A note from AFRY Management Consulting

Methodology & key assumptions Report – Economic impacts

Report Identifier: 2025/ 0236866

1 Introduction

1.1 Sectoral coverage and approach

This report covers the methodology used to determine the whole-economy system costs of the four pathways in the National Energy System Operator (NESO) Future Energy Scenarios (FES), also referred to as the NESO pathways in this document:

- Holistic Transition (HT);
- Electric Engagement (EE);
- Hydrogen Evolution (HE); and
- Falling Behind (FB).

This includes the investment (CAPEX) and operating costs (OPEX) of decarbonising the supply of electricity and hydrogen and the end-user sectors. Where a sector is modelled as part of FES, drivers of cost changes are outputs from the FES modelling and we have taken a bottom-up approach to costing, considering:

- CAPEX: the upfront capital costs associated with new and replacement infrastructure / technologies;
- Decommissioning costs (where deemed to be a significant cost): the costs associated with decommissioning infrastructure / technologies;
- OPEX;
  - Fixed OPEX: the annual costs associated with operation and maintenance of the infrastructure / technology. These costs occur annually regardless of the output from that technology;

— Other variable OPEX: the operation and maintenance costs which vary depending on the output of the technology (excluding fuel costs which are included in a separate category); and

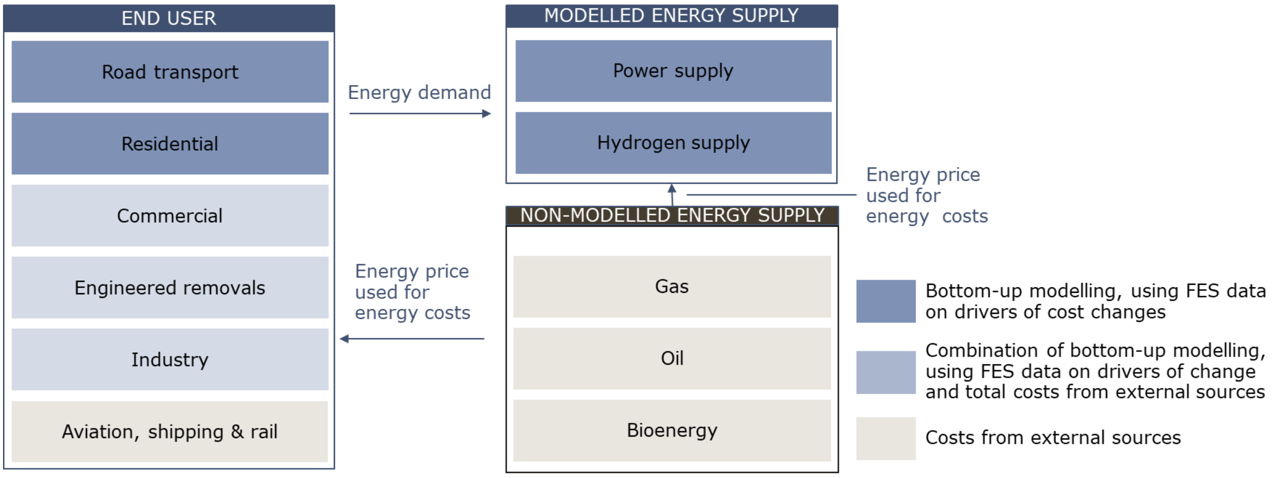
— Fuel costs.

— Carbon costs: There is a recognised social cost attached to greenhouse gas emissions and their environmental impact. We illustrate this value by calculating carbon costs based on the Government Green Book values for appraisal[1].

However, FES does not model all sectors associated with decarbonising. To provide an indication of the overall decarbonisation costs including non-modelled sectors, estimates for the non-modelled sectors were taken from work completed by the Climate Change Committee's (CCC) Carbon Budget 7 (CB7)[2], referred to as CCC CB7 in this report. This is used as an estimation for these costs but it should be noted that the assumptions in CB7 will not necessarily be consistent with the NESO pathways.

A summary of the approach for each sector is shown in Exhibit 1.1.

Exhibit 1.1 – Summary of approach to costing each sector



1.2 Common inputs across sectors

1.2.1 Money base

All inputs are converted to real 2025 money using a GDP deflator provided by NESO. We understand that the GDP deflator is based on independent projections from Oxford Economics.

[1] Valuation of greenhouse gas emissions: for policy appraisal and evaluation, DESNZ, September 2021
[2] The Seventh Carbon Budget, Climate Change Committee, February 2025

1.2.2 Fuel costs

1.2.2.1 Electricity and Hydrogen

Where we have costed the supply side (electricity and hydrogen), there is an overlap between the costs of expanding supply sectors to meet growing demand and fuel costs in the end user sectors. To avoid double counting, this cost must either be removed from the supply or end user sectors. In this analysis, we have excluded this cost from the end user sectors, meaning all costs associated with hydrogen and electricity supply are included in the supply side costs.

1.2.2.2 All other fuels

For oil and gas, we have used estimated Long Run Variable Costs (LRVCs) for end user sectors and the wholesale price for the supply-side (power and hydrogen). The LRVC includes the components of the retail price which represent actual costs to society that vary according to the level of consumption but excludes fixed price components or those that only result in transfers between groups in society[3].

LRVCs have been approximated from wholesale prices provided by NESO. We understand that NESO have originally sourced the wholesale prices from Oxford Economics and Aurora. LRVCs have been approximated by adding the difference between NESO's externally sourced wholesale price projections and the 2023 DESNZ wholesale price[4] to the DESNZ LRVC[5]. Oil LRVCs differ by end user while gas LRVCs are assumed to be the same, due to the minimal difference in prices between end users.

For all bioenergy prices, a straight average of the CCC CB7 LRVC for domestic and imported fuel prices were used[6].

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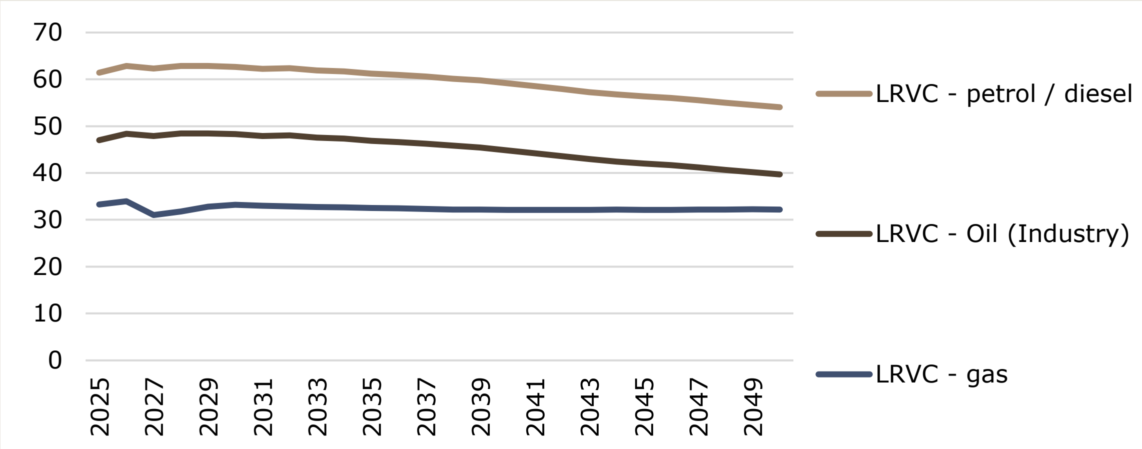
[3] Valuation of energy use and greenhouse gas emissions Background documentation, Department for Energy Security & Net Zero, October 2023
[4] Fossil fuel price assumptions 2023, DESNZ, November 2023
[5] Green Book supplementary guidance: valuation of energy and greenhouse gas emissions for appraisal, DESNZ, Tables 9-13,
[6] The Seventh Carbon Budget Methodology accompanying data costing analysis, Climate Change Committee, May 2024

Key fuel price projections

LRVC fuel price projections are approximated from wholesale prices provided by NESO and DESNZ LRVC assumptions. DESNZ LRVC fuel assumptions include the parts of the retail price that represent the actual costs to society that vary according to the level of consumption. For gas this includes the wholesale price, variable local distribution costs and variable local transmission costs. For oil, this is calculated as the wholesale price + non fuel costs – fixed costs.

Exhibit 1.2 – Key fuel price assumptions HHV, Central case (£/MWh, real 2025)



Notes:
WP - Wholesale price
HHV – High Heating Value
All end users use the same gas price LRVC
Source: Valuation of energy use and greenhouse gas emissions, Background documentation, DESNZ, October 2023

1.2.3 Carbon costs

Carbon costs have been calculated by multiplying the annual whole system carbon dioxide equivalent (CO_{2e}) by the carbon value for that year.

Whole system CO_{2e} is an output of the FES modelling and varies for each FES pathway. The carbon values[7] are those used in Government valuations and represent the monetary value that society places on one tonne of CO_{2e}[8].

1.3 Outputs

We have provided four main outputs for the system costs:

- Total in-year system costs;
- Total system costs compared to 2025;
- Comparison in-year system costs; and

[7] Green Book supplementary guidance: valuation of energy and greenhouse gas emissions for appraisal, DESNZ, Table 3
[8] Valuation of greenhouse gas emissions: for policy appraisal and evaluation, DESNZ, September 2021

- Comparison annualised system costs.

All outputs are provided in real 2025 money. Not all sectors are included in each metric because of the nature of the datasets available for some sectors.

- Commercial: CAPEX and OPEX[9] for agriculture, construction and energy efficiency have only been included in the comparison to the Falling Behind pathway;
- Industry: CAPEX and non-fuel OPEX have only been included in the comparison to the Falling Behind pathway;
- Non-road transport: has only been included in the comparison to the Falling Behind pathway; and
- Engineered removals: has only been included in the annualised comparison to the Falling Behind pathway.

We have provided system costs for a 'base case' and four sensitivities:

- Low fuel price;
- High fuel price;
- Low capital costs; and
- High capital costs

Inputs to the sensitivities were derived by NESO. These were generally a default of +/-25% for the high and low fuel / capital costs respectively, unless evidence suggested otherwise.

1.3.1 Total in-year system costs

This is the total CAPEX and OPEX spend in each year of the modelled period. Outputs include all sectors modelled using FES pathway cost drivers. We have not included costs from the CCC CB7, as these are only presented as a comparison to their baseline and are therefore not consistent with a total cost measure.

Total in-year system costs therefore include: power; hydrogen; road transport; residential; commercial heating (all capex and opex) and total commercial gas costs; and all industrial fuel costs.

1.3.2 Total system costs compared to 2025

This is the total in-year system costs (1.3.1) for year Y minus the total in-year system costs for year 2025. System costs for 2025 are modelled.

[9] Total gas costs are calculated from the total commercial gas demand in FES which includes gas demand in the agriculture and construction sectors. The gas costs in these sectors are therefore included in the non-comparison metrics.

1.3.3 Comparison in-year system cost

This is the difference in the total in-year system costs between the specified NESO pathways. This includes all system costs except for Engineered Removals.

1.3.4 Comparison annualised system costs

This is the difference in the annualised CAPEX and in-year OPEX in each modelled year between specified NESO pathways.

Annualised CAPEX spreads capital costs across the assumed lifetime of the asset, based on a given discount rate:

- for the power sector, technology specific private discount rates have been used; and
- for all other sectors, a social discount factor of 3.5% has been used[10].

This includes all system costs.

[10] Green Book supplementary guidance: discounting, HM Treasury, April 2013

2 Supply

2.1 Power

A summary of the cost components included in the power sector is shown in Exhibit 2.1.

Exhibit 2.1 – Cost components included in the power sector

Power sector areas	Cost components
Electricity generation	CAPEX and decommissioning costs
	Fixed OPEX
	Variable O&M costs
	Fuel costs
Transmission network	CAPEX
	Fixed OPEX
Offshore network	CAPEX
	Fixed OPEX
Distribution network	CAPEX
	Fixed OPEX
CO_2 transport and storage network	CAPEX
	Fixed OPEX
Interconnection	CAPEX
	Fixed OPEX
	Net import costs

2.1.1 Electricity generation

2.1.1.1 CAPEX and decommissioning costs

Total CAPEX is calculated by multiplying the capital costs (£/kW) for each technology with the uptake (kW) for that technology in each year. CAPEX is then evenly distributed across build years for each technology type.

Uptake includes the additional generation capacity installed each year as well as any assumed repowering. NESO provided for each FES pathway:

- total installed capacity for each technology type for each year; and
- capacity of new nuclear installed each year.

For all technologies except nuclear, additional generation capacity installed was estimated as the year-on-year increase in capacity. Repowering capacity was assumed for onshore wind, offshore wind, solar PV and batteries when they reached the end of their assumed lifetime (if capacity remained the same or increased in that year).

Capital cost assumptions (£/kW) were primarily provided by NESO and based on the latest edition of the DESNZ generation cost report[11] which includes the specified technology. Capital cost assumptions were the same across all NESO pathways.

For technologies where capital cost assumption data was not available in the DESNZ publication, assumptions were provided by NESO or AFRY. NESO provided Lithium-ion battery CAPEX estimates, which we understand to be a combination of Modo survey data with CAPEX data from the National Renewable Energy Laboratory[12]. Build years were primarily sourced from DESNZ assumptions[11].

We have applied the same capital cost assumptions for repowered plants as new build plants.

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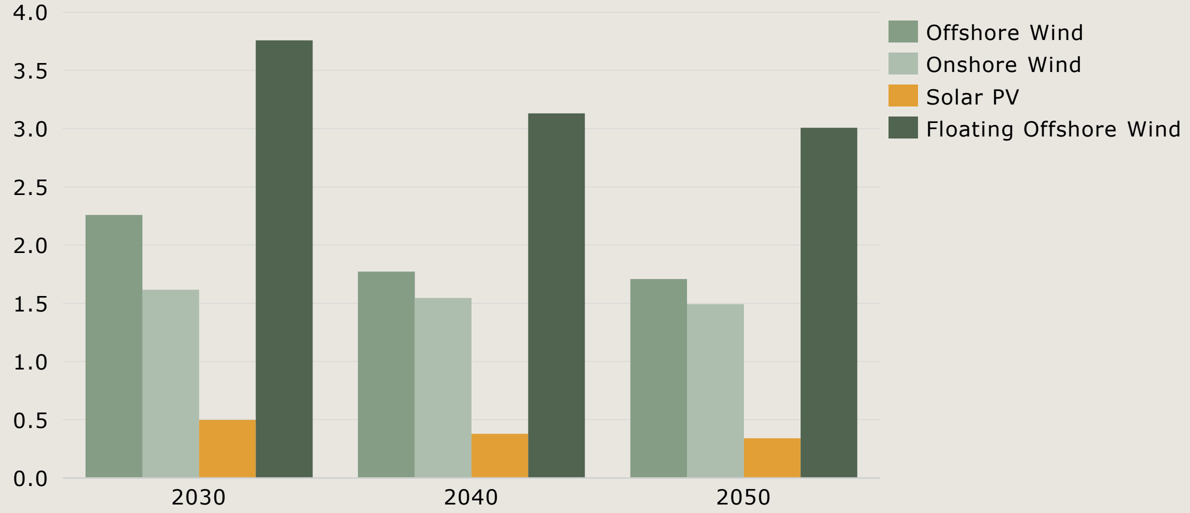
[11] Electricity Generation Costs 2023, DESNZ, August 2023 (updated in November 2023); Electricity Generation Costs 2020, BEIS, August 2020, Electricity Generation Costs 2016, BEIS, November 2016

[12] Cost Projections for Utility-Scale Battery Storage: 2023 Update, National Renewable Energy Laboratory, June 2023

Investment costs for renewable technologies

Capital cost assumptions for renewables are one of the key drivers in the overall cost assumptions. Currently renewable technologies are facing high costs, above the medium DESNZ generation cost report. For fixed bottom offshore and onshore wind, we have therefore taken high costs from DESNZ in 2025 and trended down to medium DESNZ costs. From 2040 onwards, we have applied an additional learning rate as we expect costs to continue decreasing. Offshore wind option fees were excluded from DESNZ cost assumptions, as this is a redistribution of money between developers and the Crown Estate, rather than a fundamental cost of building offshore wind. The resulting costs were benchmarked against AFRY's internal analysis and can be seen in Exhibit 2.2.

Exhibit 2.2 – Renewable technology CAPEX assumptions for Central case, £000s/kW, real 2025



Source: Electricity Generation Costs 2023, DESNZ, August 2023 (updated in November 2023)

Decommissioning cost assumptions

Decommissioning costs are only considered for nuclear and offshore wind. For all other technologies, we assume that the decommissioning cost is offset by the scrap value of the plant, resulting in a net decommissioning cost of zero. This approach is consistent with DESNZ's treatment[13] of decommissioning costs. Decommissioning is applied as a variable cost throughout the lifetime of the project.

2.1.1.2 Fixed OPEX

Fixed OPEX represents recurring annual expenses that are incurred regardless of the plant's electricity output. These include costs for staffing, scheduled maintenance, administrative overheads, and equipment upkeep that are necessary to keep the plant operational. Fixed OPEX was calculated

[13] Electricity Generation Costs 2020, BEIS, August 2020

by multiplying the total installed capacity for each pathway (kW), provided by NESO, by the assumed fixed OPEX (£/kW).

2.1.1.3 Variable O&M

Variable O&M costs (excluding fuel costs) change with the level of electricity generation. These typically include consumables, wear-and-tear-related maintenance, and other operational expenses that increase with plant usage.

Variable O&M costs were calculated by multiplying a per technology variable O&M cost assumption (£/MWh) by the total generation for each technology type (MWh). Total generation for each technology type was provided by NESO and varies by FES pathway.

2.1.1.4 Fuel costs

Fuel costs were calculated by multiplying the 'fuel offtake' in the power sector (GJ) by the corresponding wholesale price for each fuel type (£/GJ).

Hydrogen fuel costs were not included as the hydrogen costs are included in the separate costing of the supply side.

Fuel offtake is an output from the FES modelling and varies by pathway. Wholesale prices (section 1.2.2) were provided on a lower heating value (LHV) basis and are the same across all pathways.

2.1.2 Transmission network

Projections for the total capital investment and operating costs of the transmission network were provided by NESO and included in the model as total costs per year. We understand that NESO has determined transmission costs using the methodology below.

CAPEX estimates are a combination of forecasted expenditure from the RIIO ET2 Price Control Financial Model[14], Transmission Operators RIIO ET3 Business plans[15], and internal NESO modelling of transmission build beyond the ET3 period.

Transmission OPEX estimates are based on operational expenditure in the RIIO ET2 price control period[14], transmission operators RIIO ET3 business plans, and scaled with gross electricity demand beyond the ET3 period.

Transmission CAPEX and OPEX assumptions vary by scenario.

2.1.3 Offshore network

Offshore network capital costs were calculated by multiplying a £m/GW cost by the offshore wind uptake each year (GW).

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[14] RIIO-2 Price Control Financial Model (PCFM), Ofgem, May 2025
[15] RIIO-T3 Business Plan, National Grid, December 2024; Delivering a Network for Net Zero: The Pathway to 2030, Scottish and Southern Electricity Networks, December 2024; and How we get there, SP Energy Networks December 2024.

Capital costs (£m/GW) were provided by NESO and are the same across all pathways. Offshore wind uptake is the same as in section 2.1.1.1.

Fixed operating costs were calculated by multiplying an assumed operating cost (£m/GW) by the total installed capacity of offshore wind (GW). Operating costs were provided by NESO and are the same across all pathways.

2.1.4 Distribution network

Distribution networks were not modelled as part of FES, and so we have based costs on extrapolation of forecasted costs provided by Distribution Network Operators (DNOs) as part of the most recent RIIO-ED2 price control period, covering April 2023 to March 2028[16].

Total distribution network costs are broken down into six primary activities. We have categorised these based on key drivers of costs which has led to a different approach to extrapolation for each, as shown in Exhibit 2.3. Total CAPEX costs are the sum of the load related CAPEX and the non-load related CAPEX. Total OPEX costs are the sum of the non-operating costs and the network operating costs.

[16] RIIO-ED2 Final Determinations, Ofgem, November 2022

Exhibit 2.3 – Distribution network cost calculation methodologies

Cost activity	Description	Cost calculation methodology
Load related expenditure	The investment required to ensure the network has sufficient capacity to accommodate the load on it.	Multiplied a base cost[1] (£/GW) with the annual increase in peak demand (GW)
Non-load related capex	Replacement or refurbishment of assets which are at end of life or need replacing on safety or environmental grounds.	Scaled a base value[2] by the ratio of peak demand
Non-operating capex	Capital costs from activities unrelated to core activities.	Remains constant
Network operating costs	Day-to-day costs to maintain and operate the distribution network.	Scaled a base value[2] by the ratio of peak demand
Closely associated indirects	Back of office functions involved in construction and operation of network assets.	Not considered in CAPEX and OPEX calculation
Business support costs	Operating costs required to support the DNOs overall business.	Not considered in CAPEX and OPEX calculation

1. Base cost (£/GW) calculated by dividing the total load-related CAPEX from Ofgem's Final Determinations by the average increase in peak demand across the NESO pathways during the 2023-2027 period.
2. Base values (£) were calculated as the total non-load related CAPEX / network operating costs over the RIIO-2 period divided by five (to achieve an average annual value).

2.1.5 CO_2 transport and storage network

The cost of transporting and storing CO_2 is assumed to scale with the increase in CO_2 captured.

Assumed capital costs (£/tCO_2) are multiplied by the increase in tonnes of carbon dioxide captured from one year to the next, where tCO_2 is a measure of network capacity.

Capital costs (£/tCO_2) are the same across all pathways and determined by AFRY analysis of announced projects. The increase in tonnes of carbon dioxide captured is calculated from the total tonnes of carbon dioxide captured, which is an output of the FES modelling and varies by pathway.

Note that this approach assumes that CAPEX costs occur at the time of an increase in CO_2 captured. However, in reality, the infrastructure will likely be built before it is fully utilised.

Assumed OPEX (£/tCO_2) is multiplied by the total tonnes of carbon captured in that year.

These costs, shown in the power sector, include the costs of CO_2 transport and storage for all sectors including Engineered Removals, except for the

Hydrogen sector (included in the total Hydrogen sector costs), and where these costs are already included in costs taken from the CCC CB7[17].

2.1.6 Interconnection

2.1.6.1 CAPEX and OPEX

Interconnector investment costs are driven both by the capacity of the interconnector and the length of the interconnector. We have therefore categorised each new assumed interconnector based on their length:

- Short interconnectors: <300km
- Long interconnectors: >300km

We have multiplied the new capacity of short interconnectors based on a cost assumption for short interconnectors (£/kW) and the new capacity of long interconnectors by a cost assumption for long interconnectors (£/kW).

New interconnector capacity was provided by NESO and varies by pathway. CAPEX cost assumptions are based on AFRY analysis and are the same across all pathways.

OPEX cost assumptions (£/kW) are the same for all interconnectors and are multiplied by the total capacity of interconnectors in each year.

2.1.6.2 Net import costs

Net import costs were determined by subtracting export revenues from import revenues for each modelled year. Export revenues and import revenues are a direct output from the FES modelling and vary by scenario.

2.2 Hydrogen

A summary of the cost components included in this analysis in the hydrogen sector are shown in Exhibit 2.4.

[17] Carbon captured through Direct Air Carbon Capture and Storage (DACCS) and Bioenergy with Carbon Capture and Storage (BECCS) and in industry are not included here, as these are already included in the CCC cost assumptions (see section 3.6)

Exhibit 2.4 – Cost components included in the hydrogen sector

Hydrogen sector areas	Cost components
Hydrogen production and storage	CAPEX
	Fixed OPEX
	Variable OPEX
	Fuel costs (excluding electricity)
Hydrogen transmission network	CAPEX
	Fixed OPEX
Hydrogen distribution network	CAPEX

2.2.1 Hydrogen production and storage

2.2.1.1 CAPEX, fixed OPEX and variable OPEX

NESO provided the total costs for hydrogen production and storage for CAPEX, fixed OPEX, and variable OPEX. Costs were provided by pathway and year.

We understand that NESO's hydrogen costs have been calculated using the FES outputs for the quantities of hydrogen production and storage, and a range of public sources[18] for the costs of these technologies.

2.2.1.2 Fuel costs

Fuel costs were calculated by multiplying the relevant fuel offtake from the hydrogen sector with the corresponding wholesale prices.

Fuels used in the Hydrogen sector by scenario were provided by NESO as an output of their FES modelling and include:

- Electricity;
- Biomass; and
- Gas

Of these, only gas costs are included in the fuel costs of the hydrogen sector. Electricity costs are already accounted for in the power sector. All biomass production of hydrogen in FES is assumed to be fitted with Carbon Capture and Storage (CCS) and so these costs are captured within the Engineered Removals sector (Section 3.6).

[18] This includes: Hydrogen in the electricity value chain, DNV, 2019; Levelised cost of green hydrogen modelling, 2025 to 2050, NESO; Clean Hydrogen Monitor, Hydrogen Europe, 2024; Global Hydrogen Review 2024, iea, 2024; Low-Carbon Hydrogen from Natural Gas: Global Roadmap; IEAGHG, 2022.

Wholesale gas price projections (section 1.2.2) were the same across all pathways.

2.2.2 Hydrogen transmission network

The total costs for hydrogen transport were provided by NESO, with a breakdown into CAPEX, fixed OPEX, and variable OPEX[19].

2.2.3 Hydrogen distribution network

Hydrogen distribution network costs were only assumed to apply to the Hydrogen Evolution scenario, as this is the only scenario with residential hydrogen heating[20].

CAPEX costs were calculated by multiplying the number of customers transitioning to hydrogen in the residential sector by a cost per customer.

The number of customers transitioning to hydrogen was estimated as the year-on-year increase in hydrogen heating units in the residential sector. This assumes one heating unit per customer.

The cost per customer was calculated based on cost data provided as part of ARUP's study 'The Future of Great Britain's Gas Networks'.[21]

[19] Our understanding is that NESO have sourced these costs from: European Hydrogen Backbone, ehb, April 2022

[20] Some industrial, commercial and power generation are expected to connect to hydrogen in the other pathways which may arise in a small distribution network but we expect this to be minimal compared to in the Hydrogen Evolution scenario.

[21] Future of Great Britain's Gas Networks, Report for National Infrastructure Commission and Ofgem, Final Report, ARUP, October 2023

3 End Users

3.1 Road Transport

A summary of the cost components included in the road transport sector is shown in Exhibit 3.1.

Exhibit 3.1 – Costs included in the road transport

Road transport areas	Cost components
Vehicles (cars, vans, buses, motorbikes and Heavy Goods Vehicles (HGVs))	CAPEX
	Fixed OPEX
	Fuel costs
Electric charging infrastructure	CAPEX
	Fixed OPEX
Hydrogen refuelling infrastructure	CAPEX
	Fixed OPEX

Notes: We have not included the costs associated with refuelling infrastructure for internal combustion engines (ICEs) or natural gas vehicles in cost estimations.

3.1.1 Vehicles

3.1.1.1 CAPEX

To calculate CAPEX, we multiplied vehicle capital cost assumptions (by vehicle type) by annual vehicle uptake data.

Vehicle uptake is defined as the total additional purchases each year (new sales and replacements). This was provided by NESO, based on inputs to their FES pathway modelling and varies by scenario.

Vehicle cost projections were largely derived from the CCC CB7 modelling assumptions[22].

[22] The Seventh Carbon Budget Methodology Accompanying Data, Climate Change Committee, May 2025

Investment costs for cars

One of the biggest drivers of the total system costs is the upfront investment costs for Internal Combustion Engines (ICEs) and Battery Electric Vehicles (BEVs). The cost of cars assumed in this analysis are below. While ICEs are assumed to slightly increase with time, battery electric vehicles are assumed to have a steep learning curve. Cost parity between EVs and ICE cars is reached by 2027, which is aligned with the CCC assumption of cost parity between 2026 and 2028 (depending on the size of car).

Exhibit 3.2 – CAPEX cost assumptions of cars (£000s/car, real 2025)

Fuel type	2025	2030	2040
Petrol / diesel	34.9	36.4	36.4
Battery electric	39.3	33.9	32.4

Notes: The petrol / diesel car CAPEX cost is an average of the CCC's petrol and diesel CAPEX cost assumptions for cars
Source: The Seventh Carbon Budget Methodology Accompanying Data, Climate Change Committee, May 2025

3.1.1.2 Fixed OPEX

Total operating costs were calculated by multiplying an operating cost assumption by the total stock data for each vehicle type in each year.

Stock data was provided by NESO and varies by scenario. Operating costs includes maintenance and insurance costs for the vehicle.

Fixed operating costs for vehicles

Another significant driver of total system costs is the fixed operating costs of road transport. Due to their high maintenance costs, OPEX of vans is a significant cost, as well as the OPEX for cars. Exhibit 3.3 shows our assumptions for maintenance costs for cars and vans.

Exhibit 3.3 – OPEX cost assumptions of cars and vans (£/car, real 2025)

Fuel type	2025	2030	2040
Cars - Petrol / diesel[1]	1,142	1,156	1,156
Cars - Battery electric[1]	1,067	1,011	1,011
Vans - Petrol / diesel[2]	5,162	5,286	5,286
Vans – Battery electric[3]	4,110	4,057	4,057

Sources:
1. The Seventh Carbon Budget, Charts and data, February 2025. For years that weren't provided by the CCC, costs are interpolated.
2. Managers Guide to Distribution Costs – Sample, Logistics UK, 2019
3. AFRY analysis

3.1.1.3 Fuel costs

NESO provided the fuel use by fuel type (TWh) for each FES pathway. We multiplied this fuel use by the corresponding fuel prices to calculate the total fuel costs.

Fuel types for vehicles in the FES modelling were:

- Natural gas;
- Petrol / diesel;
- Electricity; and
- Hydrogen

We have only included the costs of natural gas and petrol / diesel in the road transport sector as costs associated with hydrogen and electricity are included in the supply side. The fuel price used for natural gas and petrol / diesel is an estimated LRVC, as described in section 1.2.2.2.

3.1.2 Electric charging infrastructure

3.1.2.1 CAPEX

The investment costs of electric charging were calculated by multiplying the cost of each charger type by an estimated uptake number for each charging type. A premium was added to this for Vehicle to Grid (V2G), which was calculated by multiplying the number of vehicle to grid chargers by the assumed premium for V2G (£/unit) on top of the cost of a one-directional charger.

Total stock of chargers was estimated from the total number of vehicles. Separate estimations were made for public and private chargers.

For public chargers, we based our assumption on the number of public chargers per BEV in the CCC's CB7, which we applied to the electric vehicle stock in each FES pathway. The share of slow (<50kW), fast (50-100kW) and ultra-fast (>150kW) chargers in this total was based on a review of existing charging infrastructure across Europe.

To estimate the number of private EV chargers, we have assumed this is equal to a proportion of the number of dwellings in Great Britain (GB) that have off-road (private) parking, and therefore charging, capability. The proportion is equal to the battery electric vehicles (BEVs) as a percentage of the total car fleet.

The total number of V2G chargers was assumed to equal the number of vehicles with vehicle to grid capability, which was provided by NESO.

Annual uptake of chargers was calculated as the year-on-year change in stock, added to the number of chargers that require replacement because they have reached their end of life.

Public charger costs were largely sourced from a UKEVSE report[23] and are assumed the same across all pathways and years. Private charger costs and the V2G charger premium were provided by NESO, based on a literature review and stakeholder engagement.

3.1.2.2 OPEX

OPEX was calculated by multiplying an assumed maintenance cost by the total stock for each charger type and each modelled year. V2G chargers are assumed to have the same OPEX as conventional chargers.

3.1.3 Hydrogen refuelling

Investment costs were estimated by multiplying the number of additional hydrogen refuelling stations by the capital cost assumption for one refuelling station.

The number of hydrogen refuelling stations was estimated as this is not an output of the FES modelling. We used the current ratio of conventional HGV refuelling stations to HGVs as a proxy for the number of hydrogen refuelling stations required - the majority of hydrogen vehicle stock is made up of HGVs in FES. We applied this ratio to the projected number of hydrogen vehicles[24] to estimate the required number of hydrogen refuelling stations.

Cost assumptions for hydrogen refuelling are sourced from a United States Department of Energy report[25] and are the same for all years and NESO pathways.

OPEX was calculated by multiplying an assumed maintenance cost (£/unit) by the total number of stations for each modelled year.

3.2 Residential

A summary of the residential costs included in the analysis are shown in Exhibit 3.4.

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[23] Making the right connections, General procurement guidance for electric vehicle charge points, UK Electric Vehicle Supply Equipment Association, 2019
[24] Hydrogen vehicles include HGVs, cars, motorbikes, vans and buses
[25] Hydrogen Fuelling Stations Cost, Department of Energy United States of America, 2021

Exhibit 3.4 – Residential costs included in analysis

Residential sectors included	Cost components
Individual dwelling heating technologies inc. required retrofits to housing	CAPEX
	Fixed OPEX
Heat networks	CAPEX
	Variable OPEX
Energy efficiency measures	CAPEX
Heating, cooling, appliances and lighting	Fuel costs

Notes: We have not included the investment or fixed OPEX costs associated with cooling, appliances and lighting in this analysis as these are not directly tied to decarbonisation strategies in the NESO pathways. Microgeneration is not included in the end user sectors as it is included in the power sector.

3.2.1 Individual dwelling heating technologies

There are two main investment costs associated with updating the heating technology in a residential building:

- new technology: the investment in the equipment and installation of the new technology; and
- building retrofits: investments required to make the building suitable for the new technology type (e.g. replacing radiators)

We have calculated both costs using the approaches outlined below. The total cost is the sum of these:

- new technologies: multiplied heating technology unit cost by the annual uptake (sales); and
- building retrofits: multiplied an additional retrofit cost by the annual increase in the heating technology stock. This means retrofit costs are only applied to new installations and not replacements.

Both uptake and total stock for each heating technology are provided by NESO as number of units per year and vary by FES scenario.

Cost assumptions differ across NESO pathways. NESO provided learning curves, which were applied to the 2025 cost assumptions and differ across NESO pathways. 2025 cost assumptions[26] were primarily from Boiler Upgrade Statistics (BUS)[27] and a Eunomia report[28], with adjustments made to split out the cost of the heating technology and retrofits.

Fixed (non-fuel use) operating costs represent an annual servicing cost (£/unit). This was multiplied by the total stock data for each heating

[26] For hybrid technologies, the cost was assumed to be the cost of both technologies. This may be slightly over-estimating the costs of these technologies as we would expect the capacity of the hybrid systems to be lower
[27] Boiler Upgrade Statistics, DESNZ, 2025
[28] Cost of Domestic and Commercial Heating Appliances, Eunomia, February 2023

technology. The annual cost was obtained from a research publication by the Scottish Government[29].

Key heating technology costs

A large driver of capital costs in the residential sector is the cost of replacing heating technologies with low-carbon alternatives. There are two components to this cost – the cost of the individual technology and the costs of associated required building retrofits. Exhibit 3.5 shows key assumptions in the analysis.

Exhibit 3.5 – Holistic Transition key individual dwelling heating technologies cost assumptions, Base case (£/unit, real 2025)

CAPEX element	2025	2030	2040
Air source heat pump – technology cost	7,809	5,076	4,451
Air source heat pump – retrofit cost	5,206	3,384	2,967
Ground source heat pump – technology cost	19,202	14,785	13,633
Ground source heat pump – retrofit cost	8,229	6,337	5,843
Gas boiler[1]	2,812	2,812	2,812

Source: 1. Cost of Domestic and Commercial Heating Appliances, Eunomia, February 2023

3.2.2 Heat networks

In the NESO pathways, a significant proportion of residential housing is expected to connect to heat networks, either low carbon district heating or fossil fuel communal heating.

To calculate the cost of low carbon district heating[30], we have multiplied a cost (£/TWh of heat supplied) by the demand for heating from heat networks (TWh).

The cost of heat networks was derived from existing and under-construction heat network projects[31] and is the same across all NESO pathways and modelled years.

Demand for heating from heat networks was provided by NESO and varies across pathways.

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[29] Low carbon heating in domestic buildings – technical feasibility: cost appendix, Scottish Government, December 2020
[30] Due to data limitations at the time of the work, this only captures the capital costs of low carbon district heating. If fossil fuel communal heating was included, this would increase the costs, particularly in the Falling Behind Scenario.
[31] Heat Networks Investment Project: Case study brochure, BEIS, February 2024 & Heat Networks: 2024 Q4 Pipeline, DESNZ, 2025

Note that this approach models the investment cost as occurring in the year the heat demand occurs. However, investment costs are likely to be incurred earlier.

Non-fuel OPEX costs are calculated by multiplying the heat demand from heat networks by an assumed cost for maintenance (£/MWh).

3.2.3 Energy efficiency measures

To calculate the cost of energy efficiency measures, we have multiplied the uptake of energy efficiency measures by the cost of each type of energy efficiency measure.

NESO provided both datasets. Whereas the number of energy efficiency measures varies by pathway, the cost of each measure is the same across all pathways. Note that NESO assume all energy efficiency measures are applied by 2035, meaning no further energy efficiency costs beyond 2035.

3.2.4 Fuel costs

We multiplied fuel use by the corresponding fuel price to calculate the total fuel costs.

For each FES pathway, NESO provide two sources of fuel demand for the residential sector:

- total residential fuel demand for gas, electricity and hydrogen; and
- residential heating only demand for electricity, hydrogen, gas, oil, bioLPG, biomethane and biomass.

For the fuel cost calculations, we have used total residential fuel demand for gas and residential heating demand for oil, bioLPG, biomethane and biomass.

This assumes that there are no appliances, lighting or cooling fuel demand from oil, bioLPG, biomethane and biomass. Electricity and hydrogen demand are not included as these are included in the supply side costs.

The fuel price used for residential gas is an estimated LRVC, as described in section 1.2.2.2.

3.3 Commercial

A summary of the commercial costs included in the analysis are shown in Exhibit 3.6.

Exhibit 3.6 – Commercial cost components

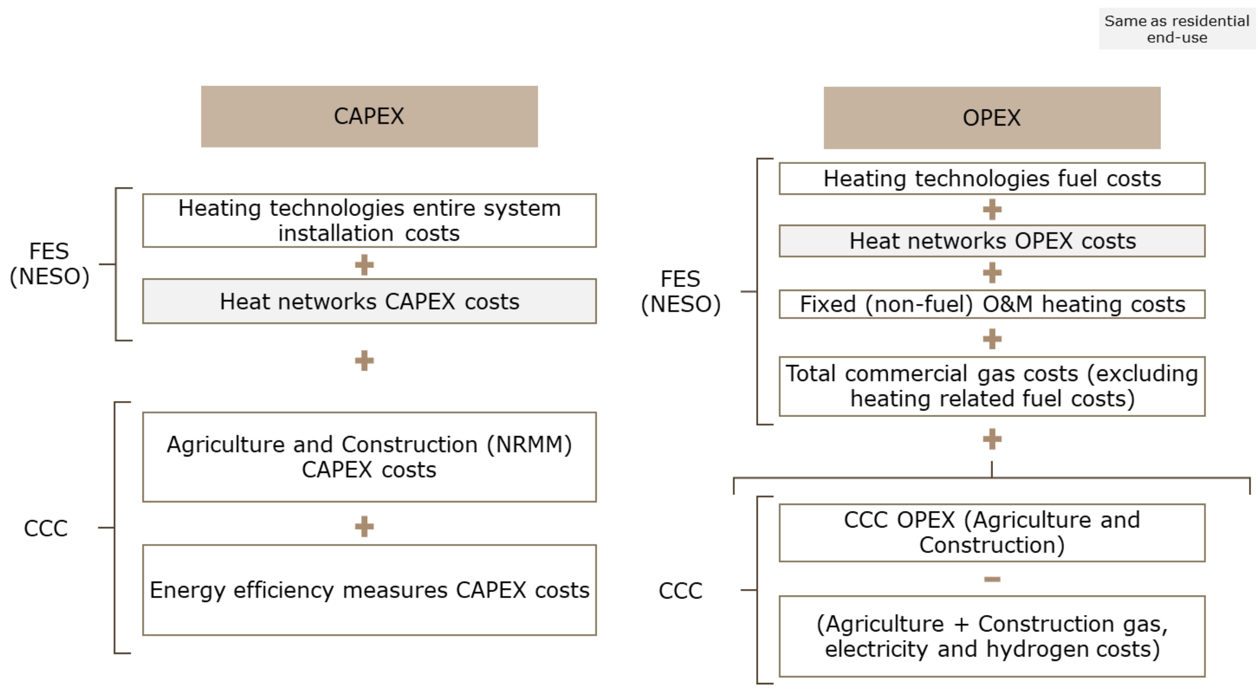
Commercial sectors	Cost components
Non-residential buildings individual heating technologies	CAPEX
	Non-fuel OPEX
Non-residential buildings heat networks	CAPEX
	Non-fuel OPEX
Non-residential buildings energy efficiency measures	CAPEX
Agriculture	CAPEX
	Non-fuel OPEX
Construction	CAPEX
	Non-fuel OPEX
Non-residential buildings (heating, cooling, appliances, lighting) and agriculture and construction	Fuel costs

Notes: This analysis does not include investment and fixed operating costs related to air conditioning, data centres, computing, and catering as these are generally not directly tied to decarbonisation strategies in the NESO pathways. While catering appliances do involve some decarbonisation-related costs (e.g. electrification of cooking), this is a small overall cost and so has minimal impact on the total costs.

Given limited data from the commercial sector, some costs have been taken from the CCC CB7 modelling. This is summarised in Exhibit 3.7.

Exhibit 3.7 – Summary of approach to the commercial sector costs

Agriculture, construction and energy efficiency CAPEX and fixed OPEX costs are taken directly from the CCC CB7.



Notes: NRMM – Non-Road Mobile Machinery. This is a CCC CB7 sub-sector, which we have used for construction costs

3.3.1 Non-residential buildings individual heating technologies

Investment costs for heating in non-residential buildings are calculated by multiplying the annual uptake by a unit cost assumption for each heating technology type.

Annual uptake was provided by NESO.

To determine the cost of an individual installed unit we estimated the average size of each unit (based on fuel use, efficiency and load factor) and multiplied by a cost per kW. Cost assumptions were largely derived from the CCC CB7[32] or BUS Statistics[33]. These costs represent the costs of installation and any building retrofits required.

Fixed (non-fuel use) operating costs represent an annual servicing cost (£/unit), and were calculated by multiplying a £/kW cost (obtained from a publication by the Scottish Government[34]) by the average unit capacity. This was multiplied by the total stock data for each heating technology.

3.3.2 Non-residential building heat networks

The same approach to heat networks in the residential sector was used for the commercial sector. See section 3.2.2 for details.

3.3.3 Non-residential buildings energy efficiency measures

Investment costs for energy efficiency were straight from the CCC CB7[35] (with adjustments for inflation). Note that this is the cost relative to the CCC's baseline, rather than a total cost.

3.3.4 Agriculture and Construction

3.3.4.1 CAPEX

The NESO pathways do not include modelling of the agriculture or construction sector. We have therefore taken investment costs for agriculture and construction (non-road mobile machinery) sub-sectors directly from the CCC CB7 modelling[35] (with adjustments for inflation).

The CCC present these as costs in the CCC's Balanced Pathway scenario in addition to those in the CCC's Baseline scenario. We have therefore only applied this cost as a comparison to the Falling Behind scenario and this is not included in total cost outputs. For each of the net-zero pathways (Holistic Transition, Hydrogen Evolution and Electric Engagement), costs are the same.

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[32] Methodology Report – UK, Northern Ireland, Wales and Scotland carbon budget advice, Climate Change Committee, May 2025
[33] Boiler Upgrade Scheme Statistics: February 2025, DESNZ, March 2025
[34] Technical Feasibility of Low Carbon Heating in Domestic Buildings, Government of Scotland, 2020
[35] The Seventh Carbon Budget Full Dataset, Climate Change Committee, February 2025

3.3.4.2 OPEX

In CB7, the CCC present OPEX costs as a total of fuel and non-fuel OPEX. To avoid double counting of electricity, hydrogen and gas fuel costs, we have subtracted the CCC's electricity, hydrogen and gas fuel costs for these sub-sectors from the CCC's total OPEX for these sub-sectors.

These fuels are excluded because electricity and hydrogen costs are included in the supply side in this analysis and NESO provide total commercial gas demand, including demand from these sub-sectors, which is used in the total fuel cost calculations (see section 3.3.5).

The CCC's agriculture and construction costs of gas, electricity and hydrogen consumption were calculated using the CCC CB7 gross energy demand by fuel (TWh) multiplied by the LRVC per sector (£/MWh) as provided by the CCC in their methodology report dataset[36].

3.3.5 Non-residential total fuel costs

We multiplied fuel use by the corresponding fuel price to calculate the total fuel costs.

For each FES pathway, NESO provide two sources of fuel demand for the commercial sector:

- total commercial fuel demand for gas, electricity and hydrogen; and
- commercial heating demand for electricity, hydrogen, gas, oil, bioLPG, biomethane and biomass.

For the fuel cost calculations, we have used total commercial fuel demand for gas and commercial heating demand for oil, bioLPG, biomethane and biomass. Oil and biomass fuel costs used in the agriculture and construction sectors are included in the OPEX for these sectors (see section 3.3.4).

Electricity and hydrogen demand are not included as these are included in the supply side costs.

The fuel price used for commercial gas is an estimated LRVC, as described in section 1.2.2.2.

3.4 Industrial

A summary of the industrial costs included in the analysis are shown in Exhibit 3.8. Due to data limitations, the industrial sector primarily relies on cost from the CCC's CB7 study for investment and non-fuel OPEX.

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[36] The Seventh Carbon Budget methodology report (costing analysis), Climate Change Committee, May 2025

Exhibit 3.8 – Industrial sector cost components

Industrial sectors	Cost components	Main data source
Total industry	CAPEX	CCC CB7
	Non-fuel OPEX	CCC CB7
	Fuel costs	FES

Notes: The only data NESO produce about the industrial sector is the fuel use.

3.4.1 CAPEX

For CAPEX, we use the CCC CB7 'additional capital expenditure[37]' for industry as a proxy for the additional CAPEX costs in the net-zero NESO pathways relative to the Falling Behind scenario. This cost is only included in the outputs where costs are presented as a comparison to the Falling Behind scenario.

We exclude the 'Non-road mobile machinery' CAPEX from the total 'Industry' CAPEX as this is included in the Commercial category.

3.4.2 OPEX

CCC provide additional OPEX costs as a total of fuel and non-fuel OPEX. To avoid double counting of fuel costs, we have subtracted the CCC's fuel costs for industry from the CCC's total OPEX for these sub-sectors.

Electricity and hydrogen costs are included in the supply side in this analysis. NESO provide total industry gas, bioenergy and oil demand which is used in the total fuel cost calculations (see section 3.4.3).

The CCC's fuel costs for industry were calculated using the CCC CB7 additional energy demand by fuel (TWh) multiplied by the CCC's LRVC (£/MWh) for that fuel.

We have also excluded the 'Non-road mobile machinery' OPEX costs from the total 'Industry' OPEX as this is included in the Commercial category.

This resulting cost is the fixed OPEX for the relevant industrial sub-sectors compared to the Baseline scenario. This is therefore only included in the NESO FES outputs where costs are presented as a comparison to the Falling Behind scenario.

3.4.3 Fuel costs

To calculate fuel costs in the industrial sector for each fuel type, we have multiplied the total fuel use per fuel type by the relevant fuel price.

Total fuel use for gas, bioenergy and oil for the industrial sector are provided by NESO by pathway as an output of FES.

[37] The Seventh Carbon Budget, Full Dataset, Climate Change Committee, February 2025

The fuel price used for commercial gas, oil and bioenergy is an estimated LRVC, as described in section 1.2.2.2.

Electricity and hydrogen demand are not included as these are included in the supply side costs.

3.5 Aviation, shipping and rail

A summary of the aviation, shipping and rail costs included in the analysis are shown in Exhibit 3.9. Due to data limitations, this sector primarily relies on cost from the CCC's CB7 study.

Exhibit 3.9 – Sector cost components

Sectors	Cost components	Main data source
Aviation, shipping and rail	CAPEX	CCC CB7
	Non-fuel OPEX	CCC CB7
	Fuel costs	CCC CB7

Notes: NESO does not provide any data on aviation, shipping and rail.

3.5.1 CAPEX and non-fuel OPEX

We have taken the capital and operating costs for shipping, aviation and rail directly from the CCC CB7. We have used the same costs across all NESO pathways.

This is most comparable to the difference in costs between the Pathways and the Falling Behind scenario – we do not have costs for the Falling Behind scenario.

3.5.2 Fuel costs

The CCC OPEX cost includes a fuel cost associated with the electricity / hydrogen demand. To avoid double counting, we have removed these fuel costs from the CCC's OPEX costs by multiplying the electricity / hydrogen demand provided by the CCC with the corresponding LRVC[38] and removing from the OPEX costs.

3.6 Engineered Removals

A summary of the engineered removal costs included in the analysis are shown in Exhibit 3.10.

[38] The Seventh Carbon Budget methodology report (costing analysis), Climate Change Committee, May 2025

Exhibit 3.10 – Sector cost components

Sectors	Cost components
BECCS for biofuels	CAPEX, OPEX, fuel costs
DACCS	CAPEX, OPEX, fuel costs
BECCS Enabled Hydrogen	CAPEX
	Non-fuel OPEX
	Fuel costs
Power Sector BECCS	CAPEX
	Non-fuel OPEX
	Fuel costs

Notes: For power sector BECCS and BECCS enabled hydrogen, NESO provided data for bottom-up modelling. However, for BECCs for biofuels and DACCs, only CO_{2e} abated was provided.

3.6.1 BECCS for biofuels and DACCS

We have used an average abatement cost / tonne of CO_2 for each of DACCS and BECCS for biofuel and multiplied by the relevant tonnes CO_2 abated.

Tonnes CO_2 abated per year is provided by NESO for each of the NESO pathways.

The abatement cost / tonne of CO_2 is taken from the CCC CB7 report[39]. The CCC have calculated this by dividing the net present value of a unit's lifetime cost by the net present value of its lifetime abatement. This approach therefore represents the annualised costs.

This includes the capital expenditure driven by plant construction and carbon capture infrastructure and operating expenditure, including fuel costs.

Despite the electricity costs being included in the supply side, we have also included the electricity cost here. This is because NESO and the CCC have adopted differing assumptions regarding the operation of DACCS. Whereas the CCC assumes DACCS runs baseload, NESO assumes DACCs will run on curtailed renewable energy. The electricity costs in the NESO scenario are therefore essentially free, but with this you would expect lower load factors and therefore higher capital costs. However, if DACCS runs baseload, operating costs would be expected to be higher and the power sector would need to be expanded to accommodate this extra demand, hence leaving in the electricity costs.

[39] The Seventh Carbon Budget, February 2025, Climate Change Committee, https://www.theccc.org.uk/wp-content/uploads/2025/02/The-Seventh-Carbon-Budget.pdf

3.6.2 BECCS enabled hydrogen

The calculation approach for BECCS enabled hydrogen is the same as for other hydrogen production technologies (see section 2.2.1). However, the CAPEX, OPEX and fuel costs are assigned to Engineered Removals rather than the hydrogen sector.

3.6.3 Power sector BECCS

The calculation approach for power sector BECCS is the same as for other electricity generation technologies (see section 2.1.1). However, the CAPEX, OPEX and fuel costs are assigned to Engineered Removals rather than the power sector.

Note that for both the hydrogen and the power sector, the cost of the infrastructure associated with the transport and storage of carbon are included in the power sector as carbon networks have been included as one cost.

Annex A Glossary

Acronym / word	Meaning
ASHP	Air Source Heat Pump
BECCS	Bioenergy with Carbon Capture and Storage
BEV	Battery Electric Vehicle
CAPEX	Capital costs
CCS	Carbon capture and storage
CO2e	Carbon dioxide equivalent
DACCS	Direct Air Carbon Capture and Storage
DNO	Distribution Network Operator
EE	Electric Engagement
FB	Falling Behind
FES	Future Energy Scenarios
Fixed OPEX	Fixed annual operating and maintenance costs
GB	Great Britain
GSHP	Ground Source Heat Pump
HE	Hydrogen Evolution
HGV	Heavy Goods Vehicle
HT	Holistic Transition
ICE	Internal Combustion Engine
LRVC	Long run Variable Cost
NESO	National Energy System Operator
NRMM	Non-Road Mobile Machinery
O&M	Operations and maintenance
OPEX	Operating costs
Other variable OPEX	Costs dependent on the outputs, excluding fuel costs
Stock	Total number of units in a year
Uptake	Additional units commissioned in a year + replacements of existing units
V2G	Vehicle to Grid

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