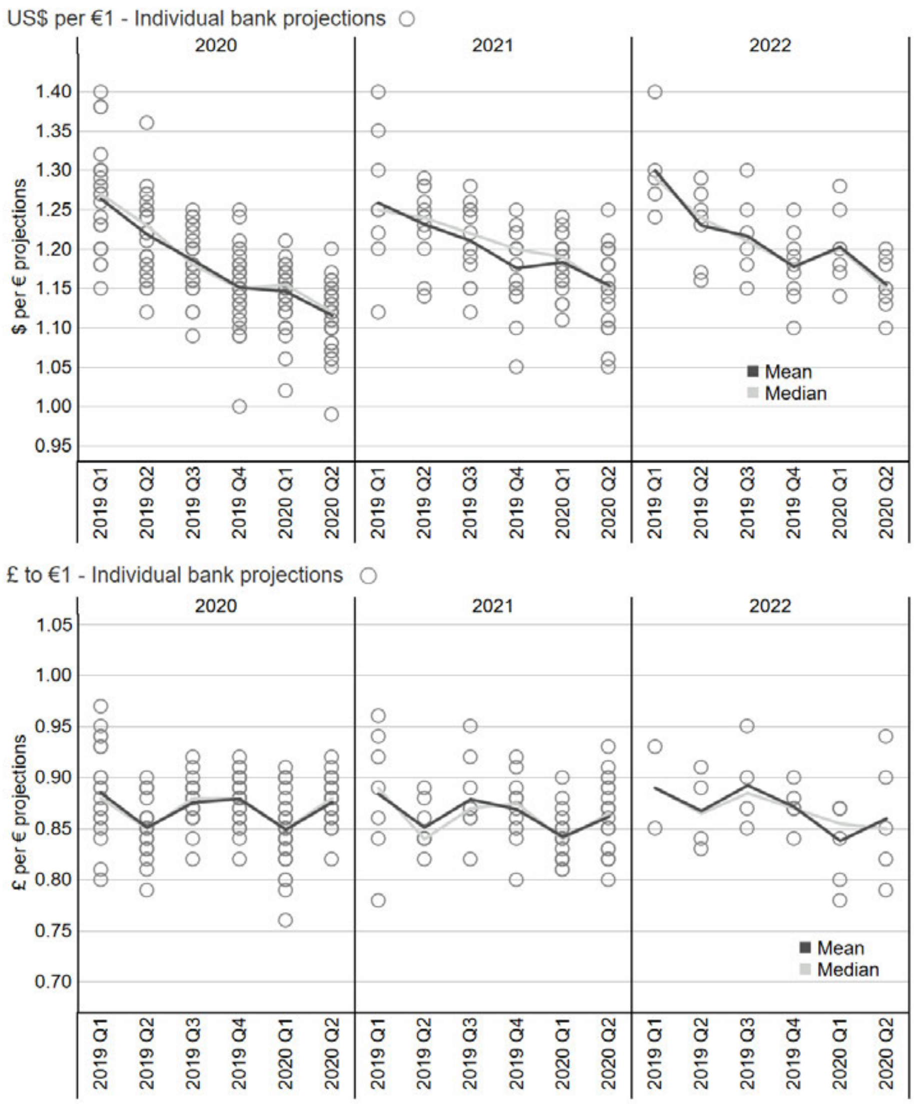
49 For example, if inflation is higher in the US than in the euro-zone, this will strengthen the dollar in real terms (assuming no change in nominal exchange rates).

market, and to trace how individual financial institutions change their forecasts over time.

Figure 85 present the evolution of the individual financial institution forecasts for the dollar per euro and pound per euro exchange rates, respectively, in 2020-2022 between our Q1 2019 and Q2 2020 updates.

For both exchange rates, the number of the forecasts in the dataset decreases for the years furthest in the future, as fewer institutions project the long-term. For this Q2 2020 update, the dollar per euro exchange rate has 40 financial institution forecasts for 2020, and 8 for 2022.

Figure 85 – Individual financial institutions forecasts for nominal rates



Notes: The entirety of the dataset shown was not used in every quarterly update. For instance, we started to use the 2022 financial institution forecasts in our Q2 2020 update.
Sources: Bloomberg, AFRY.

A.6.2 Q2 2020 assumptions

There continues to be significant uncertainty in exchange rates, driven by the Covid-19 pandemic as well as a variety of political events. This creates uncertainty in future commodity prices, which tend to be priced against global rather than local currencies.

Table 15 shows the real exchange rates and annual inflation rates for the US, UK and the Eurozone assumed in our Q2 2020 modelling.

Table 15 – Inflation and real exchange rates (real 2020 money)

[redacted]

A.6.2.1 Inflation projections

There is currently great uncertainty regarding the impact of the Covid-19 pandemic and resulting lockdowns on the global economy. In its recent outlook, the IMF assumes GDP decreases across the US, UK and the Euro-zone in 2020: -5.9%, -7.5% and -6.5% respectively.

The IMF also highlights possible inflation outcomes according to developments during recovery from the Covid-19 pandemic. In one case, disruptions could occur in supply chains thus increasing prices of goods and therefore impacting inflation. On the other hand, continuation of weak global demand could decrease inflation for a longer period.

Our inflation rate forecasts are well below the target rate of 2% in all regions in 2020 in line with the GDP decreases. However, a bounce back is generally expected for the major economies after 2020 as governments and central banks are implementing measures to limit the financial impact, though individual forecasts show a wide range. These measures include cutting interest rates, supporting businesses with loans and asset purchases, and protecting employment. Therefore, inflation rates are expected to recover towards 2% across the regions with the US and UK having faster recoveries compared to the Euro-zone.

A.6.2.2 Exchange rate projections

The dollar per euro spot rate has been volatile over the last few months driven by the Covid-19 pandemic however the overall trend has been a strengthening of the dollar. This is expected to continue through 2020 with increased demand for the dollar, having the perception of a low-risk currency. From 2021, however, the median Bloomberg forecast suggests the dollar is expected to weaken against both the euro and the pound.

The pound is expected to strengthen slightly towards 2022. The transition period for Brexit is set to end by 31 December 2020 but there is still uncertainty regarding the future relationship as the negotiations on trade were only resumed in late April due to the Covid-19 pandemic, leaving limited time for a decision.

Figure 86 – Real exchange rate assumptions (real 2020 money)

[redacted]

ANNEX B – GRIDLINK RESULTS

Table 16 shows GB annual baseload wholesale price projections in the 'with GridLink' case.

Table 16 – Annual baseload wholesale electricity price projections for Great Britain (€/MWh, real 2020 money)

[redacted]

Table 17 shows France annual baseload wholesale price projections in the 'with GridLink' case.

Table 17 – Annual baseload wholesale electricity price projections for France (€/MWh, real 2020 money)

[redacted]

Table 18 shows GridLink flows, utilisation and congestion rent in the 'with GridLink' case.

Table 18 – GridLink flows, utilisation and congestion rent

High

[redacted]

Central

[redacted]

Low

[redacted]

ANNEX C – DETAILED SENSITIVITY CBA RESULTS

Figure 87 shows SEW impacts for the sensitivities.

Figure 87 – GridLink socio-economic welfare impact - Sensitivities, (€m, 25yr NPV, 4% discount rate)

[redacted]

Increase of GridLink capex by 5%
m€, real 2020 money

[redacted]

Decrease of GridLink capex by 5%
m€, real 2020 money

[redacted]

Decrease of GridLink opex by 5%
m€, real 2020 money

[redacted]

ANNEX D – COMPARISON OF INSTALLED CAPACITY AND DEMAND ACROSS SCENARIOS

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

ANNEX E – AFRY'S DEMAND PROJECTION METHODOLOGY

E.1 Afry's modelling of electricity demand in the transport sector

Move is our European transport sector model used to simulate the evolution of the transport fleet and future electricity demand from transport. It is also a key tool for assessing carbon reduction policies across the energy system.

Figure 88 – Move's place in Afry's energy system

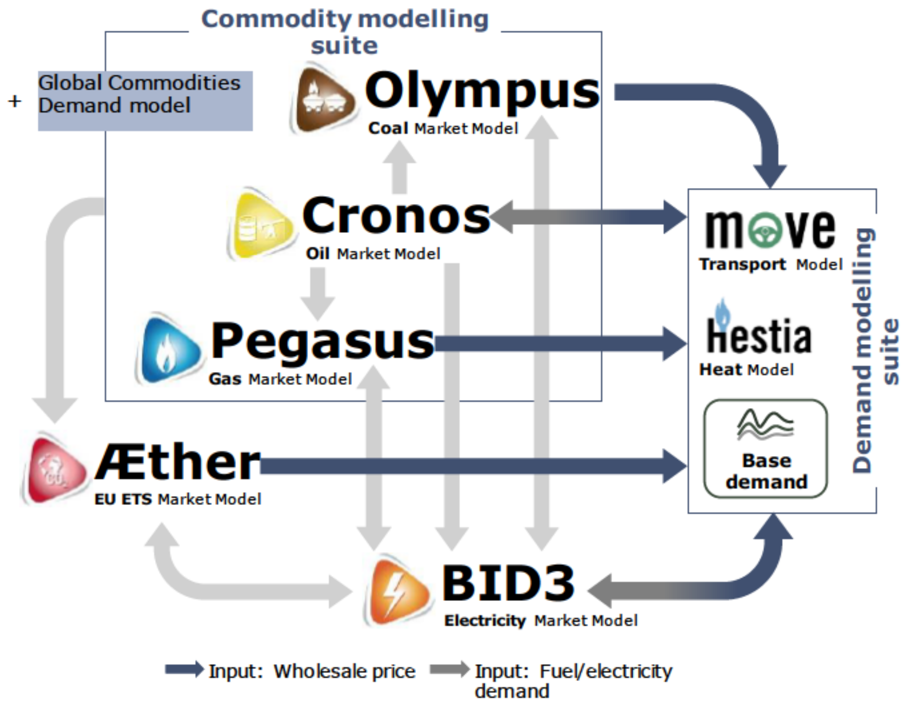
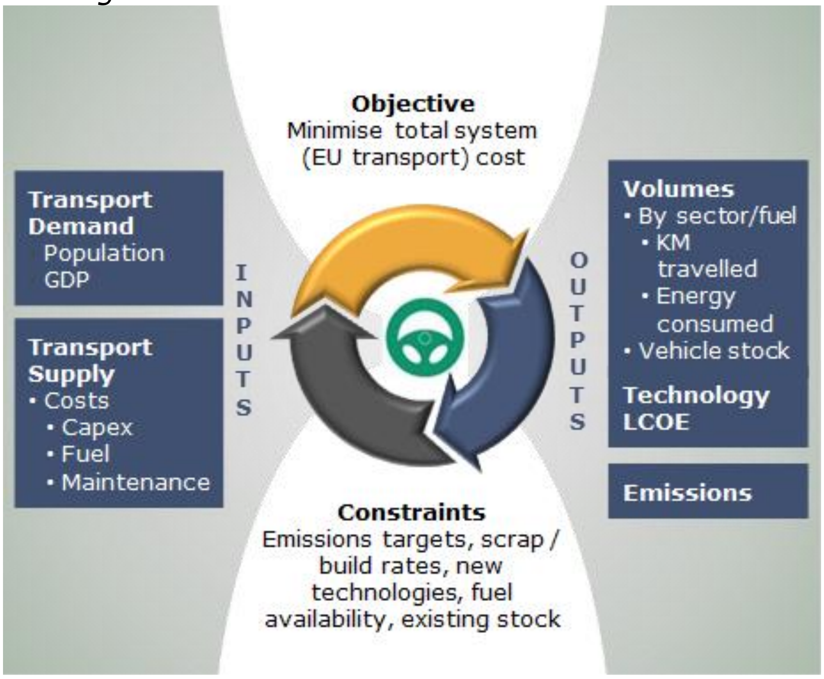


Figure 89 – Move overview

Move determines the future transport stock and transport energy use by finding the cheapest way of meeting demand for transport from a range of transport technologies



E.1.1 Why do we need a transport sector model in AFRY's energy system?

Emissions from transport form a considerable share of total CO_2 emissions. For instance, road transport alone (i.e. cars, trucks, buses and motorbikes) produces more than one fifth of the total CO2 emissions in the EU; and transport is the only major sector in the EU where greenhouse gas emissions are still rising.

Road transport has historically been dominated by oil-based fuels. Now more than ever, new technologies are progressively allowing a shift away from oil-based fuels. Research and mass adoption of lithium-based batteries is allowing batteries' energy density to increase and costs to decrease; moreover fuel cells and natural-gas-powered internal combustion engines are being introduced in several markets.

We have developed a transport model, to find the lowest cost solution to fulfil a growing demand for transport, while considering how different technologies can contribute to the decarbonisation of the overall energy system.

By using Move within our suite of models (Exhibit G.11), we are also capable of investigating the impact of different future modes of transport (e.g. car sharing, autonomous driving) on the energy system.

E.1.2 How does Move work?

Move is based on linear optimisation, where the future transport stock and energy use is determined by finding the cheapest way of meeting demand for transport within the scenario set by the user (Exhibit G.12). Scenario parameters include vehicle scrapping rates, capital / operational costs of vehicle technologies, technology availability, and country-specific incentives for clean vehicles or bans on polluting vehicle technologies.

The model choses which vehicle types consumers would buy based on parameters such as fuel type, fuel efficiency, lifetime, investment costs and running costs (a vehicle can run on a single fuel or a fuel mix). For each vehicle type ((e.g. cars, light trucks, buses etc.), we model three different ranges of annual vehicle kilometres (to reflect the different driving patterns that exist within each type) as well as three different hurdle rates (to reflect different payback periods of different customer types. This gives nine segments within each vehicle type.

E.1.3 Demand

Demand for transport is primarily driven by population growth and economic outputs (GDP), using a similar methodology to that used in the EU Reference Scenario 2016 for energy and transport. Importantly, transport is modelled in terms of vehicle kilometres rather than passenger or tonnage kilometres. We do not assume any fundamental changes in consumer behaviour (e.g. from autonomous / shared vehicles).

E.1.4 Supply

The critical drivers of supply relate to fuel costs and the cost of purchasing vehicles. Operations and maintenance costs are relevant but secondary. Unlike the commodity models, we do not assume any capacity constraints on the manufacturing of any of the vehicle technology types.

E.1.5 What does Move provide?

The key outputs of the model are:

- evolution of the vehicle fleet per type;
- kilometres travelled by segment/technology;
- energy use by segment/technology;
- technology costs; and
- emissions.

More granular outputs such as hourly flexible demand and vehicle-to-grid are analysed within our Power Market model (BID3). To that end, BID3 includes country-specific driving and charging patterns, based on real historical data.

E.2 Afry's modelling of electricity demand in the heat sector

Hestia is our heat sector model used to simulate the evolution of the heat system. It is a key tool for assessing carbon reduction policies across the energy system.

Figure 90 – Hestia's place in Afry's energy system

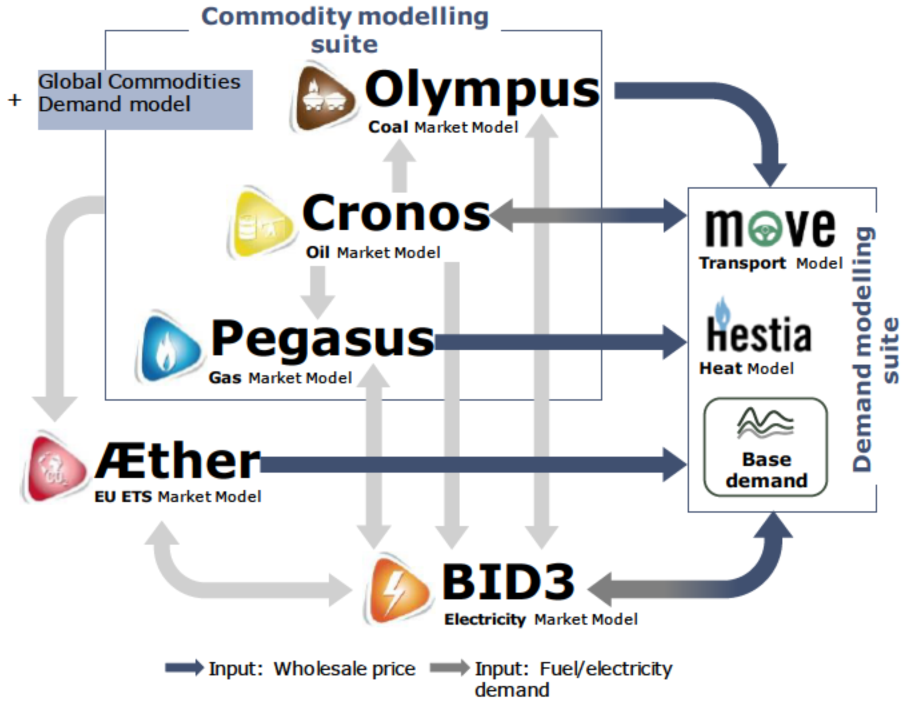
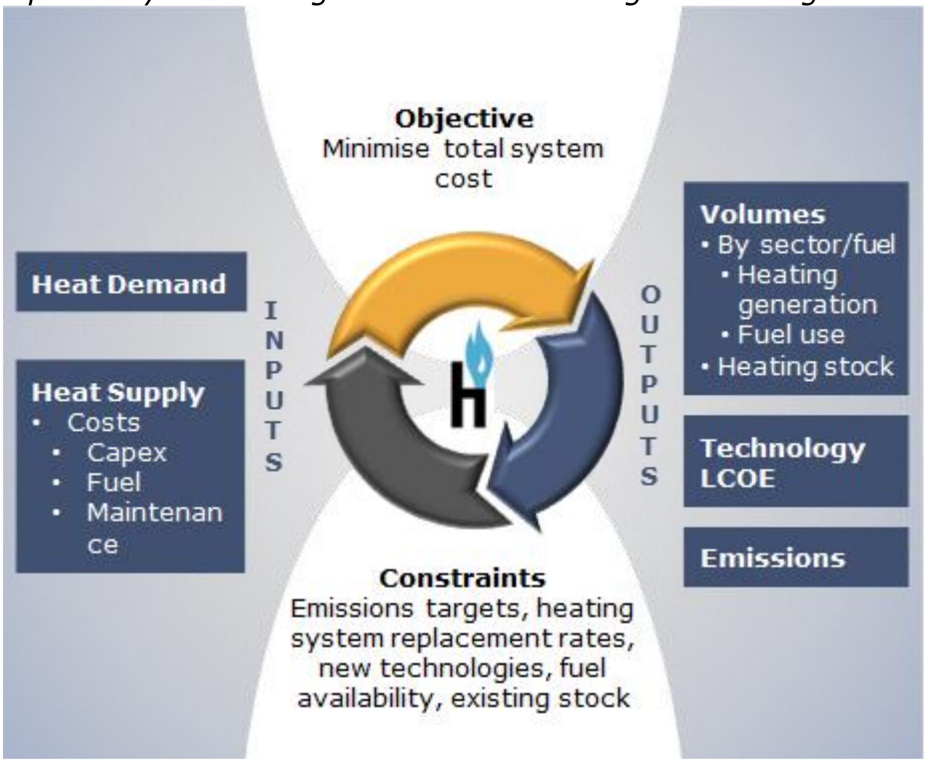


Figure 91 – Hestia overview

Hestia determines the future heating stock and heat energy output by finding the cheapest way of meeting demand from a range of heating technologies



E.2.1 Why do we need a heat sector model in AFRY's energy system?

The European Union has a stated ambition to reduce Greenhouse Gas (GHG) emissions to 80% below 1990 levels by 2050. So far the main focus has been on decarbonising the electricity sector, however it is becoming increasingly clear that to achieve this target, the EU will require a coherent policy for the heating sector.

The difficulty in decarbonising this sector lies in the fact that heating technologies are a mix of decentralised and centralised, and thus rely on a combination of top-down policies and bottom-up consumer decisions to drive the switch to low carbon technologies. This makes understanding which low-carbon heating solutions will prevail in future complex. While numerous scenarios focus on an electric-based heating future (primarily around heat pumps), more recently, proposals for hydrogen-based solutions, drawing on repurposing of the existing gas infrastructure and hydrogen production with associated Carbon Capture and Storage (CCS) have become more prominent.

Whichever solution for longer-term heat decarbonisation emerges, it is likely to rely on a mix of energy vectors with a move away from the high dependence on natural gas toward a much more prominent role for electricity (e.g. heat pumps) and/or low-carbon gases, including bio-methane and hydrogen.

In order to provide insight into this uncertainty, we have developed our heat model Hestia. This model allows us to assess the impact of the development of heat technologies, demand and costs, in line with the emission targets. We use the results from our heat modelling to further increase the validity of our projections and the consistency of fuel and electricity prices.

E.2.2 How does Hestia work?

Hestia is based on linear optimisation, where the future heating stock and output is determined by finding the cheapest way of meeting demand, given a set of constraints, including carbon emissions, existing heating stock, heat appliance replacement rates, new technology capabilities and costs, and new technology availability.

The model choses which heating systems to deploy based on parameters such as emission intensity, fuel efficiency, average availability, peak day availability, capital costs and operating costs (including their evolution over time).

New technology availability refers to supply chain considerations for investment in new heating technologies, the regulatory framework for the replacement the existing heating technologies and fulfilling emission targets.

E.2.3 Demand

Demand for heat is derived a Fraunhofer Institute study which takes account of several factors including: population growth and economic outputs (GDP); energy efficiency gains; the evolution of European policy; the European building stock; and the stock of industrial assets.

E.2.4 Supply

The critical drivers of supply relate to fuel costs, heat technology costs (capex and opex) and technical parameters (efficiencies, load factors) and technology build constraints.

E.2.5 What does Hestia provide?

The key outputs of the model are:

- expected heating capacity and production trends;
- fuel costs and volume; and
- emissions.

E.3 Afry's hourly demand profile methodology

Details of the split of demand into the various components at the annual level are outlined in A.2. In this section we look at the hourly profile for the different components. The different components of demand are:

- a base profile, typically representing most of the demand;
- additional electrical heating;
- non-flexible EV (electric vehicle) charging;
- semi-flexible EV charging (roughly corresponding to time of use tariffs); and
- electrolysis (though not an input demand as such).

Some markets have specific profiles, such as for data centres, on top of these profiles.

In the remainder of this annex we will go through each of the components in turn.

E.3.1 Base profile

This profile typically covers nearly all the demand in 2020, and is based on historical hourly demand.

Typically the raw hourly demands come from ENTSOE or the relevant TSO. This is often based on a sum of generation. We try to make these consistent with our generation – for example adding assumed embedded generation when it is not in the ENTSOE demand data.

With this data 2 further steps are carried out:

1. The annual demand for the historical years are detrended – by removing increasing/decreasing trends explained by factors such as GDP, or year (as a proxy for an energy efficiency trend). The resulting scaled hourly demand are calculated.
2. Over the modelling historical years these values are normalised by dividing by the average of the hourly demands.

E.3.2 Additional Electrical heating

Electrical heating is included in the base profile to the extent there has been electrical heating historically. Going forward this will change as the annual demand using the base profile increases or decreases. However, if this is less than the total electricity consumption for heating coming out of the Hestia modelling, an additional profile needs to be added for the additional heat demand.

In Q2 we made the simplifying assumption to model this additional demand as if it was all ASHP, on the assumption the forms of heat demand less influenced by temperature (such as GSHP, resistive heating and industry heating) will be in the covered by the part of heat demand in the base profile.

We have taken within-day profiles for space and water heating from historical French data. Then the following steps are carried out:

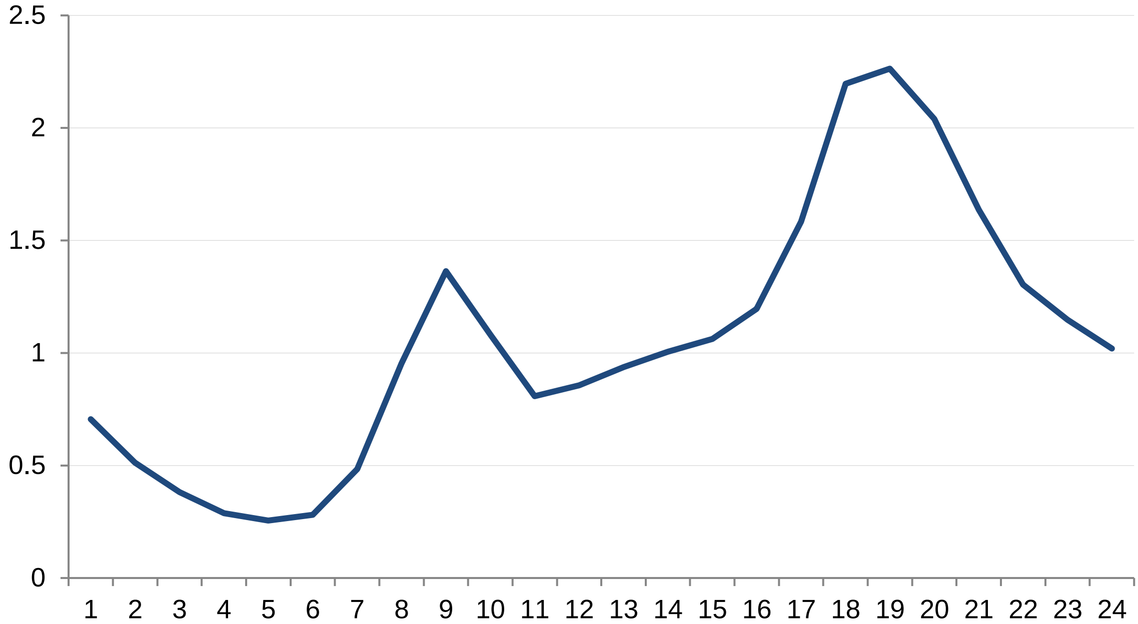
1. A national/zonal temperature is calculated for each hour, based on a weighted average of temperatures[50] at the major cities/towns within the country/zone.
2. A 24 hour rolling temperature is calculated (the current hour plus the previous 23 hours for each hour).
3. This is turned into a degree day value (i.e. zero when the rolling temperature is above 15C and 18 minus the rolling temperature otherwise.
4. The space heating is calculated by assuming it is proportional to the rolling degree day value, multiplied by the within-day profile.
5. For France the water heating is scaled such the space and water heating match historical data. Colder locations will have a greater proportion of the demand in the space heating component, warmer locations a lower proportion.
6. This is converted into an electricity demand by dividing by a coefficient of performance based on an assumed relationship between coefficient of performance and temperature.
7. Across 10 years (2009-18) this is capped at the P99.9 level.
8. The profiles are normalised such that the average of the 5 modelled historical years is 1 (overall, not in individual historical years).

E.3.3 Non-flexible EV demand

There is very little EV demand in the base profile, particularly given 2019 is not one of the historical years modelled. For new EV demand, we assume around 30% of this charges based on convenience, with a high volume of charging in the evenings as commuters return from work. Figure 92 shows an example (January business days, CET country).

[50] Based on MERRA2 reanalysis.

Figure 92 – Electric Vehicle charging profile for inflexible electric vehicles (1=Annual averaging charging)



E.3.4 Semi-flexible EV demand

This is used for the other 70% of new EV demand. The following steps are used.

Based on data from a previous quarter, a run of a BID3 module is carried out where this part of the EV demand is fully flexible, meaning that the charging of EVs is optimised, based on various constraints such as:

1. Storage volume (i.e. total battery capacity).
2. Maximum charging rate (which can vary with how fully charged the battery is).
3. A driving profile.
4. Various constraints to limit the impact of perfect foresight.

For each country/zone, these demand values are averaged to form a sample day profile (i.e. a business day and non-business day for each month, so 576 values).

As an example, in the summer there will be a relatively high volume of charging around the middle of the day, so use the solar output.

E.3.5 Electrolysis

When we state demand numbers, we do not tend to include Electrolysis, in much the same way as pumped storage consumption is often excluded from demand data. However for completeness we will describe our approach to Electrolysis.

Each country has a hydrogen demand for heat and transport, based on Hestia and Move. In addition to this there is the (quite limited in these scenarios) demand from hydrogen CCGTs and GTs. The default position is this is met by SMR (steam methane reformation) with CCS, and a LRMC of hydrogen production is calculated from our SMR costs.

The build and dispatch of Electrolysis is optimised against this LRMC, subject to electrolysis production also not exceeding demand from hydrogen. The scenarios have fairly significant build by 2050 (e.g. over 10GW in GB in central scenario), but this generally starts coming in after 2040.

ANNEX F – IMPACT OF CAP AND FLOOR ON THE SOCIAL WELFARE RESULTS

F.1 Cap and floor applied to GridLink

Figure 93 shows the indicative cap and floor values used for an assessment of the impact of cap and floor on the welfare results. The cap and floor were calculated using the *Standard cap and floor financial model* developed by Ofgem. The IFA2 cap and floor model[51] was used as a starting point, in which capex and opex assumptions were updated to GridLink values and inflation assumptions were updated. Other financial and market assumptions based on long-term averages, such as rates of return and risk free rates were kept fixed from IFA2 model.

For this assessment, the assumed allowed revenues for GridLink were the sum of the congestion rent revenues and the capacity market revenues.

Figure 93 – GridLink cap and floor estimates

[redacted]

F.2 Modelling the cap and floor regime

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

[51] Cap and floor financial model – IFA2 FPA, Ofgem https://www.ofgem.gov.uk/publications-and-updates/final-project-assessment-ifa2-interconnector-france

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

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

This is due to the following mechanism:

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

F.3 Impact of cap and floor regime on the socio economic welfare

Figure 94 details the impact of cap and floor on the welfare assessment.

In the High scenario, as the cap is reached in most years, there is a transfer of welfare from congestion rent revenue to GB consumer surplus. A similar but smaller transfer happens in the Central scenario. On the other hand, in the Low scenario where the floor binds in some years, there is a small transfer from GB consumer to congestion rent revenues in GB and France.

Figure 94 – GridLink socio-economic welfare impact in GB and France after cap and floor, (€m, 25yr NPV, 4% discount rate)

High

[redacted]

Central

[redacted]

Low

[redacted]

ANNEX G – Q&A ON MODELLING METHODOLOGY (CRE QUESTIONS)

In this Annex we go through a number of questions GridLink received from CRE.

Germany – TSO's do not take account of wind when meeting peak demand, nevertheless some wind will be available. Does the model include/ exclude this wind at peak. Please explain impact on electricity price of including/ excluding this wind at peak.

The AFRY approach is to model 5 historical years (2012, 2014, 2015, 2017, 2018), including hourly wind and solar generation (derived using reanalysis data – 3Tier for wind, Transvalor for solar), and using hourly demand based on the historical demand profiles plus profiles for additional electrical heating derived using historical temperature data. We build capacity such that with average availabilities, there is enough capacity to meet demand (and only a very small excess). Therefore there is no requirement to explicitly assume a derating factor for wind, but the contribution to meeting the demand is taken into account.

Germany has reserves of coal fired power station which are kept available in the event of peak shortfalls. Are these stations included in the assumptions on German installed capacity? Does the model use these stations to meet peak demand? Please explain how the cost of maintaining these stations on standby is incorporated into the electricity price and what impact will be on electricity price if/ when these stations are decommissioned/ replaced.

Germany has three classes of coal plant held in reserve:

Capacity Reserve "Kapazitätsreserveverordnung – mechanism similar to capacity market currently under discussion with the EU. Temporary mechanism approved and in place until 2021.

Standby Reserve "Sicherheitsbereitschaft"– eight lignite plants with a total capacity of 2.7GW mothballed for emergency use – the first mothballed on 1 Oct 2016. After a period of 4 years they will each be decommissioned. Currently being re-evaluated by EU under state aid rules.

Grid reserve "Gesetzlich an Stillegung gehindert"– power plants maintained on standby in southern Germany – will be decommissioned when North/ South bottlenecks removed.

The AFRY model assumes that each of these plants have a (very high) reserve price and if used will be bid into the market at that price. As such if these plants are despatched this would have an impact on peak prices and the model will take this into account.

The AFRY forecasts do not anticipate these plants being despatched to a significant extent.

Most reserves disappear in the medium-long term.

For any given level of demand how does the model optimise the generation mix to meet demand at the lowest cost? Please provide some examples of spot years which show the relative costs of coal, gas, interconnectors etc and demonstrate the generation mix chosen is the optimal choice.

The starting point is using BID3's Autobuild module (endogenous investment module) to minimise total (discounted) fixed and variable costs across the modelled period. While this makes some approximations, these are far fewer than other endogenous investment modules we have come across. There are, however some constraints on the build, including stopping unabated gas build from 2050 in the high scenario (later in other scenarios).

However, partly to better model market rules, we also manually assess IRRs (versus hurdle rates) afterwards, modifying the build accordingly.

Both the dispatch part of the autobuild module, and main BID3 dispatch are based on linear programming, so by definition will meet demand at least costs, i.e. use the generators with lowest costs first.

Figure 95 – Indicative illustration of Autobuild and Dispatch modules of BID3

[redacted]

Figure 96 presents cash flows against required cash flows to meet a target rate of return for onshore wind in Great Britain and solar PV in the south of France, both commissioned in 2036. It illustrates the economic viability of renewables projects developed on a merchant basis in AFRY's modelling.

Figure 96 – Cash flows versus required cash flows for onshore wind commissioned in 2036 in GB, and solar PV in France in 2036 – Central scenario (€/kW, real 2020)

[redacted]

Please advise what type of battery storage is used in the (peak) generation mix.

We model Lithium batteries. Generic options range from 2 hours to 9 hours, though there are batteries with less storage either based on the current mix or based on modelling ancillary services.

Figure 97 – Breakdown of installed battery capacity – Central scenario (GW)

[redacted]

Please advise what if any financial support mechanisms the model assumes for gas fired power stations. The model shows a significant increase in installed gas fired generation in Germany. If there are no financial support mechanisms please demonstrate that gas fired generation is economic without a subsidy.

There is some scarcity rent (i.e. generators bidding above costs) in our modelling – the extent of bidding up is a function of capacity margin. Further to this we have capacity markets where they currently exist. In markets (including Germany) that do not currently have capacity markets we introduce capacity markets, for example in 2040 in Germany in the central scenario. Figure 98 shows an example of cashflow (i.e. gross margin less annual OPEX) versus the level that would be required (if cashflows were flat across the economic lifetime). While it is evident that some CCGTs in the 2030s, prior to the introduction of a capacity market make a little less than the 8% hurdle rate, IRRs are still at respectable levels. New entrants in 2040 over-recover initially, to offset lower revenues after 2050.

Figure 98 – Cashflows versus required cashflows for a CCGT plant commissioned in 2030 in Germany – Central scenario (€/kW, real 2020)

[redacted]

QUALITY AND DOCUMENT CONTROL

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