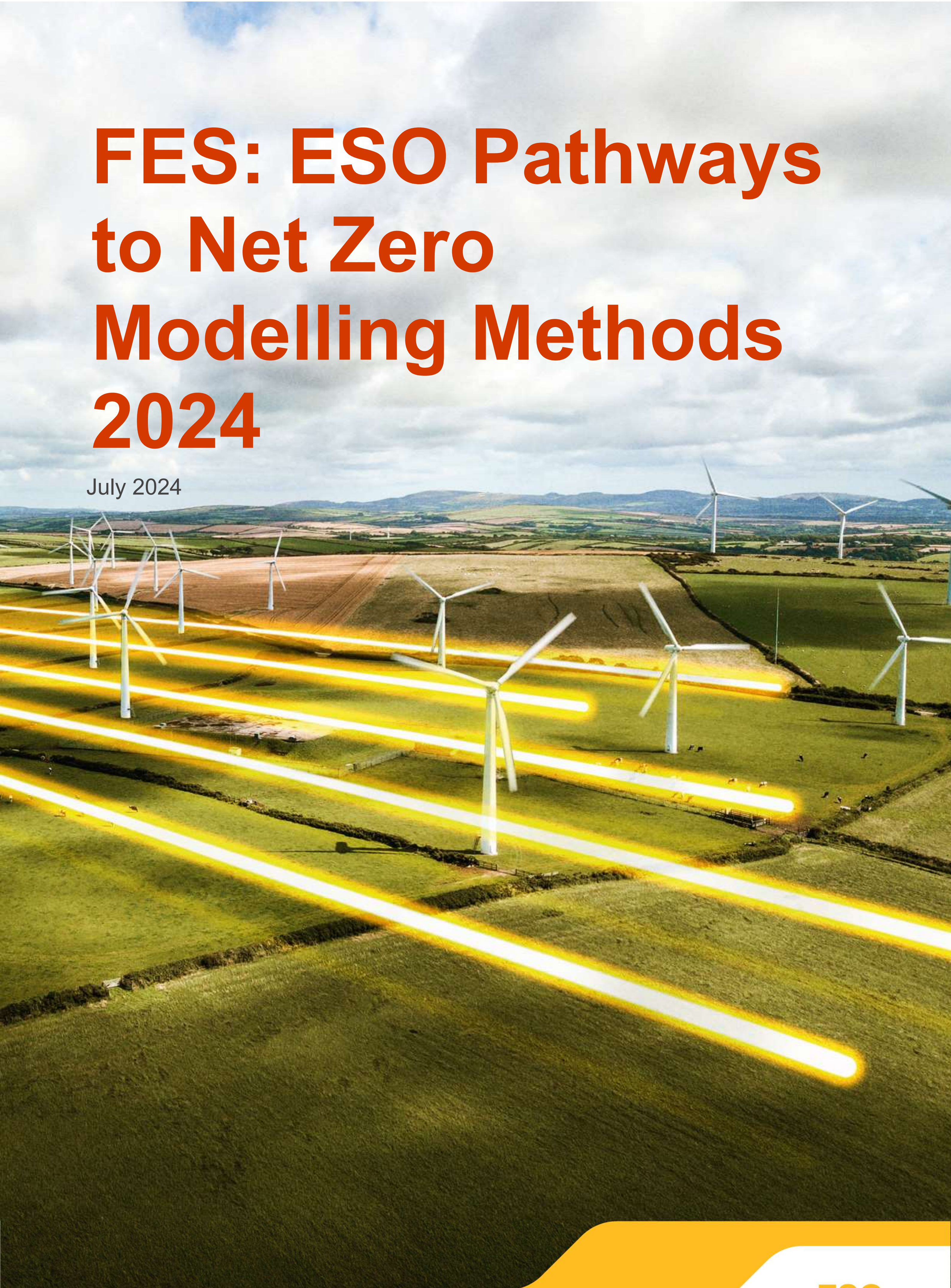
FES: ESO Pathways to Net Zero Modelling Methods 2024

July 2024



Contents

Contents 2
Introduction 3
General Approach 4
Modelling Overview 5
Changes to our modelling this year 6
Five-Year Forecast 7
Economic Modelling 8
End consumer demand 9
Whole system demand 21
Electricity supply 28
Natural gas supply 36
Bioenergy 39
Hydrogen (H_2) supply 39
Electricity supply model 40
Emissions 40
Regional Electricity Demand 43
Appendix A 46
Annex – LOLE step by step guide 47

Introduction

Our **Modelling Methods** publication is just one of a suite of documents we produce as part of our Future Energy Scenarios: ESO pathways to net zero ("The Pathways") process. A huge amount of work including modelling, analysis and interpretation goes into the production of the main document. For ease of use, we only highlight significant changes to our modelling methods in the main Pathways document. Alongside this publication, we have the **Pathway Framework** that details all the assumptions and levers that are used as input into our models. Our **Data Workbook** contains all the outputs from the numerous models, the detailed tables, graphs and charts. We also publish a summary document, Future Energy Scenarios: pathways at a glance, and a number of other items. For more information and to view each of these documents visit our website: nationalgrideso.com/future-energy/future-energy-scenarios

As our modelling continues to evolve, we will update this document to reflect those changes, ensuring our latest methods, models and techniques are shared. As with our other FES & Pathways documents we welcome your feedback, please contact us at: fes@nationalgrideso.com

Process chart keys

The keys to the process charts used in this document are summarised below:

General Approach

The Pathways are not a single prediction of what the future of energy will be, but they are intended to form a range of possible routes to achieve net-zero carbon emissions based on a set of defined assumptions. These pathways reflect the input from a range of stakeholders which inform the assumptions and levers with the various models we use to produce the outputs. More information on these can be found in our "Pathway Framework" document which is published alongside this one on the ESO website.

Figure 1: Overview of general approach to our Pathway modelling

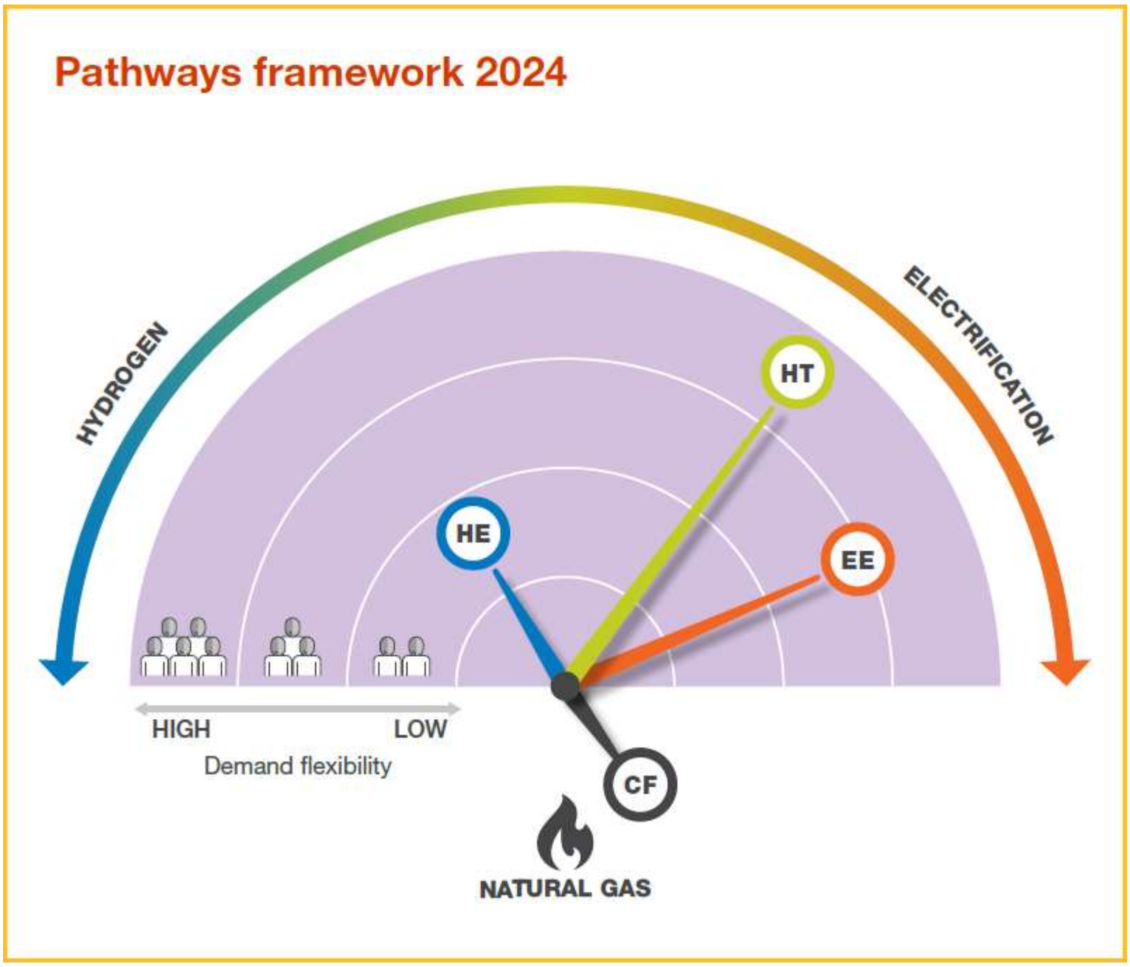


Figure 2: Pathways 2024

Once the pathways to be investigated have been agreed, we determine the assumptions to use in our modelling and the "levers" within the models that can be adjusted to reflect those routes. As we carry out our modelling, we review the results to ensure that they are credible, updating the levers and assumptions, if necessary, to arrive at a range of results that fit within the defined framework with clear differentiation between individual pathways and the possible outcomes that could be experienced as we approach 2050.

More information on the pathways and assumptions can be found in the "Pathway Framework" document published on the Future Energy Scenarios website[1].

Modelling Overview

Our modelling typically starts with a view of how demand will change into the future. This is conducted through a number of sub-sector models which ultimately inform the levels and profiles of electricity, natural gas, hydrogen and other vectors. This view of demand, and how much of this can be altered by instruction or short-term price signal, provides the target that supply side models must meet in optimising production of energy, dispatch of assets and storage utilisation. Some supply side modelling further informs the total demands for other models, such as how much natural gas is required for power production. This results in some feedback loops between the demand and supply stages and iterations of the overall results.

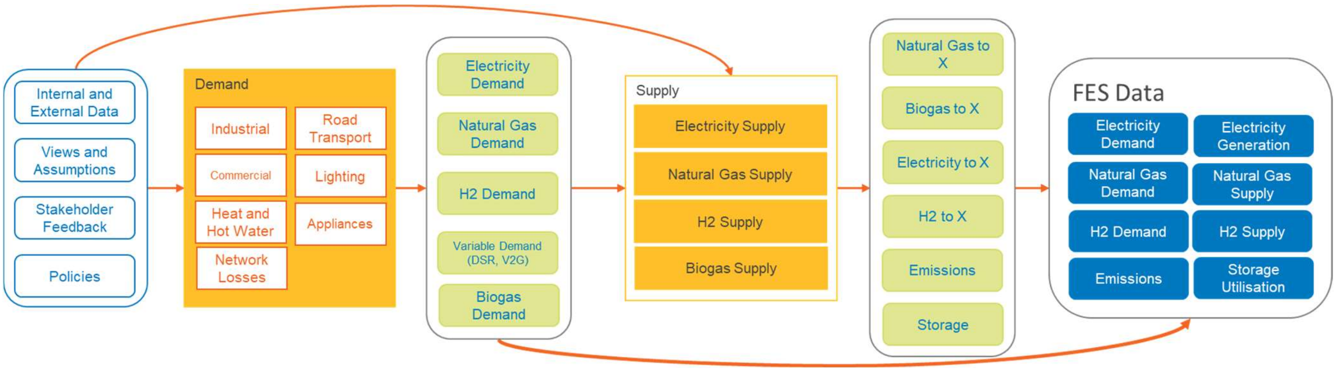


Figure 3: Overview of Pathway Modelling Stages

We use a combination of information gathered through stakeholder engagement, research, industry news and policy tracking and third-party data providers in our analysis. It is the role of our experienced analysts to determine the inputs to our modelling based on the above sources. Our modelling inputs and outputs go through extensive quality checks, during which our analysts use their wide-ranging expertise to review the data produced. Where there are discrepancies in the modelling outputs, these are reviewed, and a decision is taken on the corrective action to be made. This can include but is not limited to correction of inputs and re-running models or modification of outputs based on evidence from the data sources.

Because of the staged nature of the modelling processes, some inputs used for energy demand modelling can be different to those used in energy supply modelling. This can happen because many energy demand outputs must be fixed early in the modelling cycle, yet energy supply and dispatch modelling may need the most up to date outlooks for quantities such as future wholesale prices. Decisions are taken when notable discrepancies arise. For the example of changing energy prices, these don't necessarily require reviews of the forecasts of energy demands, because many consumers fix their costs in advance. Similarly short-term changes should not lead to significant changes in long term outlooks for energy demand. However, we always keep changes and discrepancies under review if they occur.

[1] nationalgrideso.com/future-energy/future-energy-scenarios

Regional Results

Our current modelling is produced by multiple different tools that we have produced, developed, or procured since the Future Energy Scenarios were first published. As these have evolved and been replaced over time there are different levels of regional granularity across these and we carry out further work to break GB level results into smaller areas, such as Grid Supply Point for electricity demands.

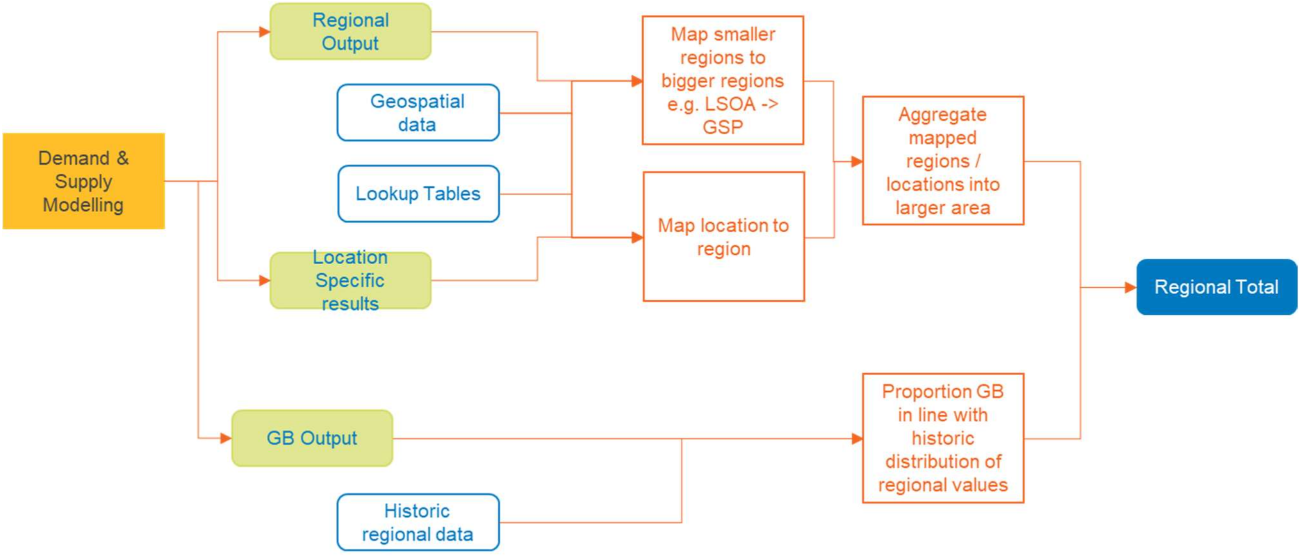


Figure 4: Creation of Regional Results

More detail on how we create the regional electricity values is included in the “Regional Electricity Demand” section of this document.

Changes to our modelling this year

This year we have introduced specific developments in how we model The Pathways. In summary these are:

- Plexos dispatch model has now fully replaced BID3 within the Pathway modelling
- Using the “Capacity Expansion Module” to optimise the build of electricity and hydrogen supply assets, along with associated storage, for the pathways from 2030 onwards on a techno-economic basis
- Re-derived the coefficients within the Industrial and Commercial model to reflect changes in the relationship between energy use, prices, and the wider economy since this model was originally created
- Made change to how we model demand from data centres:
  - We have increased the coverage of the information used in the data centre modelling to model data centre demands around cities such as Manchester, Newcastle and Leeds
  - We have improved how we model potential data centre capacity out to 2050 by applying a linear forecast for data centre growth for the period beyond the latest planned connections
- Demand Side Response (DSR) modelling has been improved to take better account of embedded generation and EV flexible capacity that had been classified as DSR historically. This gives a more realistic growth vector for the sector. The behavioural drivers for Electric Engagement have

also been adjusted to match Holistic Transition to represent a more equal drive for flexibility improvements in both pathways

- Modelling of lighting demands has been enhanced such that:
    - Natural illumination, housing types, population densities and statistical requirements for lighting have been utilised to create a new model of demand from lighting
    - The sources of population and housing data have been aligned with those used in the Spatial Heat Model to ensure consistency
    - Data from the European Product Registry for Energy Labelling database has been used to provide a comprehensive list of light bulb energy usage from products currently on the market
    - The method of applying uncertainty to lighting output efficiency of bulbs in use across the entire population has been updated, based on results from a study undertaken in January 2024
- We bolstered our hydrogen supply modelling by expanding our peer-reviewed hydrogen production asset database to provide a fact-based foundation on which the hydrogen supply CEM could expand. The database allowed us to develop a strong understanding of what projects, locations, scale of production, and type of technology could be realistically developed in the next decade
- Added the ability for the Spatial Heat model to take known locations for hydrogen production from the hydrogen production asset database and use these as “seeds” for growth of hydrogen networks

Five-Year Forecast

We include a Five-Year Forecast (5YF) within the Data Workbook. This is developed with different assumptions to the pathway-based results. It represents our best view for demand and supply over the short to medium term. The pathways reflect a broader range of possibilities around this view, projecting beyond the first years out to 2050.

Uncertainty Modelling

There is significant uncertainty for a credible single view of the future in the timeframe which the Pathways consider, making validation of individual technologies difficult. Instead, we use a combination of in-depth analysis by our team of experienced analysts and stakeholder feedback to develop pathways which represent the potential Pathways that the 2050 energy system could fit into.

To better understand the impacts of changes in short-term demand forecasts we have utilised uncertainty distributions to the single point forecasts of the “Five-Year Forecast” of demand.

This was achieved by reviewing the ranges of modelling error with the relevant analysts and fitting probability distributions around these. These ranges and distributions were arrived at through comparison to historic performance against outturns, sensitivity to changes in input parameters and validated by the internal experts to ensure that they represented the level of uncertainty appropriate to that model. These distributions were then used within Monte Carlo simulations with further expert review of the ranges generated, at both individual model level and in combination, to validate that these were credible.

Economic Modelling

The modelling that is used in producing the pathways utilises cost elements and techno-economic information to create the demands and supply solutions. Some of the areas where this is included in the modelling are:

- Road Transport
    - Implements a “Bass diffusion” model for the roll out of new technologies and incorporates a total cost of ownership basis for numbers of new vehicles within the modelling
- Spatial Heat Model
    - Incorporates a total cost of ownership approach to heating technology uptake for each building archetype within a climate zone. This consists of capital costs for the product, fuel costs to run and any incentives or grants available. Functionality to include the costs for hydrogen and district heating network build are included within this. The costs of energy efficiency measures and any thermal storage are included within the total cost of ownership
    - The model also has functionality to reflect “willingness to pay” of different consumers which affects uptake based on payback period
    - Operation profiles for each technology within the model are influenced by costs. For example, when a Time of Use Tariff price profile is implemented, heat pump demand is shifted away from peak times through thermal storage or hybrid fuel switching to avoid peak prices. This affects the flexibility within different pathways
- Industrial and Commercial demand
    - Initial stages use an econometric model to represent the relationships between energy use, the wider economy (measured by gross value-added) and energy prices across the modelled sub-sectors
    - Later stages incorporate the cost of changing to alternative technologies and pay-back periods for these where commercial and industrial sectors are moving to low carbon alternatives
- Supply modelling
    - New build of electricity generation, hydrogen production, and storage assets post 2030 are optimised within the Plexos model to deliver the lowest overall cost solution given the expected demand and any constraints placed on that solution
    - Running of electricity generation and hydrogen production, along with utilisation of storage assets, is optimised to meet a given demand in each hour of the year at the lowest overall cost within the bounds of any other constraints placed on the that solution

In each case, the input assumptions on which these models run can vary between pathways and certain functionality may or may not be used in the final results.

End consumer demand

This section describes the methods used to model energy demand. Energy demand modelling is split into six components:

1. Electricity demand overview
2. Gas demand overview
3. Industrial & Commercial (I&C) demand
4. Space Heating & Hot water
5. Residential demand
6. Road transport demand

Electricity demand overview

Our future projections for overall electricity demand are created using forecasts and assumptions from other models used in The Pathways e.g.

- Industrial & Commercial demands
- Residential appliances, lighting, and air conditioning
- Heat and district heat
- Road and rail transport

As per Figure 5 below, the components are combined to provide a view of the underlying electricity demand on the system before further information is added to calculate the demand met from the transmission system, or the whole system demand. These additional components include the losses from the transmission or distribution of electricity, exports via interconnectors to other countries and the amount of consumer demand that can be altered in response to price signals or is met through generation sources not connected to the transmission network. This area also includes the electricity needed to produce hydrogen or other non-consumer loads.

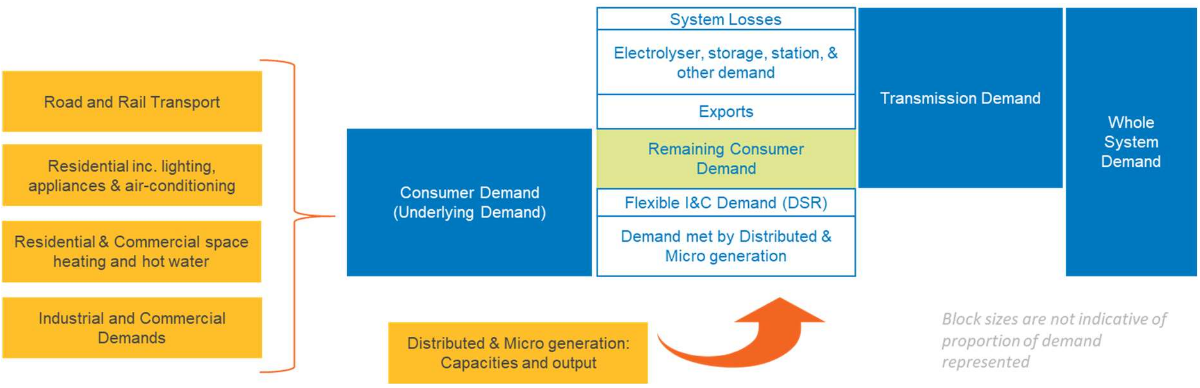


Figure 5: Overview of electricity demand components

These demands are further divided in the total electrical energy needed to meet all demand in a given year, which we refer to as “Annual demand”, and the demand at the maxima/minima points in the year known as the “Peak” or “Minimum” demand respectively.

Annual demand

In the “The Energy Consumer” chapter of The Pathways document, we consider “end consumer demand,” regardless of where (transmission, distribution or on site) the electricity is generated. Demand is weather corrected to reflect a “normal” set of seasonal conditions, removing the impact of abnormal weather events. Moreover, it **does not include** losses, exports, station demand, pumping station demand or other forms of storage demand. Annual losses data is in the data workbook published alongside the other documents.

When we illustrate residential, I&C, heat, and transport components we have not assigned the distribution or transmission losses. We estimate these losses at the system level to average around eight per cent. Where annual electricity demands are discussed, it is normally given in financial year.

We do not have direct information on the make-up of demand, so these components must be estimated as described in the following sections:

- The Department for Energy Security & Net Zero (DESNZ) publishes monthly sales data for residential and I&C demand and this forms the basis of our demand estimates. For each annual The Pathways publication, the latest Energy Trends data[2] is used and this frequently brings small revisions to history
- The Energy Trends residential annual data is annually weather corrected, using information from the Balancing and Settlement Code administrator, Elexon
- Industrial & Commercial demand is assumed to make up the remaining underlying demand and is split using ratios from Energy Trends
- Estimated losses are calculated from internal data sources and may differ from other publications

Demand components - historic

We calculate underlying historic demand as follows:

- We start with National Grid transmission system data. We take GB historic, weather corrected, metered “National Demand”. This is the total demand seen from the electricity transmission network, excluding interconnector exports, station demand and pumping demand
- Weather corrected data is published in the Electricity Ten Year Statement (ETYS)[3] and The Pathways data tables
- Out-turn “National Demand” data is published on our website[4]
- We then add an estimate of the output from non-transmission generation, by taking our view of capacity of distribution connected generation, including an estimate for those that are individually <1MW in size
- Output across the year and at the time of peak demand relative to the installed capacity (i.e. load factor) for these are derived from a number of sources:
    - Our own data (half hourly transmission generation, solar and wind data)
    - ElectraLink metering data
    - The Digest of UK Energy Statistics (DUKES)[5]
    - Datasets purchased from third parties

To get historic peak demands for the components of demand:

- We take annual, weather corrected, Energy Trends[6] residential demand data
- We create a peak using weather corrected residential demand data from Elexon
- The remaining peak demand is assumed to be I&C
- Remaining peak demand is split using Energy Trends proportions

[2] https://www.gov.uk/government/collections/energy-trends
[3] https://www.nationalgrideso.com/research-publications/etys/documents
[4] Data search | ESO (nationalgrideso.com)
[5] https://www.gov.uk/government/collections/digest-of-uk-energy-statistics-dukes
[6] https://www.gov.uk/government/collections/energy-trends

Demand components – summer

Summer minimum demands (looking at minimum underlying demand on the system and the impact of solar) are created in a similar fashion to peak. The differences are:

- Summer demands take observed historic demand as a start point
- Solar generation has a significant effect on demand as installed capacities increase
- No demand side response is currently assumed due to little information on summer behaviour, particularly demand turn-up
- Storage is modelled as demand, rather than generation, at times of system minimum demand

Gas demand overview

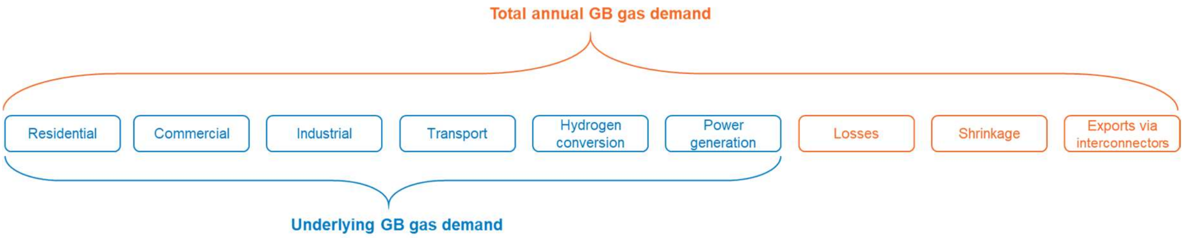


Figure 6: Total annual demand is underlying GB demand plus losses, shrinkage, and exports via interconnectors

The annual gas demand is defined as the total Local Distribution Zone (LDZ) consumption, plus the consumption at sites that are directly connected to the National Transmission System (NTS). Total GB annual gas demand includes gas exported to Ireland via the Moffat interconnector and exports to the continent via the Interconnector and BBL pipelines to Belgium and the Netherlands, respectively. In the energy demand section of The Pathways document, demand only refers to underlying GB demand (excluding interconnector exports) whereas in the supply section gas supplies are matched to total.

As highlighted by the 1st March 2018 “Beast from the East”, extreme cold weather events could still occur on a fairly regular basis even in a warming climate. It was therefore agreed that it is more appropriate to use the non-climate change adjusted weather data for modelling peak gas demand whilst we continue to use climate adjusted data for modelling annual and seasonal normal demand.

Total underlying GB gas demand is put together by individually modelling the following gas demand components: residential, industrial, commercial, transport, and gas for power generation. These components are separated into demand which is connected at distribution and transmission level. We also model the gas demand required for the conversion to hydrogen where this is appropriate to the pathway.

Exports to Ireland and continental Europe as well as NTS and LDZ shrinkage are added to underlying GB demand to get to total gas demand. Forecasts of gas exports from GB to Ireland (inc. Northern Ireland & Isle of Man) are based on Gas Networks Ireland’s Network Development Plan 2023[7] and the Northern Ireland Gas Capacity Statement 2023-24 to 2032-33[8], which forecast gas demand over the next 10 years. Long term projections to 2050 are developed by estimating the relative speed of decarbonisation of underlying sectors, aligned with decarbonisation targets and forecasts of indigenous supply.

Gas demand for power station generation is produced from the pan-European dispatch tool which we use which produces an hourly dispatch for the GB electricity system. This is covered in more detail within the electricity supply section.

Losses, and gas used for operating the system, (commonly referred to as shrinkage) are included at the total system level.

[7] https://www.gasnetworks.ie/corporate/company/our-network/network-development-plan/
[8] https://gmo-ni.com/assets/documents/NIGCS-23-24-Report-Final-v3-min.pdf

All values are weather corrected where appropriate to ensure we don't allow more extreme weather to skew the results. Peak gas demand is calculated for a 1-in-20 day, as described in our Gas Demand Forecasting Methodology[9].

Gas for Hydrogen conversion

Natural gas use for hydrogen conversion is modelled from the total hydrogen demand values from across our heating, industrial (processes), transport, and generation demand models. The source of the hydrogen is based on framework assumptions for The Pathways and the hydrogen supply modelling described later in this document. These are in turn informed by the research and stakeholder engagement we conduct each year. Once we know how much hydrogen is needed, and how it is assumed to be produced, we can work out the natural gas required to produce the hydrogen. For hydrogen supplied through methane reformation processes, a projected conversion efficiency, combining process efficiency and shrinkage from the plant's own use fuel determines the natural gas requirements within the hydrogen supply modelling.

Industrial & Commercial demand

Our I&C demand model forecasts natural gas, hydrogen, and electricity demand for 24 sub-sectors of I&C activity including offices, hotels, retail, agriculture, manufacturing, construction, and high intensity production processing. An overview of this model is shown in Figure 7, below.

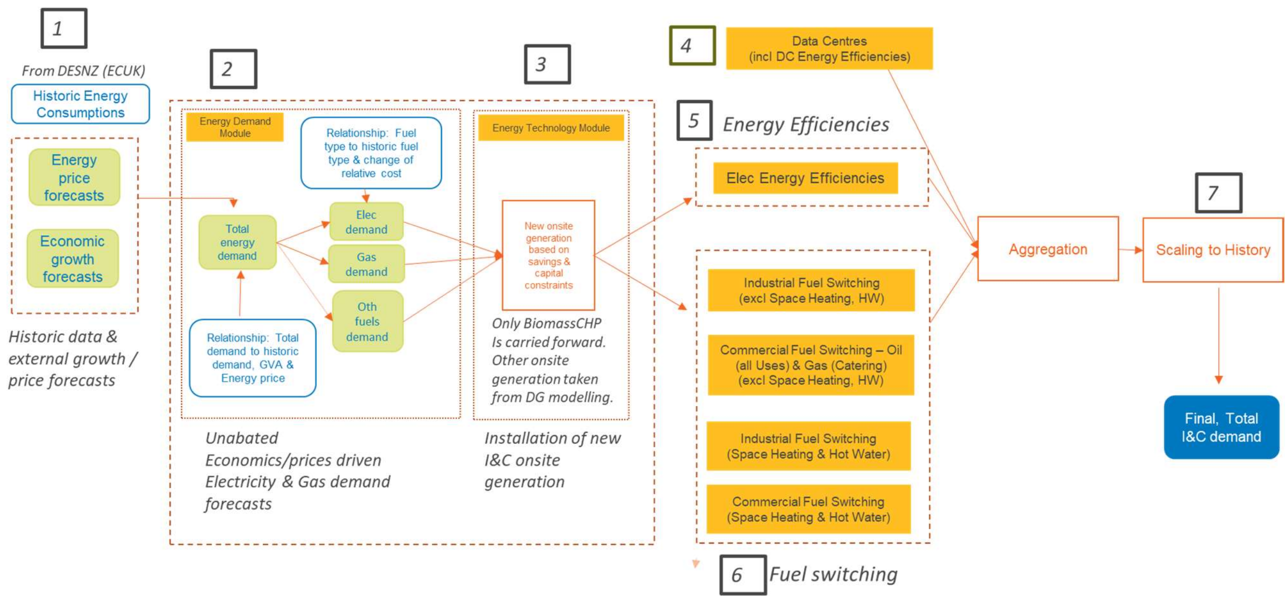


Figure 7: Model for Industrial & Commercial demand.

The initial parts of the model (represented by items 1 and 2 in the figure above), use sub-sector level econometric relationships between historic total energy demand and economic output and energy prices. Feeding into this are the latest historic energy demands, as well as updated projections of economic growth for each sub-sector (represented by Gross Value Added) as well as retail and wholesale energy price forecasts.

The typical effective energy price paid within our econometric model is a weighted three-year average of the current year's energy prices and the two previous years. We also model the sensitivity of energy demand to energy prices, noting that businesses often pass through a proportion of their costs (inflation).

[9] https://www.nationalgrid.com/sites/default/files/documents/8589937808-Gas%20Demand%20Forecasting%20Methodology.pdf

The forecast total energy demands are then split into electricity, natural gas and other fuel-types, according to a historical relationship between fuel-type shares and energy prices. This set of fuel projections represent unabated energy demand forecasts, as shown as item 2 in the figure above.

A further module (represented by item 3 in the above), then studies the economics of installing individual technologies (such as Biomass CHP (Combined Heat and Power)) to determine if there is a case for building new on-site generation in order to reduce costs and future energy consumptions.

The further three modules in the I&C modelling system consider the electricity consumption of data centres (item 4), future electrical energy efficiency improvements (item 5), and fuel switching away from fuels such as natural gas and oil to clean fuels such as electricity and hydrogen (item 6).

The final module (item 7) then completes the aggregation, per fuel, of individual sub-sector forecasts, The latest DESNZ Energy Trends energy outturns are then added, to scale the forecast time-series appropriately.

Data Centre Demand

For The Pathways 2024, we have updated our data centre model by engaging with stakeholders to understand the latest data and trends and changed our forecasting methodology to reflect the insight gained. We used information from Distribution Network Operators (DNOs) and Transmission Owners (TOs) to model the extent of planned connections and their geographical distribution, and then extrapolated these predictions assuming a continuous growth in data centre demands towards 2050. The results have been successfully benchmarked against several industry forecasts and case studies from other European TSO's.

We also account for the fact that some of the new standalone data-centre energy demand will occur because of a migration and hence reduction in energy demand from on-premises I&C computing infrastructures.

Residential demand

Residential demand is the energy used in our homes and is affected by our activities and choices. Individually, these choices can vary dramatically but tend to form relatively predictable patterns.

A key driver of residential demand is simply how many people and houses there are in the country. Our base housing and population assumptions, developed from analysis from Oxford Economics, are consistent across our modelling pathways.

We create residential electricity demand from individual data sources which are then summated to a national level and use deterministic pathway modelling where we wish to illustrate policy outcomes, or current social trends, which may not be reflected in historic data.

The component parts we use to model residential energy demand in this way are:

- Appliances
- Lighting
- Insulation
- Air conditioning
- Home energy management systems
- Heating technologies (see Space heating and hot water)

For each component part, we use historical data, where available, as our starting point. The main source is DESNZ's Energy Consumption in the UK[10] data. We also gather information on mobile phones, tablets and wi-fi routers from Ofcom's Communications Market Reports.[11]

[10] Energy Consumption in the UK, https://www.gov.uk/government/collections/energy-consumption-in-the-uk
[11] https://www.ofcom.org.uk/research-and-data/multi-sector-research/cmr

Appliances

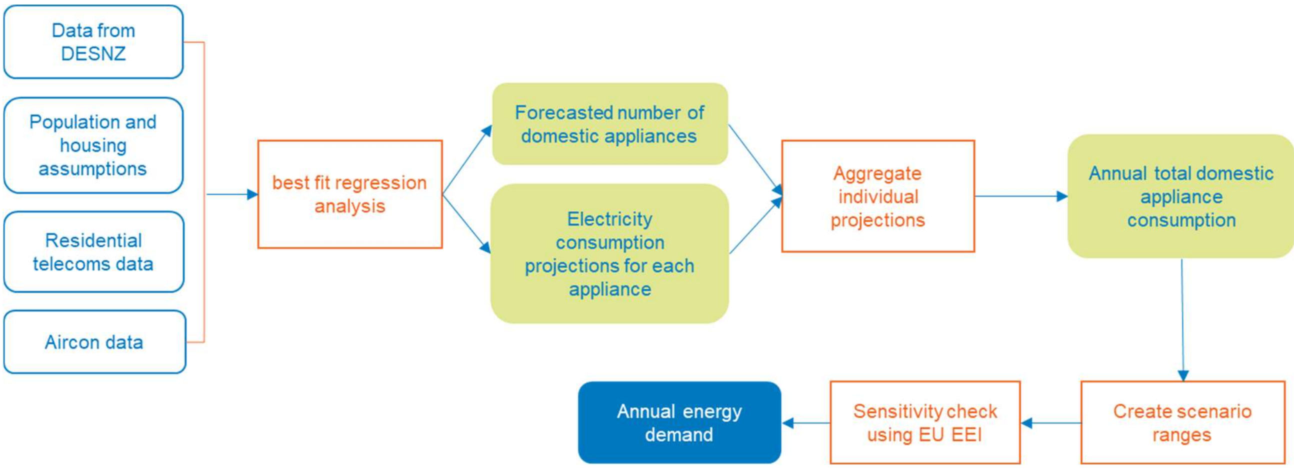


Figure 8: General appliances model

For demand from appliances, we create projections of annual energy demand using:

- Household projection data provided by external consultants
- Regression analysis, based on 5 to 20 years of historical government ECUK data. The length of history used and the confidence interval selected depends on the data quality
- Deterministic factors like social trends, government policy or global events
- Outcomes from reported external projects and stakeholder engagement

The source data used in these projections is cleansed to remove outliers. We benchmark these against stakeholder feedback and trial outcomes. We adjust each projection with our pathways' assumptions to create the results for each component.

Lighting

Residential light modelling uses Energy Consumption in the UK (ECUK) data[12] to model possible outcomes in demand from light.

The current lighting model is based on the outputs of the components highlighted below, which are in turn combined to produce a probabilistic lighting energy forecast for specified regions and time intervals.

The components:

Daylight Hours and Weather effect, this calculates the number of hours that natural light occurs daily, based on the date and global position, before adding light variance based on random historic weather data.

Buildings and Population, databases containing this information are queried to establish housing types and population densities, for specified areas.

Lighting Requirements, uses tables of lighting data for household and recreational tasks to uncover the average light intensity required in each room of the house.

Energy Efficiency and Demand, uses current commercial information, to determine the energy use of light bulbs across different types and technologies.

Building Utilisation, applies a study by Loughborough University of how various buildings are utilised throughout the day.

[12] https://www.gov.uk/government/collections/energy-consumption-in-the-uk

Space heating and hot water

Heat is a major component of end consumer demand and incorporates both heat to warm the home or workplace (space heating) and provide hot water plus heat for I&C processes (process heat).

Process heat demand is covered within our Industrial & Commercial model described earlier in this document. Space heating, and heat to produce hot water, are covered by the Spatial Heat model introduced in FES 2021. This model was developed by Element Energy, National Grid & National Grid ESO through Network Innovation Allowance funding[13].

Simplistically, the spatial heat model carries out the steps in Figure 9, below.

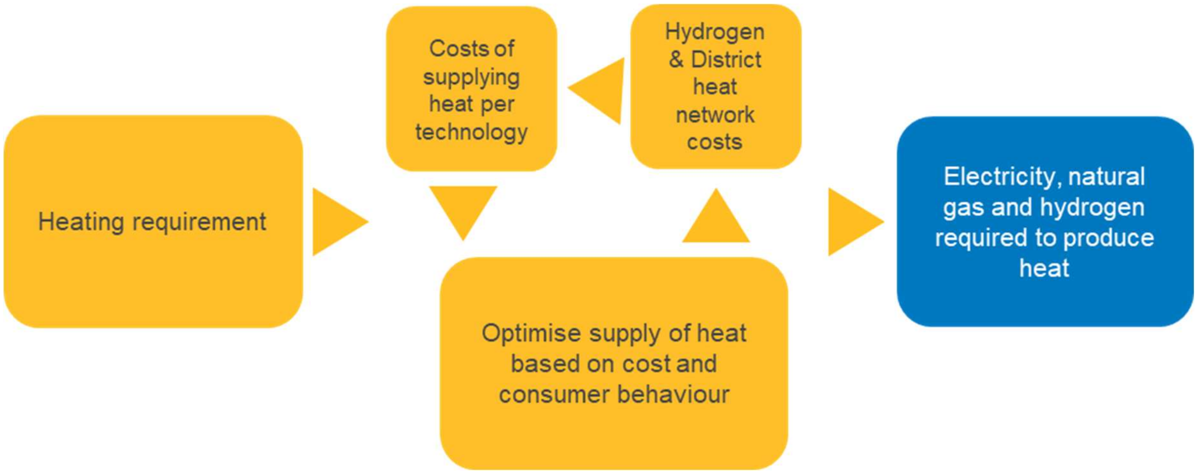


Figure 9: Overview of Spatial Heat model

Heating Requirement

Domestic and non-domestic heating requirements are calculated based on building types and associated efficiencies, the time-of-day heat is required, and climate data. These are performed at the level of Lower Layer Super Output Areas (LSOA) in England and Wales and the equivalent Data Zone (DZ) in Scotland. These areas are defined by the Office of National Statistics (ONS).

New build and demolition of properties are represented through growth rates input to the model for each region. New properties receive one of the input-defined technologies within the model settings in line with the pathway assumptions.

[13] https://smarter.energynetworks.org/projects/nia_nggt0154/

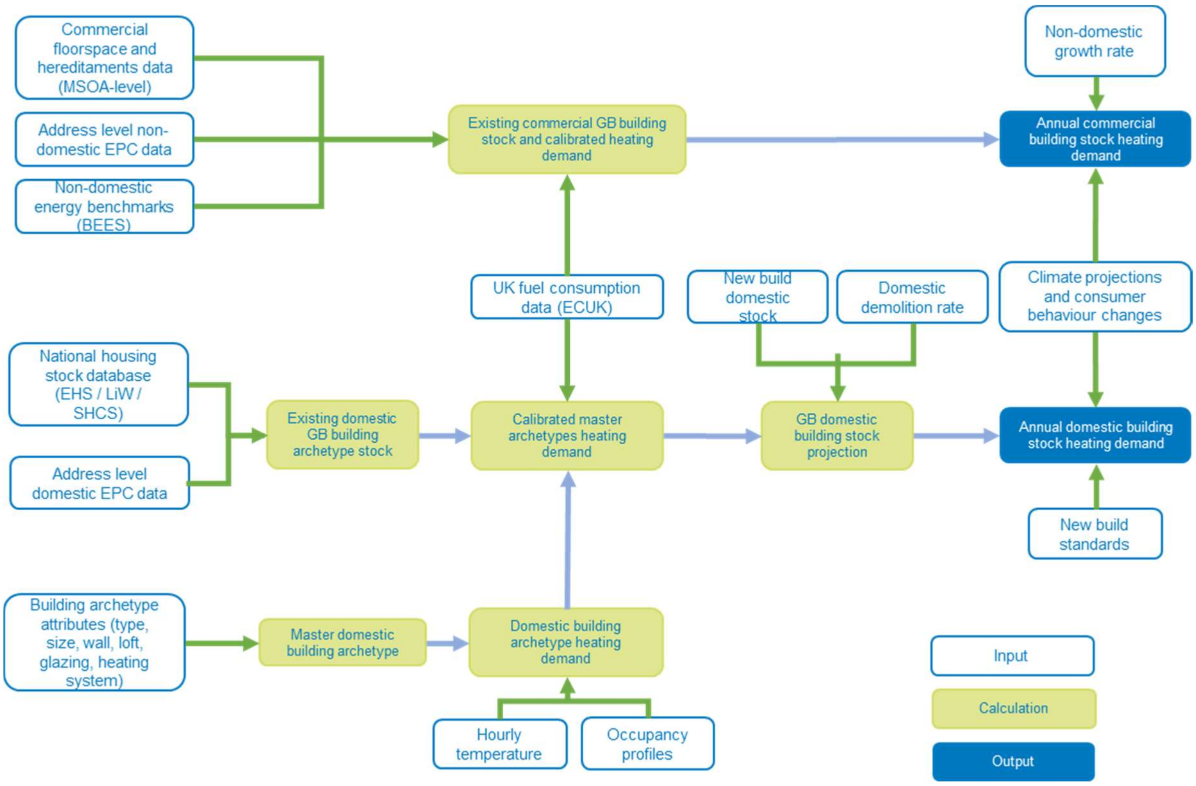


Figure 10: Spatial Heat model heating demand module. Diagram based on original supplied by Element Energy.

Costs to supply heat

The costs to produce heat from a variety of potential technologies are calculated, including:

- building or developing hydrogen and/or district heat networks
- estimated costs of producing hydrogen or district heat for heating
- directly input costs of natural gas and electricity

The cost calculations in this area also incorporate the use of storage for hydrogen used in heating. These are calculated at Local Authority (LA) level, incorporating the costs to supply that individual area.

For The Pathways we assume an “unconstrained” electricity and natural gas network, this is effectively an infinite capacity to transport electricity or gas where it is needed. Network upgrade costs for electrification and natural gas networks are not included. Hydrogen and district heat networks are “grown” within the model from the relevant source location to meet heat demand as part of the optimisation stage.

Table 1: Sources of heat and hydrogen in use in the heat model

Item	Technologies
District Heat Sources	Air Source Heat Pump (ASHP), biomass, biomethane, Ground Source Heat Pump (GSHP), Gas CHP
Hydrogen Sources	Steam Methane Reformation, electrolysis, imports
Property Heat Sources	Technology examples include district heat, ASHP, GSHP, natural gas boiler, hydrogen boiler, biomass boiler, electric storage, electric resistive, hybrid heat pump with bioliquid, electric resistive or hydrogen. Gas or biomass CHP.

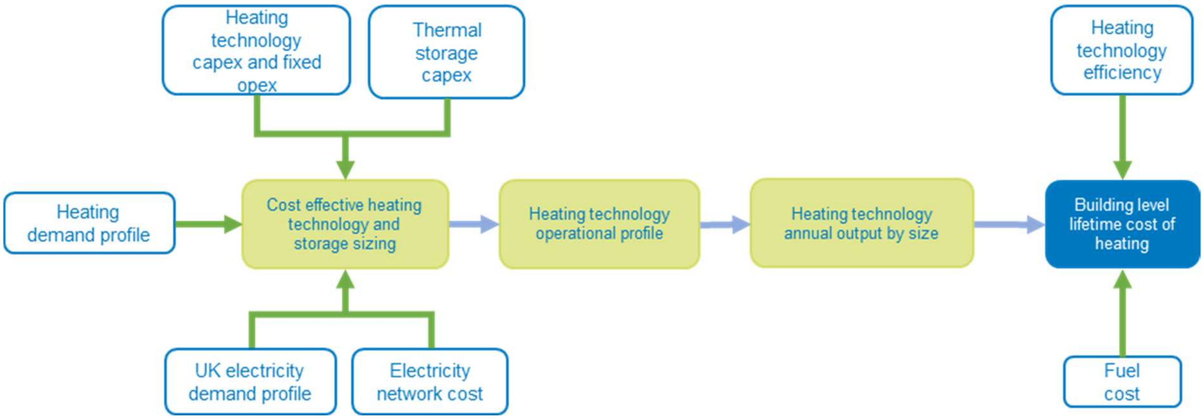


Figure 11: Building level heating costs. Original diagram supplied by Element Energy.

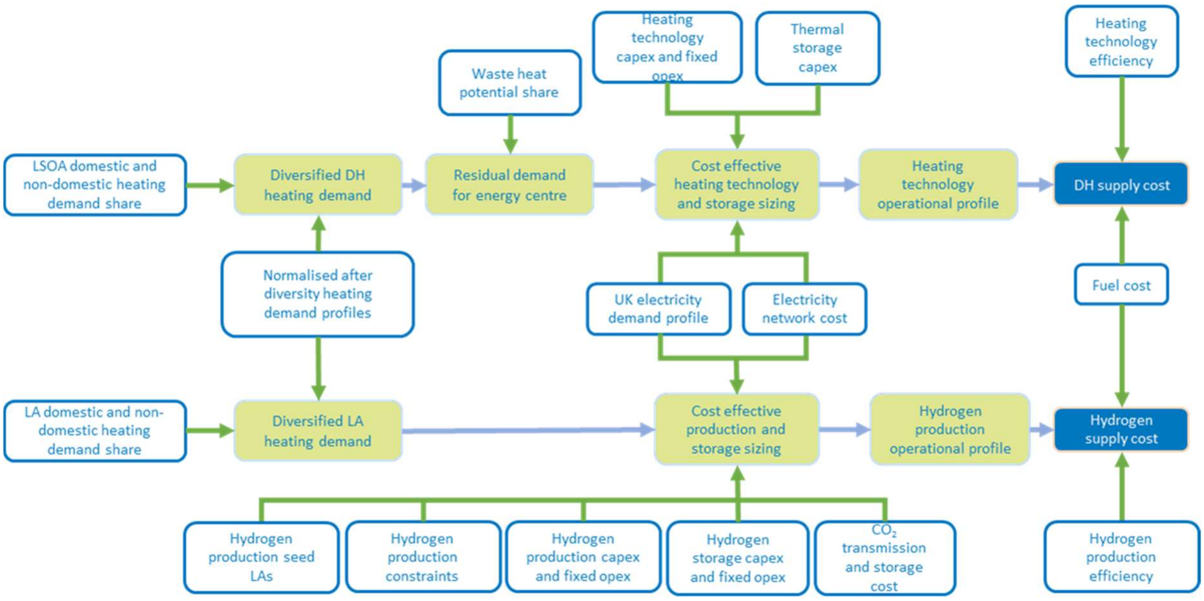


Figure 12: District Heat and Hydrogen energy costs. Original diagram supplied by Element Energy.

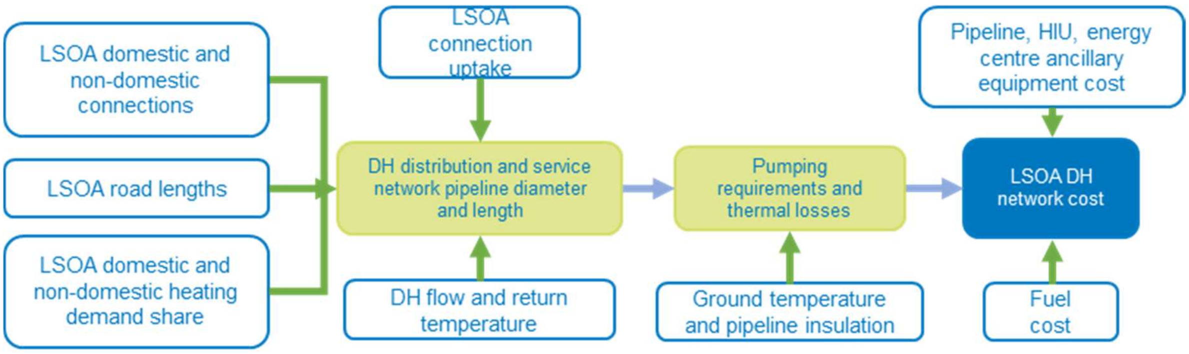


Figure 13: Network costs to supply district heating. Original diagram supplied by Element Energy

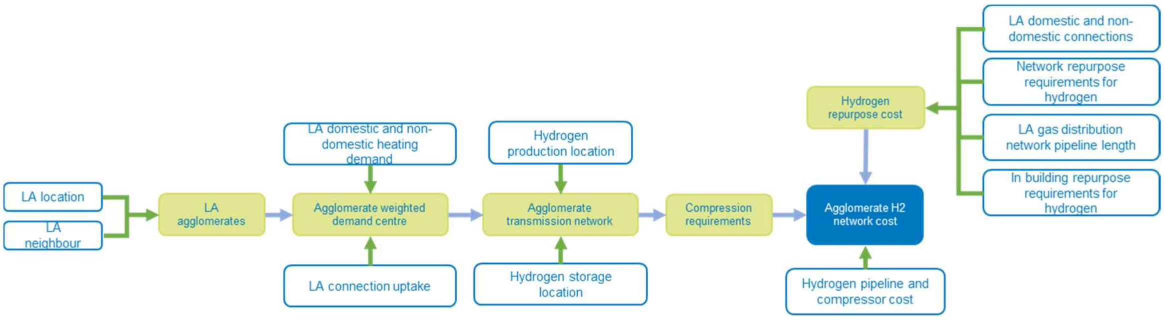


Figure 14: Network costs to supply hydrogen. Original diagram supplied by Element Energy

Optimise pathways

Having calculated a set of heating requirements and costs to supply heat, the next stage is to optimise which technologies meet the heating requirements in each area. This is an iterative process aiming to supply heat at the lowest cost for each building type, including assumed grants, within the modelled area and incorporates a view of consumer behaviour such as level of disposable income for that area and willingness to pay. This provides a view on the uptake of heating technologies, energy efficiency and thermal storage across GB. Policies, such as the date from which no new natural gas boilers can be installed, are also applied as part of this optimisation, and can vary between pathways.

A component of this iterative process is to grow the networks that supply either district heat or hydrogen for heating. These would begin with the local area that contains a source of district heat or hydrogen then test how the costs to supply heat to properties changes as adjoining areas are grouped together and the relevant network costs are recalculated. This will ultimately reach a balance between the network size and the cost effectiveness in supplying heat through the technology supported by that network. This model does not cover use of hydrogen for purposes other than heating and as such does not include network requirements to deliver hydrogen for other uses. For The Pathways 2024, we have enhanced the modelling process such that seed locations for hydrogen supply are pre-specified rather than the model being free to site supply sources within the local authority of its choice This has improved the representing of planned hydrogen clusters and how heat sources may utilise the hydrogen production within those areas. The seed locations and hydrogen production type are defined by the hydrogen asset database and pathway framework.

District heat sources and hydrogen supply sources are calculated within the model from the lowest cost production method per area within any constraints applied to the model. An example of these constraints is the availability of renewable energy sources to supply green electricity for hydrogen production. This also incorporates the optimisation and use of storage of hydrogen, or thermal storage in the case of district heat, such that production does not have to equal demand at time of use.

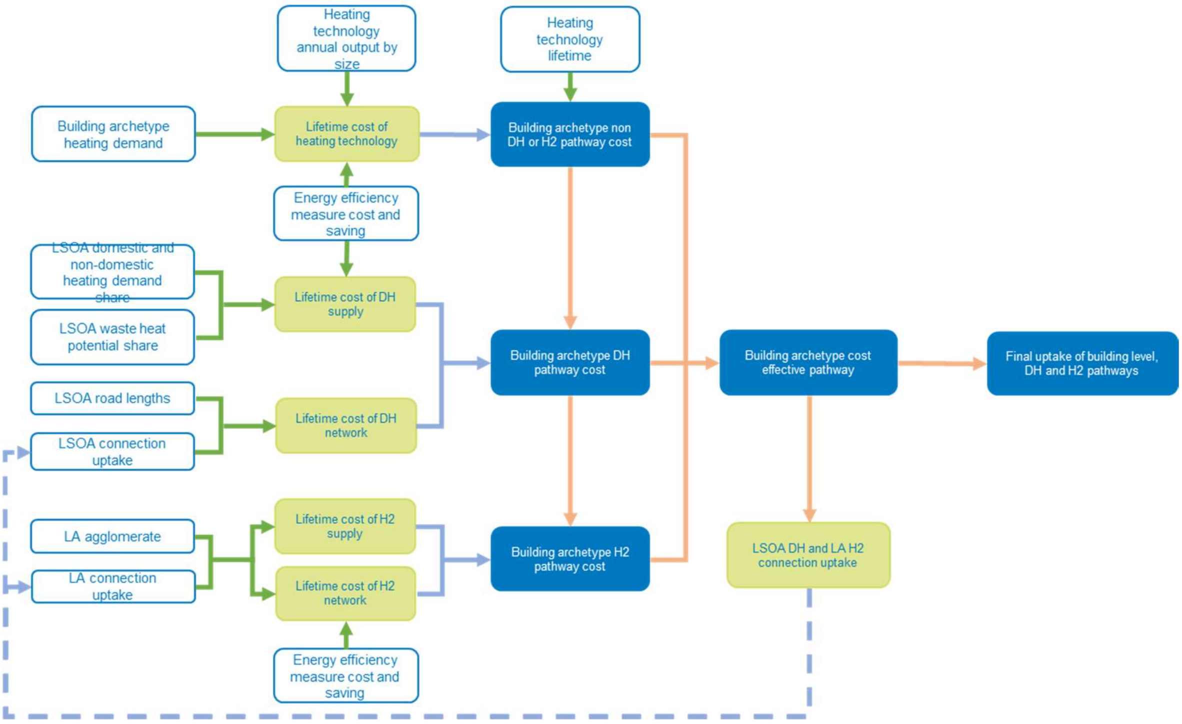


Figure 15: Pathway optimisation. Original diagram supplied by Element Energy

Time step

The modelling performs each of the above elements for each time step, currently set at 5 years. At each time step, end-of-life heat sources are replaced at a property level and new properties added with the most cost-effective heating technology for their area at that time. These then retain that heat source until it again becomes end-of-life.

Outputs

From the above steps, the sources of heat and associated fuels are returned such that we have a view of the electricity, natural gas and hydrogen demand at each time step. Values between the time steps are derived from a straight line between the calculated data points.

Results for regional areas above LSOA/DZ are calculated by summing the LSOA/DZ areas that make up a local authority area, Grid Supply Point, or all of GB.

Road transport

The road transport model includes Battery Electric Vehicles (BEVs), Plug-in Hybrid Electric Vehicles (PHEV), natural gas vehicles and hydrogen Fuel Cell Electric vehicles (FCEVs). It utilises multiple strands to produce the annual demand for each fuel type. The model looks at passenger cars, light goods vehicles, Heavy Goods Vehicles (HGV), motorbikes and buses or coaches. These are defined in line with DVLA/DfT definitions from their vehicle licensing statistics.

To model the uptake of various road transport types and fuels we use a total cost of ownership model. We start by reviewing uptake rates from recent years using DVLA/DfT vehicle licensing statistics. We make assumptions on various factors including future vehicle purchase and running costs, as well as any changes to legislation such as the ban on sales of Internal Combustion Engine vehicles (ICE). The uptake rates, determined by the total cost of ownership for the different pathways, gives the expected number of low carbon vehicles on the road.

The number of miles driven per year, along with the propulsion ratio (kWh/Mile), produces the kWh/year of the low emission vehicle fleet. For the number of miles driven per year we use historical average mileage data from DfT road traffic statistics. For the propulsion ratio we use forecast assumptions from DfT tag data book where applicable, and a range of published resources where not applicable.

The influence of Autonomous Vehicles (AV) (level 4 automation[14] and above) is included within the pathways. Each pathway has assumptions for the rate of uptake of AVs, their mileage, their efficiency, and the number of additional cars they displace.

Transport demand at system peak and minimum

The peak and minimum demand calculation method changed from FES 2019 with the introduction of a full year's demand profile, developed under a National Innovation Allowance (NIA) project[15]. This covers both residential and non-residential charging.

The study estimated that at that time, 75% of annual charging demand occurred at the home, with the remainder at workplace and public charge points. Assumptions on how this split of annual charging demand between different charging locations changes over time are included on a pathway basis. For example, Housing Survey and National Travel Survey statistics are used to determine the proportion of drivers with access to off-street, adequate on-street and inadequate on-street parking. For those vehicles without off-street parking, each pathway makes different assumptions for the proportion of those vehicles' annual demand which can come from overnight charging. Each pathway also includes different assumptions for how workplace and public charging infrastructure will be utilised in future.

Bus and HGV charging is assumed to be split between depot and public charging locations. Our depot charging profile was not determined by the NIA project, it is based on DfT road traffic statistics for when HGVs travel. Autonomous taxis are assumed to charge at depots, off peak time.

At the evening winter peak on the transmission system (5pm-6pm), residential charging is assumed to be subject to differing levels of smart charging across the pathways. Public and workplace charging is assumed to be non-smart as drivers prioritise their onward journeys.

Vehicle-to-Grid

During 2019 we consulted on our Vehicle-to-Grid (V2G) analysis and carried out a "Bridging the Gap"[16] information gathering exercise on the future road transport. Following the feedback received, from FES 2020 we have considered a wider range of outcomes for V2G.

We assume that:

- Only a proportion of the most engaged consumer segments will participate in V2G services due to the additional cost of the charger and awareness or inclination to make use of V2G technology
- Private cars with 7kW smart bi-directional chargers are available – based on a typical mass market charger and cars on sale in 2020
- On average, owners offer up to 50kWh in their battery for V2G use
- There is a delay between purchasing an EV and adopting Vehicle to Grid
- V2G only becomes a mass market option from the late-2020s, based on the CCS charging standard planned rollout for V2G[17]

Hydrogen Demand

Overall hydrogen demand in our results is a combination of outputs across our modelling as detailed elsewhere in this document. This incorporates:

- Hydrogen for industrial and agricultural uses
- Hydrogen for space heating and hot water
- Hydrogen for power production
- Hydrogen for transport

We then align our hydrogen demand and supply values such that load factors of production technologies remains credible and that the total demand is reflective of that linked to known supply projects.

[14] https://www.smmt.co.uk/wp-content/uploads/SMMT-CAV-position-paper-final.pdf
[15] http://www.smarternetworks.org/project/nia_ngso0021
[16] https://www.nationalgrideso.com/news/future-energy-scenarios-bridging-gap-net-zero
[17] https://theenergyst.com/evs-v2g-vehicle-to-grid-battery-storage-smartgrid/

Whole system demand

Whole system demand looks at the demand that must be met across end consumers plus the demands from power or hydrogen production, system losses, exports to other countries and filling energy storage systems.

Annual Electricity Demand Assessment

Our Annual Electricity Demand Assessment tool (AEDAS) has been created to collate all the demand components in one place to calculate annual electricity demand, peak and minimum electricity demand, and system losses.

The table below summarises inputs and their suppliers.

Table 2: Suppliers and inputs of AEDAS

Supplier	Inputs
Appliances Model	Annual electrical demand from cold, computing, cooking, consumer entertainment, lighting, wet and air conditioning appliances
Industrial & Commercial	Industrial and commercial electricity demand with I&C heat pumps included (HP calculated by Spatial Heat model)
DESNZ - Energy Trends	Annual residential, I&C demand
Spatial heat	Annual, peak and minimum demands from space heat and hot water. Includes district heat and heat pumps.
Distributed generation	Total capacity Annual generation Peak and minimum generation Summer generation output under normal and average warm spell conditions
DSR Model	Residential Demand Side Response (DSR) Industrial and Commercial DSR
DESNZ - ECUK	Heat and rail demand
Electricity supply team	Distribution wind double count correction
Elexon	Outturn and weather corrected data Annual demand Half hourly residential profiles Direct connects demand
ETYS	Peak transmission losses
EV	Annual demand, peak demand, summer min am/pm, V2G data
Hydrogen	Annual SMR demand CCS demand (non-hydrogen) Electrolysis demand Hydrogen storage demand

Supplier	Inputs
Storage	Capacity (storage) Power (charge/discharge) Annual demand Peak and minimum demand and load factors
Week 24	Distribution losses
ESO short term demand forecast	Historic demand Transmission losses Station demand Pumping demand Annual/minimum/peak demand on the transmission system

In bringing the demand information together from these separate models, the overall level of demand is calibrated against historic data and other forecasts made by the National Grid ESO short term demand forecasting team. This ensures alignment of The Pathways with the best data available to National Grid ESO.

Demand pathways are compared against historic out-turn data and pathways, and projections made by the Committee on Climate Change (CCC) and our dispatch model to ensure that demands within The Pathways are credible and consistent with other views.

Model of annual gas demand

Similar to AEDAS, our Model of Annual Gas Demand (MAGDEM) system aggregates total gas demand from the individually modelled demand components, and then splits it by LDZs. Each model from the table below feeds into MAGDEM. Each individually modelled gas demand forecast is re-based to the most recent weather corrected calendar year of gas demand. The splitting of GB demand into LDZ regions is not reported in The Pathways and is done for input into a more detailed long-term gas demand forecasting process for the Gas Distribution Network companies and National Gas Transmission, with a selection of the data being published within the Gas Ten Year Statement (GTYS).

Table 3: Suppliers and models that feed gas demand data into MAGDEM

Model components
Industrial & Commercial
Spatial heat
Plexos – gas demand for power generation
Exports to Ireland
Exports to continental Europe
Large demand sites – both LDZ and NTS
Transport
Gas Distribution Networks (GDNs) data – used for historical demands by gas load band and LDZ shrinkage forecasts
NTS shrinkage

Electricity peak system demand

Peak system demand is the maximum end consumer demand and taken from the distribution and transmission systems in any given financial year. Demand is weather corrected to Average Cold Spell

(ACS[18]). This is end consumer demand plus losses. For clarity, it does not include exports, station demand, pumping demand and storage demand.

Industrial and Commercial load reduction is not deducted from this total to ensure a full understanding of unconstrained peak. Residential (non-EV) load reduction, however, is deducted from this total as this response is behavioural (rather than a large response to real time price signals).

In order to make long-term ACS peak projections from annual demand we carry out the following steps:

- Historic National Grid ESO weather corrected transmission annual and ACS peak demand data is the start point
- The Pathways system demand is created by adding our assessment of the annual and peak output from non-transmission generation

To work out peak and annual demand by component:

- We start with historic public domain residential data from Energy Trends (published by DESNZ)
- We weather-correct this on an annual basis using information from Elexon
- An annual to peak ratio derived from weather-corrected Elexon data is then applied to the resulting residential annual demand to create a residential peak
- This data is assumed to be true for history. Future residential peaks are calculated assuming the Elexon annual to peak ratio remains fixed, and we add on peak demand from other future technologies like heat and transport, as well as the influence of trends from appliances, heat and light
- Residential annual demand takes this start point and the projections use the trends indicated by the other models used in The Pathways
- The residential annual to peak ratio is assumed to be true, and the I&C annual to peak ratio is derived from the remaining peak demand
- The remaining annual I&C part of demand is split using ratios from Energy Trends, and our assessment of total non-residential demand
- Again, trends from our modelling are used to project future I&C demand on an annual basis, and the I&C annual to peak ratio applied
- Finally, we add an estimate of pure DSR (true demand reduction) – currently we believe of the 1.8GW of triad response observed, almost all of this is now provided by behind the meter generation due to changes to the TNUoS charging methodology
- This process creates a total underlying ACS peak system demand, as well as a weather corrected annual average demand
- For summer minimum calculations a similar process is followed using Elexon data and observed/forecast demands on the transmission system

Heat pump demand at peak

From FES 2021, heat pump demand at the time of the demand peak is an output from the Spatial Heat model described in the “Space heating and hot water” section of this document.

The Spatial Heat model uses flexibility tools like thermal storage and hybrid boiler systems to optimise fuel consumption based on hourly price sensitivity. The output includes expected electricity use including any secondary heating requirements.

[18] The Average Cold Spell (ACS) peak demand is the demand level resulting from a particular combination of weather elements that give rise to a level of peak demand within a financial year (1 April to 31 March) that has a 50% chance of being exceeded as a result of weather variations alone.

Industrial & Commercial electricity DSR

The analysis and modelling of the potential DSR from the I&C sectors starts with a qualitative assessment of the available market intelligence including stakeholder engagement and available literature. Quantitative assessment is undertaken using contracted and observed DSR information from the EMR (Energy Market Reform) Capacity Market Register, and Balancing Service contracts. This then forms two different modelled components:

- DSR through contracted flexibility (when parties trade and directly contract with one another to procure flexibility). Two factors are analysed: the deployment of business engagement with DSR through contracted flexibility and the shiftable load that business can offer, considering limitations due to their operating profile.
- DSR due to price flexibility (occurring when any party varies its demand or generation in response to the price of energy at a particular time and/or location). Two factors are analysed: the deployment of business engagement with pricing flexibility schemes (i.e. dynamic TOUTS, Critical Peak Pricing etc.) and the shiftable load that business can offer, considering limitations due to their operating profile.

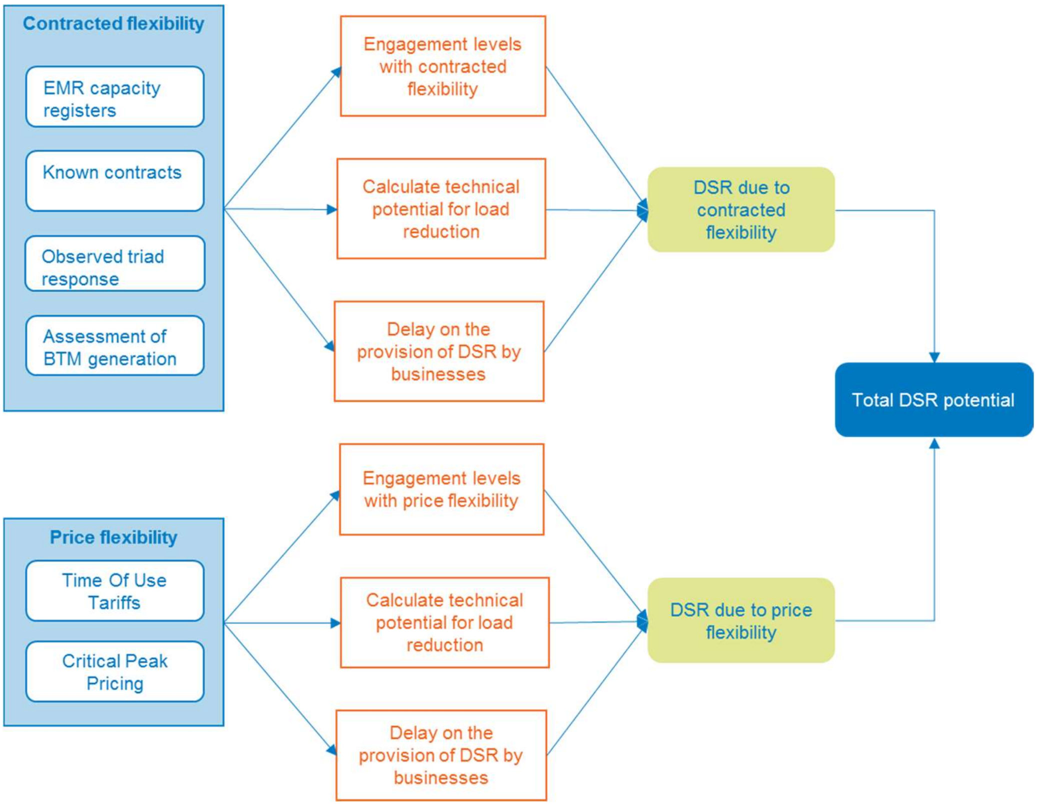


Figure 16: Industrial & Commercial DSR process chart

The above steps produce the results of the total DSR potential. To assess the pure DSR potential, namely DSR due to load reduction only (excluding storage and on-site generation), existing data is very limited. Capacity Market registers[19] and data from ESO ancillary service tenders were used to understand the current status of 'load reduction only DSR' and the trends were then extrapolated for the future potential. The new DFS product launched in 2022 has provided a wealth of data on smaller providers who have historically not engaged directly with the market.
The data is sanitised to remove embedded generation even where this is operating behind industrial and commercial loads and so appears as demand reduction from a metering perspective. As there is not a completely transparent methodology to always identify this capacity, extensive research is carried out to

[19] https://www.emrdeliverybody.com/CM/Registers.aspx

identify this with stakeholders, service providers, and the operational data held by ESO. It is also necessary to exclude some genuine demand reduction capacity from our forecasts to avoid double counting with other flexibility categories such as smart charging.

In The Pathways, space heating technologies are chosen within the Spatial Heat Model based on a percentage uptake distribution against calculated payback period for available technologies (including any grants available). Industrial and commercial heat pumps for space heating are also part of the Spatial Heat model described earlier in this document. These heat pumps will replace gas heating where economic to do so and the Spatial Heat model returns annual and peak electricity demands from these. The model also considers the operation of these heat pumps with respect to price signals to deliver DSR.

Residential electricity Demand Side Response

The modelling of changes in residential load in response to either price signals or direct participation in balancing services has been revised for The Pathways 2024 to represent the growth and success not only of suppliers engaging in time of use tariffs but also of customers directly accessing ancillary and other balancing markets that has resulted in significant growth in the available data of consumers taking part in this market area.

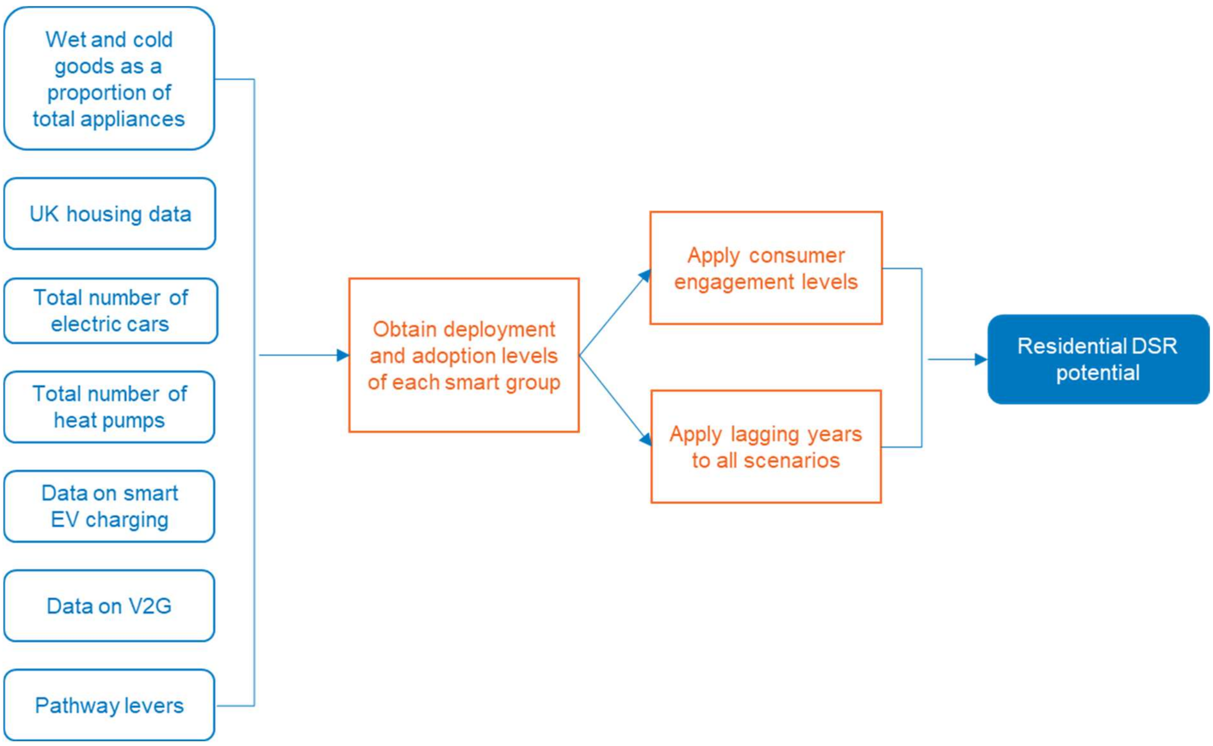


Figure 17: Residential Demand Side Response

Stakeholder feedback gathered in 2018 and 2019 strongly indicated the first and strongest consumer adoption of Time of Use Tariffs occurs on ownership of their first EV as this is a significant electrical demand and, consequently, proportion of a household electricity bill. TOUTs introduce consumers to the concept of DSR which may be controlled and monitored via a mobile phone app. TOUTs are introduced to consumers in car-show rooms, EV brochures and energy supplier information. We also believe a similar effect will occur if a homeowner adopts a heat pump heating system as this will have the same drivers of increased electricity demand and hence costs.

Based on this feedback, it is now assumed in our modelling that consumers begin mass adoption of TOUTs as they begin to use EVs. Once a consumer is introduced to TOUTs for EV (Electric Vehicle) charging, it is then assumed that as their household appliances are replaced over the following years, smart energy using devices have an increased presence within the home.

The residential DSR pathways are built on the assumption that the DSR effect on reducing peak demand relies on a combination of automated smart appliance adoption and the presence of smart pricing in the market. Our modelling reflects levels of consumer engagement with DSR grow as participation with smart technology develops and varies depending on the specific pathway modelled.

The residential DSR model now comprises of the following inputs:

- Number of GB homes – which allows us to model penetration of TOUTs and DSR in homes over time
- A high electricity demand technology which encourages consumers to consider a TOUT
- First adoption of one of the following technologies is the trigger:
    - Electric car ownership levels from The Pathways' Road Transport Model
    - Heat Pump (HP) ownership levels from the Spatial Heat Model
    - Consumer switching behaviour data from Ofgem, used to differentiate the pathways
    - Residential Demand: proportion of demand from white goods (refrigeration/washing appliances) of total residential demand. It is assumed these appliances can be placed under a DSR regime, with the consumer retaining visibility and control of DSR activity. At peak it is assumed that only these home appliances might perform DSR – other appliance classes are seen as too disruptive to lifestyles to assume they will regularly use DSR incentives
    - Annual demand savings for appliances only in the range 1%-4% are assumed, reflecting evidence from trials[20]
- Further Assumptions:
    - Number of years lag between purchase of an Electric Vehicle or Heat Pump (HP) and adoption of a TOUT
    - Number of years lag between purchase of an EV or HP and adoption of a Vehicle to Grid tariff and 2-way charger. Set to a minimum of 5 years as the EU V2G standard (CCS) is expected in 2025
    - Number of years lag between purchase of an EV or HP and purchase of a smart white appliance – 10-12 years being the average lifetime of white goods, with shorter delays in faster decarbonising pathways
    - Consumer tendency to adopt TOUTs and DSR behaviour
    - No DSR is currently assumed for summer minimum periods due to a lack of data from real world trials that measure what consumers might do in circumstances with low, or negative electricity prices. Further data to support this modelling would be welcomed

Model outputs are in the form of demand reduction percentages, which are then applied in EV, heat and peak demand modelling.

The effect of Economy 7/10 tariffs is captured within the Elexon Residential profile that is included within the peak demand calculations. Further information on this area would help us model home heat with a greater level of sophistication and would be welcome.

Consumer Engagement with smart technologies and DSR

Within our modelling, we use data from Ofgem to split consumers into the six segments defined since 2017[21]:

- Happy shoppers
- Savvy researchers
- Market sceptics

[20] AECOM Review of Smart Meter Trials for Ofgem: https://www.ofgem.gov.uk/gas/retail-market/metering/transition-smart-meters/energy-demand-research-project
[21] https://www.ofgem.gov.uk/publications-and-updates/consumer-survey-2020-update-consumer-engagement-energy

- Hassle haters
- Anxious avoiders
- Contented conformers

This information is updated every year. We vary the level of engagement applied to each market segment individually based upon The **Pathways Framework** and assume that certain consumer segments will evolve differently under the pathways according to their level of interest. The engagement levels modelled vary for different appliances and for consumer price flexibility. The engagement levels change over time within the models in response to both technology development and changes in attitude and will reflect the landscape of each pathway. Despite the adoption of smart appliances, the decrease in peak demand is delayed as it follows learning and adaptation curves, i.e. the appliances once purchased are not utilised to their full potential straightaway.

Future consumer behaviour is difficult to model due to the current lack of real-world data to understand behaviour or adoption of pioneering products that have not been tested in the past (i.e. EV smart chargers). Therefore, we model possible consumer behaviours according to The Pathways framework levers and pathways' landscapes.

With regard to smart EV charging for example, high levels of engagement are assumed in all pathways, where it is assumed that smart charging is the least disturbing option for the consumer, widely promoted by market trends and policy. In general, we believe that where possible conditions will be established that encourage consumers to participate in avoiding peak time charging.

Electricity supply

Electricity supply components include electricity generation installed capacity, electricity generation output, interconnectors and storage. Our pathways consider all sources and sizes of generation, irrespective of where and how they are connected from large generators connected to the National Electricity Transmission System (NETS), medium-size I&C generation connected at the distribution level, through to small-scale, sub-1 MW generation connected directly to commercial premises or domestic residences throughout GB.

In all pathways there is enough supply to meet demand. This means all pathways meet the reliability standard as prescribed by the Secretary of State for DESNZ – currently three hours per year Loss of Load Expectation (LOLE). Details on how LOLE is calculated are given in the annex to this document.

The electricity supply analysis covers all years between now and 2050. In the first few years of the time horizon, our analysis is largely driven by market intelligence, including National Grid ESO connection registers [22] and data procured from third parties. From FES 2021 we have also made use of the Embedded Capacity Registers published by Distribution Network Operators (DNOs) to extract current and planned storage capacities. Links to each DNO's ECR can be found on the Energy Networks Association's "databases" page[23] or directly from each DNO. These registers represent the DNOs' current views of future connected generation within their licence area and we intend to use these for other generation types in future analysis as it becomes more reliable. If you have information that may assist in developing the view of generation, please contact the relevant DNO.

In addition, we consider commercial contracts such as Capacity Market (CM) Contracts and Contracts for Difference (CfD) as an indication of the likelihood of planned generation progression to completion. Between 2020 and 2030, there is a mixture of market intelligence and assumptions, with assumptions playing an increasing part towards the end of the decade. Beyond 2030, less market intelligence is available, so we rely more on our framework assumptions used to reflect uncertainty across the pathways and the Electricity supply model described below. These can be accessed in the **Pathway Framework** document.

Electricity supply model

To simulate generation and storage build out and dispatch of electricity supply we use PLEXOS energy modelling software, produced by Energy Exemplar[24]. This is a pan-European electricity dispatch model capable of simulating the electricity market in GB and other countries.

[22] Data search | ESO (nationalgrideso.com)
[23] https://www.energynetworks.org/industry-hub/databases
[24] https://www.energyexemplar.com/plexos

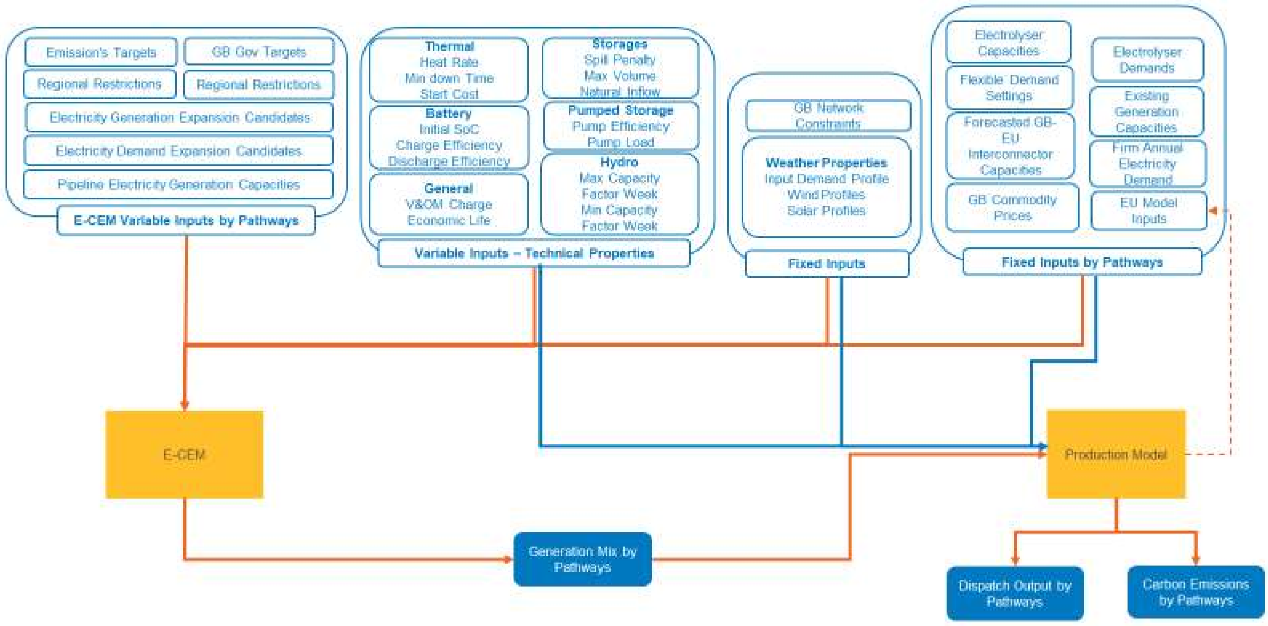


Figure 18: Electricity Supply Model

PLEXOS simulates the energy system through four phases which are the System Initialization Phase, Long Term (LT) Plan Phase, Projected Assessment of System Adequacy (PASA) Phase, Medium Term (MT) Schedule Phase and Short Term (ST) Schedule Phase. The electricity supply model contains two parts, the Electricity Capacity Expansion Module (E-CEM) and the Production Model, which make use of these phases in the PLEXOS modelling software. These phases are described in more detail in the later E-CEM and Production model sections.

The E-CEM is primarily concerned with future generation and storage capacity build out to 2050 and mostly uses the LT Plan Phase coupled with some ST Schedule to check certain properties. The generation and storage capacity output from the E-CEM is taken and employed by the Production Model which runs the PASA phase to feed optimal outage patterns to the MT and ST phases. By doing this, PLEXOS schedules outages at times of max reserve. The Production Model provides output on energy production using detailed unit commitment and economic dispatch modelling. The following sections provide more detail on each part of our modelling process, the System Initialisation Phase, the E-CEM and Production model. Figure 18 above provides a high-level overview of the inputs, outputs, and interdependencies between the models with the dotted line representing European output from the Production Model feeding into the E-CEM.

System initialisation phase

The system initialisation phase is where the model of the current GB system, its future requirements and where the time horizon are established. We conduct extensive stakeholder engagement and pair this with market intelligence to establish what the known generation and storage pipeline is within the pathways. After this phase, the E-CEM can provide detail on what the energy mix will be in 2050 and the production model will supply dispatch data subject to pathways. The following subsections detail how the GB system model was established.

Transmission installed capacities

The electricity supply transmission installed capacities uses a rule based deterministic approach to establish a suitable mixture of transmission connected generation before 2030 and for a subset of these technologies between 2030 and 2050. This consists of an individual assessment of each power station (at a unit level where appropriate), considering a wide spectrum of information, analysis, and intelligence from various sources, such as those mentioned above.

The pathway narratives provide the uncertainty envelope that determines the emphasis placed on the different types of generation technology within each pathway. Each power station is placed accordingly within their technology group in order of likelihood of that station being available in each year.

The placement of a power station within this likelihood is determined by several factors, such as market intelligence, energy policy and legislation. Project status and economics, which are applicable to that power station, are also considered. The contracted capacity or TEC Register provides the starting point for the analysis of power stations which require access to the NETS. It provides a list of power stations which are using, or planning to make use of, the NETS. Although the contracted capacity provides the basis for most of the entries into the total generation capacity, the analysis is not limited to generators with a signed connection agreement. Other projects where information has been received in the very early phases of scoping (i.e. pre-connection agreement) are also considered. Technologies included under transmission level in the model are listed in the table below.

Table 4: Technologies included in transmission level model

Technologies for renewable and thermal generation		
Reservoir Hydro	CCGT (Combined Cycle Gas Turbines)	Solar PV
Biomass	CCGT CHP	Steam Oil
Biomass CHP	OCGT (Open Cycle Gas Turbine)	Tidal
Coal	Onshore Wind	Waste
DSR	Offshore Wind	Hydro Pumped Storage
GT		Nuclear

Distribution installed capacities

Our distributed generation installed capacities include those non-transmission sites that are greater than 1MW and are typically connected to one of the 14 distribution networks. We also include sites that are less than 1MW (micro generation) and the smallest of these sites may be connected directly to properties behind the meter (e.g. rooftop solar).

For sites greater than 1MW we consider 28 technologies covering both renewable and thermal generation:

Table 5: Technologies considered in the Distributed generation model, 1MW or above

Technologies for renewable and thermal generation		
Gas CHP	Diesel reciprocating engines	Tidal
Advanced Conversion Technology CHP	Gas reciprocating engines	Waste
Anaerobic Digestion CHP	Hydrogen reciprocating engines	Wave
Biomass CHP	Advanced Conversion Technology	Solar
Geothermal CHP	Anaerobic Digestion	Onshore Wind
Waste CHP	Biomass dedicated	Offshore Wind
CCGT (Combined Cycle Gas Turbines)	Hydro	Battery
OCGT (Open Cycle Gas Turbine)	Landfill gas	Compressed air
	Sewage	Liquid air
	Sewage CHP	Pumped hydro

To determine the current volumes of renewable generation we obtain data from various sources including the Ofgem Feed in Tariffs (FiT) register, the Renewable Energy Planning Database, Embedded Capacity Registers from the Distribution Network Operators and the CM register. The projections per technology capacity are based on growth rates that reflect historical trends and any changes in the market conditions. Where available, growth of known future projects is used.

For those sites less than 1MW, including generation or storage at residential levels, we consider 9 technologies:

Table 6: Technologies considered in the Distributed generation model, less than 1MW

Technologies for renewable and thermal generation less than 1 MW		
Biogas CHP	Battery	Solar PV
Anaerobic Digestion	Hydro	Onshore Wind
Biomass CHP	Gas CHP	Hydrogen CHP

Baseline data, from the Renewable Obligation Certification Scheme, Embedded Capacity Registers, and FiT data, at GB level per technology, has been used to determine the starting point. Historical trends have been used to project the deployment of sub 1MW generation in the future.

Electricity interconnector capacities

We developed electricity interconnector capacity projections to establish the level of interconnection we expect in each pathway and its associated build profile. There are a range of electricity interconnector capacity represented across the pathways. The range is informed by considering different sources of information. These sources include:

- Interconnector Register
- Analysis and approval of projects for cap and floor regimes by Ofgem
- Optimum level of GB interconnection in the NOA
- Benchmarking against other published scenarios and stakeholder engagement with industry

The total level of interconnection in each pathway is informed by the **Pathway Framework**. Interconnector capacities are higher in the pathways with greater levels of societal change, as high levels of non-flexible generation favour more flexible sources such as interconnection. Interconnectors play an increasingly important role providing flexibility in the net zero pathways.

Our analysis starts by identifying all the potential projects and their expected commissioning dates to connect to GB. This information is from a range of sources including the electricity European Network of Transmission System Operators (ENTSO-e) Ten-Year Network Development Plan[25], 4C Offshore[26] and the European Commission[27]. Where only a commissioning year is given, we assume the date to be 1 October of that year. Following stakeholder feedback, we include the full list of projects that we considered in Table 7 below. It should be noted that this only states which projects have been considered in our pathways and not whether they have been included. Projects in this list could appear in all our pathways, no pathways or at least one pathway.

We assess each project individually against political, economic, social and technological factors to determine which interconnector projects would be built under each pathway. If it does not meet the minimum criteria, we assume it will not be delivered in the given pathway, or that it will be subject to a commissioning delay. We calculate this delay using a generic accelerated High Voltage Direct Current (HVDC) project timeline. All projects which have reached final sanction are delivered, though they may be subject to delays in some pathways.

In all pathways, we assume that the supply chain has enough capacity to deliver all interconnector projects. While we analyse individual projects, we anonymise the data by showing only the total capacity per year, due to commercial sensitivities.

[25] ENTSO-e, Ten-Year Network Development Plan, https://tyndp.entsoe.eu/
[26] 4C Offshore, Offshore Interconnectors, https://www.4coffshore.com/transmission/interconnectors.aspx
[27] https://energy.ec.europa.eu/topics/infrastructure/projects-common-interest_en

The table below lists the potential interconnector projects that we considered for inclusion in our pathways. This also shows the neighbouring markets that we assume the project will connect to. Projects in this list may appear in all our pathways, no pathways, or at least one pathway. In addition to the projects in this list we also consider additional 'dummy' projects to neighbouring markets that may not have started development yet. We also consider projects that we have been made aware of through stakeholder engagement but which are not yet in the public domain and hence cannot be listed here. It should be noted that we only consider projects as interconnectors if they are connected to both the GB network and another European network. Projects that are being developed that connect generation located in another country directly to GB but not to that country's network (e.g. some wind projects) are considered as electricity generation in our pathways.

Table 7: Potential interconnector projects considered in the pathways 2024. This only states which projects have been considered in our pathways and not whether they have been included. Projects in this list could appear in all our pathways, no pathways or at least one pathway

Country	Projects considered
Belgium	Cronos, Nautilus, Nemo Link
Denmark	Aminth, Viking Link
France	Aquind, Eleclink, FAB Link, Gridlink, IFA, IFA2, Kulizumboo
Germany	NeuConnect, Tarchon
Iceland	Atlantic Superconnection
Ireland	East-West Interconnector, Greenlink, MARES, Moyle, LirIC
Netherlands	Britned, Lionlink, Seneca
Norway	Continental Link, Maali, NorthConnect, NSL
Morocco	Xlinks

Electricity interconnector annual and peak flows

Our dispatch model has been used to model all markets that can impact interconnector flows to GB for our pathways. As with FES 2019, this includes: Belgium, Czechia, Denmark, Finland, France, Germany, Ireland, Italy, Netherlands, Northern Ireland, Norway, Poland, Portugal, Slovakia, Sweden and Switzerland. From FES 2020, Austria, Slovenia, Luxembourg and Spain are also included. Our pan-European modelling assumes ongoing cooperation between System Operators on either side of each interconnector using a volume coupling trading model[28].

Interconnector annual flows are modelled on the same basis as the electricity generation output described in the earlier section to ensure consistency. Peak flows, on the other hand, are modelled slightly differently. The interconnector peak flows are modelled using a similar approach to that used to calculate EMR de-rating factors, which look to assess the contribution from interconnectors at times of system stress (these periods mostly occur between 5 and 8 pm in winter). This approach is described in the Electricity Capacity Report[29]. However, there are a few differences between the EMR and the pathways analysis. Firstly, because the Pathways covers a much longer time horizon, we can't use the full 30 years of weather history used for EMR (essentially the simulations would take too long). Therefore, we select between 3 and 6 historic weather years that lead to the highest number of stress periods. Secondly, the timing of the process means that the interconnector flows in the pathways are calculated on draft data because they are needed to help complete the generation mix and ensure the 3 hours' Loss of Load Expectation criteria is met (although the draft data will be close to the final values at this point).

[28] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/958195/secretary-of-state-electricity-trading-arrangements-guidance.pdf
[29] https://www.emrdeliverybody.com/CM/Capacity.aspx

The market fundamentals of the neighbouring countries are strongly inspired by reports from national electricity Transmission System Operators, national regulators and the ENTSO-E Ten Year Network Development Plan (TYNDP). Since FES 2019, we have used data that covers an extensive number of countries: Belgium, Denmark, France, Germany, Ireland, the Netherlands, Northern Ireland, Norway, Italy (north), Poland, Spain, and Sweden.

Electricity storage

The electricity storage technologies which have been included in our pathways this year are the same as those used since FES 2018:

- Battery Energy Storage Systems (BESS)
- Pumped Hydroelectricity Storage (PHES)
- Compressed Air Electricity Storage (CAES)
- Liquid Air Electricity Storage (LAES)

As some large-scale electricity storage technologies have not been present in the market for very long, such as lithium-ion batteries, there is limited data available for modelling and analysis based on observed behaviour or long-term trends. We have examined several different data sources including the Capacity Market register, Embedded Capacity Registers, and data procured from a third party to better understand the potential of storage as well as those currently underway or under development. For batteries less than 1 MW, data from the microgeneration certification scheme was used.

Generation and storage capacity expansion candidates

To reach Net Zero it will require a significantly larger generation portfolio then at present. For PLEXOS to assess which types of generation to build and where to build, we create a list of capacity expansion candidates that the E-CEM can select from. The technologies included as expansion candidates are listed in the table below.

Table 8: Expansion Candidate Technologies

Expansion Candidate Technologies		
Biomass	Solar PV	Hydrogen Gas Turbine
Biomass CCS	Tidal	Hydrogen Reciprocating Engines
Diesel reciprocating engines	Offshore Wind	Nuclear
Gas CCGT CCS	Onshore Wind	Nuclear SMR
Gas Reciprocating engines	Waste	CAES
Battery storage	LAES	
	Hydro pumped storage	

For each of expansion candidates, data was sourced from open-source data sources such as the Department for Energy Security and Net Zero Electricity Generation Costs data[30] and market intelligence via stakeholder engagement.

Energy and Carbon prices

The prices for carbon, British natural gas, and coal are based on averages of the latest industry forecasts available from Oxford Economics and Aurora Energy Research. The carbon prices have additional inputs from the UK Government Autumn Statement 2023.

[30] Electricity generation costs 2023

European Market Inputs

European market price input for the E-CEM is generated via output from an updated FES 2023 production model. Sensitivity analysis is conducted on power prices simulated by the dispatch model for European countries by varying weather data input and maintenance outages.

Weather Properties

The model uses the year 2013 for weather input. The weather in 2013 is deemed to be representative of a typical year with colder and milder spells. Within ESO other teams take the output from E-CEM and test additional weather years against the simulated capacity.

Government Energy Targets

Governmental energy targets are accounted for in the model. These targets act as constraints forcing the model to achieve each target depending on the pathway. The targets included in the model are as follows.

- Emissions, decarbonised grid by 2035
- Nuclear, 24GW installed capacity by 2050
- Offshore Wind, 50 GW installed capacity by 2030
- Power to X, 5GW of electrolysers by 2030
- Solar PV, 70 GW installed capacity by 2035
- Unabated Natural Gas will be off the system by 2035

GB Network Constraints

The model assumes the network capacities as detailed by the second Transitional Centralised Network Plan (tCNSP2) out to 2044.

Electricity Capacity Expansion Module (E-CEM)

The E-CEM simulates all phases of the PLEXOS modelling software but is primarily concerned with the long-term planning phase of the system. It builds the future generation and storage capacity subject to several factors, such as generation cost, current generation capacity, and policy targets. Answering questions such as which technology to build, how much of a technology to build, when to build it and where to build. The E-CEM then assesses the adequacy of this system and creates maintenance events that can test the operability of the system over the short term. However, this is limited in the E-CEM to save on computational time but is analysed in greater detail in the production model.

The LT plan phase in E-CEM finds the optimal combination of electricity generation new builds and retirements, so that it minimizes the net present value (NPV) of capital & production costs of the system over the long-term planning horizon from 2030 to 2050, subject to energy balance, feasible energy dispatch, feasible generation build and other constraints. The capacity expansion problem is formulated in PLEXOS as a Mixed-Integer Linear Program.

PASA then assesses system adequacy on the output of the LT Plan Phase. It does this by scheduling maintenance events for the subsequent simulation phases of MT and ST. PASA models planned and random maintenance and outages of plants and transmission lines and their severities. It also calculates reliability metrics such as loss of load probability (LOLP).

MT Schedule simulates over long horizons and large systems in a short execution time. Its results can be used stand-alone or, more importantly, to decompose medium-term constraints, objectives, and hydro release policies so that they can be properly accounted for in the full chronological simulation ST Schedule. The MT Schedule Phase simulates the management of hydro storages, fuel supply and emission constraints.

The ST Schedule mimics the pricing and dispatch of real market clearing engines. The ST Schedule has different methods for modelling the chronology. In the E-CEM, the full chronology method is not employed to save on computational time.

The output from the E-CEM is checked for robustness, the capacity for each technology is checked against our view of the project pipeline and future assumptions. If there are discrepancies, the model inputs are reassessed, and the simulation is run again. The plant list from the E-CEM is handed over to the Production Model which uses a full chronology method for modelling the ST Schedule Phase.

The Production Model

The production model is a unit commitment and economic dispatch model that seeks to emulate, as far as possible, the outcome from real market-clearing engines. To produce as accurate a dispatch simulation as feasible, the model accounts for as many variables as is feasible. Our model contains information such as the existing and future assets (derived from E-CEM) considered in The Pathways studies, techno-economic system parameters, demand profiles, various flexible demand archetypes, renewable weather profiles, market-related prices, operational constraints, among other things.

The production model is used to optimise all the input information provided with the objective of minimising the total system cost, subject to constraints. This optimisation is performed for each calendar year from now out to 2050 for each of the net zero pathways and the counterfactual. The solution files contain detailed dispatch outcomes, as well as a large amount of supplementary information, at a temporal granularity of 1 hour.

Natural gas supply

In The Pathways, we model natural gas that enters the National Transmission System and natural gas that is injected directly into the Distribution Networks (DN). We do not include gas that does not enter either the transmission or distribution networks. This could include, for example, gas used offshore in oil or gas production, or small amounts of biogas generated and used on the same site. Both these categories appear in DESNZ's Digest of UK Energy Statistics, but we do not include them in either demand or supply.

The gas supply pattern for each pathway is created from the different gas supply components, described in more detail below. The models we use are supported by market intelligence, historical data and assumptions developed from knowledge gathered from stakeholders.

Potential supply ranges are derived for each supply component from bottom-up analysis of the maximum and minimum supplies into the GB market across all The Pathways' modelled years. These ranges take account of the physical infrastructure and the possible gas volumes arriving at each supply point. Once the gas demand is determined for each pathway the supply components can be matched. The **Pathway Framework** drives the level of each supply type based on political, economic, social, and technological factors. In the rest of this section, we describe each supply component in more detail.

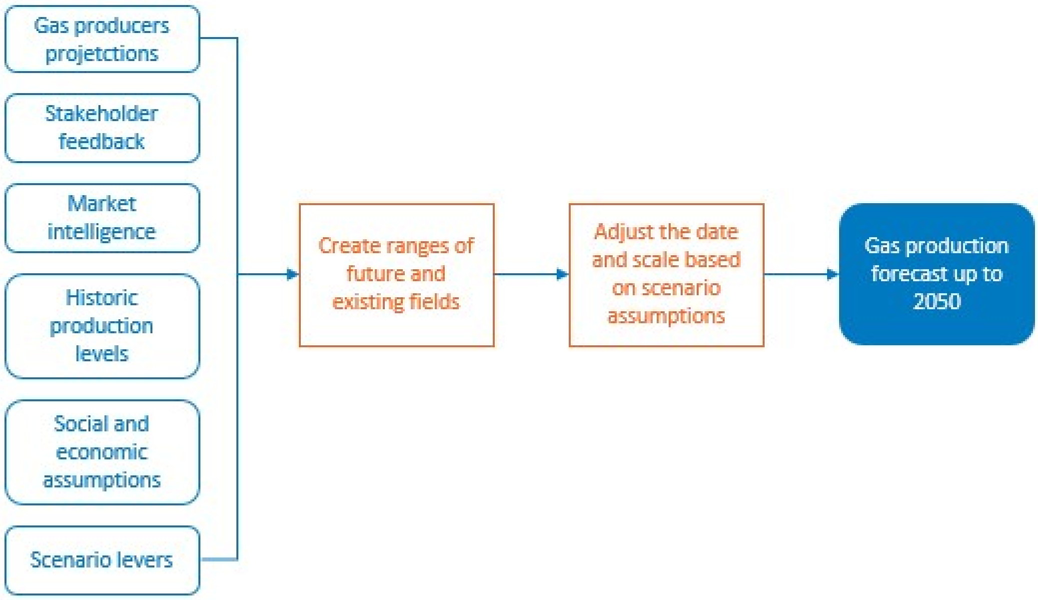


Figure 19: General gas supply process chart. Note, for continental interconnectors add European gas demand and supply data as input.

UK Continental Shelf (UKCS)

The UKCS is the seabed surrounding the United Kingdom. From this region gas producers extract natural gas which is mostly sent to the UK. A small amount of gas from the UK sector of the North Sea flows to the Netherlands rather than to GB, but we do not consider that in The Pathways. Our projections for UKCS production are derived using a mixture of gas producers' future projections, stakeholder feedback gathered during our stakeholder consultation period, and commercial market intelligence. We create ranges by adjusting the date and scale of future field developments based on historic production and the economic and political conditions as laid out in the **Pathway Framework**. For example, in the high case we might assume that all projected field developments happen on schedule. In the low case, we assume that some new developments will be delayed or not go ahead at all.

Norwegian supplies

Our analysis of Norwegian gas is usually divided into the North Sea, the Norwegian Sea and the Barents Sea. Gas is exported by pipeline to several countries in NW Europe, including the UK, and also as LNG (Liquified

Natural Gas). Norwegian LNG is included in our LNG analysis. First, we create a total production range for existing and future Norwegian fields. Our primary data source is the Norwegian Petroleum Directorate[31]. The range is derived by making separate assumptions for future field development based on historic production and the future economics. For example, in the high range we assume a high level of production in the Barents Sea, whereas in the low range we have no production from this area. Once we have created a production range, we then calculate how much will come to the UK, using a mixture of historic flows and existing contracts as a guide.

Shale gas

Shale gas is still at a very early stage of development, and there are no wells in commercial production. For several years we have based our projections on analysis by the Institute of Directors. All the 2024 pathways assume no shale gas production in the UK.

Liquefied Natural Gas

LNG is traded in a global market connecting LNG producers to natural gas users. As such, the deliveries of LNG are subject to market forces such as the arbitrage between global market prices and particular weather spikes driving a change in gas demand. We assume that a minimum level of LNG will always be delivered to the GB market, and our assessment of this is based on historic levels. These levels are flexed based on the volume of GB gas demand and indigenous supply.

Continental interconnector imports

The GB market is connected through the IUK interconnector to Belgium and the BBL interconnector to the Netherlands. For future continental interconnector imports we look at gas supply and demand across northwest Europe and estimate the potential gas available for export to GB. Projected flows through the interconnectors are compared to the historic interconnector imports observed over the last 3-4 years. We recognise that gas can be both imported to GB and exported through IUK, and from 2019 also through BBL.

Generic imports

The balance between LNG and continental gas is very hard to predict for the reasons described in the sections above. For example, in mid-2018 we were expecting low deliveries of LNG to GB for the coming winter. In fact, conditions in the world market were such that deliveries to GB reached near record levels, catching nearly all industry commentators and players by surprise. By mid-2019 deliveries had fallen again, but then picked back up again later in the year and into 2020. As projections for future years carry even more uncertainty than for the season ahead, we project only a maximum and minimum range for both LNG and continental gas and leave the balance to be made up by generic imports. This is gas that can be any mixture of LNG and continental gas. The calculation ensures that if all the generic import were to be LNG then the generic plus the minimum LNG already assigned must not be greater than the capacity of the LNG terminals. A similar calculation ensures that the interconnector capacities will not be breached.

[31] http://www.npd.no/en/

Annual supply match

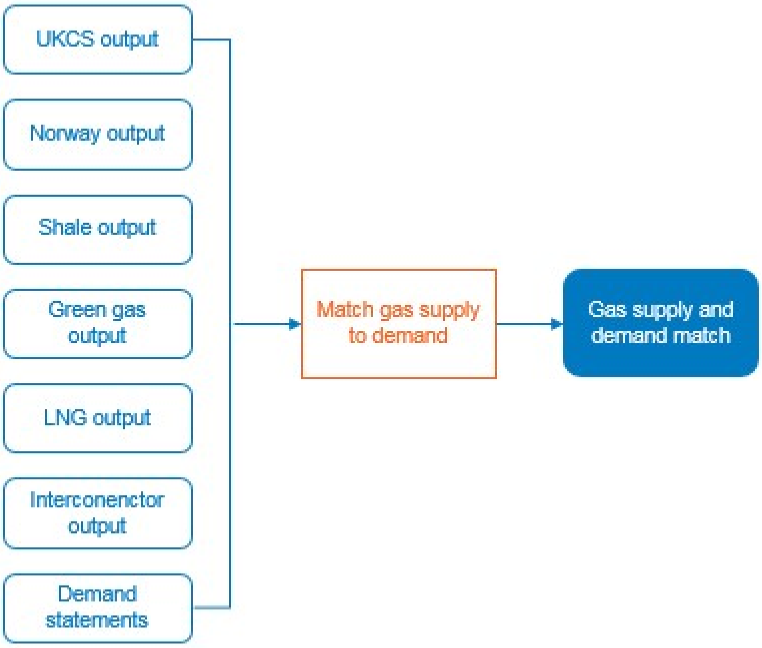


Figure 20: Annual match process chart

The annual supply match allocates gas supplies to meet demand using a ranking order. We allocate indigenous gas production — UKCS, shale and green gas — to our supply match first, because it is all UK based and will have large domestic supply chain investments in place. There is also less opportunity for these supplies to reach other markets, unlike LNG for example. Following this we allocate the Norwegian imports, the levels of which are driven by the **Pathway Framework**. Then minimum levels of LNG and continental gas imports are added. Finally, a supply/demand match is achieved by allocating generic import, which as mentioned above and can be made up of either LNG or continental pipeline gas or both.

Peak gas supply

We carry out the peak supply match to ensure current domestic production and import infrastructure can meet a peak demand day. For indigenous gas production — UKCS shale and green gas — there is a 20% difference between maximum and minimum production levels across the seasons. This is based on observed values from offshore UKCS production. For onshore shale gas there is currently no data to derive a likely difference between maximum and minimum. As these sources are likely to be base load, but with outages for maintenance, we have used the same maximum to minimum swing as for the UKCS.

For imported gas and storage, the design capability of the import facility is used to determine the capacity. This may differ from the approach in shorter-term documents, such as the Winter Outlook, which are based on near-term operational expectations.

The total of these supplies is then matched to the peak demands to calculate the margin of supply over demand. We also carry out security of supply (SoS) analysis where we remove the largest piece of infrastructure from the supply mix and again calculate the margin of supply over demand; this is referred to as an N-1 assessment[32].

[32] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/753170/BEIS_Ofgem_Statutory_Security_of_Supply_Report_2018.pdf

Bioenergy

The bioenergy model is designed to integrate bioenergy demand across the whole system, ensuring a sustainable and balanced supply chain. It incorporates bioenergy demand from various sectors, including power generation, heating, and transport, with demands derived from sector-specific models such as Plexos, the New Spatial Heat Model, and the Total Ownership Model. For sectors not directly modelled in The Pathways, such as aviation sector, it refers to bioenergy usage from the CCC the 6th Carbon Budget report.

For the bioenergy supply, it accounts for various bio resource types, for example, wood pellets, energy crops, waste, etc.—to meet specific demands. The CCC the 6th Carbon Budget report serves as a benchmark to ensure the total bioenergy demand and supply remain within the sustainable limits outlined in the CCC's balanced pathway.

Additionally, the model also seeks to balance domestic bioenergy resources with imports across different pathways, using the import ranges outlined in the CCC the 6th Carbon Budget report as the benchmark, this ensures a comprehensive view of potential future sources of bioenergy.

Biomethane

Biomethane is a naturally occurring gas that is generated from Anaerobic Digestion (AD). AD is a biological process where microorganisms break down organic matter such as sewage, plant material and food waste in the absence of oxygen to produce biomethane.

The unrefined product is usually referred to as biogas. This is not suitable for injection into gas networks but can be used for on-site electricity generation and heating. When biogas is refined to make it suitable for network injection, we refer to it as biomethane.

The biomethane range is derived using the latest information available from biomethane sites currently connected to a gas network, and the distribution network owners' latest information on possible future connections. To derive the high and low case we apply different growth rates and assumptions to new connections due to the differing economic and political conditions within each pathway. To support our projections, we use market intelligence and test our results with relevant industry experts.

Bio Substitute Natural Gas (BioSNG)

Bio Substitute Natural Gas is a gas that is derived from gasification of biomass. The process uses high temperatures to produce a synthetic natural gas which, after cleaning and refining, can be injected into a gas network. BioSNG is in the early stages of development. A commercial demonstration plant has been under development with funding from Ofgem's Network Innovation Competition (NIC).

Hydrogen (H_2) supply

For The Pathways 2024 we have revised how we model the supply of hydrogen. Short-term growth of hydrogen supply is closely linked between projects that require hydrogen and the supply of that hydrogen, for instance hydrogen fuelled public transport projects with onsite production. Further hydrogen supply projects are linked to other initiatives, such as the creation of hydrogen hubs.

Our Hydrogen Asset Database includes a record of all relevant information on these projects and feeds the early years hydrogen project forecast to the Hydrogen Capacity Expansion Model (H-CEM) as inputs. The H-CEM then simulates the long-term planning phase using the PLEXOS energy modelling software.

As is the case with the E-CEM, described earlier in this document, the H-CEM builds adequate production and storage requirements to meet increasing hydrogen demands subject to policy targets, fuel, and emissions targets. The build of electrolysis is optimised as part of the E-CEM and the electrolysis capacities are then fed into the H-CEM which covers all other components of hydrogen supply.

The H-CEM finds the optimal combination of production and storage new builds during the period 2030-2050 to meet the hydrogen demand. Any capacity built prior to 2030 is not considered part of the optimisation with H-CEM building additional capacity on top. The formulation of the problem is not materially different to that used in the Electricity CEM described in the Electricity Capacity Expansion M section of this document, just with a focus on hydrogen components.

Electricity and natural gas use required to produce this hydrogen is included in the demand that is used in modelling the supply of these energy vectors.

In determining the sources of known projects, we have utilised the items in Table 9, and conducted our own research using public materials, developer reports, and stakeholder input:

Table 9: Sources used to create Hydrogen Asset Database

Example of sources for Hydrogen Asset Database
UK government Hydrogen Roadmaps
Aurora electrolyser database IEA hydrogen database

Electricity supply model

Emissions

Across our pathways we have three which meet net zero by 2050. The remaining "Counterfactual" pathway does not reach net zero by 2050 but still has a level of decarbonisation across the timeframe. There are other binding commitments such as carbon budgets set by the Climate Change Committee (CCC) which form part of our analysis.

Emissions modelling can be broadly broken down into two main areas, sectors modelled directly by the team and sectors where we use analysis from third party organisations, such as the CCC.

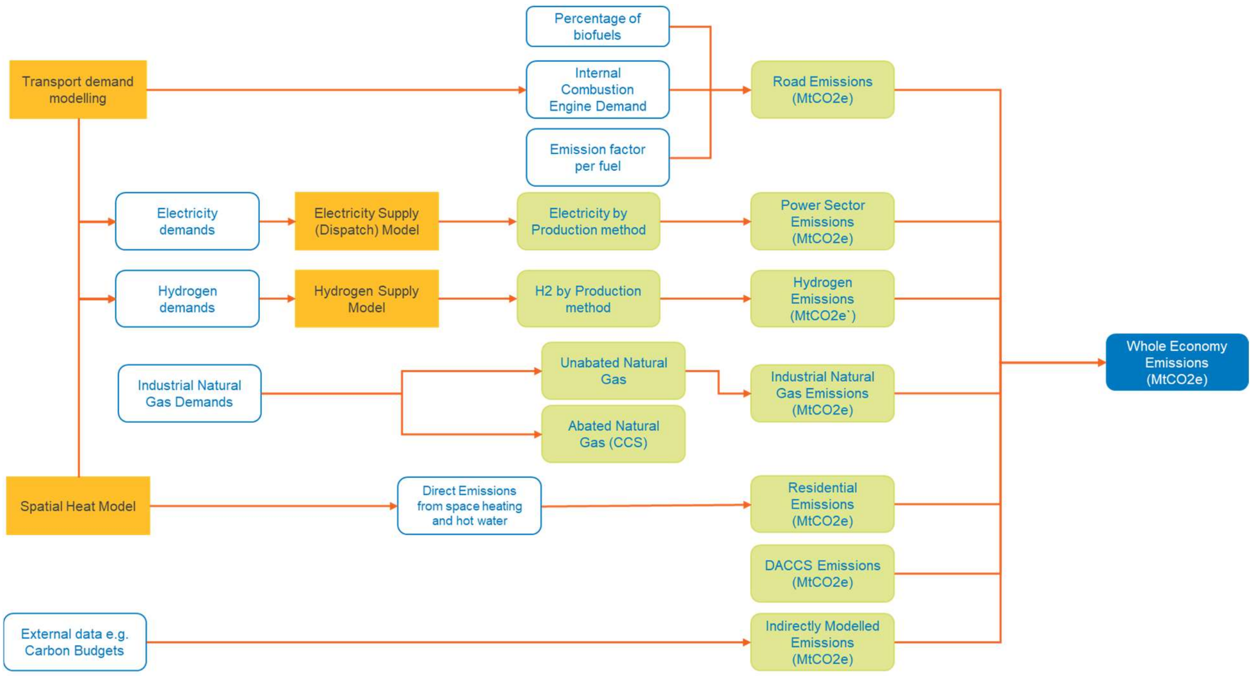


Figure 21: Emissions Model Overview

Historic Emissions

Our starting point is updating historic emissions published by the government. Finalised emission numbers have a 2-year lag e.g., for The Pathways 2024 emissions up to 2022 are finalised and available. Due to changes in methodology for emissions calculations from year-to-year, historical numbers may change compared to previous publications.

Direct modelling

Our emissions modelling is closely coupled with the bioenergy supply ranges. This is because bioenergy is a finite resource and can provide negative emissions, bioenergy with carbon capture and storage (BECCS) can be utilised to help meet net zero. Our modelling assumes that bioenergy is sustainably resourced, and we use ranges provided by the CCC to ensure we stay within a credible range of bioresource.

Transport

Emissions counted in this sector are direct tailpipe emissions from internal combustion engines only, the emissions associated with the electricity and hydrogen needed to power alternative vehicles are captured in at in the “Power” and “Hydrogen supply” sectors respectively. Using the TWh petrol/diesel demands percentage of the demand which comes from bioenergy, to calculate this we use the “Renewable Transport Fuel Obligation” from the department of transport. We are then able to apply an emission factor for each fuel demand to get emissions in each pathway.

Residential

Emissions from this sector come directly from the spatial heat model for emissions made in supplying heat for homes and commercial properties. As we only model the direct emissions in this sector, we do not include the emissions for electricity and hydrogen production to avoid double counting these and these emissions are captured in as part of the power generation and hydrogen emissions described below.

Power generation

Emissions from power generation are a direct output from the modelling we do in our dispatch model (see section Electricity supply model, above). The power sector can utilise BECCS to achieve negative emissions, which is beneficial to not only achieve a net negative power system but also provide the negative emissions required to offset hard to abate sectors such as agriculture. As mentioned above we have an upper limit of bioenergy available in any given year and the amount of bioenergy used in each pathway varies across each sector.

Hydrogen

Similar to the power sector, emissions are calculated from the hydrogen supply model. Of the various hydrogen production methods available, renewable powered electrolytic hydrogen has no emissions, CCS enabled hydrogen is low carbon will a small amount of emissions and hydrogen produced through biomass gasification yielding negative emissions. We are therefore able to utilise different production methods to not only meet hydrogen demands and make use of biomass for negative emissions.

Direct air with carbon capture and storage (DACCS)

DACCS is a negative emissions technology that has shown its potential and could play in a key role in a mix of negative emissions technologies needed to offset emissions from hard to abate sectors to reach net zero We consider its usage in all our net zero pathways with different levels. We continually assess the progress of DACCS projects, R&D, and update our pathways appropriately. We assume DACCS will require electricity when running, which creates an additional demand for electricity. We assume that this electricity comes from renewable sources, utilising energy that would otherwise be curtailed.

Industrial natural gas

For this we take the natural gas demand and apply CCS from 2030. For the resulting uncaptured natural gas, we apply a conversion factor to get the emissions from this sector. We use industry intelligence to get a sense of the size, efficiencies, and timelines of when CCUS could come into play.

Carbon Capture Use and Storage

Our modelling is reliant in the deployment of CCUS to meet emissions targets and goals while maintaining security of supply. CCUS is deployed in line with the pathway framework. The UK is well positioned by having a good understanding from oil and gas exploration as well as being well situated geographically to store CO2 which has been captured. The British geological survey estimates that the total storage capacity of CO2 in the UK could be 78 billion tonnes of CO2[33] which is more than sufficient to meet the CO2 storage needs we have in our modelling.

Indirect modelling

The sectors which we don’t model directly are:

- Aviation, Agriculture, Shipping, LULUCF, Waste, F-gases, BECCS for biofuels and Fuel Supply

For these sectors we currently use analysis undertaken by the CCC. Our three net zero pathways take outputs from the CCCs “Balanced Net Zero Pathway”. We have removed climate feedback from CCC emissions in light of the change in the conversion factor for non-CO2 greenhouse gas emissions to be in line with the latest government data. We have also made minor updates to the emissions to align it with the latest actuals. The “Counterfactual” pathway shows a slower rate of decarbonisation.

[33] North Sea Transition Authority (NSTA): Carbon Capture and Storage - The move to net zero (nstauthority.co.uk)

Regional Electricity Demand

Overview of the data

The Pathways are intended to illustrate credible demand and supply outcomes from now to 2050 at a GB level. To support further analysis within the electricity industry, the pathways are broken down to regional datasets.

The datasets include a view of gross (underlying) and net (transmission) demand for each pathway out to 2050. Each year includes three study periods, namely Winter Peak, Summer Minimum AM and Summer Minimum PM.

The data is provided for each Grid Supply Point (GSP) and demand Direct Connect (DC). A GSP is a connection between the Transmission network and the Distribution network, whilst a DC is a connection between the Transmission network and a large energy user.

Modelling method - active demand

The modelling approach is described in more detail below. At a high level we start by working out the current demand split in our start year at each GSP and DC. This is achieved by taking demand as metered at the transmission network and adding to this the component of demand that is supplied by non-transmission connected generating assets. The result is the total gross demand.

This gross demand is then split by demand subcomponents so that in our starting year we know what proportion of each GSP's demand is residential, industrial, commercial, heat and transport. The Pathways' growth rates are then applied to these subcomponents and therefore the change in demand at each GSP will reflect the portfolio of demand subcomponents seen at each GSP.

Current active demand split

The Pathways show how electricity demand will change between now and 2050. Our analysis considers the sub-components of demand. These are residential (non-heat), Industrial & Commercial, electrification of heat & transport, and demand for hydrogen production via electrolysis.

Before we can apply our growth rates, we must first understand how the current electricity demand is split regionally according to these sub-components. This is a two-step process: first we determine the gross demand at each GSP, and then we apportion this across the sub-components.

Step 1: Gross demand

Gross demand is the total underlying consumption that you would observe if you were to add up all electricity use irrespective of which network the customer connects to or where the energy is supplied from. As not every household has a smart meter it is difficult for us to determine this demand during the study period of interest. We must make use of the metered and other data we have access to and apply some assumptions.

We map each large individual (embedded) generation site to a GSP. In many cases this mapping is per the Distribution Network Operator or Transmission Owner (TO) data, but where gaps existed, we mapped to the nearest GSP geographically. For micro-generation (sub 1 MW) the relevant data on installed capacity was mapped to the nearest GSP. This is then scaled up to match the total micro-generation installed capacity. The installed capacity at each GSP is then converted to a generation output by multiplying with technology specific load factors. It is these generation output values that are added to the net demand to give us a gross demand for each GSP (and DC) for the starting year.

For Scotland, we use Week 24[34] Schedule 11 data to as the source of net demand and the contribution of small & medium embedded generation to that net demand. This data is provided to the ESO by DNOs as part of Grid Code obligations. It is from this data that we establish the gross demand for each GSP in Scotland. This difference in method from England & Wales was developed in consultation with the Scottish TOs.

[34] Week 24 submissions are part of the Data Registration Code and are submitted by the DNOs. Here we use the schedule that relate to the demand on the day of GB peak demand and GB minimum demand.

For England & Wales, the starting point is Elexon Settlement data flows CDCA (Central Data Collection Agent) I030 (GSP volumes) and CDCA I042 (metered volumes for each BM unit); both available on the Elexon Portal[35] and Elexon Open Settlement data[36]. These represent metered net demand as measured at the transmission network. Because we are looking at typical demand during each study period (rather than demand at a specific historic half hour), we use the average of the data over the last 5 years. From this we calculate the percentage that each GSP typically contributes to net demand during each study period. These percentages are then applied to the GB level net demand calculated earlier in The Pathways analysis to get an energy value (in MW) for our starting year. Once we have net demand by GSP we can determine the underlying gross demand[37] by GSP by adding the energy generation output of non-transmission connected power stations (embedded and sub 1 MW). Once again this is an area we have limited data for and as such we make a number of assumptions in this process.

Step 2: Gross demand subcomponents

To estimate the split of domestic and non-domestic demand to be used per GSP in our analysis start year, electricity consumption data from DESNZ was used[38]. This data provides the breakdown of 2016 electricity consumption by output area. The output areas are: Middle Super Output Areas (MSOAs) for England and Wales and Intermediate Geography Zones (IGZ) for Scotland.

We map these output areas to our Grid Supply Points according to a nearest neighbour approach. That is, we assumed that the electricity demand of each IGZ and MSOA is supplied by the closest GSP.

Once we have allocated each output area to a GSP we use the DESNZ data to calculate a percentage split of domestic and non-domestic demand in each GSP. This percentage is then applied to our start year GSP gross winter peak to estimate the current domestic and non-domestic demand of each GSP.

For the summer minimums, some scaling is required to the regional data reflected in The Pathways GB dataset. This is required because the DESNZ data gives an annual split and, whilst this annual split is reflective of the winter peak split, it is not reflective of summer minimums.

The DESNZ data does not split non-domestic demand down into its constituent parts. Therefore, to obtain I&C demands, we split the non-domestic component according to the Great Britain split as published in The Pathways.

This process produced the gross demand of the GSP for each demand component in our starting year (for electric transport treatment, please see below).

Forecast active power

Demand

Having determined the demand subcomponents for each GSP (and DC) in our starting year we are now able to apply our forecasts to calculate the demand by GSP out to 2050.

Residential, Industrial & Commercial

Our residential demand trends for each pathway are applied to the starting year residential demand at each GSP. This gives a GSP level residential forecast for every pathway and year. The same process is applied to I&C trends.

Heat demand

The electrical demand for heat pumps and district heating at each GSP comes from the Spatial Heat model introduced in FES 2021. This model's methodology is described earlier in this document. This model

[35] https://www.elexonportal.co.uk/
[36] https://www.elexon.co.uk/data/open-settlement-data/
[37] Note: Gross demand in this dataset does not include station demand, pumping demand or exports. We have not modelled these Direct Connects. We also do not include transmission losses at this stage.
[38] https://www.gov.uk/government/statistics/lower-and-middle-super-output-areas-electricity-consumption

considers housing types and relevant technology, policy, and economic factors with the results presented at different levels of geographical granularity or network boundaries.

Transport demand

We take our annual GB forecast demands for each charging profile and proportionally split this to GSPs. This split is based on historic data of where vehicles are registered and the mileage travelled within regions.

Our start year demand split is based on the number of registered EVs as a proportion of the whole fleet per GSP and the annual mileage in that GSP. This data is from Department for Transport (DfT) statistic tables VEH0132, VEH0105 and TRA8901. In later years, the geographic dispersion of registered EVs is based on the current dispersion of all vehicles and the locational demand is proportionate to the annual mileage for those regions. The proportions in the interim years from the current day figures to the whole fleet figures are calculated as a smooth curve between the two splits.

Direct connects

Rail network direct connects follow the growth of rail as assumed in The Pathways. Hydrogen production direct connects follow The Pathways' projections for hydrogen demand growth, utilising outputs from the Production Model outlined above for forecast demands in the study periods. The demand of the other types of direct connects stays constant across the years.

Supply

The embedded and sub 1MW generation forecasts are apportioned according to the existing geographical distribution for all technologies (wind, hydro, storage and other distributed generation technologies). The exception to this is solar, for which as solar installed capacity increases, we assume a more widespread regional distribution across the country. For storage, the existing capacity and new sites with a known location are allocated to a GSP using a project-based approach.

Future growth that does not yet have a known location is split out to GSP level based upon the year-by-year increase in all DG technologies spatially. Per each GSP, the current and forecasted embedded generation capacities are provided along with peak winter & summer forecasts.

Modelling method – reactive power

Current reactive power split

For England and Wales, the starting point of the net reactive power (Qnet) is the National Demand Data (NDD)[39]. This is due to resolution of reactive power metering in Elexon datasets not aligning with the active demand datasets we have used. These represent metered net reactive demand as measured at the transmission network. Where NDD was missing metering for certain GSPs or DCs, Week 24 data was used.

For Scotland, we use Week 24 Schedule 11 as the source of demand data for the net reactive power, with the NDD being available for benchmarking. This is congruent with the current active demand split methodology outlined above.

The gross reactive power (Qgross) in each GSP includes the metered net reactive power with the additional network's losses and gains (including DNO network). These 'Low Voltage' gains are input data from the ESO and TOs in 2019, based on their power systems models.

Forecast reactive power

To understand the trends of the gross reactive power, assumed power factors of each demand sub-component are applied to the corresponding active demand forecasts. These trends are then applied to the current split of gross reactive power and produce the gross reactive power forecast for the pathways.

The power factors for each subcomponent were produced based on literature reviews and in-house modelling.

[39] NDD is part of National Grid's operational demand metering.

Appendix A

Study periods

- Winter peak is a view of peak demand between the hours of 17:00 and 18:00 – typically November-February on a weekday.
  - The peak demand is Average Cold Spell – a high demand condition, which has a 50% probability of being exceeded
  - Electric Vehicles are a demand – smart charging behaviour assumed
  - Some V2G considered as supply
  - All storage considered as a supply
  - This period is of interest as these are the maximum demands on the system
  - Note EV smart behaviour is an assumption but demands could be higher or lower under certain circumstances

- Summer minimum AM is a view of demand between 05:00 and -06:00, typically in June-August on a summer Sunday morning.
  - Electric Vehicles are a demand – no smart behaviour assumed (people charge how they would charge assuming todays behaviour)
  - All storage considered as a demand – spread over 4-6 hours to avoid creating a new low demand point
  - This period is of interest as these are the currently minimum demands on the system

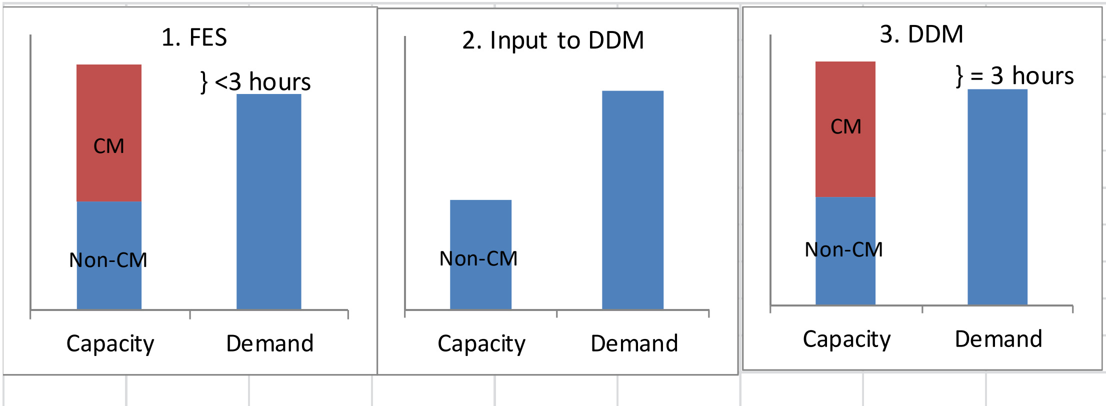
- Summer minimum PM is a view of demand between 13:00-1400, typically June-August, summer Sunday afternoon.
  - Electric Vehicles are a demand – no smart behaviour assumed (people charge how they would charge assuming todays behaviour)
  - All storage considered as a demand – spread over 4-6 hours to avoid creating a new low demand point

  This period is of high interest due to solar PV which peaks at this time and reduces transmission demands – but flows around the system may still be high.

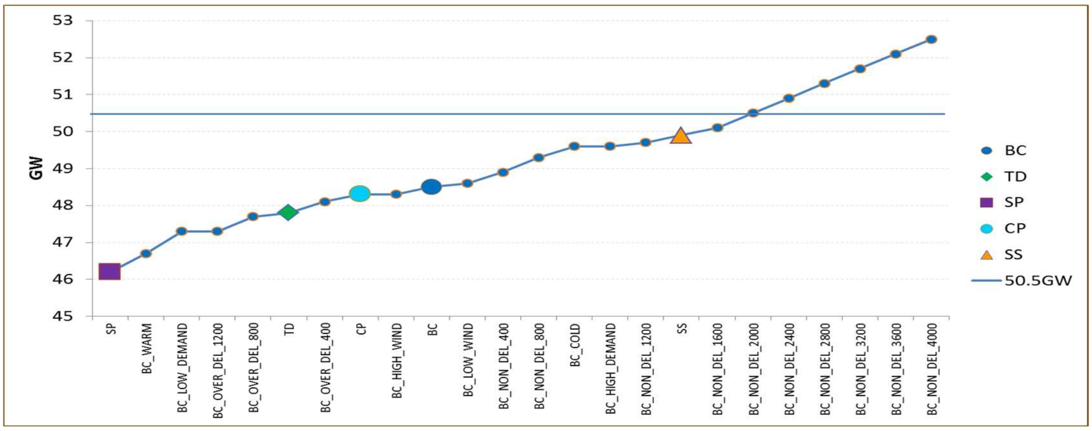
Annex – LOLE step by step guide

This annex illustrates why the theoretical implementation of the GB Reliability Standard leads to a CM Base Case with LOLE <3 hours (steps 1 to 7) and then the market delivers a LOLE lower than that (steps 7-1) but can still be said to target the market implementation of the Reliability Standard. This process can be summarised into 9 steps:

1. The Pathways plus Base Case have <3 hours LOLE
2. Input into the Dynamic Despatch Model (DDM)[40] Non-CM capacity for a pathway along with the demand
3. DDM run to give CM capacity required to give 3 hours LOLE



4. Repeat 1 to 3 for all pathways and sensitivities
5. Input all pathways and sensitivities (all = 3 hours LOLE) into Least Worst Regret (LWR) tool[41]
6. Run LWR tool to give cost optimal answer

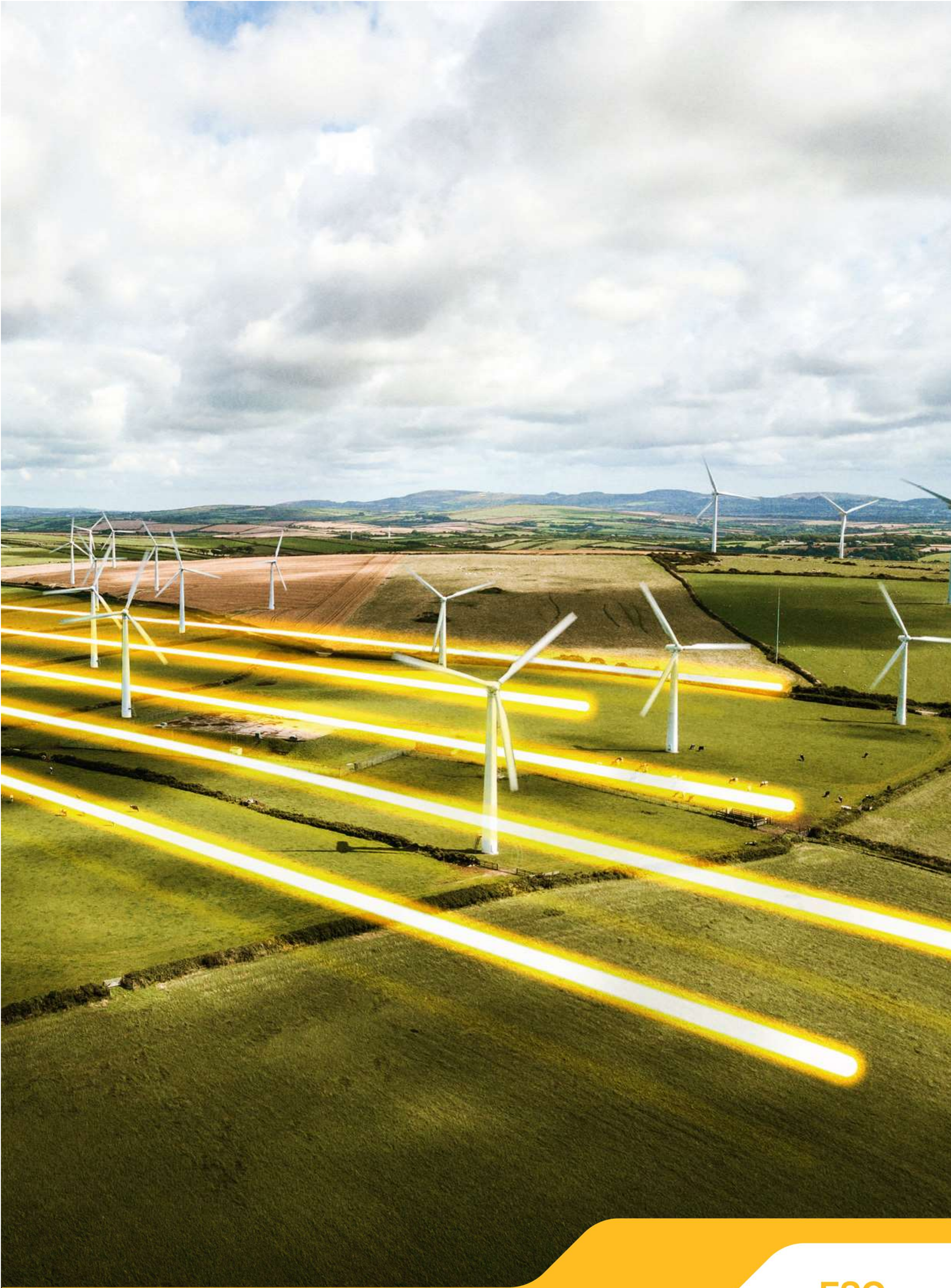


7. Resulting capacity(50.5GW) > Base Case (48.5GW) hence Base Case <3 hours LOLE
8. Auctions result so far have delivered low prices and more capacity has been procured resulting in Base Case <2 hours LOLE for the period of the auctions (note Sec of State adjustments to Demand Curve can increase the capacity targeted and reduce LOLE still further e.g. 20/21)

[40] Software modelling tool used for the production of the Electricity Capacity Report (ECR)
[41] Details of Least Worst Regret approach and methodology can be found in page 87 of the 2017 Electricity Capacity Report, https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/116/Electricity%20Capacity%20Report%202017.pdf

9. Update auction results for known developments e.g. unsuccessful CM plant remaining open, higher availabilities etc. which result in the Base Case and The Pathways with LOLE initially <1 hour LOLE thereafter within range of 0.5 to 2.5 hours LOLE which then returns you to step 1.

Note, virtually all electricity markets around the world deliver more capacity than required to meet their Reliability Standard some significantly more e.g., Netherlands and Ireland.



ESO