Flexibility in Great Britain

Appendix 1 – Modelling data input assumptions

August 2021

Acknowledgments

The Carbon Trust and Imperial College London wrote the Flexibility in Great Britain report based on an impartial analysis of primary and secondary sources, including expert interviews.

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Who we are

Established in 2001, the Carbon Trust works with businesses, governments and institutions around the world, helping them contribute to, and benefit from, a more sustainable future through carbon reduction, resource efficiency strategies, and commercialising low carbon businesses, systems and technologies.

The Carbon Trust:

- works with corporates and governments, helping them to align their strategies with climate science and meet the goals of the Paris Agreement;
- provides expert advice and assurance, giving investors and financial institutions the confidence that green finance will have genuinely green outcomes; and
- supports the development of low carbon technologies and solutions, building the foundations for the energy system of the future.

Headquartered in London, the Carbon Trust has a global team of over 200 staff, representing over 30 nationalities, based across five continents.

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Abbreviations

Abbreviation	Meaning
ATR	Auto Thermal Reforming
BEIS	Department for Business, Energy and Industrial Strategy
CapEx	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CH4	Methane
CO2	Carbon Dioxide
DACCS	Direct Air Carbon Capture and Storage
DSR	Demand Side Response
EV	Electric Vehicle
GB	Great Britain
GCV	Gross Calorific Value
GHR	Gas Heated Reformer
H2	Hydrogen
IWES	Integrated Whole Energy System model
Li-Ion	Lithium Ion
NCV	Net Calorific Value
NG	Natural Gas
NOx	Nitrogen Oxides
OCGT	Open Cycle Gas Turbine
OpEx	Operating Expenditure
PEM	Proton Exchange Membrane
SMR	Small Modular Reactor

Abbreviation	Meaning
Solar PV	Solar Photovoltaic
TES	Thermal Energy Storage
V2G	Vehicle-to-Grid
WACC	Weighted Average Cost of Capital

1. Introduction

This document sets out the input assumptions used in the Carbon Trust and Imperial College's Flexibility in Great Britain report, which was published in May 2021. Further details on the IWES (Integrated Whole Energy System) model structure can be found in Chapter 2 of the Flexibility in Great Britain report[1], and details of the scenarios modelled and their results are presented in Chapter 3.

All costs are given for technologies built as new on 1 January 2050 but presented in £(2019) values.

All modelled scenarios calculated energy system costs in 2050. CAPEX costs were annuitised over the lifetime of the technology, taking into account the weighted average cost of capital (WACC) for that technology.

The model does not include policy costs.

2. Energy system demand data

The demand assumptions, in terms of annual final energy consumption, are shown in Figure 1. These assumptions are identical to those used in analysis conducted by Imperial College for the Climate Change Committee in their 2018 report, '*Analysis of Alternative UK Heat Decarbonisation Pathways*,[2]' with the exception of hydrogen demand for heavy duty vehicle use, which was derived from Climate Change Committee analysis on the role of hydrogen in 2050[3].

These demand figures are consistent over all scenarios modelled. Additional electricity demand from hydrogen production (electrolysis and natural gas reforming), hydrogen storage and direct air carbon capture and storage (DACCS) vary by scenario.

Each source of demand has its own time-varying demand curve during the year. Imperial College used their proprietary demand curves for power and heating demands. Demand for hydrogen is assumed to be flat

[1] Carbon Trust (2021). Flexibility in Great Britain.

[2] CCC (2018) Analysis of Alternative UK Heat Decarbonisation Pathways.

[3] CCC (2018). Hydrogen in a low carbon economy. 87 TWh is the mid-point between hydrogen demand for transport in the 'Niche Hydrogen' scenario and the 'Full Hydrogen' scenario.

across the year for high temperature process heat and heavy goods vehicles. Electric vehicle charging profiles were sourced from National Grid's Future Energy Scenarios 2019[4].

Demand side response flexibility is only available in the high flexibility scenarios. In these scenarios the input assumptions are that:

- 41% of daily domestic smart appliance demand can be shifted within the day. There are negligible losses associated with this demand shift.
- Up to 80% of light vehicle charging demand can be moved within a day, of which 25% of these vehicles cannot only 'not charge', but can also discharge any remaining power back into the grid (Vehicle to Grid, V2G)

Up to 20% of non-domestic power demand can be shifted within a day. In the model, non-domestic power demand, which includes 13.0 TWh from cooling, is grouped with non-smart appliance domestic load. 20% of this total demand (318.3 TWh) can be shifted within a day in the high flexibility scenarios.

[4] National Grid ESO (2019). Future Energy Scenarios.

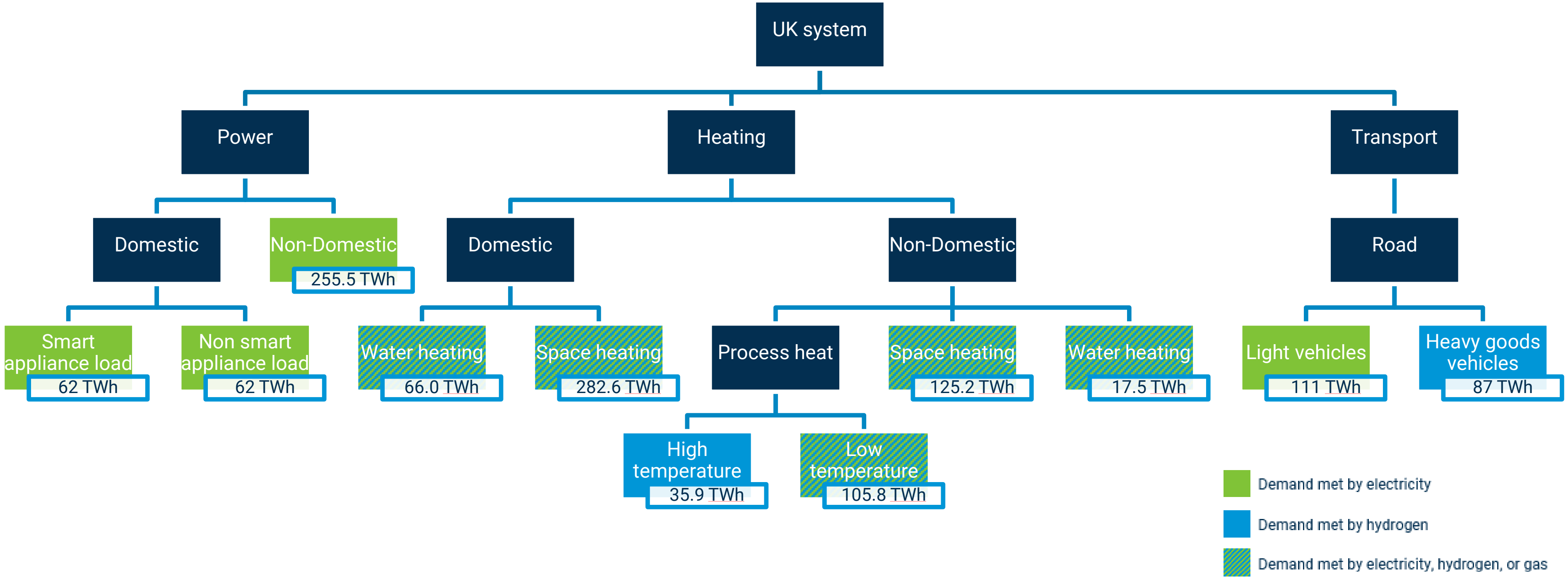

Figure 1: Input annual demand assumptions (final energy consumption)

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3. Electricity generation infrastructure

3.1 Deployment

By 2050, it is assumed that all currently existing generation infrastructure will have been decommissioned (or repowered/refurbished), with the exception of pumped hydro and some nuclear plants (Sizewell B and Hinkley C). In addition, the number of new nuclear and hydro plants is capped based on their expected rollout. The techno-economic assumptions that define the different electricity generation technologies that that the model can choose to deploy are listed in Table 1 and Table 2.

3.2 Costs

Table 1: Economic characteristics of electricity generation technologies

Technology	CapEx in 2050 (2019£)	Fixed OpEx in 2050 (2019£)	Variable OpEx in 2050 (excluding fuel costs)	No Load Cost	Start-up costs (per start up)	Lifetime	WACC	Deployment limits[5]
Onshore wind	777 £/kW	32 £/kW/yr	-	-	-	30 years	5.5 %	30 GW
Offshore wind	1525 £/kW	32 £/kW/yr	-	-	-	30 years	5.5%	120 GW
Rooftop solar PV	785 £/kW	17 £/kW/yr	-	-	-	25 years	5.8%	150 GW combined solar limit
Utility scale solar PV	375 £/kW	11 £/kW/yr	-	-	-	25 years	5.8%	
Gas (NG/H2) CCGT[6]	611 £/kW	31 £/kW/yr	38 £/MWh	1,306 £/hr	30,778 £	25 years	7.5%	-
Gas (NG/H2) OCGT	578 £/kW	31 £/kW/yr	38 £/MWh	1,306 £/hr	30,778 £	25 years	7.5%	-
Post Combustion Gas CCS	1,203 £/kW	61 £/kW/yr	44 £/MWh	1,483 £/hr	30,778 £	25 years	13.8%	-
Nuclear - Large	3,870 £/kW	78 £/kW/yr	5 £/MWh	109 £/hr	56,710 £	40 years	9.5%	Capped at 9.3 GW
Nuclear - SMR	5,437 £/kW	121 £/kW/yr	5 £/MWh	109 £/hr	56,710 £	40 years	9.5%	-
Biomass	2,730 £/kW	33 £/kW/yr	38 £/MWh	1,306 £/hr	30,778 £	25 years	10%	-

[5] Unless otherwise stated in the sensitivity analysis assumptions set out in the main Flexibility in Great Britain report.

[6] NG = Natural Gas fuelled, H2 = Hydrogen fuelled

Technology	CapEx in 2050 (2019£)	Fixed OpEx in 2050 (2019£)	Variable OpEx in 2050 (excluding fuel costs)	No Load Cost	Start-up costs (per start up)	Lifetime	WACC	Deployment limits[5]
Biomass with CCS	3,308 £/kW	33 £/kW/yr	44 £/MWh	1,483 £/hr	30,778 £	25 years	10%	-
Large scale hydro (not pumped hydro)	1,692 £/MWh	0.023 £/kW/yr	-	-	-	65 years	10%	Capped at 2GW (in addition to 2.7 GW of pumped hydro)

3.3 Technical characteristics

Table 2: Technical characteristics of the electricity generation technologies

Technology	Min stable generation (% of capacity)	Frequency response slope	Frequency response max (% of capacity)	Ramp rate (% of capacity/hr)	Minimum up time	Minimum down time	Max annual load factor	Generation efficiency
Onshore wind	0%	0	0%	100 %/hr	0 hrs	0 hrs	*	-
Offshore wind	0%	0	0%	100 %/hr	0 hrs	0 hrs	*	-
Rooftop solar PV	0%	0	0%	100 %/hr	0 hrs	0 hrs	*	-
Utility scale solar PV	0%	0	0%	100 %/hr	0 hrs	0 hrs	*	-
Gas (NG/H2) CCGT	50%	0.85	17%	60 %/hr	4 hrs	4 hrs	90%	53%
Gas (NG/H2) OCGT	40%	1.00	40%	100 %/hr	1 hr	1 hr	85%	34%
Post combustion Gas CCS - CCGT	40%	1.00	5%	50 %/hr	4 hrs	4 hrs	90%	47%
Nuclear - Large	60%	NA	0%	1 %/hr	4 hrs	4 hrs	90%	35%
Nuclear - SMR	60%	NA	0%	1 %/hr	4 hrs	4 hrs	90%	35%
Biomass	50%	0.85	17%	60 %/hr	4 hrs	4 hrs	90%	35%
Biomass with CCS	40%	1.00	5%	50 %/hr	4 hrs	4 hrs	90%	30%
Hydro	0%	0	-	100 %/hr	0 hrs	0 hrs	-	-

* Typical load factors for renewables across the Core Scenarios were: Onshore Wind (22-24%), Offshore Wind (55-60%) and Solar PV (10-11%).

3.4 Fuels

The emission factors, prices, and availability of fuels are shown in Table 3. Fuel emission factors were measured on a gross calorific value basis (GCV).

There are no prices assumed for hydrogen or electricity as these are generated and consumed within the modelling scenario and are not an input.

Table 3: Fuel emission factors, costs, and constraints

Fuel	Emission factor	Price	Availability
Natural Gas	184.55 gCO2e/kWh fuel input (GCV)	0.022 £/kWh (NCV)	No limit
Biomass (wood pellets) - CH4 and NOx	15.45 gCO2e/kWh fuel input (GCV)	6.7 £/GJ	173 TWh/yr
Biomass (wood pellets) - CO2 from direct combustion	349.41 gCO2e/kWh fuel input (GCV)		
Biomass (wood pellets) - Well-to-'Tank' CO2 emissions	37.44 gCO2e/kWh fuel input (GCV)		
Biogas	0.21 gCO2e/kWh fuel input (GCV)	113 £/MWh	14 TWh/yr
Uranium	0 gCO2e/kWh fuel input (GCV)	4,318 £/kg	No limit

Where biomass is combusted without CCS, net emissions are the CH_4 & NOx + Well-to-Tank emissions.

Where biomass combusted with CCS, net emissions are: $-(CO_2$ emissions * CCS capture rate) + (CH_4 & NOx emissions + well-to-tank emissions).

Any CO2 emissions emitted to atmosphere during combustion are not counted in the net emissions calculation as the CO2 has relatively recently been removed from the atmosphere.

Similarly, for biogas, the figure in the table above reflects the non-CO2 emissions emitted at the point of combustion.

4. Hydrogen production technologies

Hydrogen production technology cost and performance data was sourced from Element Energy's review of the hydrogen supply chain for BEIS in 2018[7]. The assumptions used in the model are shown in Table 4.

Table 4: Techno-economic characteristics of hydrogen production technologies

Technology Group	Technology Type	Capacity/unit	Cost sensitivity	CapEx in 2050 (2019£)	Variable OPEX in 2050 (2019£)	Fixed OpEx in 2050, excluding fuel costs (2019£)	Efficiency	Carbon capture rate	Lifetime	WACC
Gas + CCS	ATR + GHR + CCS[8]	1000 MW	-	364 £/kW	0.0	24.4 £/kW/year	90 %	96%	40 years	10%
Electrolysis	PEM	100 - 1000 MW	Low	265 £/kW	0.0	29.3 £/kW/year	45.0 kWh/kg H_2	-	30 years	10%
	PEM	100 - 1000 MW	Central	340 £/kW	0.0	29.3 £/kW/year	48.0 kWh/kg H_2	-	30 years	10%
	PEM	100 - 1000 MW	High	620 £/kW	0.0	29.3 £/kW/year	51.5 kWh/kg H_2	-	30 years	10%
	Alkaline	100 - 1000 MW	-	455 £/kW	0.0	29.3 £/kW/year	48.0 kWh/kg H_2	-	30 years	10%
Biomass + CCS	Gasification + Water-Gas Shift	50 -100 MW	-	1173 £/kW	0.0	103.4 £/kW/year	69 %	90%	30 years	10%

[7] Hydrogen supply chain evidence base, Element Energy Ltd, 2018
https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/760479/H2_supply_chain_evidence_-_publication_version.pdf

[8] ATR + GHR + CCS = Auto Thermal Reforming + Gas Heated Reformer + Carbon Capture and Storage

5. Flexibility technologies

5.1 Energy storage

Table 5: Economic characteristics of storage technologies

Technology	CapEx in 2050 (2019£)	Fixed OpEx in 2050 (2019£)	Lifetime	WACC
Li-ion battery (5 kW)	250 £/kWh	12 £/kW/yr	10 years	6.5 %
Li-ion battery (5 MW)	115 £/kWh	9 £/kW/yr	10 years	6.5 %
Li-ion battery (50 MW)	55 £/kWh	9 £/kW/yr	10 years	6.5 %
Pumped hydro storage	1,692 £/MWh	0.023 £/kW/yr	65 years	10.0%

The deployment of pumped hydro in 2050 was assumed to be fixed at 2.7 GW in the Low and High Flexibility scenarios. The model could deploy an additional 2 GW large scale hydro generation (not pumped storage) to be built in the High Flexibility scenarios.

Table 6: Technical characteristics of storage technologies

Technology	Duration	Cycle limit	Depth of discharge (%)	Round trip efficiency	Minimum duration
Li-ion battery (5 kW)	4 hours	2 cycles/day	80 %	85 %	-
Li-ion battery (5 MW)	4 hours	2 cycles/day	80 %	85 %	-
Li-ion battery (50 MW)	4 hours	2 cycles/day	80 %	85 %	-

Pumped hydro's technical characteristics are as followed:

- Minimum stable generation: 0% of capacity
- Frequency response slope: 0
- Ramp rate: 100% of capacity/hr
- Minimum up/down time: 0 hrs

5.2 Thermal energy storage

Table 7: Economic characteristics of thermal energy storage (TES)

Technology	CapEx in 2050 (2019£)	Fixed OpEx in 2050 (2019£)	Lifetime	WACC
Building scale TES (residential)	102.5 £/kW_{th}	-	10 years	3.5 %
Building scale TES (commercial)	75 £/kW_{th}	-	10 years	3.5 %
District heating scale TES	11 £/kW_{th}	-	10 years	13.8 %

Thermal storage, at all scales, is assumed to have an efficiency of 70%. Furthermore, it is assumed that heat is lost to the environment at a rate of 1%/hour.

5.3 Demand side response

Table 8: Economic characteristics of demand side response (DSR)

Technology	CapEx in 2050 (2019£)	Fixed OpEx in 2050 (2019£)	Lifetime	WACC
Domestic DSR	28 £/kW	-	10 years	10 %
Non-domestic DSR	244 £/kW	-	10 years	10

The CapEx of DSR consists of the cost of technologies that unlock the flexibility of an asset, rather than the flexible asset itself. These are the same values used in the Analysis of Electricity System Flexibility for Great Britain report published by the Carbon Trust and Imperial College London in 2016 and represent the lower bound of the estimated cost range[9].

For clarity, the upfront costs of purchasing electric vehicles (EV) or potentially smart domestic appliances were not included in the model. It was assumed that these assets are primarily purchased to provide other services, so the purchase price shouldn't be included in the energy system cost. Similarly, the cost of EV charging infrastructure enables smart charging and V2G flexibility, but its primary function is not provision of system services. In addition, the use of EVs is consistent across all scenarios, so including the cost would make no difference to a comparison between two scenarios.

[9] An analysis of electricity system flexibility for Great Britain, Carbon Trust and Imperial College London, 2016 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/568982/An_analysis_of_electricity_flexibility_for_Great_Britain.pdf

5.4 Hydrogen storage

It is assumed that **underground** storage is used as centralised and long-term hydrogen storage. There is a restriction associated with the discharge of the storage (10% of energy stored/day) due to the need for a "gas cushion" for the stability of the storage.

Table 9: Economic and technical characteristics of underground hydrogen storage

Location / type	Maximum capacity (of H2)	CapEx in 2050 (2019£)	Fixed OpEx in 2050 (2019£)	Variable OpEx in 2050 (2019£)	Round trip losses	Lifetime	WACC
Cheshire Basin	4,237 GWh	5,085,630 £/GWh capacity	202,579 £/GWh capacity/yr	149 £/GWh stored/yr	0.33%	40 years	10 %
East Yorkshire	58,356 GWh	1,998,322 £/GWh capacity	122,874 £/GWh capacity/yr	244 £/GWh stored/yr	0.13%	40 years	10 %
East Irish Sea	32,373 GWh	8,927,064 £/GWh capacity	565,406 £/GWh capacity/yr	150 £/GWh stored/yr	0.33%	40 years	10 %
Wessex	227,273 GWh	5,085,630 £/GWh capacity	202,579 £/GWh capacity/yr	149 £/GWh stored/yr	0.33%	40 years	10 %

It is assumed that **overground**, medium-pressure storage is used as distributed storage close to high energy demand locations to support of the supply of gas to localised peak demands. This storage is flexible as it can be discharged or charged rapidly.

Table 10: Economic and technical characteristics of above ground hydrogen storage

CapEx in 2050 (2019£)	Fixed OpEx in 2050 (2019£)	Variable OpEx in 2050 (2019£)	Losses	Lifetime	WACC
11450,000 £/GWh	340,000 £/GWh	-	0%	40 years	10 %

6. Heating technologies

The technical and economic characteristics of the heating technologies available to be deployed in the model are shown in Table 11. Please see Section 2.3.1 of the main Flexibility in Great Britain report for a description of how these were deployed in each of the core heating scenarios.

Table 11: Economic characteristics of heating technologies

Technology	Scale	Size	CapEx in 2050 (2019£)	Fixed OpEx in 2050 (2019£)	Installation cost in 2050 (2019£)	Lifetime (years)	WACC
Gas boiler	Residential	<20 kW_{th}	75 £/kW	6 £/kW/yr	1,000 £ (50 £/kw	12	3.5%
	Non-Domestic	20+ kW_{th}	63.75 £/kW	5.1 £/kW/yr	Total cost 15% lower than residential	12	3.5%
Hydrogen gas boiler	Residential	<20 kW_{th}	75 £/kW	6 £/kW/yr	1,500 £	12	3.5%
	Non-Domestic	20+ kW_{th}	63.75 £/kW	5.1 £/kW/yr	Total cost 15% lower than residential	12	3.5%
Heat pump	Residential	<10 kW_{th}	600 £/kW	22 £/kW/yr	1,200 £	12	3.5%
	Non-Domestic	10+ kW_{th}	570 (£/kW)	20.9 £/kW/yr	Total cost 5% lower than residential	12	3.5%
Resistive heating	Residential	<10 kW_{th}	120 £/kW	-	300 £	12	3.5%
	Non-Domestic	10+ kW_{th}	102 £/kW	-	Total cost 15% lower than residential	12	3.5%

7. Direct Air Carbon Capture and Storage (DACCS) infrastructure

Table 12: Economic and technical characteristics of DACCS

	Low cost DACCS sensitivity	High cost DACCS sensitivity
Capacity of single DACCS plant/unit	1 $MtCO_2$/yr	1 $MtCO_2$/yr
Cost of single DACCS plant/unit	£ 769,230,769	£ 76,923,076,923
Lifetime	30 years	30 years
WACC	12 %	12 %
Fixed OpEx	28,519,279 £/yr	28,519,279 £/yr
Assumed max annual capacity factor	90 %	90 %
Electricity requirement	0.33 MWh/tCO_2 captured	0.33 MWh/tCO_2 captured
Heat requirement	3 MWh/tCO_2 captured	3 MWh/tCO_2 captured

8. Network infrastructure

8.1 Electricity networks

Table 13: Economic characteristics of electricity networks

Network	Cost	Lifetime	WACC
GB transmission	1150 - 1,500 £/MW/km	40 years	2.8 %
GB interconnectors	1500 - 4700 £/MW/km	40 years	2.8 %
Urban distribution network cost	29 - 83 £/kW/year of increased peak demand	45 years	3.92 %
Rural distribution network cost	130 - 176 £/kW/year of increased peak demand	45 years	3.92 %

Distribution network cost values are derived from the average network upgrade costs across all regions, which themselves are made up of components costs detailed in Imperial College's Distribution Network Planning Model (DistPlan).[10]

As a minimum, interconnectors between the UK and other countries are assumed to be upgraded over the next 30 years so that they have the following capacities[11]:

Table 14: Current and planned interconnection capacity

Country	Current Capacity[12]	Additional capacity	Capacity in 2050
France	3 GW	2.4 GW	5.4 GW
Ireland	1 GW	0.5 GW	1.5 GW
Netherlands	1 GW	0.0 GW	1.0 GW
Norway	1.4 GW	0.0 GW	1.4 GW
Belgium	1 GW	0.0 GW	1.0 GW
Denmark	0 GW	1.4 GW	1.4 GW
Total	**7.4 GW**	**4.3 GW**	**11.7 GW**

In the high flexibility scenarios modelled, interconnection capacity could increase even further, to a maximum of 20GW.

8.2 Gas networks

The model assumes the existing natural gas transmission is maintained and new hydrogen transmission is built to the existing gas transmission network. Pipeline cost is assumed £2.8 million per km and compressor cost is £1.7 million per MW. The lifetime of transmission assets is assumed to be 40 years, and the WACC was assumed to be 10%.

[10] Within the IWES model the representation of local networks is carried out by the Distribution Network Planning (DistPlan) Model. A brief overview of DistPlan can be found in Section 3.2.3 of: IndustRE (2017) Quantifying the benefits of Flexible Industrial Demand.

[11] This is based on Ofgem (2021). Existing and Future Interconnectors [Accessed 15 June 2021]

[12] Capacity expected to become operational by end 2021.

No new gas distribution networks were built as they were assumed to be compatible with hydrogen transport already.

Natural Gas and hydrogen losses from the transmission and distribution network are not considered in the model.

Gas distribution network decommissioning costs were assumed to cost £1bn/yr in the electric heating scenario, and no decommissioning occurred in the other scenarios.

8.3 CCS transport and storage

The cost of CO_2 storage cost was assumed to be £13/tonne. All storage sites are offshore and are largely distributed along the east coast of England and Scotland (north of East Anglia) and off the north west coast of England.

The cost of a CCS network was assumed to cost £989/tCO_2/km/yr

The WACC for storage and transport was assumed to be 5.7%

8.4 Heat networks

The capital cost of heat networks was assumed to be around £5,800/household and the connection cost is £7,800/household. The WACC was assumed to be 5.3% and lifetime 40 years for the infrastructure and 20 years for appliances. In addition, there is one-off £2,000/household conversion cost including gas pipe removal, replacement of gas appliances and installation of hot water storage.

9. Carbon Target

There is a carbon target of -49.8 $MtCO_2e$ across all the core modelling runs for 2050. This was derived from the Climate Change Committee's Further Ambition scenario, in which the power sector (inclusive of Bioenergy with CCS and DACCS) provides the negative emissions required for the wider GB economy to meet net zero.

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