

# FES Modelling Methods 2020

Revised June 2021



## Contents

Contents .....	2
Introduction .....	3
End consumer demand .....	4
Whole system view .....	14
Flexibility .....	28
Annex – LOLE step by step guide .....	41

## Introduction

Our **Modelling Methods** publication is just one of a suite of documents we produce as part of our Future Energy Scenarios (FES) 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 FES document. Alongside this publication, we have the **Scenario 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 **FES- in- 5** and our FAQs. For more information and to view each of these documents visit our website: [nationalgrideso.com/future-energy/future-energy-scenarios](https://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 documents we welcome your feedback, please contact us at: [fes@nationalgrideso.com](mailto:fes@nationalgrideso.com)

### Process chart keys

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



## Covid-19 impact

Covid-19 will impact many aspects of the future of energy. However, the uncertainty and lack of evidence at the time of analysis means that it has not been included in FES20. The impact of Covid-19 will be discussed with stakeholders in the second half of 2020 and will form part of FES 2021.

## Five Year Forecast

We include a Five Year Forecast within the FES document and Data Workbook. This is developed differently to the scenarios. It represents the ESO's best view for demand and supply over the short-term. In most cases, key levers or assumptions are in the middle of the scenario range. The scenarios then reflect uncertainties around this view, projecting beyond the first five years all the way out to 2050.

## End consumer demand

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

1. Electricity demand overview.
2. Gas demand overview.
3. Industrial and commercial demand.
4. Residential demand.
5. Road transport demand.

## Electricity demand overview

Future projections for annual and peak are created using forecasts and assumptions from other FES models e.g.

- Industrial and commercial demands;
- Residential appliances and air conditioning;
- Heat and district heat; and
- Road and rail transport.

## Annual demand

In the FES document “Consumer View” chapter, we consider “end consumer demand,” regardless of where (transmission, distribution or on site) the electricity is generated. Demand is weather corrected to seasonal normal for annuals. Moreover, it **does not include** losses, exports, station demand, pumping station demand or other forms of storage demand. Annual losses data is in the FES data workbook.

When we illustrate residential, industrial and commercial, 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 have to be estimated.

The Department for Business, Energy and Industrial Strategy (BEIS) publishes monthly sales data for residential, industrial and commercial demand and this forms the basis of our demand estimates. For

each annual FES, the latest Energy Trends data is used and this frequently brings small revisions to history.

- The Energy Trends residential annual data is annually weather corrected, using information from Elexon.
- Industrial and 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)<sup>1</sup> and the FES data tables.
- Out-turn “National Demand” data is published on our website.<sup>2</sup>
- 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.
  - In house data (half hourly transmission generation, solar and wind data);
  - ElectraLink;
  - The Digest of UK Energy Statistics (DUKES)<sup>3</sup>; and
  - Datasets purchased from third parties.

To get historic peak demands for the components of demand:

- We take annual, weather corrected, Energy Trends residential demand data;
- We create a peak using weather corrected residential demand data from Elexon;
- The remaining peak demand is assumed to be industrial and commercial; and
- Remaining peak demand is split using Energy Trends proportions.

---

<sup>1</sup> <https://www.nationalgrideso.com/insights/electricity-ten-year-statement-etys>

<sup>2</sup> <https://www.nationalgrideso.com/balancing-data/data-finder-and-explorer>

<sup>3</sup> <https://www.gov.uk/government/collections/digest-of-uk-energy-statistics-dukes>

### 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.
- A small increase in summer minimum demand for additional residential air conditioning load due to the potential impact of climate change is added to FES demands for illustrative purposes. For instance, this was just under 1GW by 2050 in the period 1pm-2pm in our Steady Progression scenario in FES20. We will model air conditioning in more detail in future publications once we have sufficient quantitative evidence.

### Gas demand overview

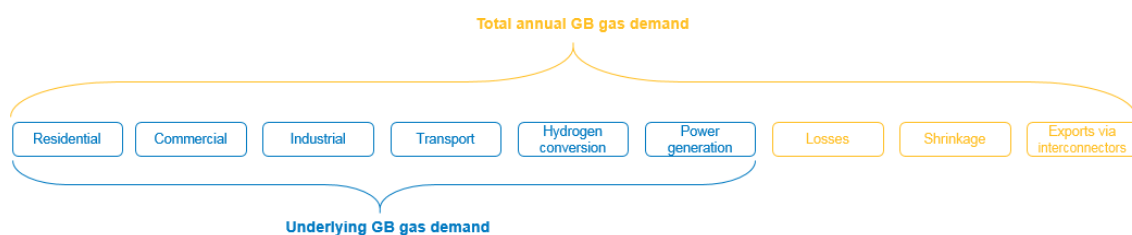


Figure 1: Total annual demand is underlying GB demand plus losses, shrinkage, and exports via interconnectors

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 Interconnector UK. In the energy demand section of the FES document, demand only refers to underlying GB demand (excluding interconnector exports) whereas in the supply section gas supplies are matched to total In view of experience from 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 agreed that it is more appropriate to use the non-climate change adjusted weather data for modelling peak demand whilst we continue to use the adjusted data for modelling average demand.

Our hybrid heat pump modelling capability uses insight from the FREEDOM Project<sup>4</sup> to more accurately represent the upturn in gas demand by these appliances in the winter period and their impact on peak gas demand.

<sup>4</sup> <https://www.westernpower.co.uk/projects/freedom>

Total underlying GB gas demand is put together by modelling the following individual gas demand components: residential, commercial, industrial, 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 scenario.

Exports to Ireland and continental Europe as well as NTS and LDZ shrinkage are added to underlying GB demand to gain total gas demand. The scenario forecasts for Irish exports are based on Gas Network Ireland's Network Development Plan 2018<sup>5</sup> covering the next 10 year period. To cover the period from then until 2050, we use some regression analysis in the shorter term, and then combine assumptions on alignment with decarbonisation targets and development of Irish gas demand with indigenous supply forecast data.

Gas demand for power station generation is derived from the pan-European BID3 generation dispatch tool 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. 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<sup>6</sup>.

### Gas for Hydrogen conversion

Natural gas use for hydrogen conversion is modelled from the total hydrogen demand values from across our heating, transport and generation demand models. The source of the hydrogen is based on FES2020 framework assumptions which are in turn informed by the research and stakeholder engagement we conduct ahead of each FES. 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 this 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.

### Industrial and commercial demand

Our industrial and commercial (I&C) demand model, ARUP, forecasts gas and electricity demand for 24 sub-sectors of I&C activity including offices, hotels, retail, agriculture, manufacturing, construction and high intensity production processing.

The primary part of the model, Macroeconomic Module (MEM) uses regression analysis, where economic output and energy prices are the principal explanatory variables. Once these two variables are determined, they feed into the second module, Energy Demand Module (EDM). Two economic scenarios comprised of 24 individual sub-sector output forecasts, and one retail energy price from Oxford Economics were used to create energy demand for the industrial and commercial sectors.

<sup>5</sup> <https://www.cru.ie/wp-content/uploads/2018/12/CRU18269a-GNI-Network-Development-Plan-2018.pdf>

<sup>6</sup> <https://www.nationalgrid.com/sites/default/files/documents/8589937808-Gas%20Demand%20Forecasting%20Methodology.pdf>

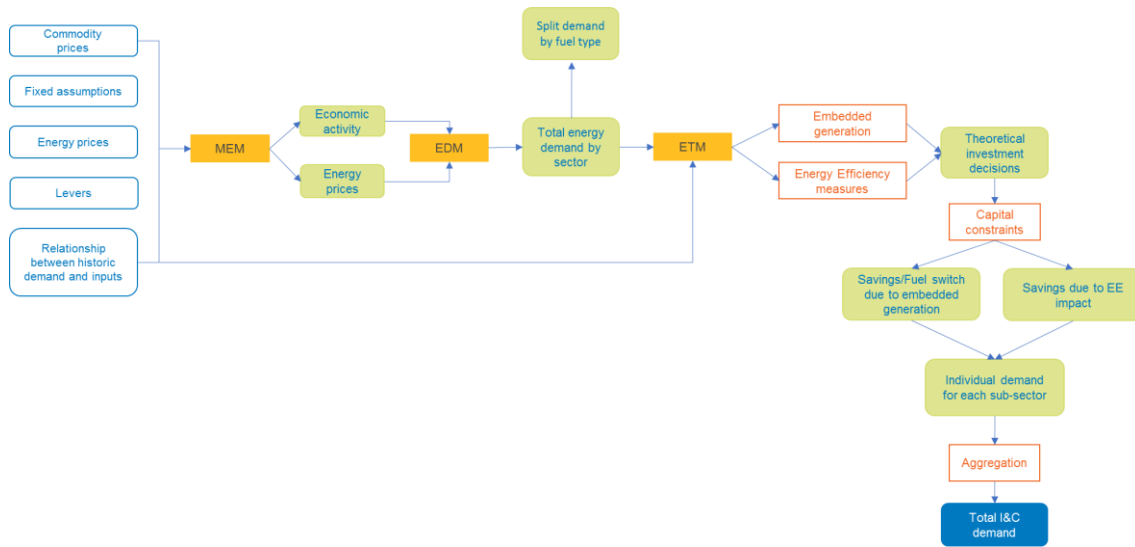


Figure 2: ARUP model for industrial and commercial demand.

The model examines these 24 sub-sectors and their individual energy demands, giving a detailed view of GB demand, and uses an error-correcting model to produce projections for each sub-sector individually. The model then has two further components in the Energy Technology Module (ETM), a bottom-up tool, that analyse how energy demand is affected by the increase in energy efficiency, and the deployment of onsite electricity generation and alternative lower carbon heating technologies.

These modules consider the economics of installing particular technologies from the capital costs, ongoing maintenance costs, fuel costs and incentives. These are used along with macro-financial indicators such as gearing ratios and internal rate of return (IRR) for each sub-sector to consider if the investment is economically viable and incorporates the likely uptake rates of any particular technology or initiative. This allows us to adjust the relative costs and benefits to see what is required to encourage uptake of alternative heating solutions and understand the impact of prices on onsite generation, which give our scenarios a wider range.

We also incorporate energy efficiency improvements in certain end uses of gas and electricity for any energy efficiency improvements not covered in the main model.

The individual sub-sector forecasts are then aggregated and the trends in gas and electricity demand forecasts are applied to the latest year of actual gas and electricity demand.

## Residential demand

The component parts we use to model residential energy demand are: appliances, lighting, heating technologies, insulation, air conditioning, and home energy management systems.

Our base housing and population assumptions, developed from analysis from Oxford Economics, are consistent across our modelling scenarios. We assume that the population of GB reaches 68.6 million and that the number of homes grows to 31.9 million by 2050 in all of our scenarios. These compare to a population of 64.9 million and 28.3 million homes in 2019.

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



For each component part, we use historical data, where available, as our starting point. The main source is BEIS' Energy Consumption in the UK<sup>7</sup> data. We also gather information on mobile phones, tablets and wi-fi routers from Ofcom's Communications Market Reports.<sup>8</sup>

## Appliances

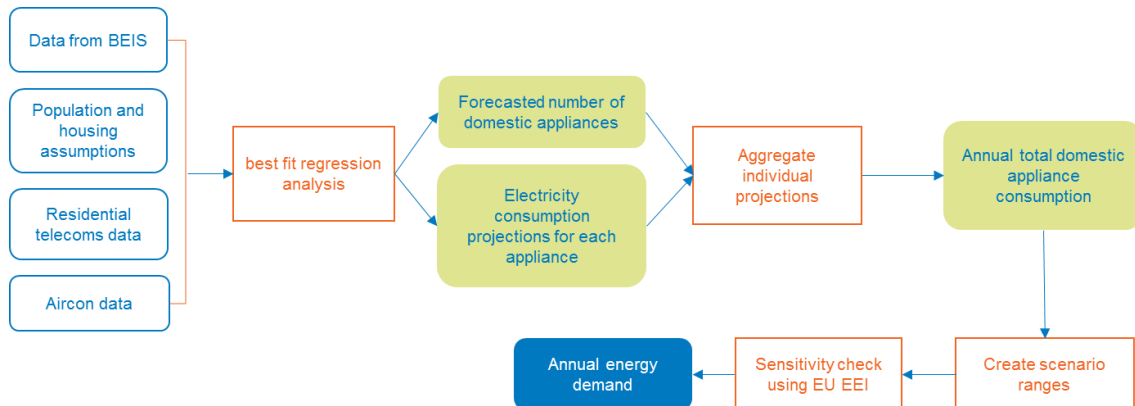


Figure 3: General appliances model

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

- A selection of historic assessments;
- Household projection data provided by external consultants;
- Outcomes from reported external projects.
- Regression analysis, based on 5 to 20 years history depending on the data quality
- Deterministic factors like social trends, government policy or global events
- Econometric methods to determine trends against social-economic factors such housing, population, GDP, productivity, household disposable income.

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 scenarios' assumptions to create the final results for each component.

## Lighting

Residential light modelling uses Energy Consumption in the UK (ECUK) data<sup>9</sup> to model possible outcomes in demand from light. Historic trends in number of bulbs and demand per bulb are modified using the potential outcomes from social trends in lighting (so called mood lighting, and multiple LEDs on decorative pieces) and light bulb policy (e.g. EU Halogen legislation).

## Heat

### Electric heating

<sup>7</sup> DECC, Energy Consumption in the UK, April 2016, <https://www.gov.uk/government/collections/energy-consumption-in-the-uk>

<sup>8</sup> <https://www.ofcom.org.uk/research-and-data/multi-sector-research/cmri>

<sup>9</sup> <https://www.gov.uk/government/collections/energy-consumption-in-the-uk>

Delta is a rule-based uptake model for domestic heating appliances. The model combines information about GB housing segments, assumed levels of building and appliance efficiencies, consumer behaviour factors, appliance and fuel costs, to calculate future domestic heating technology mix. Key outputs are number of units of each technology installed and annual consumption of electricity, gas, and other fuels.

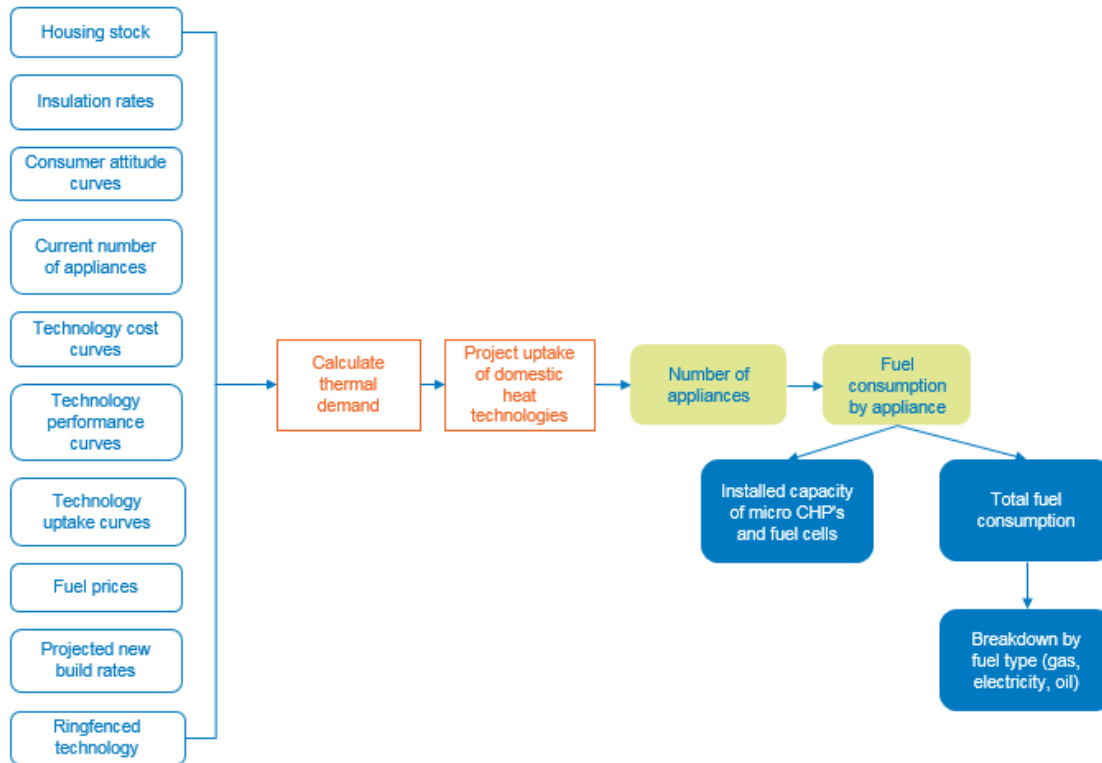


Figure 4: Delta heat pump model. Ringfenced technology includes hydrogen, distribution heat, and biofuels.

## Gas heating

For residential gas demand, we use the outcomes of our heating technology model, which creates projections of a variety of heating technologies:

- Gas boilers;
- Heat pumps, including air source, hybrid, ground source and gas;
- Fuel cells;
- Micro-combined heat and power (mCHP);
- Biomass boilers;
- Electrical resistive heating; and
- Oil boilers.

## Hydrogen heating

We include hydrogen for residential heating in all net zero compliant scenarios and we have also introduced hydrogen blending with natural gas supplies in Steady Progression. In keeping with the **Scenario Framework**, hydrogen has been developed through centralised technology of steam methane reforming (SMR) and autothermal reforming (ATR), both of which must also include carbon capture, usage and storage (CCUS) in order to be net zero compliant.

The modelling principally follows the roll out approach of the H21 study<sup>10</sup>, where over time a hydrogen network develops and enables the conversion of more and more major cities to hydrogen.

Our modelling assumes the conversion of all residential heating to hydrogen boilers within each city at the time of roll out. To do this we determine the displacement of thermal demand resulting from the hydrogen roll out and then process the remaining demand through the heating technology model.

## Road transport

The road transport model, including battery electric, plug-in hybrid electric, natural gas and hydrogen vehicles, utilises multiple strands to produce the annual demand for each fuel type. The model looks at passenger cars, light goods vehicles, heavy good vehicles, motorbikes and buses or coaches.

To model the uptake of various road transport types and fuels we use a total cost of ownership model. Assumptions on the increase and decrease of various factors include: battery costs, fuel costs, and vehicle efficiency for different scenarios, and any changes to legislation such as the ban on sales of internal combustion engines. This is reflected in our scenarios with sales of internal combustion engines removed from 2040 in our Steady Progression scenario, from 2035 in System Transformation and Consumer Transformation and from 2030 in the Leading the Way scenario. These uptake rates for the different scenarios, in relation to the expected sales projections for all vehicles, determined by the total cost of ownership and the rate of which older vehicles are scrapped, gives the expected number of low carbon vehicles on the road.

The number of miles driven per year, determined from previous average mileage, along with the propulsion ratio (kWh/Mile), produces the kWh/year of the low emission vehicle fleet.

---

<sup>10</sup> <https://www.northerngasnetworks.co.uk/wp-content/uploads/2017/04/H21-Report-Interactive-PDF-July-2016.compressed.pdf>

The influence of autonomous vehicles (level 4 automation<sup>11</sup> and above) is included within the scenarios; and where they are shared vehicles this influences the number of other 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 profile, developed under a National Innovation Allowance (NIA) project<sup>12</sup>, covering both residential and non-residential charging. The study informed that at that time, 75% of charging events occurred at the home, with the remainder at workplace and public charge points. Assumptions on the split of annual charging amounts between different charging locations are included on a scenario basis; for example, more residential charging is included in decentralised scenarios; whilst more public charging is included in centralised scenarios.

The following table shows the charging location assumptions in the FES 2020 Scenarios for cars, vans and motorbikes, and excludes cars used as autonomous taxis in the Leading the Way scenario. Robot taxis are assumed to charge at depots, off peak time. Buses and HGV charging is assumed to equally split between work and public charging locations. At the evening winter peak on the transmission system (5pm-6pm), home charging is assumed to be influenced by time of use tariffs, whereas public and workplace charging is assumed to be non-smart as drivers prioritise their journey home.

*Table 1: FES2020 Assumed Car, Van and Motorbike Charging Locations at time of system demand peak. This excludes vehicles that are used as autonomous taxis which are assumed to charge at other times of day. Vans and HGVs are split equally between Work and Public charging locations in all scenarios*

Scenario	Residential	Work	Public
Consumer Transformation	79%	13%	8%
System Transformation	41%	24%	36%
Leading the Way	75%	15%	11%
Steady Progression	55%	20%	25%
Five Year View	75%	15%	11%

### Vehicle-to-Grid

During 2019 we consulted on our Vehicle-to-Grid (V2G) analysis and carried out a “Bridging the Gap”<sup>13</sup> information gathering exercise on future road transport. Following feedback received through these, we have built on our assumptions from the conservative approach taken in 2019, to show a wider range of outcomes in FES 2020 for V2G.

<sup>11</sup> <https://www.smmmt.co.uk/wp-content/uploads/sites/2/SMMT-CAV-position-paper-final.pdf>

<sup>12</sup> [https://www.smarternetnetworks.org/project/nia\\_ngso0021](https://www.smarternetnetworks.org/project/nia_ngso0021)

<sup>13</sup> <https://www.nationalgrideso.com/news/future-energy-scenarios-bridging-gap-net-zero>

We assume that:

- Only a proportion of the most engaged consumer segments will participate in vehicle to grid 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 2019.
- On average, owners offer 50kWh in their battery for V2G use.
  - This takes into account the average 2018 UK daily car commute of 20-30 miles (Department for Transport Average Annual Car Mileage).
  - Mass market electric cars on sale as of 2020 have a minimum usable range of 90 miles, leaving at least half the theoretical range unused at the end of each day.
  - We have taken this to equate to circa 50kWh of residual charge available to V2G and used this value within the analysis.
  - As this is an emerging area we will continue to review these assumptions in future publications.
- There is a slight delay between adopting an electric vehicle, and adopting a time of use tariff or Vehicle to Grid Tariff.
- V2G becomes a mass market option from the mid- 2020s (EU: CCS V2G standard planned for rollout).<sup>14</sup>

The following table summarises our assumptions in FES 2020 for driver adoption of Vehicle- to- Grid and Time of use tariffs (TOUTs). Feedback is welcome as these assumptions are new for FES 2020. Further details the derivation of percentages is available in the later discussion of demand side response modelling.

Table 2: Assumptions in FES20 for time between ownership of an electric vehicle and participation in smart charging & V2G, along with assumed adoption rates of each

	Years Lag: Smart Charging	Years Lag: V2G	Participation in Smart Charging	Participation in V2G
Consumer Transformation	0	5	73%	26%
System Transformation	1	10	60%	12%
Leading the Way	0	5	83%	45%
Steady Progression	2	15	54%	11%
Five Year View	1	5	66%	13%

<sup>14</sup> <https://theenergyst.com/evs-v2g-vehicle-to-grid-battery-storage-smartgrid/>

## Whole system view

### Whole system demand

#### AEDAS

The main purpose of AEDAS is 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 3: Suppliers and inputs of AEDAS

Supplier	Inputs
Appliances Model	<ul style="list-style-type: none"> <li>Annual electrical demand from cold, computing, cooking, consumer entertainment, lighting, wet and air conditioning appliances</li> </ul>
ARUP	<ul style="list-style-type: none"> <li>Raw electricity demand with industrial &amp; commercial heat pumps included</li> </ul>
BEIS - Energy Trends	<ul style="list-style-type: none"> <li>Annual residential, industrial and commercial demand</li> </ul>
Delta heat	<ul style="list-style-type: none"> <li>Annual demand</li> </ul>
Distributed generation	<ul style="list-style-type: none"> <li>Total capacity</li> <li>Annual generation</li> <li>Peak and minimum generation</li> <li>Summer generation output under normal and average warm spell conditions</li> </ul>
District heat	<ul style="list-style-type: none"> <li>Annual demand. Peak and minimum demands calculated in AEDAS, based on heat pump peak modelling</li> </ul>
DSR Model	<ul style="list-style-type: none"> <li>Residential Demand Side Respond (DSR)</li> <li>Industrial and commercial DSR</li> <li>Triad split of generation and DSR</li> </ul>
BEIS - ECUK	<ul style="list-style-type: none"> <li>Heat and rail demand</li> </ul>
Electricity supply team	<ul style="list-style-type: none"> <li>Distribution wind double count correction</li> </ul>
Elexon	<ul style="list-style-type: none"> <li>Outturn and weather corrected data</li> <li>Annual demand</li> <li>Half hourly residential profiles</li> <li>Direct connects demand</li> </ul>

---

ETYS	<ul style="list-style-type: none"> <li>• Peak transmission losses</li> </ul>
EV	<ul style="list-style-type: none"> <li>• Annual demand, peak demand, summer min am/pm, V2G data</li> </ul>
Heat pump	<ul style="list-style-type: none"> <li>• Peak and minimum demand, impact of home thermal storage</li> </ul>
Hydrogen	<ul style="list-style-type: none"> <li>• Annual SMR demand</li> <li>• CCS demand (non hydrogen)</li> <li>• Electrolysis demand</li> <li>• Hydrogen Storage Demand</li> </ul>
Storage	<ul style="list-style-type: none"> <li>• Capacity (storage)</li> <li>• Power (charge/discharge)</li> <li>• Annual demand</li> <li>• Peak and minimum demand and load factors</li> </ul>
UKTM	<ul style="list-style-type: none"> <li>• Soft guidance on demand levels for 2050 compliance</li> </ul>
Week 24	<ul style="list-style-type: none"> <li>• Distribution losses (~6%)</li> </ul>
ESO short term demand forecast	<ul style="list-style-type: none"> <li>• Historic demand</li> <li>• Transmission losses (~2%)</li> <li>• Station demand (600MW at peak, 400MW Summer, 5TWh/yr)</li> <li>• Pumping demand (5TWh/yr)</li> <li>• Annual/Minimum/Peak demand on the transmission system</li> </ul>

---

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 FES with the best data available to National Grid ESO.

Demand scenarios are compared against historic out-turn data and scenarios, and projections made by Committee on Climate Change, UKTimes and BID3 to ensure that demands within the FES are credible and consistent with other views.

### MAGDEM

Similarly, MAGDEM aggregates total gas demand from individual components, and then splits it by LDZs. Each model from the table below feeds into MAGDEM.

Table 4: Suppliers and models that feed gas demand data into MAGDEM

**Model components**

- LDZ monitor
- Large loads
- NTS shrinkage
- Gas distribution networks
- Moffat interconnector
- BEIS - planning
- BID3
- Gas supply match
- ARUP
- District heat
- Delta heat

**Electricity supply**

Electricity supply components include electricity generation installed capacity, electricity generation output, interconnectors and storage. Our scenarios 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 industrial and commercial 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 addition, in all scenarios there is enough supply to meet demand. This means all scenarios meet the reliability standard as prescribed by the Secretary of State for Business, Energy and Industrial Strategy – 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 the Transmission Entry Capacity (TEC) Register<sup>15</sup>, Embedded Register<sup>16</sup>, Interconnector Register<sup>17</sup> and data procured from third parties. In addition, we consider commercial contracts such as Capacity Market (CM) Contracts and Contracts for Difference. 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. Examples of these assumptions are that there is no coal fired generation after 2025 and that the 30GW of offshore wind targeted by 2030 will be met in all the net-zero compliant scenarios. Beyond 2030, less market intelligence available so we rely more on our framework assumptions that are used to reflect uncertainty across the scenarios. These can be accessed in the **Scenario Framework** document.

The electricity supply analysis in FES does not include network or operability constraints on the transmission or lower voltage networks. As an example, to illustrate what this means, we assume there are no internal network constraints on the GB network. In terms of operability, this approach means we don't constrain our scenarios to include plant that may be required to provide system services such as inertia, frequency response or voltage support. These challenges are assessed as part of our other Electricity System Operator publications, which use the FES assumptions. Network capability is assessed

<sup>15</sup> <https://www.nationalgrideso.com/connections/registers-reports-and-guidance>

<sup>16</sup> <https://www.nationalgrideso.com/connections/registers-reports-and-guidance>

<sup>17</sup> <https://www.nationalgrideso.com/connections/registers-reports-and-guidance>



as part of the ETYS<sup>18</sup> and Network Options Assessment (NOA)<sup>19</sup>. Future operability challenges are analysed in the System Operability Framework (SOF)<sup>20</sup>.

### Transmission installed capacities

The electricity supply transmission installed capacities uses a rule based deterministic approach. This consists of an individual assessment of each power station (at a unit level where appropriate) is completed, considering a wide spectrum of information, analysis and intelligence from various sources, such as those mentioned above.

The scenario narratives provide the uncertainty envelope that determines the emphasis placed on the different types of generation technology within each scenario. 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.

### 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 13 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).

---

<sup>18</sup> <https://www.nationalgrideso.com/insights/electricity-ten-year-statement-etys>

<sup>19</sup> <https://www.nationalgrideso.com/insights/network-options-assessment-noa>

<sup>20</sup> <https://www.nationalgrideso.com/insights/system-operability-framework-sof>

For sites greater than 1MW we consider 30 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 (ACT) CHP
- Gas Reciprocating Engines
- Waste
- Anaerobic Digestion CHP
- Fuel Oil
- Wave
- Biomass CHP
- Advanced Conversion Technology (ACT)
- Solar
- Geothermal CHP
- Anaerobic Digestion
- Wind Onshore
- Sewage CHP
- Coal CHP
- Wind Offshore
- Waste CHP
- Biomass Dedicated
- Battery
- Onsite Generation
- Hydro
- Compressed Air
- CCGT
- Landfill Gas
- Liquid Air
- OCGT
- Sewage
- Pumped Hydro

To determine the current volumes of renewable generation we obtain data from various sources including the Ofgem Feed in Tariffs (FiT) register<sup>21</sup> and the Renewable Energy Planning Database<sup>22</sup>. For thermal generation we use the Combined Heat and Power Quality Assurance (CHPQA) register<sup>23</sup> 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 11 technologies:

Table 6: Technologies included in sub 1MW generation

**Technologies for renewable and thermal generation, sub 1MW capacity**

- Biogas CHP
- Battery
- Biomass CHP
- Hydro
- V2G
- Fuel Cell
- mCHP
- Solar
- Anaerobic Digestion
- Wind
- Gas CHP

<sup>21</sup> <https://www.ofgem.gov.uk/environmental-programmes/fit/electricity-suppliers/fit-licensees>

<sup>22</sup> <https://www.gov.uk/government/collections/renewable-energy-planning-data>

<sup>23</sup> <https://www.gov.uk/guidance/combined-heat-power-quality-assurance-programme>

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

## Electricity generation output

### BID3

Since FES 2017, we have calculated power generation output using a model created by AFRY<sup>24</sup> called BID3. This is a pan-European electricity dispatch model capable of simulating the electricity market in GB and other countries.

The model uses the supply and demand assumptions as inputs. This includes all of our capacity assumptions, annual demands and fuel prices. The full list of inputs and outputs is summarised in Table 7 below. The simulations are based on end-user consumption meaning that generation connected to both transmission and distribution networks are considered as supply.

---

<sup>24</sup> Formally known as Pöyry. <https://afry.com/en/service/bid3-afrys-power-market-modelling-suite>

Table 7: Inputs and outputs of BID3 model

<b>Inputs</b>	<b>Sources</b>
<ul style="list-style-type: none"> <li>• Installed and projected generation capacity data</li> <li>• Interconnector capacity data and projections</li> <li>• Forecast annual demand data</li> <li>• Demand Side Response volume &amp; prices</li> </ul>	<p><b>Capacity Market Registers</b></p> <ul style="list-style-type: none"> <li>• Generation data</li> <li>• Interconnector data</li> </ul> <p><b>Internal FES modelling</b></p> <ul style="list-style-type: none"> <li>• Annual demand data</li> <li>• Demand Side Response</li> </ul> <p><b>AFRY</b></p> <ul style="list-style-type: none"> <li>• Plant information</li> <li>• Historic weather profiles</li> </ul> <p><b>ENTSO</b></p> <ul style="list-style-type: none"> <li>• European scenario data</li> </ul> <p><b>ENTSO, AURORA, Oxford Economics, BEIS, Wood Mackenzie, Ofgem</b></p> <ul style="list-style-type: none"> <li>• Fuel and carbon prices</li> </ul>
<b>Outputs</b>	
<ul style="list-style-type: none"> <li>• Power station generation</li> <li>• Interconnector flows</li> <li>• Emissions</li> </ul>	

BID3 works by seeking to find the optimised way to meet demand using available generation, based on minimising total cost. It can analyse the impact of different weather conditions using profiles based on historic actual demand. The electricity generation output modelling for FES 2020 is based on the historic year of 2012 as this is deemed to be a fairly average year with colder and milder spells. BID3 creates an hourly time series of demand using the annual value from FES and the relevant historic hourly profile according to:

$$\text{BID3 hourly demand} = \text{FES annual demand} / (24 * 365 * \text{hourly profile value})$$

The total generation output from BID3 may be slightly different from the annual demand numbers published in FES. There are several contributing factors, which include that the BID3 output is used to meet demand from interconnector exports and storage and the fact we use actual weather from a particular year.

All electricity generation is modelled with an average availability to allow for maintenance and to simulate forced outages. This varies on a monthly or quarterly basis to allow for seasonal variations and is based on observed patterns from history. The electricity generation output is calculated by modelling GB and Europe. The outputs from the dispatch model are used to produce the FES annual power generation outputs for different generation technologies including interconnector annual flows. In addition, the outputs from Combined Cycle Gas Turbines (CCGTs) are used as an input for the gas demand modelling.

### Electricity power generation carbon intensity

The electricity generation output modelling done within BID3 also calculates the amount of carbon emitted for each plant in tonnes. The model calculates CO<sub>2</sub> emissions for boiler use, no-load, start up and generation as part of the calculation for meeting hourly demand. Utilising the same dispatch data from the BID3 model as for electricity generation output, the CO<sub>2</sub> intensity is calculated according to:

$$\text{CO}_2 \text{ intensity (g/kWh)} = \frac{\text{CO}_2 \text{ emissions from generation (g)}}{\text{Electricity generation output (kWh)}}$$

Electricity generation output refers to GB generation only. Please see more information in the FES Data Workbook.

This carbon will include all generation within the supply assumptions that are dispatched to run by the BID3 model. The current carbon intensity forecast by National Grid Electricity System Operator<sup>25</sup> will only include those sites that the ESO has visibility of<sup>26</sup>; therefore, there will be differences between the two values as the methods and data are different.

<sup>25</sup> <http://electricityinfo.org/forecast-carbon-intensity/>

<sup>26</sup> <http://electricityinfo.org/real-time-fuel-mix-and-carbon-intensity-methodology/>

## Natural gas supply

In the FES, we model natural gas that enters the National Transmission System (NTS) 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 BEIS’s Digest of UK Energy Statistics, but we do not include them in either demand or supply.

The gas supply pattern for each scenario 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 the all FES 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 scenario the supply components can be matched. The **Scenario 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.

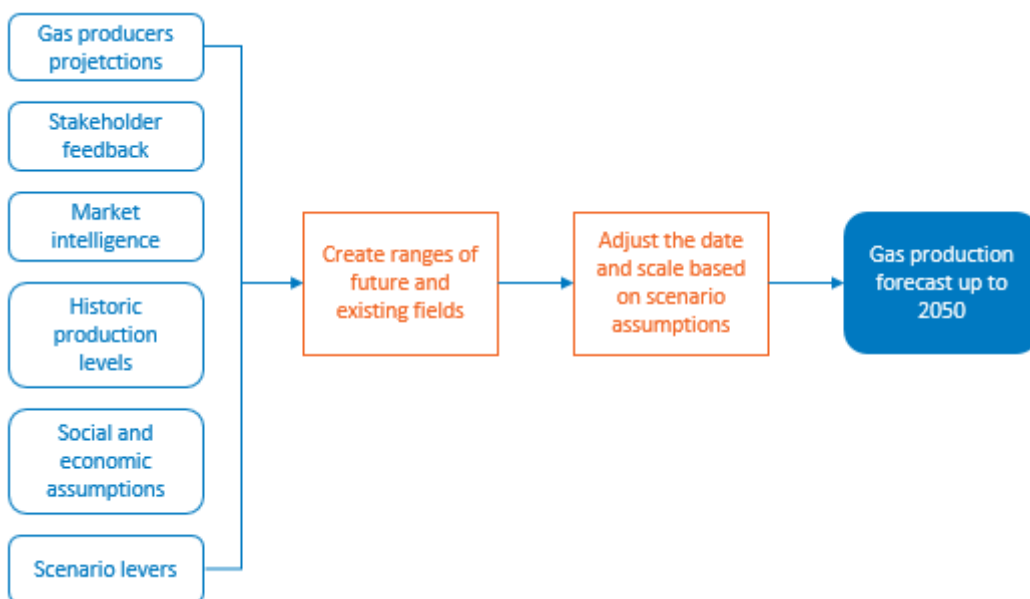


Figure 5: General gas supply process chart. Note, for continental interconnectors add European gas demand and supply data as input.

### 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 FES. 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 making adjustments to the date and scale of future field developments based on historic production and the economic and political conditions as laid out in the **Scenario 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. 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<sup>27</sup>. 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. Finally, we test our projections with industry experts to ensure our projections are credible.

### 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. For FES20, the analysis is based on a report<sup>28</sup> by UKOOG, the trade body for onshore developers. This makes use of data published by Cuadrilla following the fracking of the Preston New Road site. We use flow rates based on this report and create our high and low cases by using different assumptions on the number of wells that will be drilled.

### Liquefied natural gas (LNG)

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 north west 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 in to 2020. As projections for future

<sup>27</sup> <http://www.npd.no/en/>

<sup>28</sup> <http://www.ukoog.org.uk/images/ukoog/pdfs/Updated%20shale%20gas%20scenarios%20March%202019%20website.pdf>

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.

### Annual supply match

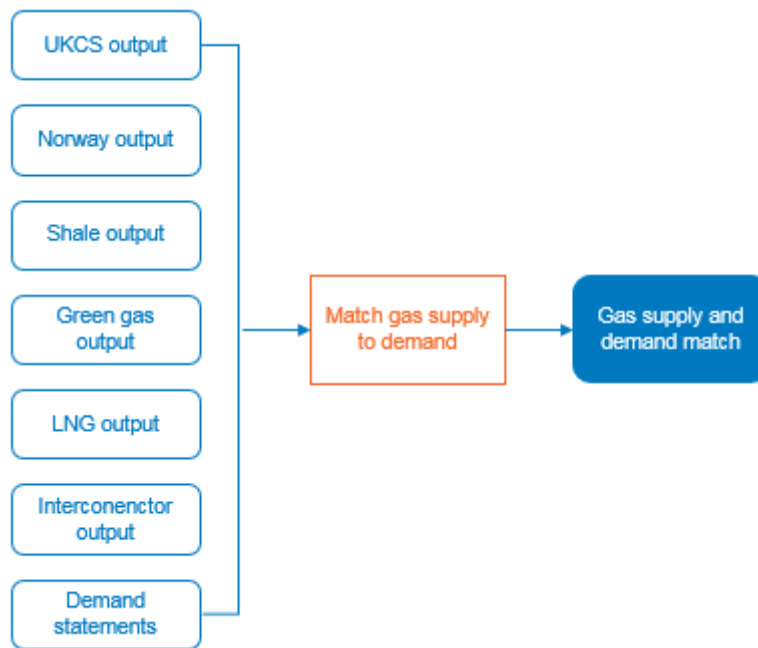


Figure 6: Annual match process chart

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 **Scenario 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 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 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<sup>29</sup>.

## Bioenergy supply

### 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. It 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 scenario. 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 (BioSNG) is a gas that is derived from household waste. 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). The supply range is based upon the flow information published in the NIC<sup>30</sup> documentation plus assumptions on the number of facilities, based upon the economic and political conditions for each scenario.

## Hydrogen supply

Hydrogen supply in each scenario is based on FES2020 framework assumptions. These are informed by the research and stakeholder engagement conducted on different hydrogen supply technologies including methane reforming with Carbon Capture Utilisation and Storage (CCUS), networked electrolysis, offshore or non-networked electrolysis, biomass gasification and hydrogen import.

Networked electrolysis is analysed in conjunction with the power generation technologies mix and the curtailment level of generation in each scenario. Offshore connected or on-shore electrolysis not

---

<sup>29</sup>

[https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment\\_data/file/753170/BEIS\\_Ofgem\\_Statutory\\_Security\\_of\\_Supply\\_Report\\_2018.pdf](https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/753170/BEIS_Ofgem_Statutory_Security_of_Supply_Report_2018.pdf)

<sup>30</sup> <https://www.ofgem.gov.uk/publications-and-updates/network-innovation-competition-project-direction-biosng>

connected to the transmission or distribution system has been analysed based on the Dolphyn project<sup>31</sup>. The period to reach cost parity between methane reforming and electrolysis is also examined. The amount of Biomass gasification for hydrogen production is included taking consideration of the total bio resources availability and other bio usages within the scenario. For various other aspects of the hydrogen supply such as hydrogen production efficiency, CCUS capture rate etc we have engaged with a wide range of stakeholders in this field in order to carry out informed analysis.

We have also considered the potential and uncertainties of international hydrogen market and included the hydrogen import in Leading the Way scenario.

### Whole system modelling (UKTM)

For our net zero scenarios, we use a cost-optimisation model, the UK Times Model<sup>32</sup> (UKTM), to guide them towards the target. UKTimes was developed at UCL with support from WholeSEM, the UKERC, and UK Government, to provide analysis of future energy systems. In meeting the carbon reduction target, UKTM selects the least-cost solution among all the possible sector and technology developments, through calculating all cost components including capital cost, fixed and variable operational cost etc., transferring future costs into present value using a discount factor.

UKTM simulates the whole energy system, considering energy demand, supply, electricity and gas networks and interconnectors. On the demand side, it uses the specific demand profiles for different products in residential, commercial and industrial sectors, as well as various vehicle types in transport sector. Efficiency factors for different products in all future years are included. The model also contains seasonal demand profiles. This combines to give an annual view of demand and supply. These inputs from the standard UKTM database are augmented with key inputs from the data gathered during the FES process and outputs of the models. These inputs override values in the “standard” UKTM database where they exist.

---

<sup>31</sup> [https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment\\_data/file/866375/Phase\\_1\\_-\\_ERM\\_-\\_Dolphyn.pdf](https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/866375/Phase_1_-_ERM_-_Dolphyn.pdf)

<sup>32</sup> <https://www.ucl.ac.uk/energy-models/models/uk-times>

Table 8: Key inputs and outputs of the UKTM model based on FES modelling

Input	Output
<b>Transport</b> <ul style="list-style-type: none"> <li>Distance per vehicle</li> <li>Total number of vehicles</li> <li>Fuel demand limit</li> </ul>	<b>Transport</b> <ul style="list-style-type: none"> <li>Electricity and hydrogen fuel demand for road and rail transport</li> </ul>
<b>Domestic Heat</b> <ul style="list-style-type: none"> <li>Total number of dwellings</li> <li>Average thermal demand</li> <li>Energy efficiency of heat pumps and non-heat appliances</li> </ul>	<b>Domestic Heat</b> <ul style="list-style-type: none"> <li>Thermal demand</li> <li>Electricity, natural gas, hydrogen fuel demand</li> </ul>
<b>I&amp;C Heat</b> <ul style="list-style-type: none"> <li>Total demand index</li> <li>Fuel demand limit</li> </ul>	<b>I&amp;C Heat</b> <ul style="list-style-type: none"> <li>Electricity, natural gas, hydrogen fuel demand</li> </ul>
<b>Hydrogen Production</b> <ul style="list-style-type: none"> <li>Electrolysis limit</li> <li>SMR+CCUS limit</li> </ul>	<b>Hydrogen</b> <ul style="list-style-type: none"> <li>Hydrogen volume produced</li> <li>Electricity, natural gas demand</li> </ul>
<b>Power Generation</b> <ul style="list-style-type: none"> <li>Capacity limit</li> <li>Generation volume limit</li> </ul>	<b>Power Generation</b> <ul style="list-style-type: none"> <li>Capacity and generation volume for main generation type</li> </ul>
<b>Emissions</b> <ul style="list-style-type: none"> <li>Limit in each sector</li> </ul>	<b>Total Bio and natural gas</b>

On the supply side, it considers gas supply and electricity generation from different sources and different technologies. Existing capacities and load factors are available for each technology, and operational cost information is also included, for future development, minimum and maximum capacity constraints as well as growth rate constraints are set up, to make sure all the developments are within realistic ranges.

Overall, more than 2000 processes are included for each model run, to ensure energy flow is within network capacity, supply meets demand, and the whole system is balanced on an annual, seasonal, and daily peak basis. Given specific assumptions for particular technology development, different scenarios that meet 2050 carbon reduction target at lowest cost can be generated.

UKTM is used to provide guidance for the scenarios that meet the 2050 decarbonisation target. We also use the extensive carbon emission data and economic data contained within the model to determine the emission level within the scenario.

We carry out further validation of the electricity supply pattern produced by UKTM by replicating the electricity demand and generation in the BID3 model described in the Electricity generation output section. BID3 models the electricity generation in considerably more detail than UKTM and this check ensures that we have an acceptable mix of generating capacity.

## Flexibility

Energy systems need to continuously match supply to demand, we call this energy balancing. Energy system flexibility is the ability to adjust supply and demand to achieve that energy balance.

To meet net zero, flexibility will become more important in all areas due to factors such as growth in levels of renewable generation, increasing electrification of heat and transport and changes in consumer behaviour. Electricity system flexibility is the area that has the greatest need for change due to the significantly increased demand we expect due to the way we heat our homes and go about our lives and the lower amount of spare capacity this leaves on the existing network at peak times. We expect electricity demand to increase in all scenarios, and in a net zero world we expect increased consumer engagement, particularly in scenarios with higher levels of societal change. This increased demand presents an opportunity for greater levels of flexibility.

Modelling of flexibility covers:

- Residential Demand Side Response (DSR);
- Industrial and commercial DSR;
- Vehicle- to- Grid;
- Electricity peaks; and
- Hydrogen production.

## 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<sup>33</sup>). This is end consumer demand plus losses. For clarity, it does not include exports, station demand, pumping demand and storage demand.

FES End User or FES Customer demand is intended to reflect customer end use demand and differs from “system demand” by not including losses and demand for electrolysis.

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).

---

33

[https://www.emrdeliverybody.com/Lists/Latest%20News/AllItems.aspx?&&p\\_Created=20161115%2011%3a17%3a12&&PageFirstRow=1&FilterField1=Category&FilterValue1=CM&&View={C0855C66-F67D-4D84-9C26-CD4CAE25D06A}&InitialTabId=Ribbon%2ERead&VisibilityContext=WSSTabPersistence](https://www.emrdeliverybody.com/Lists/Latest%20News/AllItems.aspx?&&p_Created=20161115%2011%3a17%3a12&&PageFirstRow=1&FilterField1=Category&FilterValue1=CM&&View={C0855C66-F67D-4D84-9C26-CD4CAE25D06A}&InitialTabId=Ribbon%2ERead&VisibilityContext=WSSTabPersistence) – under “Electricity capacity Report 2017”

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.
- FES 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 BEIS)
- 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 FES models
- The residential annual to peak ratio is assumed to be true, and the Industrial and Commercial annual to peak ratio is derived from the remaining peak demand
- The remaining annual industrial and commercial 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 demand side response (true demand reduction) – currently we believe of the 2.4GW of triad response observed, 1.4GW is due to behind meter generation, and 1,0 GW is due to pure demand side response. So 1GW of demand is added to the peaks derived above
- 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

Peak electrical demand from heat pumps is modelled by applying the annual outputs from the heating technology model to heat pump demand profiles. The profiles were obtained from the Customer Led Network Revolution (CLNR) trials<sup>34</sup>.

---

<sup>34</sup> Customer Led Network Revolution: Project Library. Dataset TC12  
<http://www.networkrevolution.co.uk/resources/project-library/>

Key current assumptions in this work are as follows:

- Some level of thermal storage has been assumed in all scenarios. For FES20 we have assumed a high of 40% and a low of 20%. The 40% upper limit is in consideration of the high levels of thermal insulation in the Leading The Way and Consumer Transformation scenarios which makes economic case for additional storage weaker.
- The heat pump model now makes an explicit link between the performance efficiency and temperature at winter peaks. This estimates peak day performance for Air Source Heat Pumps, Ground Source Heat Pumps, and Hybrid Heat Pumps from a temperature vs Coefficient of Performance (CoP) relationship and assumes a temperature on the day of the demand peak of -1.8°C. The -1.8°C is taken from the heat pump design standard MIS 3005 which require heat pumps be sized to meet demand on 99% of days of the year. -1.8°C also aligns with 1-in-2 temperature calculated from historic weather data. This is assumed to be equivalent to “Average Cold Spell” conditions.
- Some supplementary heating assumed at ACS conditions. This is accounted for as an impact on CoP, currently assumed as 10% decrease. Equivalent to 7% of all homes with a Heat Pump running a 3KW back up resistive heater
- On a peak day, heat pumps in hybrid systems will still draw a small amount of energy to keep pumps and ancillary equipment running even when all of the heating is provided by the natural gas or hydrogen.

### Industrial and commercial electricity demand side response (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 demand side response information from the EMR Capacity Market Register, and Balancing Service contracts. This then forms two different modelled components:

1. 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.
2. 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.

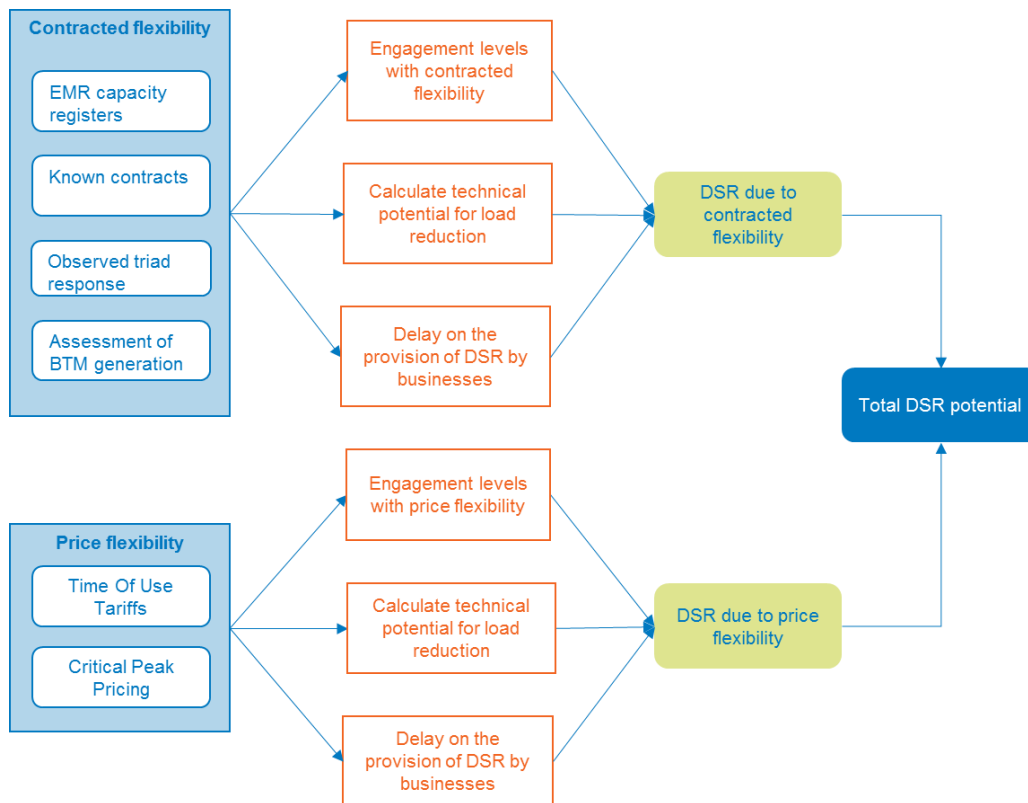


Figure 7: Industrial and commercial DSR process chart

The above steps produced 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<sup>35</sup> and Energyst reports<sup>36</sup> were used to understand the current status of ‘load reduction only DSR’ and the trends were then extrapolated for the future potential.

DSR from commercial heat pumps is modelled separately to this process, within the Industrial and Commercial modelling process. In the FES 2020 scenarios, annual heat demand is assumed to be electrified where economic to do so. It is assumed that commercial heat pumps replace space heating which is current provided by gas. Annual demand data from this process is used to generate peak and minimum demands. Within ACS peak conditions it is assumed prices are high, which in turn encourages commercial heat pumps to cease operations for up to 30 minutes – sufficient to provide a response without adversely affecting space heat requirements. All commercial heat pump load modelled is assumed to perform DSR under high price conditions.

New for FES 2020: Industrial heat pumps are assumed to be part of a larger end to end manufacturing process. No DSR from heat pumps in this sector is assumed. If further information becomes available we will begin to make assumptions for this sector.

<sup>35</sup> <https://www.emrdeliverybody.com/CM/Registers.aspx>

<sup>36</sup> <https://theenergyst.com/digital-editions/market-reports/>

### 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 in FES 20

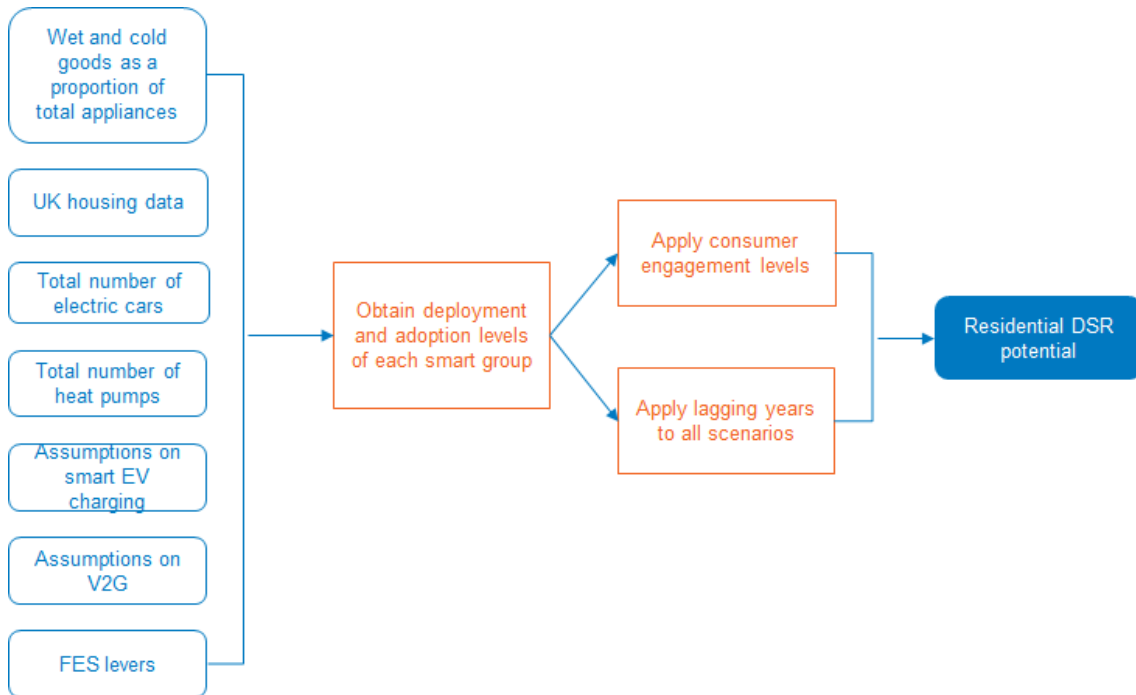


Figure 9: Residential DSR

Prior to FES 2020, we had a general market model which used generic, relevant levers and historic comparators to model residential demand side response uptake. We have built a new DSR model for FES 2020.

Stakeholder feedback gathered in 2018 and 2019 strongly indicated the first and strongest consumer adoption of time of use tariffs (TOUTs) occurs on ownership of their first electric vehicle as this is a significant electrical demand and 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, electric vehicle brochures and energy supplier information. We also believe a similar effect will occur if a home owner 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 electric vehicles. Once a consumer is introduced to TOUTs for EV charging, it is then assumed that as their household appliances are replaced over following years, smart energy using devices have an increased presence within the home.

The residential DSR scenarios are built on the assumption that DSR’s 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 demand side response grow as participation with smart technology develops and varies depending on the specific scenario 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 FES Road Transport Model
  - Heat Pump (HP) ownership levels from the Delta Heat Model
- Consumer Switching behaviour data from Ofgem, used to differentiate the scenarios (Table 9 below)
- 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 DSR.
- Annual demand savings for appliances only in the range 1%-4% are assumed, reflecting evidence from trials.<sup>37</sup>

Further Assumptions:

- Number of years lag between purchase of an Electric Vehicle (EV) or Heat Pump (HP) and adoption of a time of use tariff.
- Number of years lag between purchase of an EV or HP and adoption of a Vehicle to Grid (V2G) 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 scenarios.
- 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.

<sup>37</sup> AECOM Review of Smart Meter Trials for Ofgem: <https://www.ofgem.gov.uk/gas/retail-market/metering/transition-smart-meters/energy-demand-research-project>

The key FES 2020 assumptions with the DSR model are shown in the tables below:

*Table 9: FES20 Residential DSR Model - Lag in adoption of demand side response and annual savings from smart technology*

	Annual Saving	Years Lag: Smart Charging	Years Lag: V2G	Year Lag: Appliances
Consumer Transformation	3%	0	5	8
System Transformation	2%	1	10	12
Leading the Way	4%	0	5	6
Steady Progression	1%	2	15	12
Five Year View	1%	1	5	10

*Table 10: Engagement with Time of Use Tariffs (TOUTs) and Vehicle to Grid services (V2G)*

	General Engagement with TOUTs	V2G Engagement
Consumer Transformation	73%	26%
System Transformation	60%	12%
Leading the Way	83%	45%
Steady Progression	54%	11%
Five Year View	66%	13%

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<sup>38</sup>:

- Happy shoppers;
- Savvy researchers;
- Market sceptics;
- Hassle haters;
- Anxious avoiders; and
- Contented conformers.

This information is updated every year. We vary the level of engagement applied to each market segment individually based upon the **Scenario Framework** and developed assuming that certain consumer segments will evolve differently under the four scenarios 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 scenario. 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.

Ofgem’s most recent data 2017-2019 is shown in the next table, along with an average calculated by ourselves.

Table 11: Ofgem 2017 -2019 Switching Behaviour: Consumer Categories along with our assumptions on attitudes to DSR per consumer category

<b>Modelled DSR Attitude =&gt;</b>	Positive	Positive	Positive	Negative	Negative	Negative	
<b>Category =&gt;</b>	<b>Savvy Searchers</b>	<b>Happy Shoppers</b>	<b>Contented Conformers</b>	<b>Market Sceptics</b>	<b>Anxious Avoiders</b>	<b>Hassle Haters</b>	<b>Total</b>
<b>Average =&gt;</b>	15%	21%	19%	12%	14%	19%	100%
<b>2017 =&gt;</b>	13%	20%	20%	14%	13%	20%	100%
<b>2018 =&gt;</b>	13%	19%	20%	11%	16%	21%	100%
<b>2019 =&gt;</b>	19%	23%	16%	10%	14%	17%	99%

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 FES Framework levers and scenarios’ landscapes.

<sup>38</sup> <https://www.ofgem.gov.uk/publications-and-updates/consumer-engagement-survey-2018>

With regard to smart EV charging for example, high levels of engagement are assumed in all scenarios, where it is assumed that smart charging is the least disturbing option for the consumers, 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.

Our modelling FES is not a prediction of future consumer behaviour however we are aiming to represent a credible range of possible consumer behaviours within the FES Framework.

## Electricity storage

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

- Various types of battery technologies;
- Pumped hydroelectricity storage (PHES);
- Compressed air electricity storage (CAES); and
- 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 and data procured from a third party to better understand the potential of storage as well as those currently underway or under development. To create a range of outcomes we have examined the current deployment of storage technologies, the potential revenue streams available, as well as pairing storage with renewable technologies such as wind and solar PV. From this we have created a range of transmission and distribution connected technologies as well as some at domestic level.

AFRY's BID3 software is used to examine the usage of storage on the system to determine the potential utilisation under the generation mix for each scenario and year.

## Interconnectors

### Electricity interconnector capacities

We have developed electricity interconnector capacity projections to establish the level of interconnection we expect in each scenario and its associated build profile. There is a range of electricity interconnector capacity represented across the scenarios. 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; and
- Benchmarking against other published scenarios and stakeholder engagement with industry.

The total level of interconnection in each scenario is informed by the **Scenario Framework**.

Interconnector capacities are higher in the scenarios 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 scenarios.

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<sup>39</sup>, 4C Offshore<sup>40</sup> and the European Commission<sup>41</sup>. Where only a commissioning year is given, we assume the date to be 1 October of that year. Following stakeholder feedback, we have included the full list of projects that we have considered in Table 12 below. It should be noted that this only states which projects have been considered in our scenarios and not whether they have actually been included. Projects in this list could appear in all our scenarios, no scenarios or at least one scenario.

We assess each project individually against political, economic, social and technological factors to determine which interconnector projects would be built under each scenario. If it does not meet the minimum criteria we assume it will not be delivered in the given scenario, 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 scenarios.

In all the scenarios, 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.

The table below lists all the potential interconnector projects that we have considered in our scenarios. This also shows the neighbouring markets that we assume the project will connect to. Projects in this list may appear in all our scenarios, no scenarios or at least one scenario. In addition to the projects in this list we also consider additional ‘dummy’ projects to neighbouring markets that may not have started development yet. 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 scenarios.

---

<sup>39</sup> ENTSO-e, Ten-Year Network Development Plan 2018, <https://tyndp.entsoe.eu/tyndp2018/>

<sup>40</sup> 4C Offshore, Offshore Interconnectors, <http://www.4coffshore.com/windfarms/interconnectors.aspx>

<sup>41</sup> <https://ec.europa.eu/energy/en/topics/infrastructure/projects-common-interest>

Table 12: Potential interconnector projects considered in FES20. This only states which projects have been considered in our scenarios and not whether they have actually been included. Projects in this list could appear in all our scenarios, no scenarios or at least one scenario

Country	Projects considered
Belgium	Cronos, Nautilus, Nemo Link
Denmark	Aminth, Viking Link
France	Aquind, Channel Cable, Eleclink, FAB Link, Gridlink, IFA, IFA2, Kulizumboo
Germany	NeuConnect, Tarchon
Iceland	Atlantic Superconnection
Ireland	East-West Interconnector, Gallant, Greenconnect, Greenlink, MARES, Moyle
Netherlands	Britned, Eurolink
Norway	Continental Link, Maali, NorthConnect, NSL
Spain	ANAI, BritIB

### Electricity interconnector annual and peak flows

BID3 has been used to model all markets that can impact interconnector flows to GB for our four scenarios. As with FES19, this includes: Belgium, Czech Republic, Denmark, Finland, France, Germany, Ireland, Italy, Netherlands, Northern Ireland, Norway, Poland, Portugal, Slovakia, Sweden and Switzerland. From FES20 Austria, Slovenia, Luxembourg and Spain are also included. All our pan-European modelling assumes that Great Britain continues to be in the Internal Energy Market (IEM) or has arrangements very similar to the IEM once the UK leaves the European Union. These assumptions may change in future as we get greater clarity on the future relationship between the UK and the rest of the EU.

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<sup>42</sup>. However, there are a few differences between the EMR and FES analysis. Firstly, because the FES 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 FES 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). The EMR de-rating factors are based on the final, published, FES assumptions.

<sup>42</sup>

[https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/189/Electricity%20Capacity%20Report%202018\\_Final.pdf](https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/189/Electricity%20Capacity%20Report%202018_Final.pdf)

The market fundamentals of the neighbouring countries are strongly inspired by reports from national electricity Transmission System Operators (TSOs) and the ENTSO-E Ten Year Network Development Plan (TYNDP) edition for 2018<sup>43</sup>. From FES 2018, we have used scenarios from these sources to model uncertainties such as the speed of decarbonisation in Europe. In FES 2018, scenarios were developed for: Belgium, Denmark, France, Germany, Ireland, the Netherlands, Northern Ireland and Norway. In response to stakeholder feedback, we have extended the geographical scope to cover Italy (north), Poland, Spain and Sweden. As most European TSOs and ENTSO-E update their longer-term scenarios every two years, there has been no significant update to our supply and demand assumptions in Europe since FES 2018 and FES20 continued to use the same assumptions as in the previous two publications. The table below shows the sources we have used for countries in Europe and how we have aligned the scenarios in those reports with those for Great Britain in FES. The alignment of scenarios in Europe to those in FES was based on consideration of several factors including the speed of decarbonisation, level of decentralisation as well as other supply and demand drivers.

---

<sup>43</sup> <http://tyndp.entsoe.eu/tyndp2018/>

Table 13: European energy scenarios

Country	Source	Consumer Transformation	System Transformation	Leading the Way	Steady Progression	Five Year Forecast
Belgium	ELIA <sup>44</sup>	Large Scale RES	Large Scale RES	Large Scale RES	Base Case	AFRY Central
France	RTE <sup>45</sup>	Ampere	Ampere	Ampere	Hertz	AFRY Central
Ireland	Eirgrid <sup>46</sup>	Low Carbon Living	Low Carbon Living	Low Carbon Living	Slow Change	AFRY Central
Denmark, Germany, Northern Ireland, Italy (north), Netherlands, Poland, Spain, Sweden	ENTSO-E <sup>47</sup>	Global Climate Action	Global Climate Action	Global Climate Action	Steady Transition	AFRY Central
Norway	AFRY Central <sup>48</sup>	AFRY Central plus wind targets	AFRY Central plus wind targets	AFRY Central plus wind targets	AFRY Central	AFRY Central
All other countries	AFRY Central	AFRY Central	AFRY Central	AFRY Central	AFRY Central	AFRY Central

<sup>44</sup> [http://www.elia.be/~media/files/Elia/About-Elia/Studies/20171114\\_ELIA\\_4584\\_AdequacyScenario.pdf](http://www.elia.be/~media/files/Elia/About-Elia/Studies/20171114_ELIA_4584_AdequacyScenario.pdf)

<sup>45</sup> <https://www.rte-france.com/fr/article/bilan-previsionnel>

<sup>46</sup> <http://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid-Tomorrows-Energy-Scenarios-Report-2017.pdf>

<sup>47</sup> <https://tyndp.entsoe.eu/tyndp2018/>

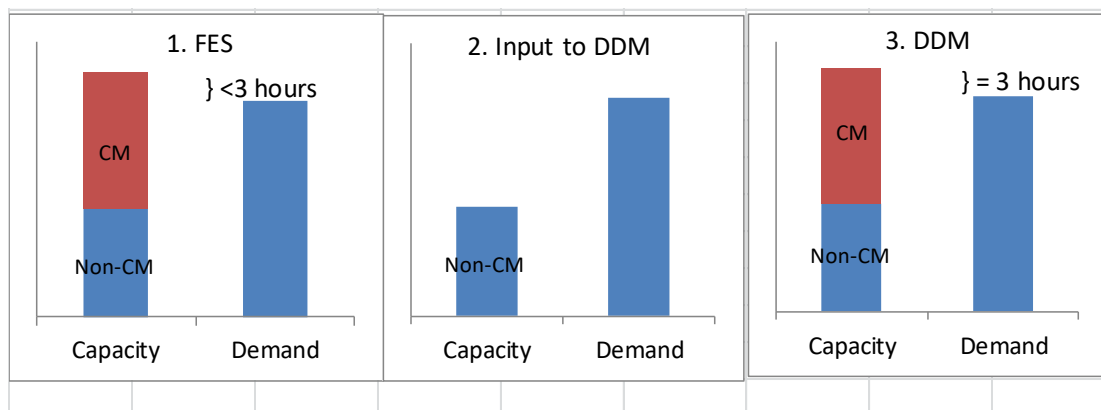
<sup>48</sup> Scenario data we procured from AFRY as part of our supplier contract for BID3



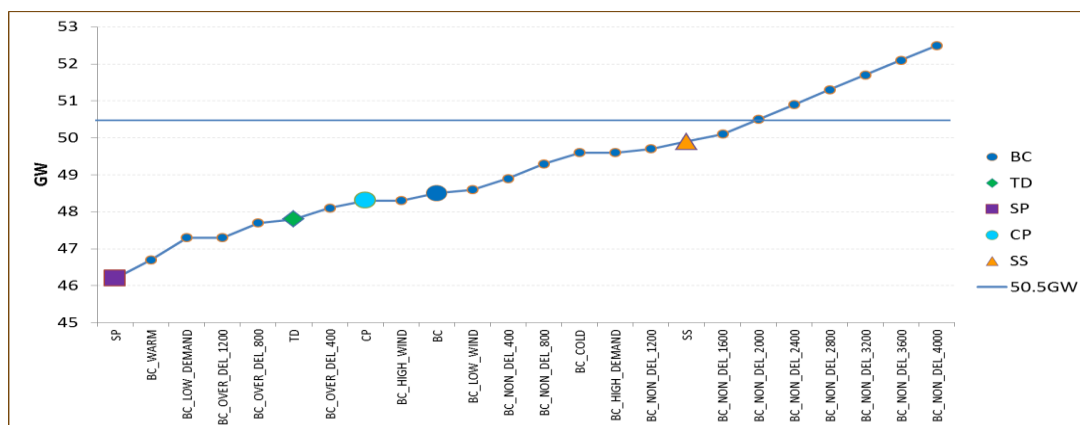
## Annex – LOLE step by step guide

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. FES scenarios plus Base Case have <3 hours LOLE
2. Input into the Dynamic Despatch Model (DDM)<sup>49</sup> Non-CM capacity for a scenario along with the demand
3. DDM run to give CM capacity required to give 3 hours LOLE



4. Repeat 1 to 3 for all scenarios and sensitivities
5. Input all scenarios and sensitivities (all = 3 hours LOLE) into LWR tool
6. Run LWR tool to give cost optimal answer



6. Resulting capacity(50.5GW) > Base Case (48.5GW) hence Base Case <3 hours LOLE
7. 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)

<sup>49</sup> Software modelling tool used for the production of the Electricity Capacity Report (ECR)

8. Update auction results for known developments e.g. unsuccessful CM plant remaining open, higher availabilities etc. which result in the Base Case and FES scenarios 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.



Faraday House, Warwick Technology Park,  
Gallows Hill, Warwick, CV346DA

[nationalgrideso.com](http://nationalgrideso.com)

**nationalgrid**ESO