January 2025

Distribution Future Energy Scenarios 2024

Customer Behaviour Profiles and Assumptions Report

nationalgrid DSO

Table of Contents

DFES 2024 Change Log

Technologies	Impact	Description
Underlying Demand	High	The previous three demand profiles have been replaced with more classes. This improvement is to better model the variety of primary substation demand patterns across the network.
Aviation, Agriculture, Rail and Maritime	High	These technologies are new to the DFES 2024 scope. All modelling and assumptions can be found in either this report, or the DFES 2024 Technology Summary Reports.
Heat networks	Medium	The modelling of heat networks has been improved to account for how heat network operators are likely to design their networks to deal with variations in heating demand. A new profile has been created, and the previous heat network profiles rescinded.
Air Source Heat Pumps	Medium	The peak demand from Air Source Heat Pumps has been amended, in line with new evidence from the DESNZ Electrification of Heat study.
Non-domestic	Low	The energy associated with non-domestic properties has been updated, in line with refreshed analysis. Non domestic heating scaling factors have also been amended to align with the NESO FES assumptions.
FES inputs	Low	All FES inputs have been updated to reflect FES 2024 data.

Produced: January 2025

Version: 1

Introduction

National Grid DSO deliver the Distribution Future Energy Scenarios (DFES) project on an annual basis for all four licence areas covered by the NGED distribution network. This provides granular scenario projections for changes in generation, demand and storage technologies which are expected to connect to the GB electricity distribution network. NGED use a scenario framework that is consistent with National Energy System Operator (NESO), along with all other Distribution Network Operators (DNOs) in Great Britain.

The DFES process can be split into three parts, each of which is summarised below:

Part 1: Volumes

The first part of the DFES process aims to provide granular scenario projections for the number of demand customers and MW of installed generation that are expected to connect to the GB electricity distribution network. The projections are informed by stakeholder engagement to understand the specific needs and plans of local stakeholders in each licence area. NGED undertake this process in conjunction with Regen. The DFES volumes are provided at an Electricity Supply Area (ESA) level, which represents the geographic area supplied by a Primary substation (which contains NG-owned distribution substations) providing supplies at a voltage below 33 kV, or a customer directly supplied at 132, 66 or 33 kV or by a dedicated Primary substation'. This allows the volumes for each technology to be spatially allocated to where it would be most likely to connect to the distribution network.

The output of this process is a large dataset of granular projections for different technologies, years, scenarios and areas of the NGED distribution network, along with a suite of reports. The data is available on the interactive DFES map on the NGED website. It provides a key data resource and evidence base to enable NGED to appraise different investment options and develop the business case necessary to support future investment, including regulated business plans.

Part 2: Customer Behaviour

For the DFES volume projections to be used by NGED in strategic network analysis, customer behaviour assumptions are allocated to the projected volumes. This accounts for the expected demand and generation profiles of new and existing customers connected to the distribution network. The output of this process is a dataset of load profiles suitable for strategic analysis of the distribution network.

Part 3: Power and energy growth data and application of growth rates

Once the expected customer behaviour assumptions are applied to the DFES volume projections, a demand set of the expected loads on the NGED distribution network can be generated. This data is then mapped to a network model in power system analysis software to undertake detailed network analysis. This data will be published on the DFES map to allow the customer to investigate future network loadings.

The MW/MVAr growth dataset for the NGED Best View scenario is used to generate percentage growth rates, which are used in a range of regulatory submissions, such as the Long Term Development Statement (LTDS), Regulatory Reporting Packs and annual data exchange with National Grid Electricity Transmission.

Customer Behaviour Modelling

Context

The primary purpose of the DFES projects for NGED is to inform strategic network analysis to understand how the projected change in customer numbers will affect the operation of the distribution network as the UK transitions towards the local and national decarbonisation targets. Table 1 shows a matrix which describes the different components required in order to undertake detailed electrical analysis of any electricity distribution network.

Table 1: Summary table of the aspects required for detailed electrical analysis of the distribution network

	Network	Customers
Assets	Network topology and connectivity information, including impedance and 'nuts and bolts' data about the assets connected to the NGED distribution network. Normally this is captured in a network model in power system analysis software.	Customers connected to the distribution network, including the type of demand or generation connected. This also includes information on the machines or assets that customers have connected to the network (such as Electric Vehicles or Heat Pumps).
Behaviour	Actions taken by the DNO to actively manage the network. This can be in the form of updated running arrangements once an arranged outage is taken, or load management schemes in place to manage network flows. This information is vital if contingency analysis is required.	Expected behaviour of customers connected to the distribution network, with reference to the focus and purpose of the network analysis to be undertaken.

The DFES volumes project provides projections for the number of customer assets that are expected to connect to the NGED distribution network in the next 25 years. It is important to note that the units used in the DFES volumes project are all quantifiable (i.e., they can be counted).

This document outlines the customer behaviour assumptions that NGED use for the purpose of strategic network analysis. These customer behaviour assumptions must be relevant to the purpose of the network analysis that is undertaken. Different factors that may impact the customer behaviour assumptions that are required could include:

- **The voltage level used as the focus of the study** – different customer behaviour assumptions are used depending on the voltage level that is the focus of the network analysis.
- **The aim of the analysis** – different customer behaviour assumptions are applicable depending on what the study aims to deliver. For example, network capability and compliance edge case assessments will require a different set of customer behaviour assumptions to a study which aims to calculate average asset utilisation over a year.
- **The level of risk** – this theme is discussed throughout the document, as there are external factors to the customer behaviour assumptions not directly in the control of a DNO. The balance between studying credible edge-case network conditions to achieve network compliance and designing a network that is operated efficiently will be different for each network company.

Intended use of profile assumptions

The profiles that are presented in this document have been created with the purpose of assessing the network's capability and compliance of the NGED 33 kV networks. These can also be applied to relevant studies on the 66 kV and 132 kV networks if appropriate levels of diversity are applied to the projected volumes.

Case study 1: Impact of diversity on Customer Behaviour

Background

When assessing the network impact, careful consideration needs to be given to ensure the level of diversity applied to customer behaviour is appropriate for the study being undertaken. In the context of customer behaviour profiling, diversity is the assessment of the coincident behaviour of a group of customers or technology types. Not accounting for diversity would result in overly onerous expected loading in network analysis. This could lead to constraints triggered by network analysis that are not observed in network operation, and unnecessary reinforcement schemes started as a result. Conversely, applying too much diversity could lead to credible network constraints being missed.

There are two methods of assessing demand diversity on the Extra High Voltage (EHV) distribution network:

1. **Aggregated demand at substation level** – A load survey is undertaken to determine the substation demand at the cardinal network edge-cases. This is with all generation unmasked to give the true underlying demand.
2. **Profiling technologies –** Each technology category that is connected, or projected to connect is assigned an explicit profile that is appropriate for the study being undertaken.

An aggregated Primary substation demand profile has traditionally been used for EHV network design, due to the challenge of building up a representative Primary level profile from the constituent volumes and other factors that can influence network loading. This inherently captures the level of diversity of all demand connected downstream and is suitable for assessing existing network demand and for short-term network assessments. The aggregated approach does not provide any information on what customers are contributing to the edge-case peaks. This makes modelling changing demand behaviour challenging.

Diversified Profiles

The ACE49 methodology[1] used for LV design is an example of how the average demand assumed per customer reduces as the size of the group increases. The kW per customer of a domestic unrestricted (profile class 1) customer reduces as the group size increases. This tends towards a constant value as the number of customers increases; this is sometimes referred to as a fully diversified profile.

When profiling specific technologies at EHV, consideration of an appropriate level of diversity is important. At EHV, the group size of a given technology (e.g., heat pumps) may be sufficiently large that the profile can be considered full diversified. It is worth noting that the ACE49 methodology aims to provide a suitable level of risk such that LV networks are designed adequately, but not over-generously for the demands on each part of the network. The profiles used in this document for application to the NGED EHV networks do also account for a level of risk; however, this risk is not quantified in this document.

Coincident Peaks of different technologies

The diversity of a single technology is only one part of determining the worst credible network conditions. All demand needs to be considered when analysing network edge-cases, as not all demand is coincident.

Figure 1 shows a few of the DFES technologies winter peak profiles described in this report with different profile shapes. Highlighting how technologies can have notably different profile shapes and peaks. Taking the peak of each of these profiles without accounting for the non-coincident nature would not accurately represent the demand on the network. To account for this, the DFES profiles are full half-hourly profiles for all representative days.

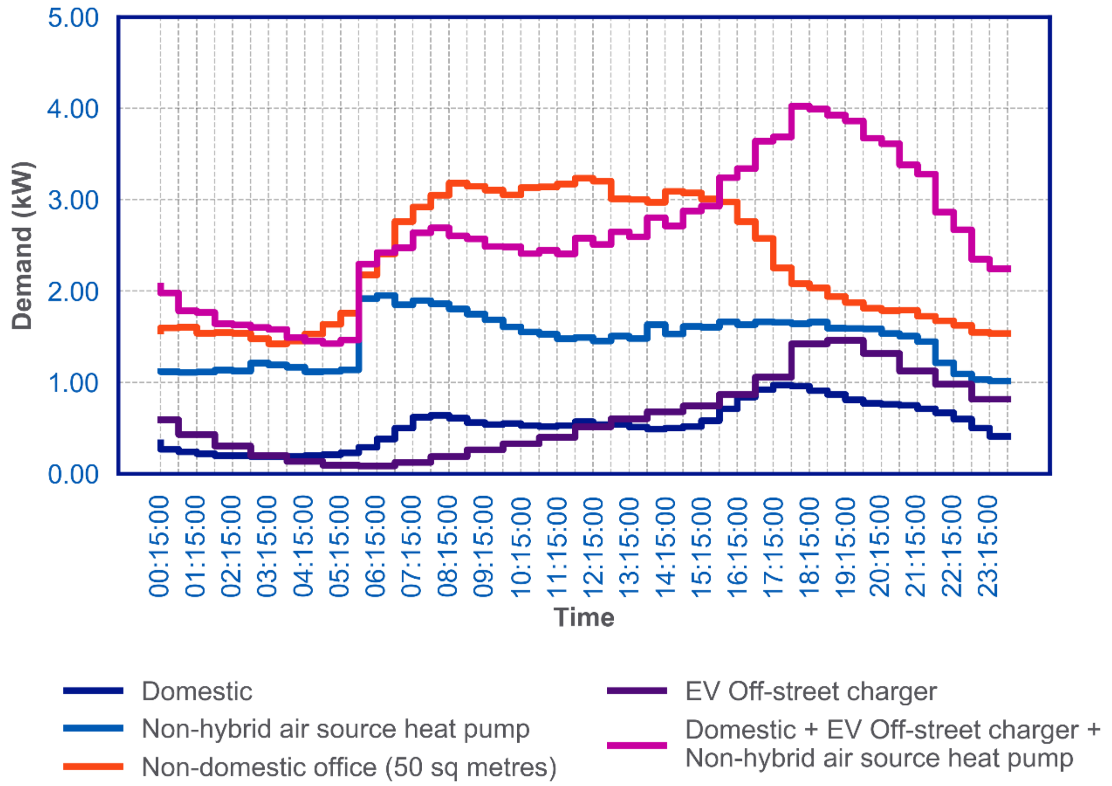

Figure 1: Example of DFES technology winter peak profiles differences

The magnitude and time of peak of a substation will depend on the constituent parts that make up the overall aggregated substation demand. The aggregated peak may change over time as the volumes and individual technology profile changes.

Diversified Primary Demand

This example highlights the impact of Primary level diversity using real-world network loadings from Portishead Bulk Supply Point (BSP) in South West NGED distribution licence area. This aggregated substation demand inherently captures the diversity observed between everything connected downstream of the Primary substation, but does not capture the diversity between Primaries.

Substations dominated by unrestricted domestic customers will typically peak in winter around 18:00; substations dominated by non-domestic customers often peak in the middle of the day. Not all substations peak in winter, an example of this is a substation that feeds demand in a holiday destination, where the peak is typically over the holiday periods.

Table 2 summarises the Primary peak and Primary at BSP peak demand for all substations connected downstream of Portishead BSP. The time of the Primary peak varies notably between 09:00 and 19:30, with the majority peaking between 17:30 and 19:00. All Primaries except Customer A peak in the winter season, noting that all have a different date of peak. The sum of the Primary Peaks is 51.43 MVA.

Table 2 gives a breakdown of the Primary demand at the time of BSP peak; the total is 45.12 MVA. This is 12.3% lower than the sum of the Primary peaks. At the time of the upstream Seabank Grid Supply Point (GSP) peak, Portishead BSP total demand is 42.64 MVA, which is 17.1% lower than the sum of Primary peaks.

Table 2: Portishead substation peaks vs BSP peak

Substation	Primary Peak (MVA)	Time of Peak	Date of Peak	Primary @ BSP Peak (MVA) *
Portishead Ashlands 11kV	6.17	19:30:00	09/01/2020	5.92
Customer A	0.71	15:00:00	07/08/2019	0.37
Clevedon 11kV	15.39	18:30:00	29/01/2020	12.74
Easton In Gordano 11kV	3.82	17:30:00	05/01/2020	3.47
Gas Lane 11kV	9.63	18:30:00	17/12/2019	9.22
Royal Portbury Dock 11kV	11.16	09:00:00	31/01/2020	8.40
Weston in Gordano 11kV	4.55	18:00:00	12/01/2020	5.01
Total	**51.43**			**45.12**

*BSP peak was at 19:00 on the 09/01/2020

This highlights the importance of using the appropriate diversified Primary demand set when analysing the EHV network. Using a Primary peak demand set to assess GSP loadings would give loadings that are 10-20% higher than are actually observed by network monitoring. Conversely, using a Primary at GSP peak demand set to assess 33 kV constraints means genuine network issues could be missed.

Representative Days

Traditionally, distribution networks are assessed using edge-case modelling, where only a snapshot of the network condition that is deemed most onerous is analysed. As the installed capacity and behaviour of demand, generation and storage is rapidly changing, it has become difficult to predict what network condition will be most onerous.

To cover a range of likely onerous cases, NGED consider a range of different potential representative days, which are used to assess network capability for the analysis purpose identified in the aforementioned *Intended use of profile assumptions* section:

- **Winter Peak Demand**, with minimum coincident generation – an assessment of the network's capability to meet peak demand conditions and determine group demand as per Engineering Recommendation P2/8[2];
- **Summer, Intermediate Warm, Intermediate Cool Peak Demand**, with minimum coincident generation – an assessment of the network's capability to meet access window demand conditions;
- **Summer Peak Generation**, with minimum coincident demand – an assessment of the network's capability to handle generation output.

The definition of seasons is taken from Engineering Recommendation P27/2 (Current rating guide for high voltage overhead lines operating in the GB distribution system)[3]:

- **Winter:** January, February and December
- **Intermediate Cool:** March, April and November
- **Intermediate Warm:** May, September and October
- **Summer:** June, July and August

The DFES forecasts project high customer uptake of low carbon technologies, such as Electric Vehicles (EVs) and Heat Pumps (HPs). Low carbon technologies are expected to allow customers to manage their demand at an individual level, such as shifting energy usage away from traditional times of peak network loading. As a result, the five representative days studied include a half-hourly power profile. This aims to help us to understand how the shape of the demand profile will change over time, which could inadvertently introduce local network peaks at times which are away from the existing time of network peak.

Case Study 2: Importance of studying multiple seasons

This case study highlights the potential impact of only considering a representative day for one season only, traditionally being the Winter Peak Demand, when assessing networks. Winter Peak Demand can often represent the maximum demand but it is not always the most onerous network condition. The demand profile for many areas of the network show that although the peak demand may appear in the cooler months, the reduction of the network's asset ratings in the subsequent warmer seasons can be greater than the corresponding reduction in demand. This can shift the network's most onerous condition away from the traditional winter Peak and onto intermediate cool, intermediate warm, or summer seasons.

Consider the demand profile below which has been observed on Halesfield 33/11 kV Primary substation in Telford in Figure 2.

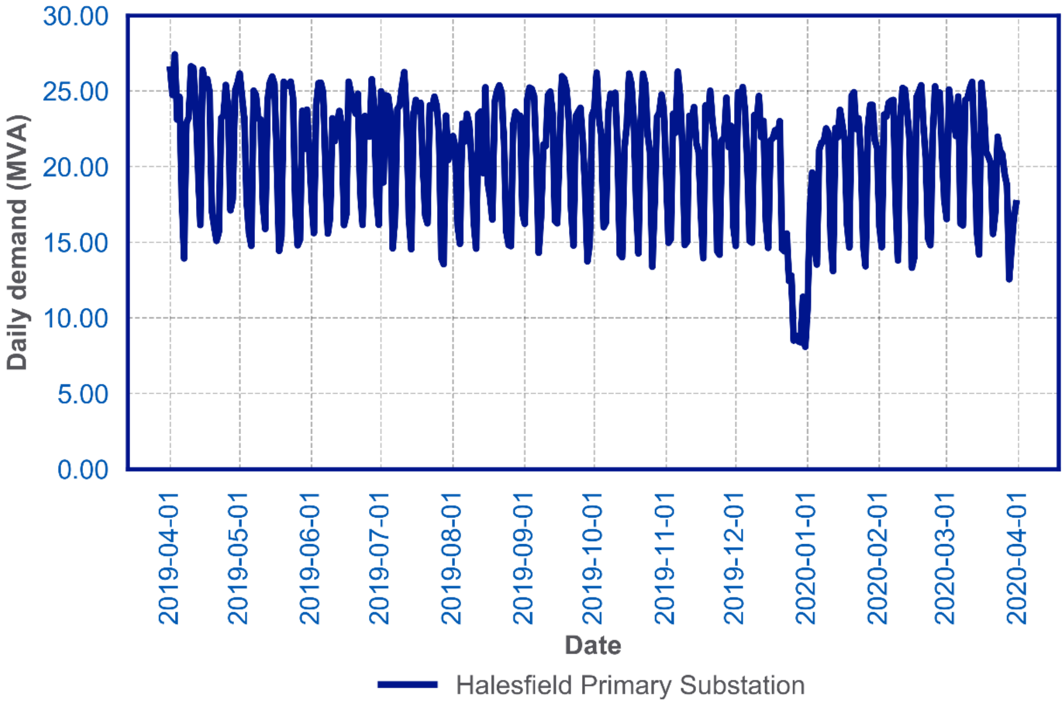

Figure 2: Output graph to show total 'underlying' demand over a yearly period at a Primary substation

Prior to reinforcement, the site was fed via two 33 kV circuits each rated 31 MVA, 29 MVA, 29 MVA, and 25 MVA for winter, intermediate cool, intermediate warm, and summer respectively. The substation's maximum demand across all four seasons was 27.4 MVA, falling within the intermediate cool season in April. This makes the site Class C under Engineering Recommendation P2/8[4], requiring Group Demand to be restored within 3 hours following a First Circuit Outage (FCO). Under a fault condition on one of the incoming circuits, the following demand would be observed on the second remaining circuit:

Table 3: Substation seasonal peak demand and rating comparison

Demand Edge-case	Month	Demand (MVA)	Asset Rating (MVA)	Utilisation
Winter Peak	February	25.4	31	81.9%
Intermediate Cool Peak	April	27.4	29	94.5%
Intermediate Warm Peak	October	26.2	29	90.3%
Summer Peak	July	26.3	25	105.2%

Table 3 highlights that although the site's maximum demand appeared in the intermediate cool season (outside of the traditionally assessed winter season), the most onerous representative day was in fact the Summer Peak Demand when taking into account the circuit's seasonal ratings.

These scenarios, typically seen in industrial and commercially dominated areas, are becoming more common as customers move towards increasingly efficient and smarter technologies, and to utilise more economic variable tariffs.

The case study shows a need to study networks across multiple seasons to identify the most onerous conditions. It further underlines the requirement to carry out these studies periodically as it can be seen from the case above that the asset utilisation per season can be relatively close to each other so the most onerous season can vary from one year to another.

Changing Nature of Demand

On 31st December 2020, changes to the Electricity Distribution Licence were introduced as part of the EU Electricity Directive 2019/944, part of the Clean Energy of all Europeans Package[5]. As part of these Licence Condition changes, DNOs are required to develop a Network Development Plan (NDP) to outline the expected development of the distribution system over a 5-to-10-year period. As part of this requirement, DNOs are required to justify any assumptions on the expected uptake of demand-side response (DSR) and energy efficiency, as a means to alter existing demand observed on the network.

In order to understand the changing nature of demand, these assumptions can be split into two separate categories of flexibility and energy efficiency services:

- **Passive/Customer led:** these are actions that customers actively take to manage their electricity demand. This can be in response to behind the meter assets installed, or as part of measures to increase energy efficiency. It is important to note that the DNO has no active part in this process and currently would have no mechanism to determine if an individual customer has changed their consumption behaviour.
- **Active/Network led:** this accounts for flexibility services that are procured and dispatched by a network operator to alleviate a particular network constraint or to defer network reinforcement.

The DFES customer behaviour assumptions aim to use credible, evidence-based assumptions for how passive/customer led flexibility and energy efficiency services can alter the existing levels of demand observed on the network. The network led flexibility services should be employed following detailed analysis to identify areas where flexibility services are required on the network.

Whilst DNOs must account for the credible expected use of customer led energy efficiency and flexibility measures, these must also be balanced with the ongoing requirement to operate and maintain an economic, efficient and coordinated network. The risk associated with assumptions on the expected level of customer led energy efficiency and flexibility measures are that if the assumptions do not materialise DNOs could be investing in a network that is inoperable at times of peak network loading.

Consider the condition where the peak demand observed on a local network is not coincident with the time and date of the GB electricity system peak. For this condition, the expected availability of customer led flexibility services at GB electricity system peak demand (which if not directly contracting with a DNO are largely driven by the electricity wholesale price signals) may not be available for the local network peak. As a result, it is prudent for DNOs to use more conservative assumptions on the expected use of customer led flexibility services, if the local network constraint is not coincident with periods of high network loading on the GB electricity system.

Application of customer behaviour profiles

To capture the complex nature of the customer behaviour modelling in the DFES studies, two different types of profiles are used:

- **Unabated profiles:** all technologies use an 'unabated' profile, which captures that credible edge-case demand profile for each of the representative days considered.
- **Flexed profiles:** Some technologies may also utilise a 'flexed' profile, which is one where a customer would respond to an external driver to flex their demand, not as part of a DNO contracted and procured service.

A flexed profile in itself is not necessarily representative of the expected behaviour of a group of customers. Instead, a split of the proportion of customers expected to be consuming energy using an unabated and flexed profile is applied. The combination of the unabated and flexed profiles together represent the average expected impact per customer on the distribution network. This profile split factor is year and scenario dependent, to account for the differing levels of consumer engagement in the DFES scenario framework.

In addition to the option of altering expected customer behaviour to account for customer-led flexibility services, a profile scaling factor is also applied to the profiles. This scaling factor accounts for any expected energy efficiency increases made by customers connected to the NGED distribution network. The yearly scaling factor is used to linearly scale each demand profile from the baseline year. It is year and scenario dependent, to account for different expected energy efficiency measures in the DFES scenario framework.

To calculate the expected aggregate customer behaviour profile, the profile components are combined with the profile scaling and expected split between unabated usage and flexed usage.

Worked Example

A visual representation of how the customer behaviour profiles are assigned to the DFES volumes projections is included in Figure 3.

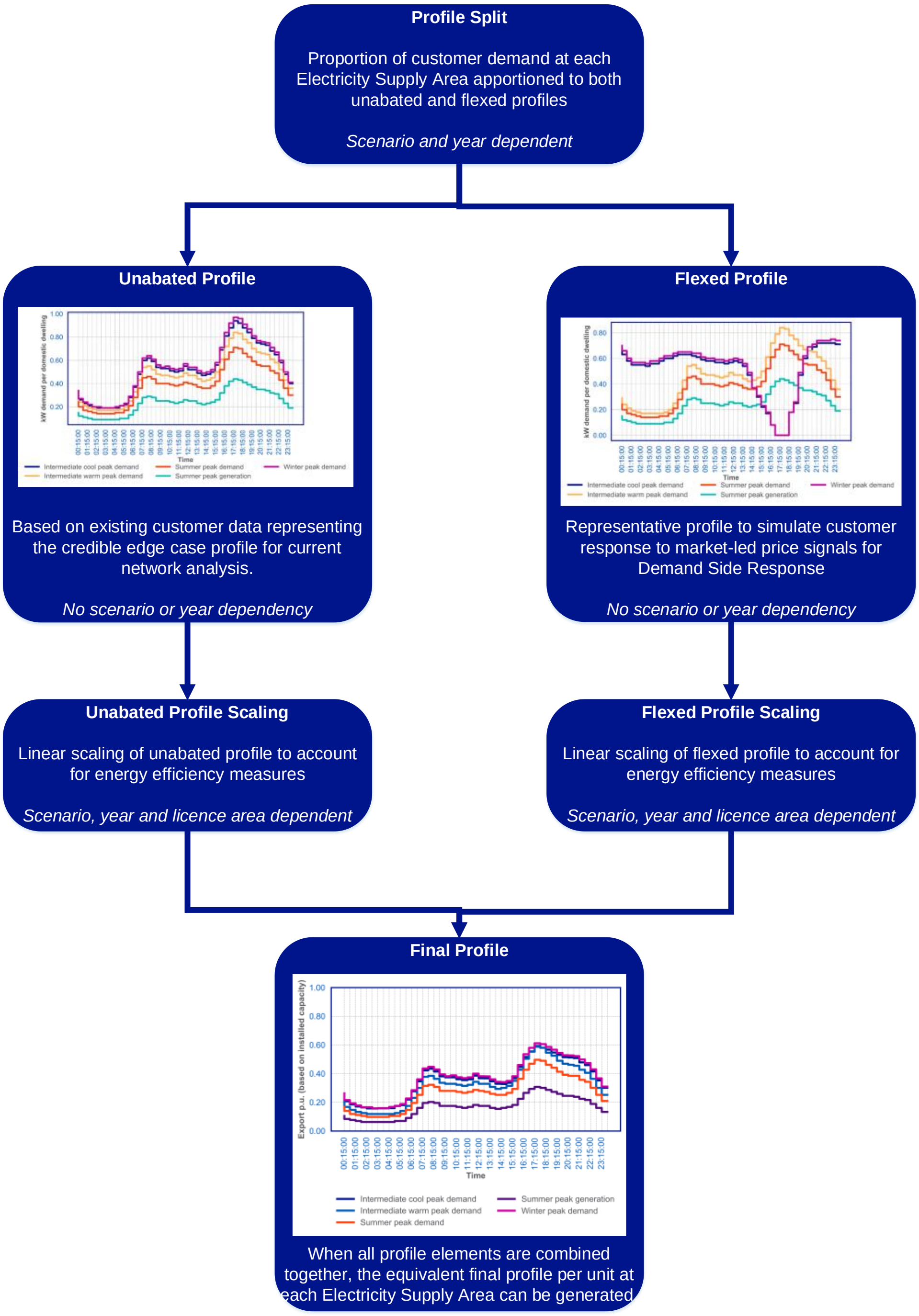

Figure 3: Representation of how customer behavioural changes are applied to the profiles for DFES analysis

Structure of profile sections

In the following sections of this report, each of the technology types studied as part of the DFES study is analysed with the customer behaviour profiles used. Each technology type section follows the structure outlined below:

- **Methodology** – a detailed description of the methodology used to obtain representative profiles with any data sources used.
- **Representative Day Profiles** – a graphical representation of the profiles used.
- **How these profiles will change over time** – how NGED expect these profiles will change over time, due to customer-led actions that the DNO is not able to influence directly.
- **Energy modelling** – outline of the assumption NGED use to benchmark the expected energy consumption of demand technologies across the NGED distribution network against other scenario-based forecasting
- **Known limitations** – a description of the areas where the profiles used could be improved to better align with expected customer behaviour
- **Future developments** – how NGED plan to improve the profiles to address some of the known limitations.

Customer Behaviour Assumptions

Generation and Storage Technologies

Solar Generation

Table 4: Table of solar generation technology types used in the DFES analysis

Technology	Subtechnology	Units used in DFES volume projections
Solar Generation	Commercial rooftop (10 kW – 1 MW)	MW of installed capacity
	Domestic rooftop (<10 kW)	
	Ground mounted (>1 MW)	

Methodology

Each solar generation customer is geographically allocated to an Electricity Supply Area where it would be most likely to connect to the distribution network. Solar generation volumes are provided as the installed capacity (MW) of generation connected.

Real power output data from all solar generation sites across the NGED distribution licence areas was collected and aggregated by each half hour for the three years prior to this analysis. Table 5 shows the solar generation data sample:

Table 5: Sample size of solar generation site used to create profiles

Licence Area	Number of sites in sample	Total installed capacity of sites in sample
East Midlands	132	1,144 MVA
South Wales	59	470 MVA
South West	177	1,009 MVA
West Midlands	67	415 MVA

Half hourly generation profiles were created for each of the five representative days used for network analysis. The generation output observed at each solar site is normalised by installed capacity to give a per unit value, before finding the maximum and minimum half hourly profile for each season by aggregating the sites to licence area. This has the benefit of ensuring equal weighting of each site’s normalised generation output and prevents results being skewed by larger sites.

To account for varying levels of diversity of solar generation output across the network, the analysis was completed with different subcategory groups that correlate to the subtechnologies used in the analysis. This allows for the capturing of the unique behaviour of each of these categories, and also captures the diversity associated with different scales of sites being connected at different voltages.

Further development of generation analysis tools allowed for better understanding of behaviour at different installed capacities level. For sites under 1MW, self-consumption behaviour was observed as shown in Figure 4. This lower perceived metered generation is due to site self-consumption, which not only means that less generation is exported to the network, but that the site has lower demand. Due to this, only sites above 1MW were included in the analysis to create the Solar Generation profile as they have lower or almost no demand.

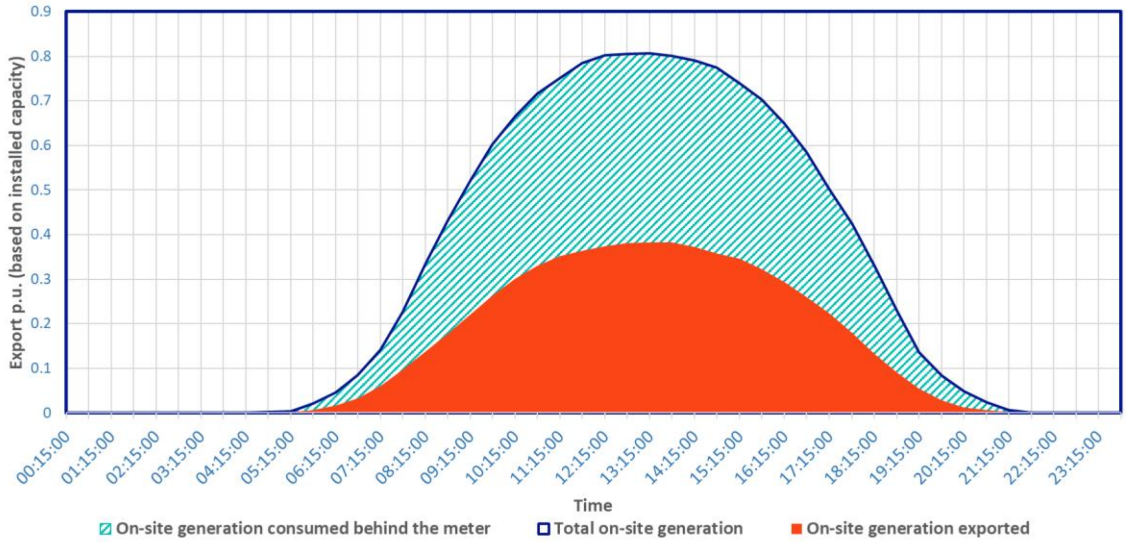

Figure 4: Comparison of behind-the-meter consumption of commercial rooftop solar generation against the total generation for the installed solar arrays.

As each licence area was analysed separately, there are four sets of solar generation profiles used for network analysis.

Representative Day Profiles

South West solar generation profiles

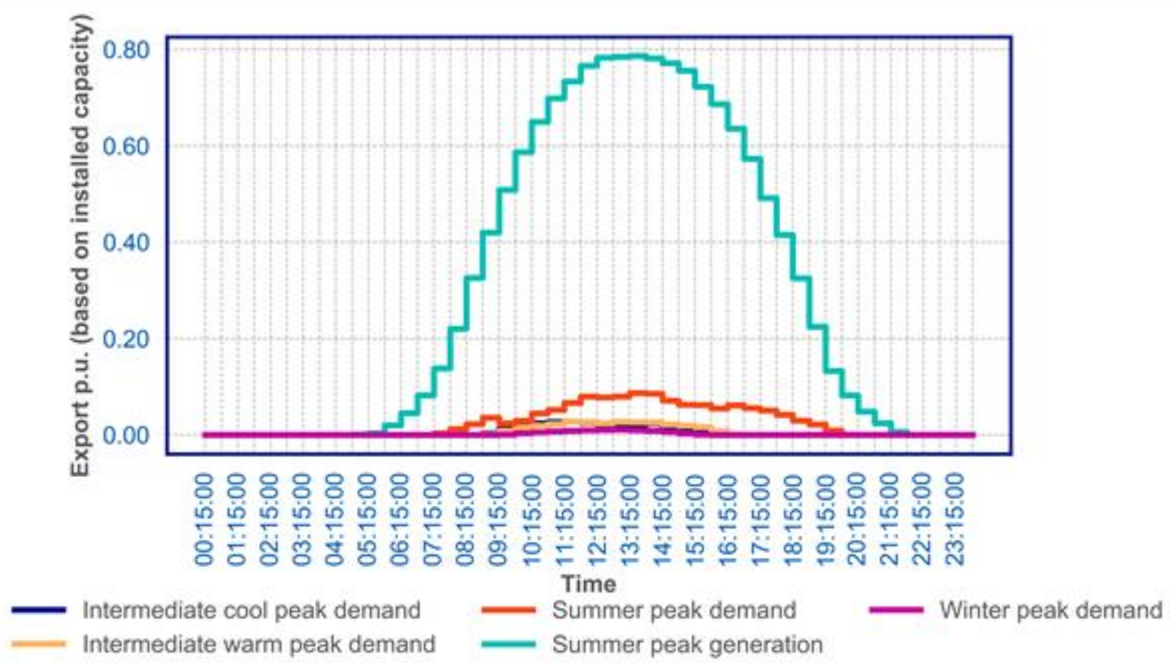

Figure 5: Representative solar generation profiles for customers in the South West licence area

South Wales solar generation profiles

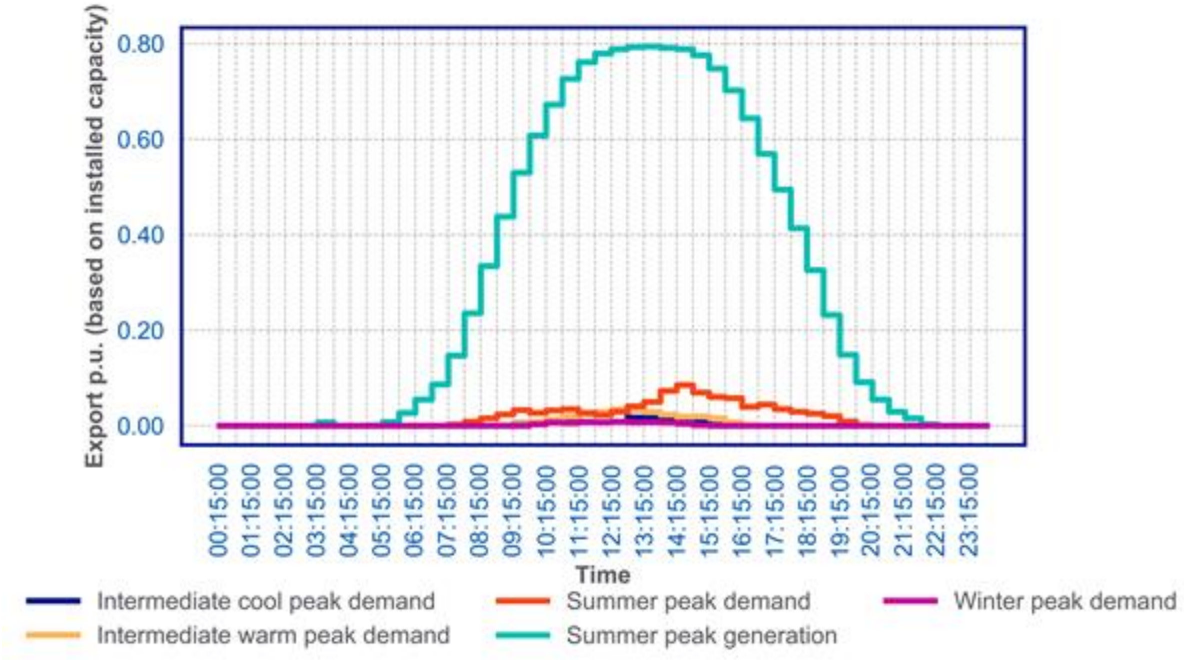

Figure 6: Representative solar generation profiles for customers in the South Wales licence area

East Midlands solar generation profiles

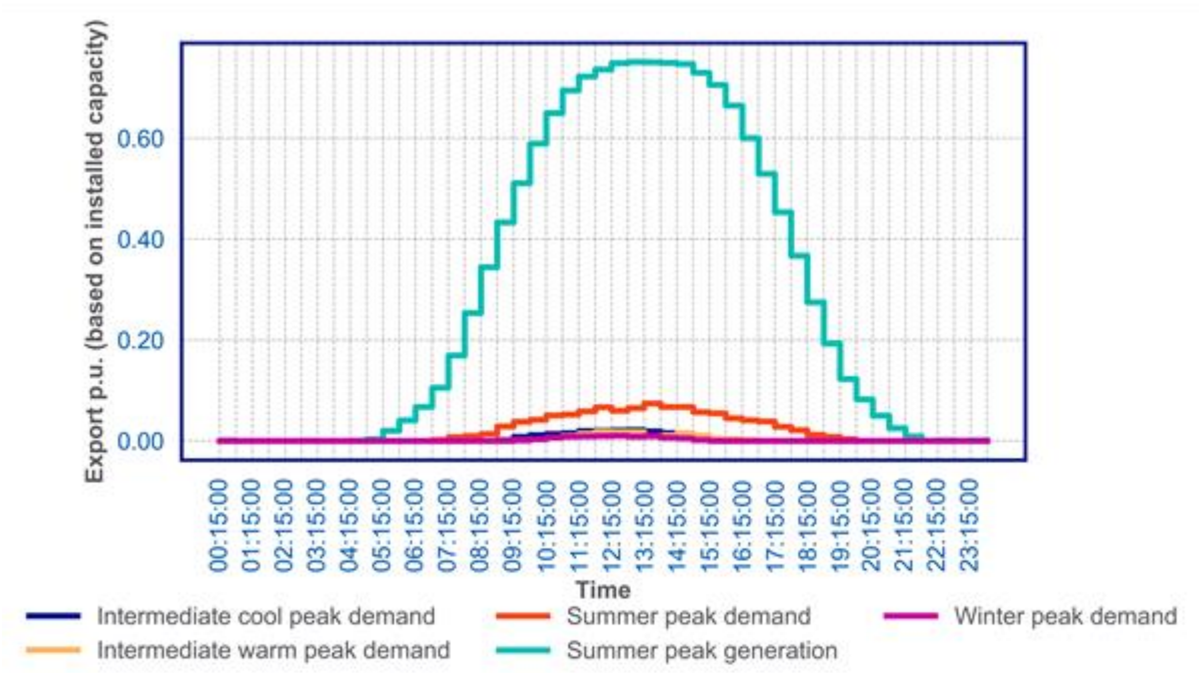

Figure 7: Representative solar generation profiles for customers in the East Midlands licence area

West Midlands solar generation profiles

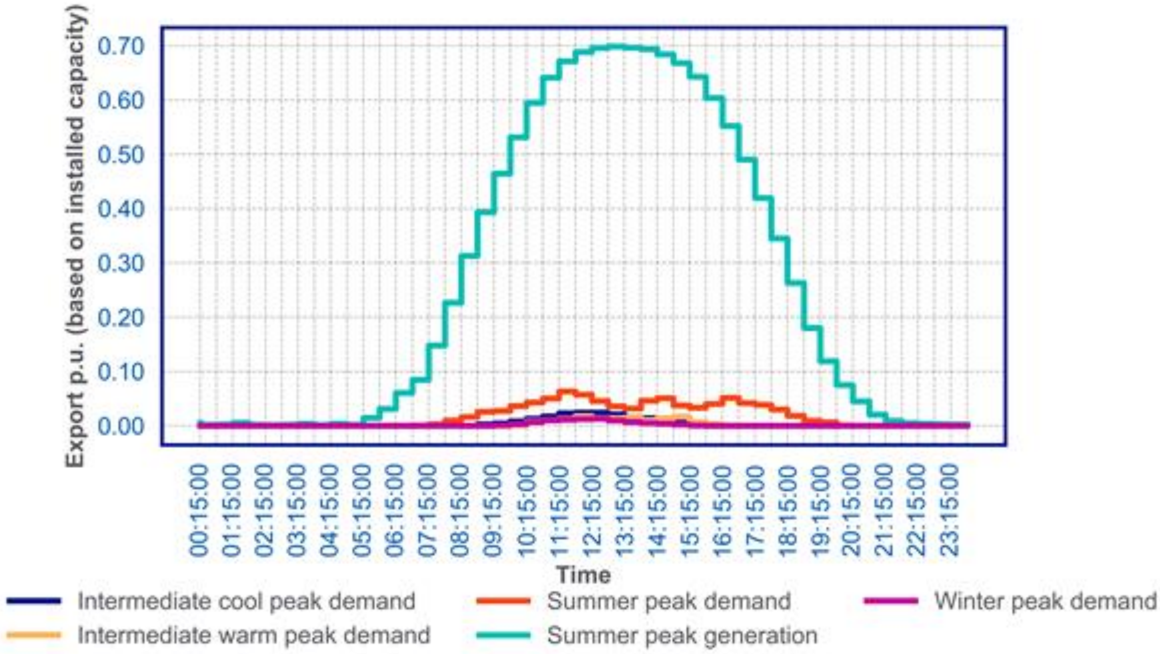

Figure 8: Representative solar generation profiles for customers in the West Midlands licence area

How will these profiles change over time

It is assumed that the load profiles for solar generation sites will not change in the future.

These profiles are normalised around the installed capacity, rather than the contracted export capacity. For instances where a customer installs much more generating plant than the contracted capacity, an export limitation scheme is implemented in the network analysis stage to limit the export of any over-installed generation. This is also the case for any generation sites with an installed Active Network Management (ANM) scheme, where the logic for the load management scheme is incorporated into the network analysis.

Known Limitations

As some of the solar generation sites across the NGED distribution network are due to reach the end of the operational life in the next 30 years, there may be opportunities for customers to replant with more efficient equipment, as well as utilising behind the meter storage and customer-led load management schemes. These potential changes have not been accounted for in this analysis. Behind-the-meter consumption of the generation was not part of this analysis, but a great consideration was given which resulted in the removal of all sites under 1MW from the analysis.

Future Developments

Further Analysis will be undertaken to better understand self-consumption, which will enable the production of Photovoltaic sub technology specific profiles. More spatially granular profiles could be something to investigate in the future.

Onshore Wind Generation

Table 6: Table of onshore wind generation technology types used in the DFES analysis

Technology	Subtechnology	Units used in DFES volume projections
Wind	Onshore Wind <1MW	MW of installed capacity
	Onshore Wind >=1MW	

Methodology

Each onshore wind generation customer is geographically allocated to an Electricity Supply Area where it would be most likely to connect to the distribution network. Onshore wind generation volumes are provided as the installed capacity (MW) of generation connected.

Real power output data from all onshore wind generation sites across the NGED licence areas was collected and aggregated by each half hour for the four years prior to this analysis. Table 7 shows the onshore wind generator data sample.

Table 7: Sample size of onshore wind generation site used to create profiles

Subtechnology	Licence Area	Number of sites in sample	Total installed capacity of sites in sample
Onshore Wind <1MW	East Midlands	76	23.8 MVA
	South Wales	91	26.8 MVA
	South West	146	34.4 MVA
	West Midlands	29	8.2 MVA
Onshore Wind >=1MW	East Midlands	21	187 MVA
	South Wales	25	494 MVA
	South West	25	215 MVA
	West Midlands	3	38 MVA

Half hourly generation profiles were created for each of the five representative days used for network analysis. The generation output observed at each wind site is normalised by installed capacity to give a per unit value, before finding the maximum and minimum half hourly profile for each season by aggregating the sites to licence area.

As each licence area was analysed separately, there are four sets of onshore wind generation profiles used for network analysis.

Representative Day Profiles

South West greater than or equal to 1MW

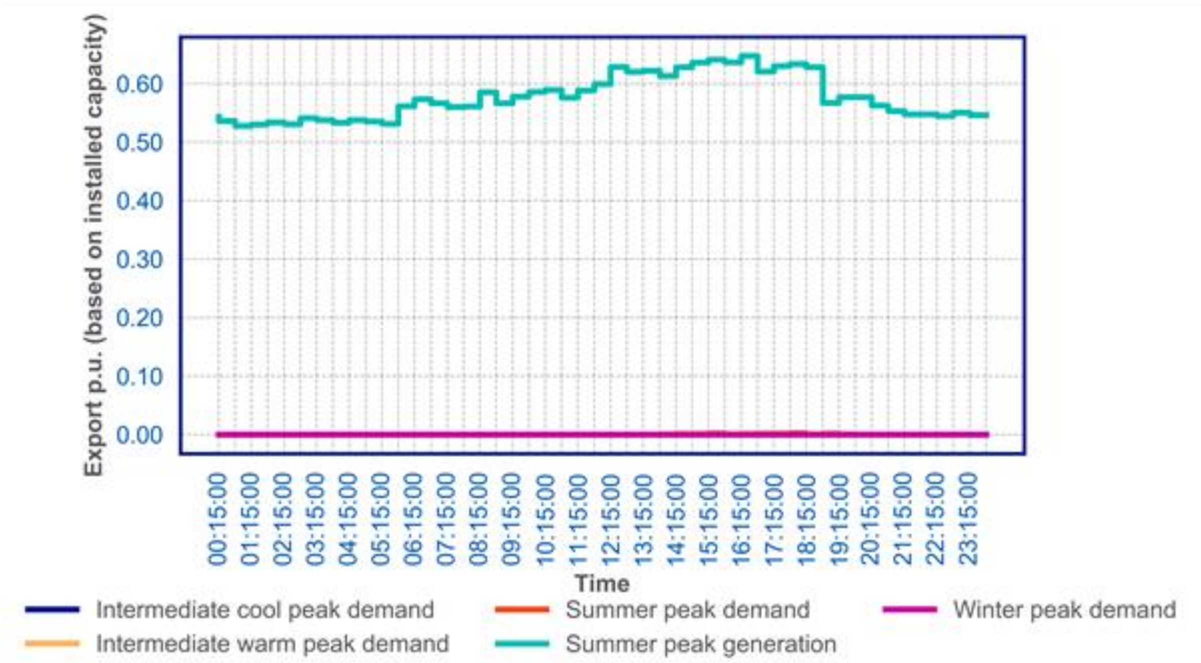

Figure 9: Representative greater than or equal to 1MW onshore wind profiles for customers in the South West licence area

South West less than 1MW

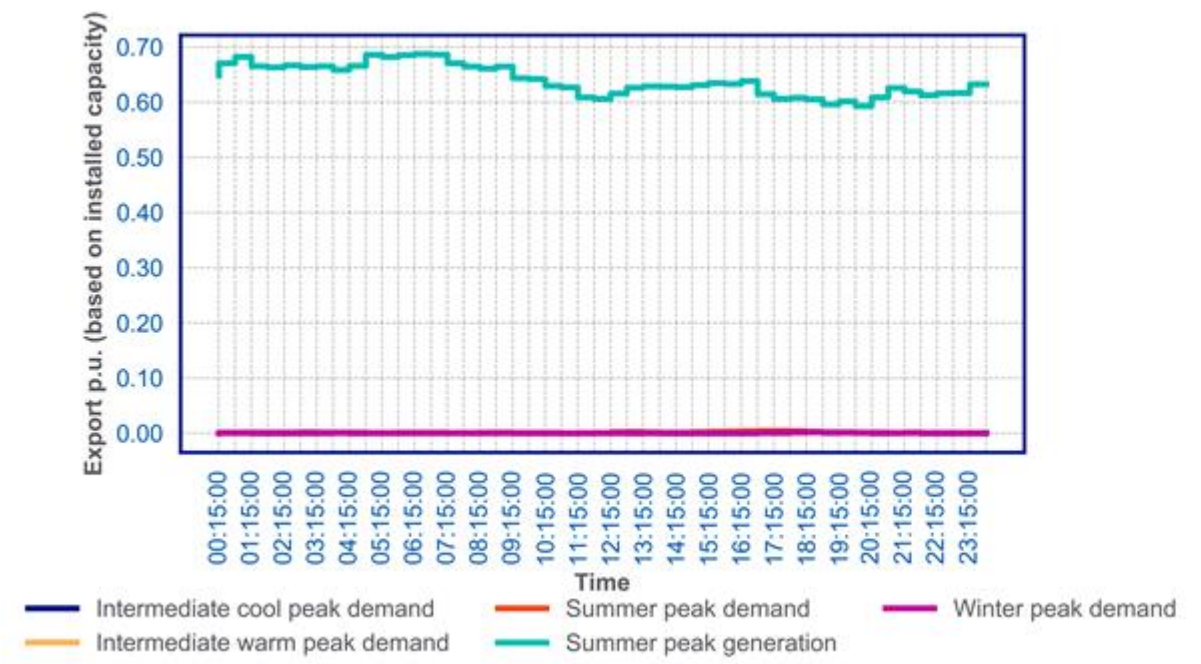

Figure 10: Representative less than 1MW onshore wind profiles for customers in the South West licence area

South Wales greater than or equal to 1MW

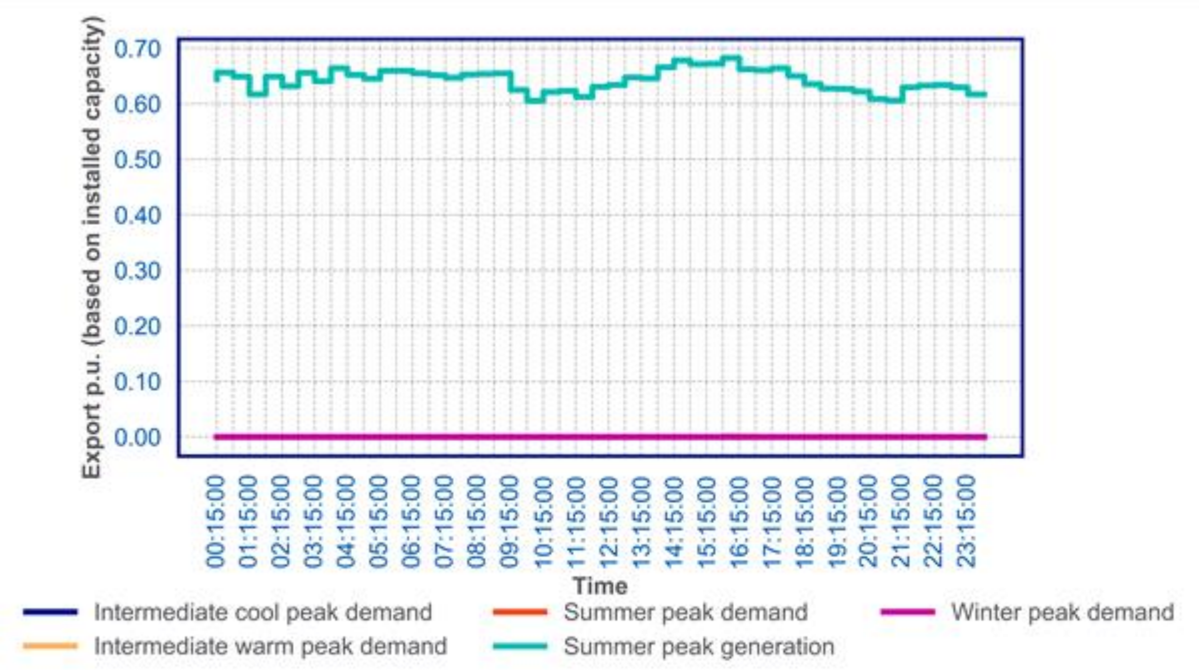

Figure 11: Representative greater than or equal to 1 MW onshore wind profiles for customers in the South Wales licence area

South Wales less than 1MW

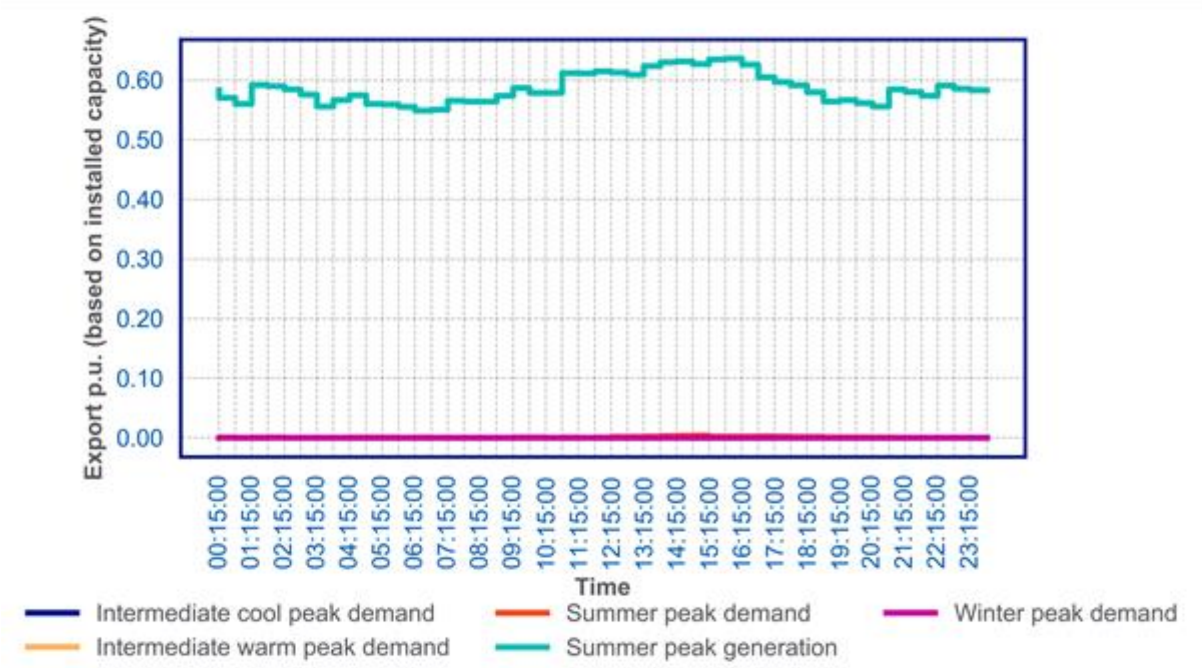

Figure 12: Representative less than 1 MW onshore wind profiles for customers in the South Wales licence area

East Midlands greater than or equal to 1MW

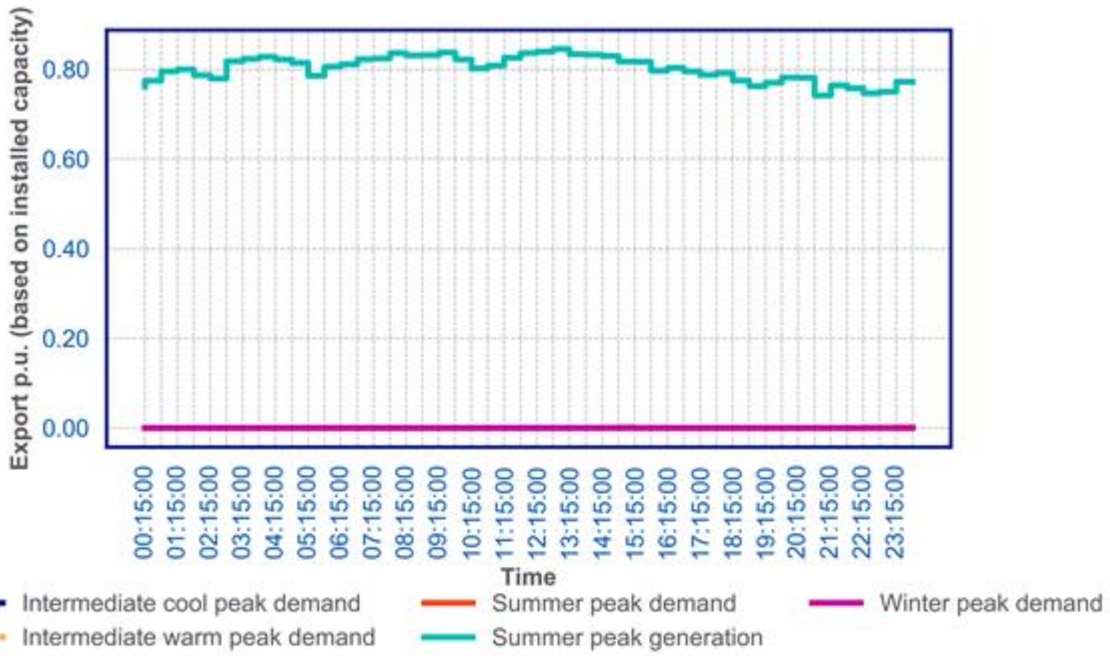

Figure 13: Representative greater than or equal to 1 MW onshore wind profiles for customers in the East Midlands licence area

East Midlands less than 1MW

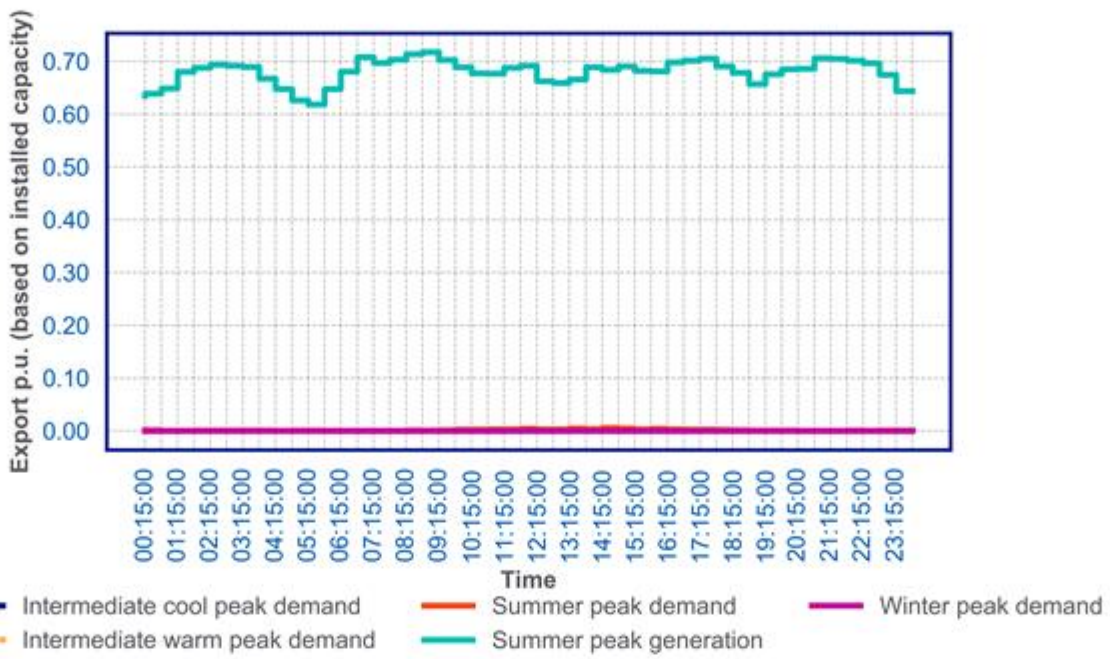

Figure 14: Representative less than 1 MW onshore wind profiles for customers in the East Midlands licence area

West Midlands greater than or equal to 1MW

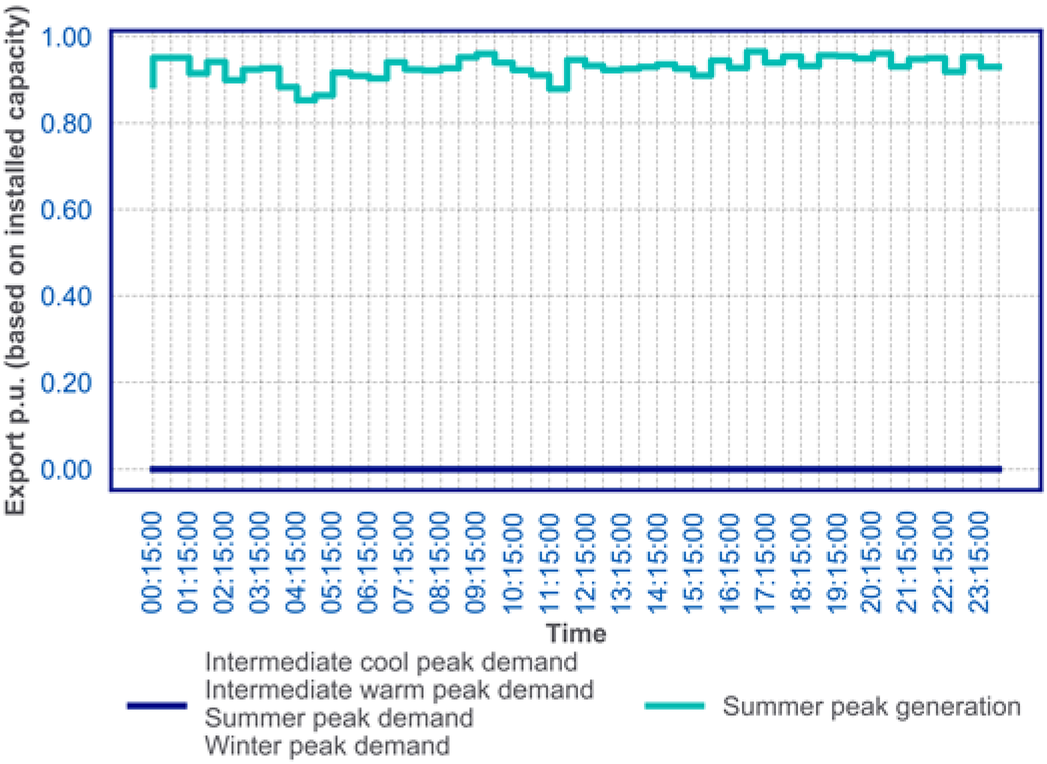

Figure 15: Representative greater than or equal to 1 MW onshore wind profiles for customers in the West Midlands licence area

West Midlands less than 1MW

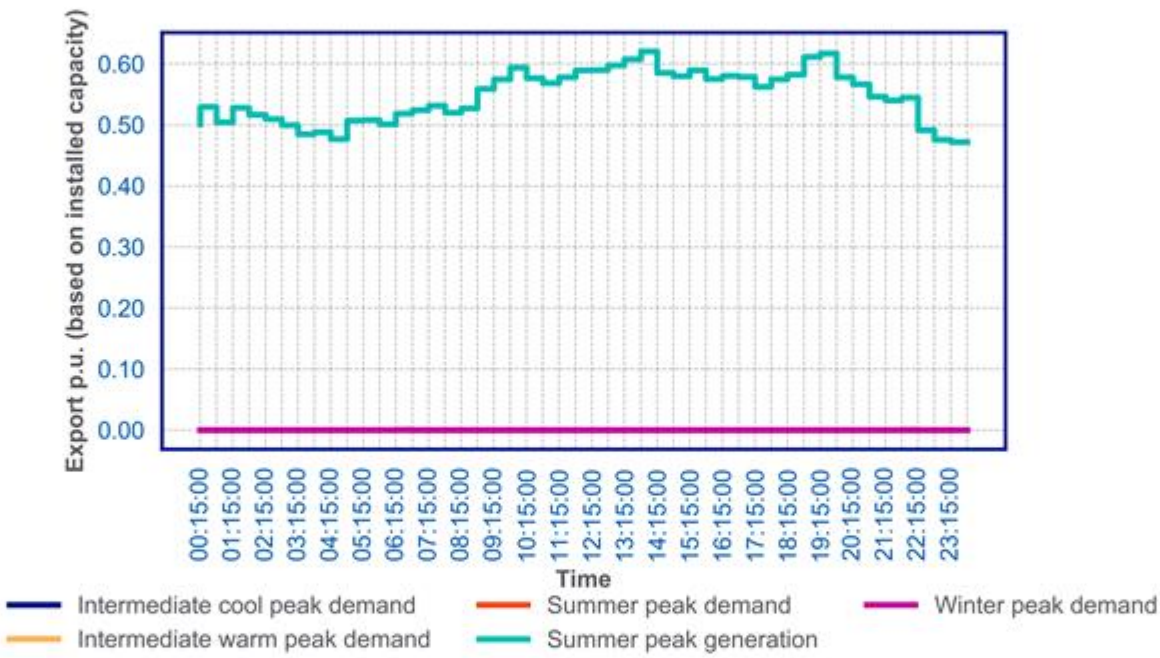

Figure 16: Representative less than 1 MW onshore wind profiles for customers in the West Midlands licence area

How will these profiles change over time

It is assumed that the load profiles for onshore wind generation sites will not change in the future.

These profiles are normalised around the installed capacity, rather than the contracted export capacity. For instances where a customer installs much more generating plant than the contracted capacity, an export limitation scheme is implemented in the network analysis stage to limit the export of any over-installed generation. This is also the case for any generation sites with an installed Active Network Management scheme, where the logic for the load management scheme is implemented in the network analysis.

Known Limitations

The DFES volume projections assume that existing onshore wind sites will replant with a larger installed capacity when these sites reach the end of their design life. In addition, there may be future opportunities for onshore wind sites to co-locate with demand sources, such as hydrogen electrolysis or energy storage. Any potential changes in onshore wind turbine efficiency and change of import requirements have not been accounted for in these profiles.

Future Developments

There are currently no future developments planned for the way in which these profiles are created, but are always open to feedback and suggestions for improvements.

Offshore wind Generation

Table 8: Table of offshore wind generation technology types used in the DFES analysis

Technology	Subtechnology	Units used in DFES volume projections
Wind	Offshore Wind	MW of installed capacity

Methodology

Each offshore wind generation customer is geographically allocated to an Electricity Supply Area where it would be most likely to connect to the distribution network. Offshore wind generation volumes are provided as the installed capacity (MW) of generation connected.

Real power output data from all offshore wind generation sites across the NGED distribution licence areas was collected and aggregated by each half hour for the three years prior to this analysis. Only two offshore wind generation customers are connected to the NGED distribution network, both situated off the coast of the East Midlands licence area.

Half hourly generation profiles were created for each of the five representative days used for network analysis. This was achieved by considering the maximum and minimum generation output observed during each half hour across the whole of each season in the aggregated generation data and normalising this by installed capacity of the sample to give a per unit value.

Both offshore wind sites currently connected to the NGED distribution network are connected at 132 kV, so no study of different diversity levels is applicable. However, as any future offshore wind sites connected to the distribution network would be most likely to connect at the 132 kV voltage level, the generated profiles are deemed at a suitable level to be used for network analysis. This profile is applied to all NGED distribution licence areas where offshore wind is projected to connect.

Representative Day Profiles

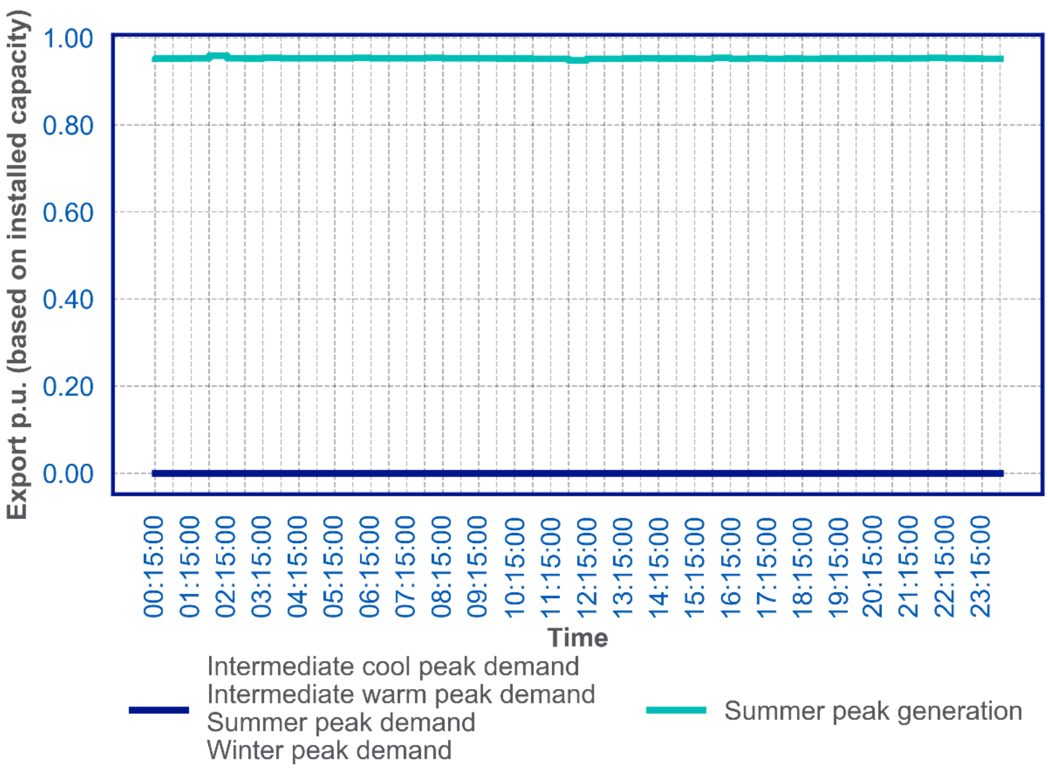

Figure 17: Representative day offshore wind profiles

How will these profiles change over time

It is assumed that the load profiles for offshore wind generation sites will not change in the future.

These profiles are normalised around the installed capacity, rather than the contracted export capacity. For instances where a customer installs much more generating plant than the contracted capacity, an export limitation scheme is implemented in the network analysis stage to limit the export of any over-installed generation. This is also the case for any generation sites with an installed Active Network Management scheme, where the logic for the load management scheme is implemented in the network analysis.

Known Limitations

The sample size used to generate offshore wind profiles is very small and may not be representative of the behaviour of a larger number of customers connected across the NGED distribution network.

Future Developments

Given the small sample size of existing customers and the relatively low projections of future offshore wind connections, no future developments have been identified for offshore wind customers.

Non-weather Dependent Generation

Table 9: Table of non-weather dependent generation technology types used in the DFES analysis

Technology	Subtechnology	Units used in DFES volume projections
Biomass & Energy Crops (including CHP)	-	MW of installed capacity
CCGTs (non CHP)	-	
Geothermal	-	
Hydro	-	
Hydrogen-fuelled generation	-	
Marine	Tidal stream	
	Wave energy	
Micro CHP	Domestic (G98/G83)	
Non-renewable CHP	<1MW	
	>=1MW	
Non-renewable Engines (non CHP)	Diesel	
	Gas	
OCGTs (non CHP)	-	
Other generation	-	
Renewable Engines (Landfill Gas, Sewage Gas, Biogas)	-	
Waste Incineration (including CHP)	-	
Retained Connection	-	

Methodology

All non-weather dependent generation customers are geographically allocated to an Electricity Supply Area where they would be most likely to connect to the distribution network. Generation volumes are provided as the installed capacity (MW) of generation connected.

In the case of infrequently despatched, non-intermittent generation, measured flows may not reflect the potential network impact. Instead, a flat (continuous output) profile was assumed for each representative day, representing the realistic behaviour that would have the worst impact upon the network. These were assumed as follows:

- **Summer Peak Generation day**: continuous export at agreed supply capacity; and
- **Peak Demand days** (all seasons): zero export.

Generation output may in reality be limited by load management schemes, such as Export Limited connections or Active Network Management schemes. In addition to this, some generation customers may hold flexibility contracts with NGED that mandate a certain profile at certain times of day or year. The behaviour of these customers is included, as part of the network analysis, but the output of non-weather dependent generation must be assumed full before network management systems can take effect in order to accurately assess network capability.

The DFES also contains an additional category of generation to represent retained connection. Across the four DFES scenarios, some technologies will see a level of decommissioning between the baseline year and 2050. This largely consists of technologies that are incompatible with net zero carbon emissions, such as unabated fossil fuel power generation.

Upon ceasing of conventional operation, the connection agreement held by the operator and the associated contracted export capacity secured with NGED is not automatically relinquished and some sites will likely retain this connection capacity. The motivation behind retaining this capacity will be to connect an alternative generation or storage technology that is more compatible with net zero emission targets.

Representative Day Profiles

All non-weather dependent generation profiles

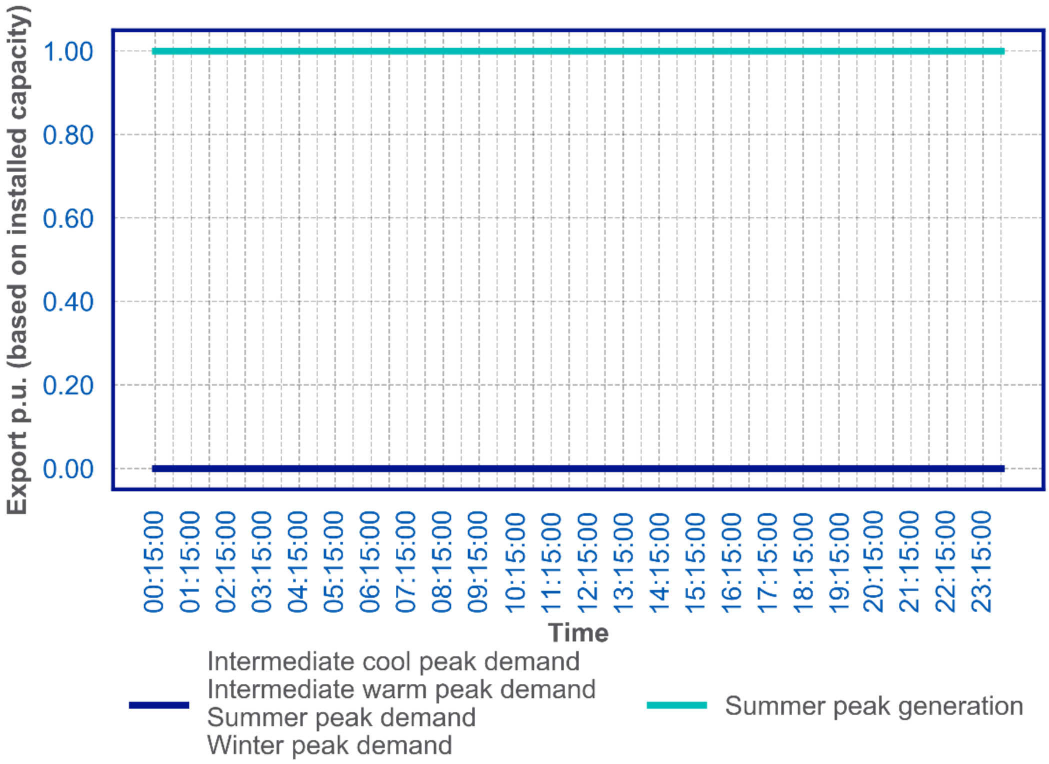

Figure 18: Non-weather dependent generation representative day profiles

How will these profiles change over time

It is assumed that the load profiles for non-weather dependent generation sites will not change in the future.

These profiles are normalised around the installed capacity, rather than the contracted export capacity. For instances where a customer installs much more generating plant than the contracted capacity, an export limitation scheme is implemented in the network analysis stage to limit the export of any over-installed generation. This is also the case for any generation sites with an installed Active Network Management scheme, where the logic for the load management scheme is implemented in the network analysis.

Known Limitations

These profiles are considered to be pessimistic as rarely all generation installed across an area of the network is exporting at the full installed capacity at any single time. When assessing each connected customer in isolation this approach is justifiable, but when assessing a group of generators connected at a Primary substation the coincident behaviour of all generators need to be used to assess a credible edge-case profile.

Future Developments

NGED is continuing to develop the tools to assess the coincident behaviour of generators connected at a Primary substation level to determine a suitable profile per generator that balances the safe design and operation of the distribution network and the design of an economic and efficient network.

Battery storage

Table 10: Table of battery storage technology types used in the DFES analysis

Technology	Subtechnology	Units used in DFES volume projections
Storage	Co-location	MW of installed capacity
	Domestic Batteries (G98)	
	Grid services	
	High Energy User	
	Other	

Methodology

All battery storage customers are geographically allocated to an Electricity Supply Area where they would be most likely to connect to the distribution network. Battery storage volumes are provided as the installed capacity (MW) of storage connected.

NG previously worked with Regen to develop an approach to model the growth and operation of storage. As part of this modelling work, a consultation paper was developed and issued, aiming to validate some of the key assumptions used to model energy storage. The results from the consultation paper are published on the NGED website.

The consultation paper proposed different energy storage business models and asked for feedback on the behaviour of energy storage in each of these business models. One noteworthy response to the consultation was that customers expressed a desire to be able to 'stack' different business models and revenue streams. Respondents also identified a preference not to commit to a specific operating mode, as the evolving nature of procurement of balancing services by the NESO in the future may change some of the proposed operating modes.

The consultation responses demonstrated that energy storage customers prefer flexibility to operate energy storage without a specific operating profile. As a result, the profile assumptions used in this study are:

- **Summer Peak Generation day**: continuous export at agreed supply capacity; and
- **Peak Demand days** (all seasons): continuous demand at agreed import capacity; and zero export.

This unconstrained mode of operation is onerous for networks. In some cases, it may trigger major reinforcements that would prove unnecessary with relatively minor changes in the behaviour of energy storage connections. Where battery storage customers hold flexibility contracts with NGED that mandate a certain profile at certain times of day or year, the behaviour of these customers is included, as part of the network analysis. However; in the absence of load management schemes to limit battery storage usage, the output of battery storage must be assumed to be worst-case in order to assess network capability.

Representative Day Profiles

Battery storage (unabated)

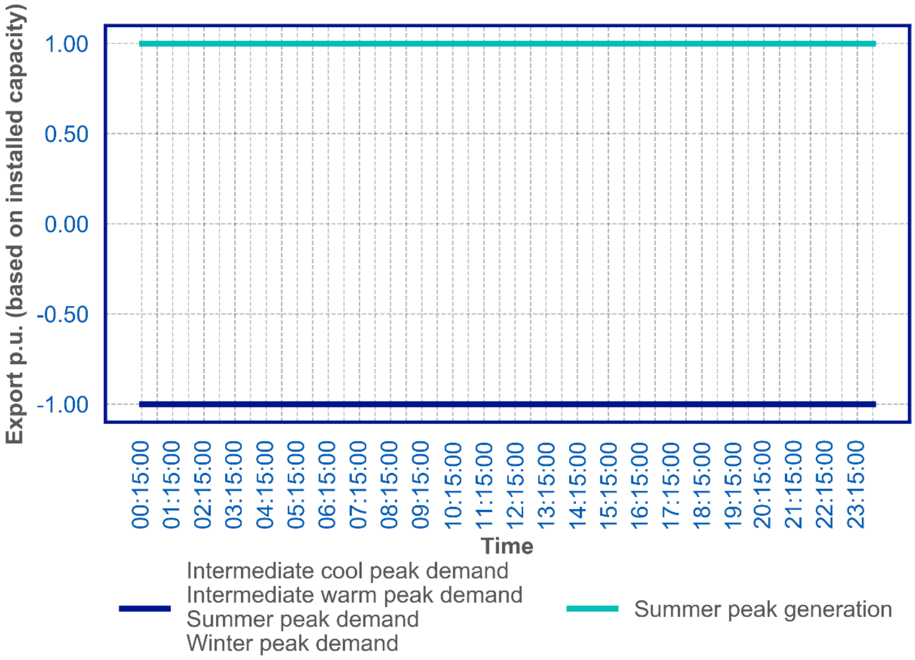

Figure 19: Battery storage representative unabated profiles

In DFES 2024 we have continued the inclusion of flexible behaviour of domestic batteries, using the same customer behaviour assumptions regarding uptake and response to domestic flexibility as those observed in the domestic demand.

Battery storage (flexed)

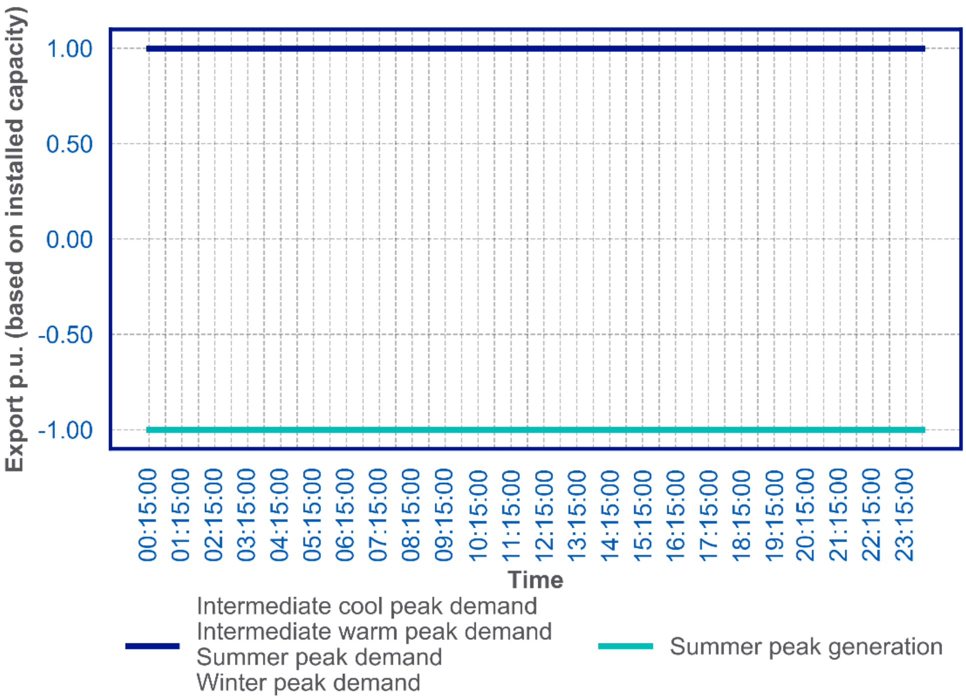

Figure 20: Domestic battery storage flexed profile

How will these profiles change over time

It is assumed that the load profiles for battery storage sites will not change in the future. These profiles are normalised around the installed capacity, rather than the contracted export capacity.

The proportion split between the unabated and flexed profile varies as shown in Figure 21 for each scenario. It is important to note that this is not representing DNO procured flexibility, which is likely to be far higher than this, but is inherent flexibility. We do not model procured flexibility at this stage of the DFES as it would potentially mask future constraints, and not flag the area for future procurement of flexibility.

The FES domestic flexibility split was used to inform the profile split for domestic batteries, as this was deemed more likely to reflect the unpaid flexible behaviour of customers, and therefore was less likely to mask constraints[31].

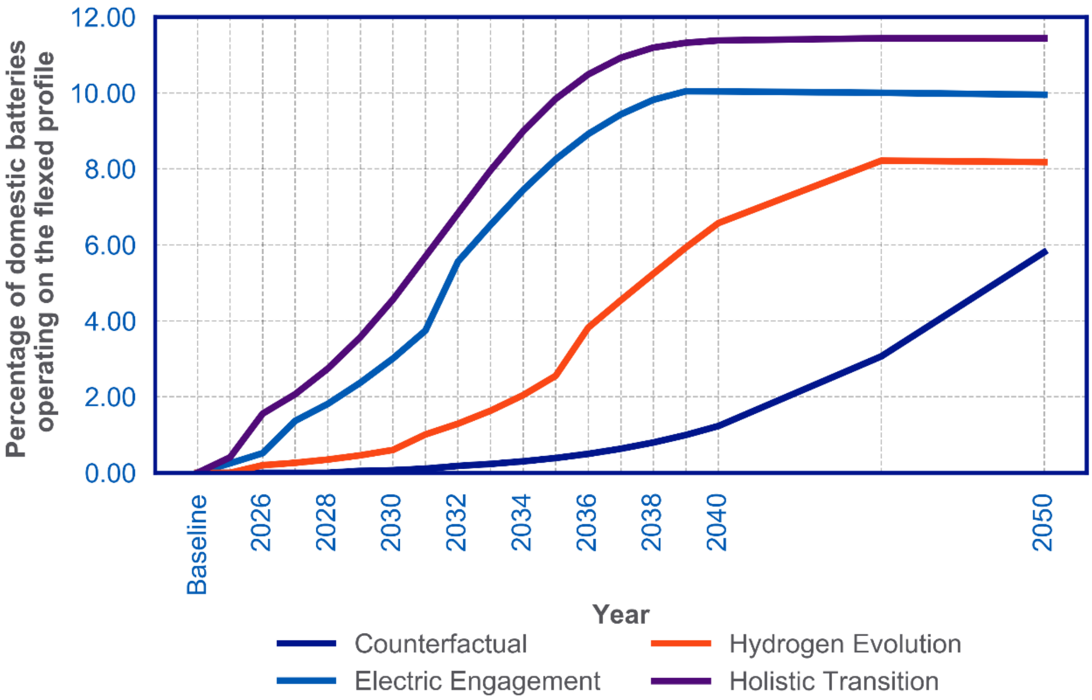

Figure 21: Profile split (proportion of domestic batteries that are following the flexed profile) of domestic batteries in each DFES scenarios

Known limitations

The projections and profiles only consider the impacts of battery storage. It is noted that there are other forms of energy storage, which may connect to the distribution network in the next 30 years. This feedback was given as part of the DFES stakeholder engagement exercise and will be incorporated into future DFES studies.

These profiles are considered to be pessimistic as rarely all storage capacity installed across an area of the network will be operating in a way to increase network loadings for each of the representative days studied. When assessing each connected customer in isolation this approach is suitable, but when assessing a group of generators connected at a Primary substation the behaviour of storage coincident to local network loadings need to be used to assess a credible edge-case profile.

Future Developments

The energy storage profiles will be reviewed in future studies, with the expansion of the suite of representative days to further assess the energy curtailment impact of measures such as ANM and DSR.

Customer Behaviour Assumptions

Demand Technologies

Underlying Demand

For the purposes of this document, underlying demand refers to the aggregate behaviour to the existing NGED customer base currently connected to the distribution network, and how electricity demands from existing customers will change over time.

Methodology

The underlying demand profiles are not included as part of the DFES Part 1: Volumes project, as this is data that NGED has access to as part of internal network design processes. As the purpose of the analysis is to study the network impact of the DFES projections on the 33 kV, 66 kV and 132 kV networks, the demand at each Primary substation needed to be modelled individually.

National Grid undertake an engineering load survey on an annual cycle to update the Primary demand sets for network design purposes. This focuses on an annual peak demand figure and accounts for abnormal network running arrangements and the export of any downstream connected generation customers. However, to be used in the half-hourly analysis, further analysis was required to determine representative half hourly profiles for different Primary substations.

Due to the absence of directional MW/MVAr monitoring at all Primary substations, it was not possible to use data directly for each Primary across the NGED distribution network. Primary substations with directional MW/MVAr monitoring were used to determine a set of representative profiles that could be retrospectively applied to other Primary substations with similar metrics.

The Primary underlying demand profiles are created as a profile normalised around the peak demand observed as part of the engineering load survey. For each half hour and representative day, the peak demand multiplied by the profile value gives an expected power demand at each Primary substation.

Clustering Methodology

A bespoke machine learning Python-based program was written to cluster the Primary substations into groups with similar profile characteristics for the representative days used in the analysis. This used metering data for a yearly period for all available sites. More information about the cluster methodology is contained in *Appendix B: Primary substation clustering* of this report.

The output of the clustering was a list of Primary substations with 'similar' behaviour (in terms of the time of peak and the profile shape) for all five representative days.

The clustering algorithm looked at the MW data and considered a fixed power-factor.

Grouping Methodology

After clustering available sites there was a need to find data that correlated with each group to define the profile. This involved collating information about the number (and type) of Meter Point Administration Numbers (MPANs), Low Carbon Technologies (LCTs) and generation connected to the Primary.

For each set of successfully clustered Primary substations, multinomial logistic regression was conducted using the proportions of MPANs, LCT and generation types as factors.

Creating the profiles

214 subcategories were generated to replace the previous Morning, Rural, and Urban types. Those older types provided simple and intuitive understanding for the type of network and customer behaviour at a Primary substation; with a greater number of profiles that simplicity has been replaced with a less intuitive, but more granular, picture of the profiles.

For the peak demand representative days, the average profile of all sites within the group was taken for each season, this was renormalized to ensure there was a 1 per unit peak to assign each Primary substation to its peak annual demand. For the peak generation representative day, the mean of the minimum profile for the sample was used.

Application methodology

Not all sites were clustered by the machine learning algorithm; to classify these sites trained regression models were used to predict seasonal clustering using each Primary substation MPAN, LCT and generation data as predictors.

Single customers

There are a number of customers connected to the NGED distribution network with connections at 132 kV, 66 kV, and 33 kV or by a dedicated Primary transformer at a Primary substation. Such customers do not have a regular daily or seasonal demand profile. As a result, the assumed profile for these customers is:

- **Peak Demand days**: continuous demand at peak annual demand observed in the engineering load survey; and
- **Summer Peak Generation day**: zero demand.

Representative Day Profiles

Profiles for active power were generated from this analysis. For detailed network design, a power factor per site may be used instead of the reactive profiles generated using this process where detailed network monitoring can be used.

Each Primary substation is assigned to one of five clusters for each representative day profiles: a Winter peak demand cluster; a Summer peak demand cluster; a Summer peak generation cluster; an Intermediate Cool peak demand and an Intermediate Warm demand cluster. For example, ALFORD was previously classed as “Rural” but is now classed as “W1, S2, Sgen2, IC4, IW1” indicating that it belongs to Winter cluster 1, Summer peak cluster 2, Summer peak generation 2, Intermediate cool peak cluster 4 and Intermediate warm peak cluster 1. The cluster numbers are related to each other, they describe a grouping of profiles from the observed data.

Winter Peak (1), Summer Peak (1), Summer Peak Generation (1), Intermediate Cool Peak (2), Intermediate Warm Peak (1) - (W1, S1, Sgen1, IC2, IW1 active power)

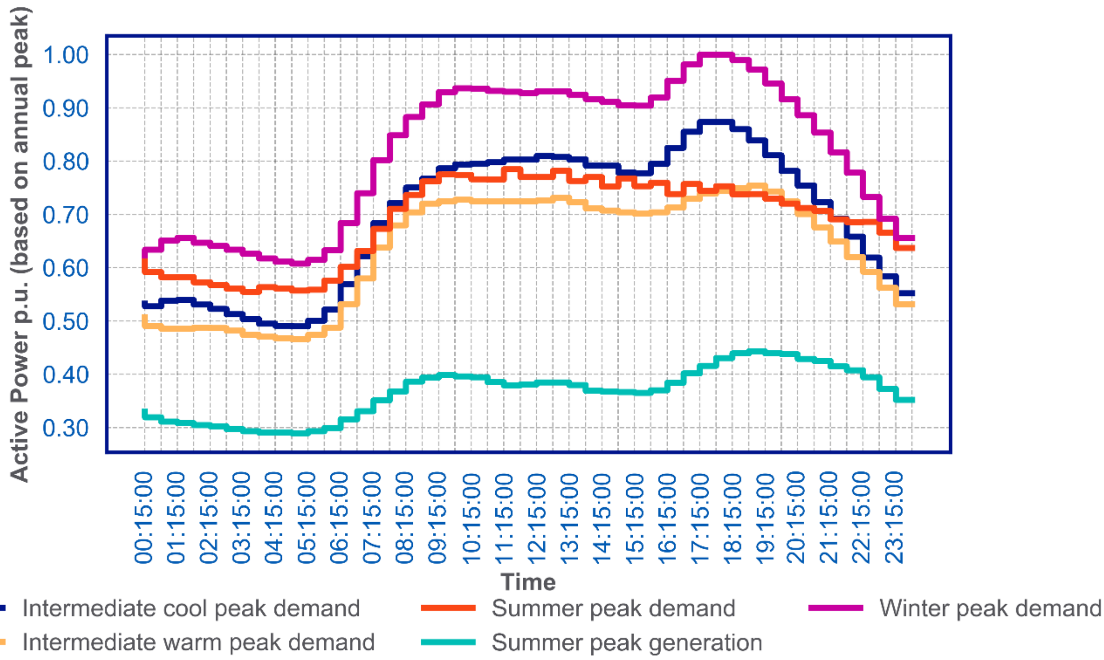

Figure 22: Representative “W1, S1, Sgen1, IC2, IW1” peaking underlying demand active power profiles

This profile is used for three Electricity Supply Areas in the DFES 2024 analysis.

Winter Peak (3), Summer Peak (4), Summer Peak Generation (1), Intermediate Cool Peak (0), Intermediate Warm Peak (1) (W3, S4, Sgen1, IC0, IW1 active power)

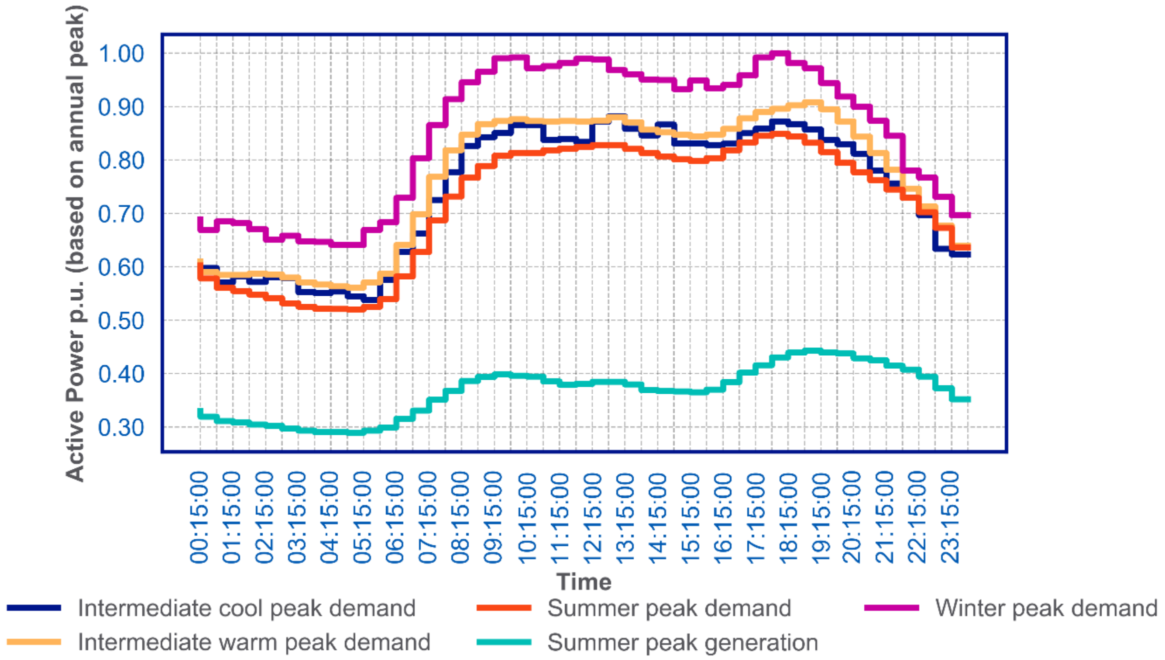

Figure 23: Representative "W3, S4, Sgen1, IC0, IW1" underlying demand active power profiles

This profile is used for one Electricity Supply Area in the DFES 2024 analysis.

Winter Peak (4), Summer Peak (4), Summer Peak Generation (2), Intermediate Cool Peak (4), Intermediate Warm Peak (2) (W4, S4, Sgen2, IC4, IW2 active power)

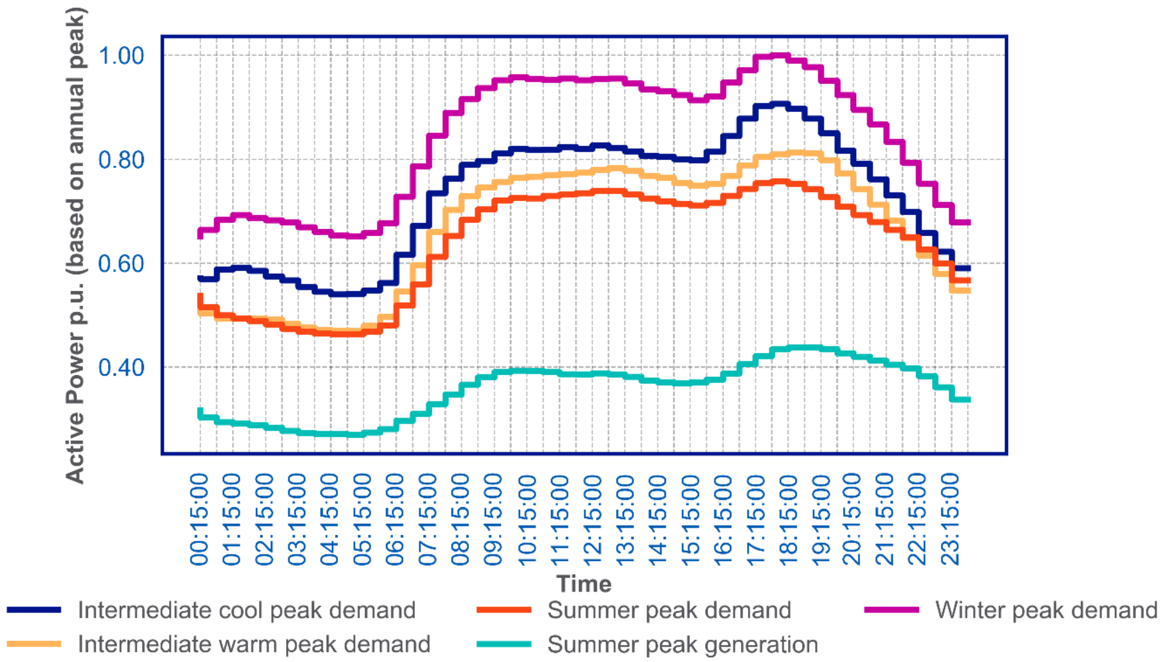

Figure 24: Representative W4, S4, Sgen2, IC4, IW2 underlying demand active power profiles.

This profile is used for six Electricity Supply Areas in the DFES 2024 analysis.

Single Customer

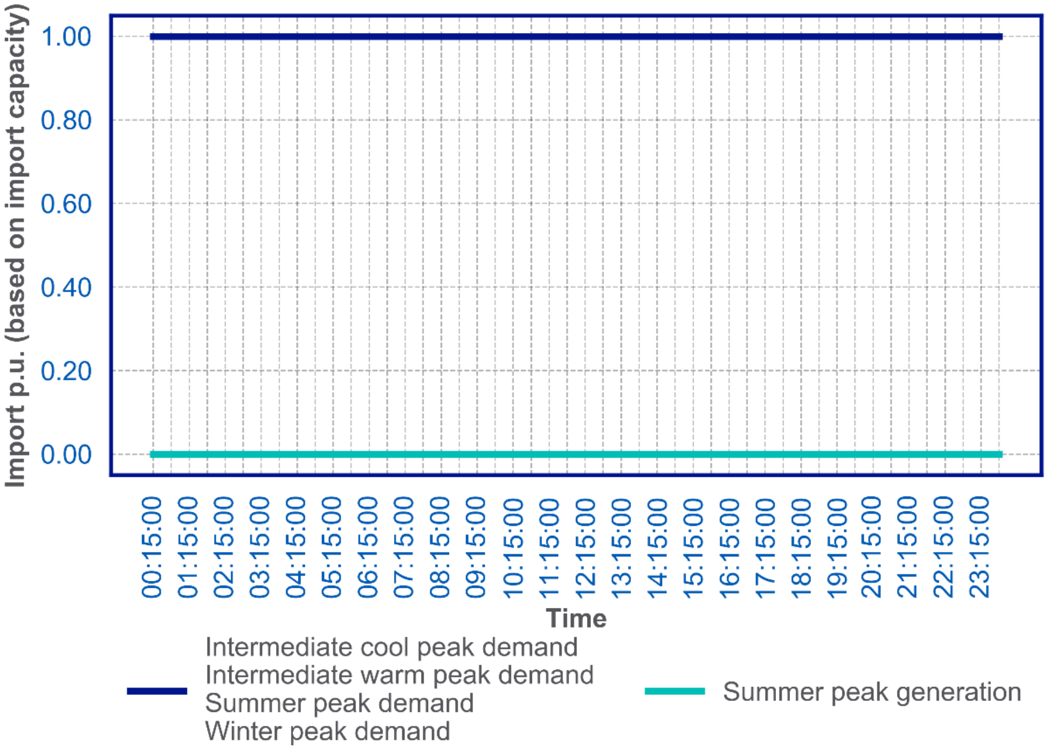

Figure 25: Representative single customer underlying demand profiles

How will these profiles change over time

Underlying demand has been consistently decreasing across NGED's licence areas for many years due to energy efficiency improvements, among other thing such as the cost-of-living crisis and Covid-19 impacts. We expect this trend to continue as new, more efficient technologies continue to emerge. Figure 26 plots the total customers connected to the NG distribution network over a ten-year period, alongside the total NG distribution electrical energy consumption and sum of licence area peak demand.

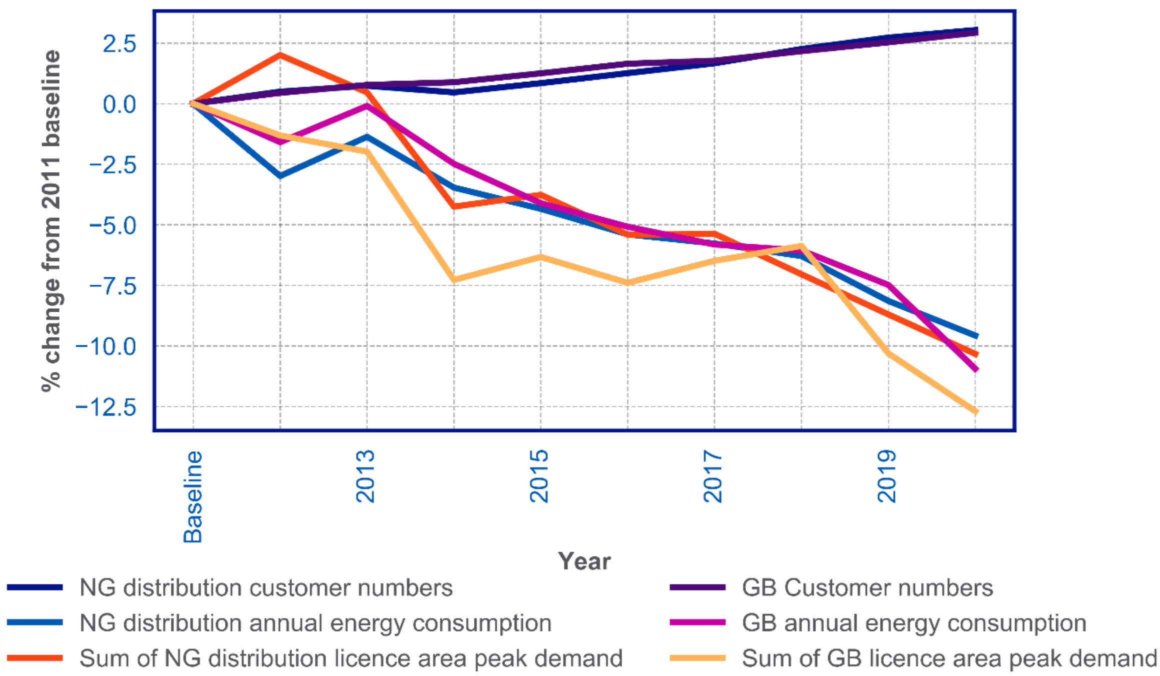

Figure 26: Total change from 2011 baseline of customer numbers, annual energy consumption and peak demand for NGED licence areas and Great Britain

These figures demonstrate that although greater numbers of customers have connected to the distribution network, the total observed peak demand per licence area and the total energy consumption has reduced over the same period. This aligns with increasing customer uptake of more energy efficient devices and a more energy conscious consumer. Future underlying demand has been extrapolated out using historic data; however, extending past the 10-year mark it is uncertain how the current demand will change, and whether this downwards trajectory is able to continue or not. To address this, the reduction has been capped at 10 years, after which the demand is flat.

In addition to the trend analysis of previous years, work has been done by the ACCELERATED innovation project to identify how underlying demand is likely to change as a result of climate change out to 2050[6]. This was done through looking at historic data, climate models, and determining what a 1 in 20 cold day will look like in 2050, and the impacts upon our network. The findings were that peak demand will likely decrease by a small amount due to these modelled weather conditions, which is reflected in our scaling factor.

Annual underlying demand percentage change from baseline

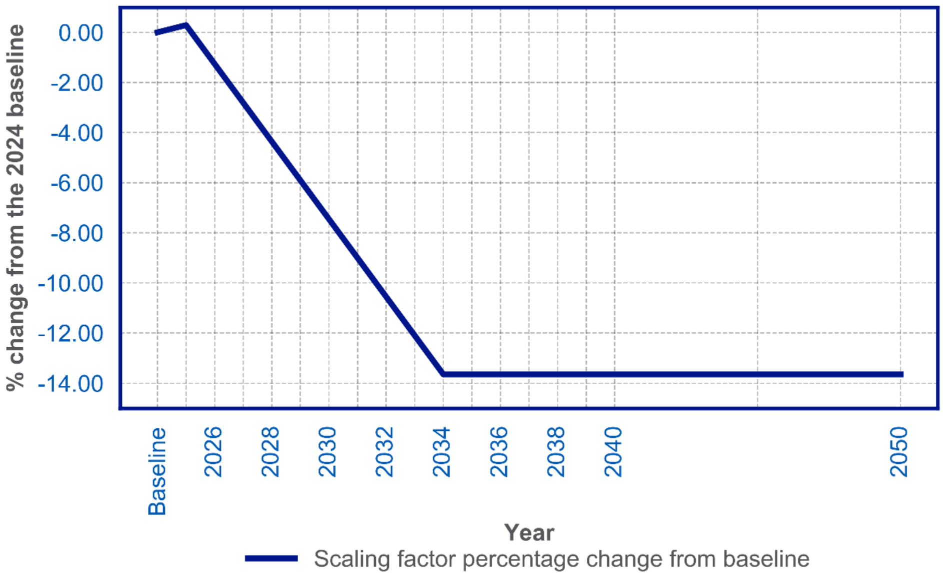

Figure 27: Projected average underlying demand change for our licence areas as a result of energy efficiency assumptions.

Energy Assumptions

The energy consumption figures focus on the local authority energy consumption. As demonstrated in Figure 26, the energy consumption across NGED's distribution network has decreased in the previous ten years. A similar process to the underlying demand decreases was undertaken to extrapolate these trends into the future. These assumptions have been used to infer a local authority specific energy reduction for each year and scenario using measurable data observed from historic NGED-specific energy consumption figures. As with peak demand projections, existing trends have been extrapolated out in the near- to medium-term; however, extending past the 10-year mark, it is uncertain how the current demand will change, and whether this downwards trajectory is able to continue or not. To address this, the reduction has been capped at 10 years, after which the demand is flat.

Annual underlying demand percentage change from baseline by licence area

Figure 28: Expected normalised annual energy consumption change averaged across the licence areas as a result of energy efficiency assumptions.

Known Limitations

Previous profiles assumed a winter profile peak, this is not the case with these profiles; these profiles are very sensitive to annual changes in underlying demand across NGED.

Abnormal running arrangements of Primary substations along with missing or erroneous half-hourly data could impact the clustering process and needs to be studied further.

The expected underlying demand reduction due to energy efficiency analysis was completed at a licence area level, and may not account for the more granular changing demand trends on a per Primary substation basis.

Future Developments

NGED has committed to improving the network monitoring installed across Primary substations during ED2[7].

Where Primary substation monitoring is not suitable to use the data directly in network analysis, the above process has been demonstrated to provide useful clusters of sites with similar behaviour based on observed data. This can further be improved by subcategorising the sample by the season that the peak demand occurred. We are looking to rerun this analysis with a greater sample size, and including more clustering features to gather further details on the archetypes. We will also look at improving methods of cleansing the time-series data.

Domestic

Table 11: Table of domestic technology types used in the DFES analysis

Technology	Subtechnology	Units used in DFES volume projections
Domestic	-	Number of new dwellings

Methodology

The DFES volumes project includes an analysis of all local authority development plans to identify new domestic developments. Each development is geographically allocated to an Electricity Supply Area where it would be most likely to connect to the distribution network. This only accounts for the electrical household demand due to lighting, cooking and entertainment. Any additional domestic demand due to the installation of Heat Pumps, Direct Electric Heating, Air Conditioning or Electric Vehicle chargers are covered in other sections of this report.

Domestic developments are provided with units of the number of domestic dwellings. Each new domestic customer is assigned an electrical demand profile for each of the five representative days considered in the analysis.

The customer behaviour assumptions are based on the Elexon Profile Class 1 profiles[8] used in the electricity settlement purposes, and are consistent with the NGED Policy Document ST:SD5A (Design of Low Voltage Domestic Connections)[9]. This process is developed for the purposes of Low Voltage network design, and uses a statistical methodology consistent with that published in the ACE49 methodology[10]. For the application of these domestic profiles for use in strategic analysis of the EHV networks, a diversity level of 57 customers was chosen. This represents the profile to be a credible usage profile for a single domestic customer, aggregated as part of a wider group of 57 domestic customers. The diversity level was chosen as the average number of additional domestic dwellings per Primary substation per year considered in the DFES volumes projections.

A limitation of the ACE49 methodology is it does not produce a half-hourly profile for all representative days assessed. To create a profile for all demand representative days, the ratio of the urban underlying demand profile referenced to winter peak was used as an approximation for seasonal scaling.

In addition to the increased level of diversity to make the profiles suitable for network analysis, an Estimated Annual Consumption (EAC) was used that is consistent with the Total Domestic Consumption Values (TDCVs) recommended by Ofgem in 2023, extrapolated out by one additional year to 2024[11]. This was deemed a suitable figure for new-build domestic properties.

To account for customers who alter their electricity demand in response to flexibility services, a flexed profile is also used. This assumes a domestic demand of zero for the time of day where a GB electricity system peak is assumed to occur in the winter and intermediate cool seasons. The total energy consumption of the flexed profile is the same as used in the unabated profile, however it allows a total domestic energy reduction at time of system peak to be consistent with the Residential Peak Shifting (Smart/TOUTs effect) figures published in the Future Energy Scenarios (FES) data workbook[31].

Representative Day Profiles

Domestic (unabated)

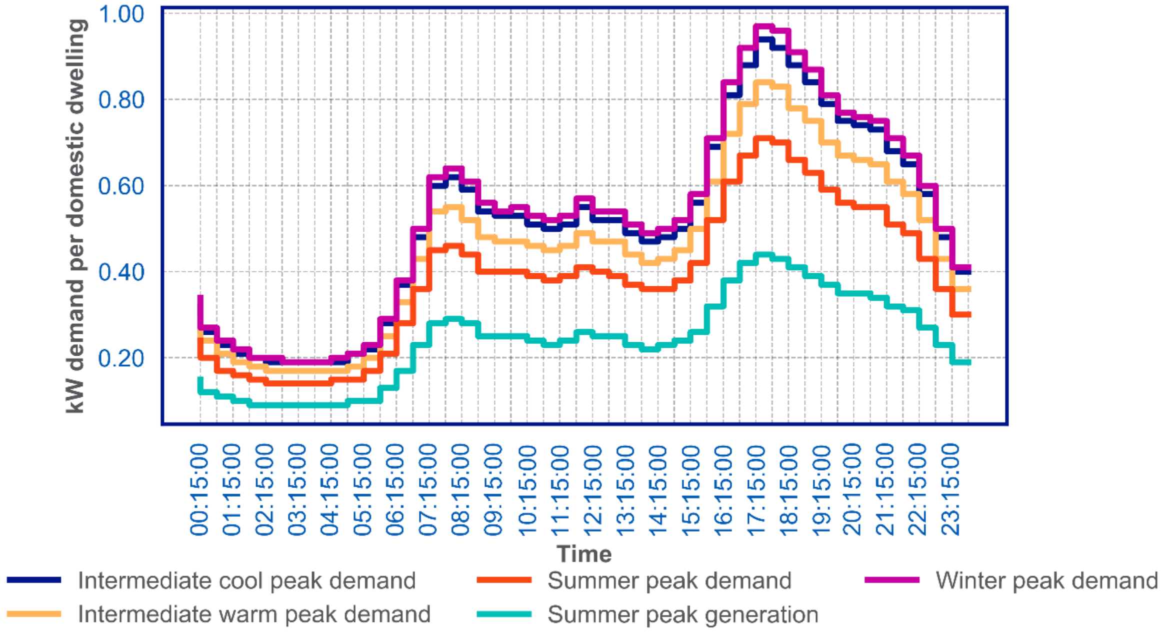

Figure 29: Representative unabated domestic profiles

Domestic (flexed)

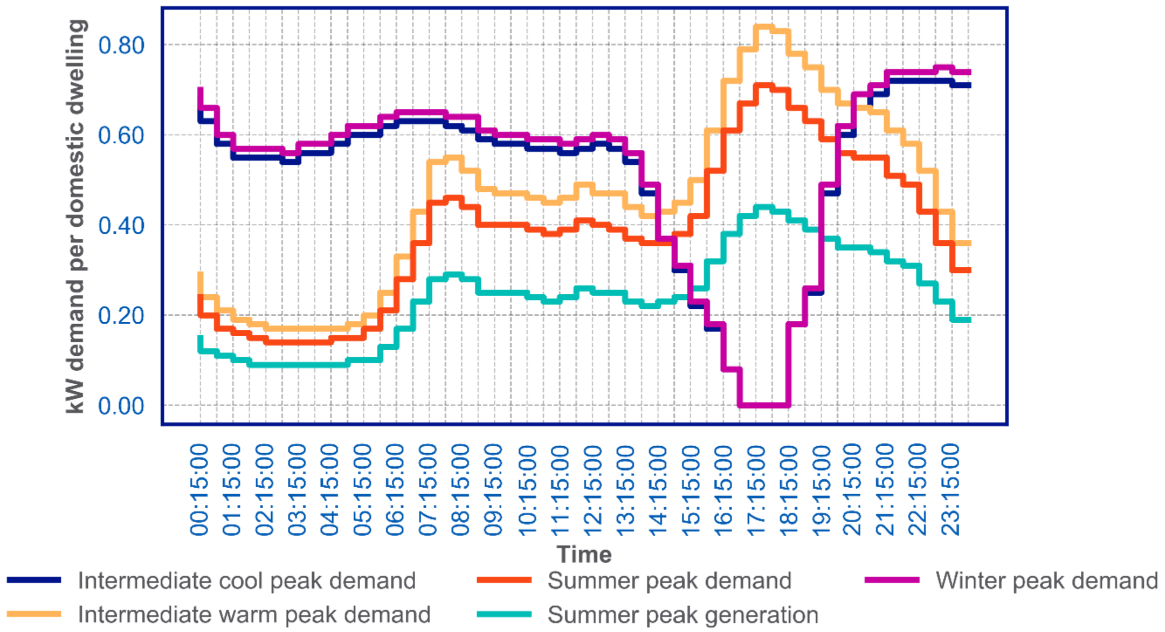

Figure 30: Representative flexed domestic profiles

How will these profiles change over time

As noted above, the flexed domestic profile is used to account for customers engaged to flex their domestic demand at times of system peak. For the demand reduction due to energy efficiency measures, analysis into the reduction in Ofgem Total Domestic Consumption Values (TDCV) has been done for the near to medium term; however, beyond that the energy per year has been capped. This is due to uncertainties around future customer behaviours, as there is currently a trend of more people living alone or in smaller household, which results in more energy per person due to the running of appliances[11]. NGED The lower value of Total Domestic Consumption Values applied also accounts for a more energy efficient home as is currently being connected to the NGED network. These energy efficiency assumptions are shown in Figure 31. These have been normalised and applied to peak domestic demand for the domestic profile scaling factor.

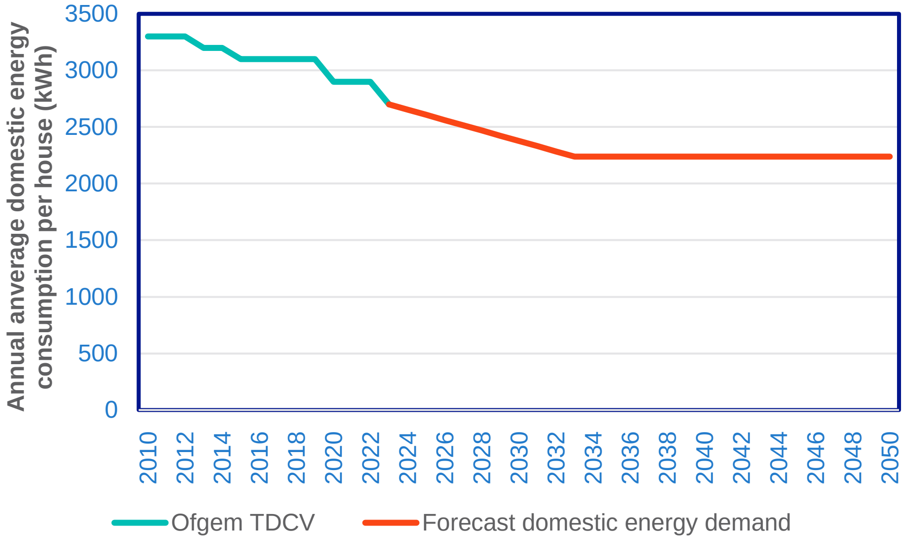

Figure 31: Expected annual energy consumption change for domestic properties as a result of energy efficiency assumptions.

The proportion split between the unabated and flexed profile varies as shown in Figure 32 for each scenario. It is important to note that this is not representing DNO procured flexibility, which is likely to be higher than this, but is inherent flexibility. We do not model procured flexibility at this stage of the DFES as it would potentially mask future constraints, and not flag the area for future procurement of flexibility.

Annual domestic profile split by scenario

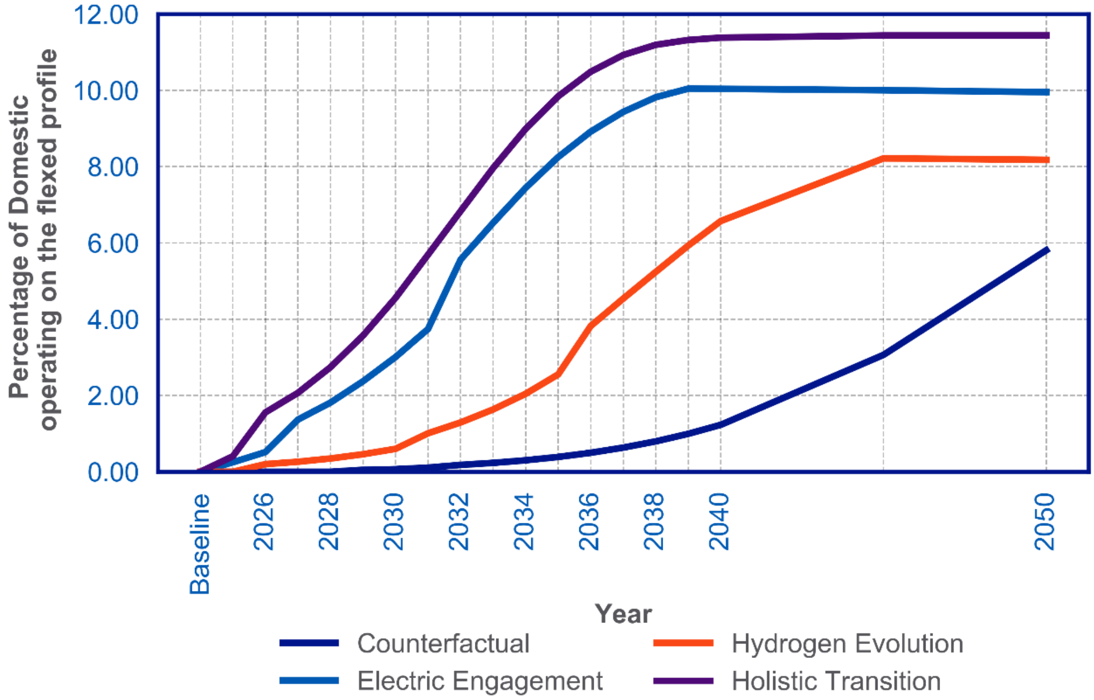

Figure 32: Profile split (proportion of Domestic that is following the flexed profile) of Domestic in each DFES scenario

Energy Assumptions

The energy assumptions for new domestic customers projected to connect to the distribution network are consistent with the Total Domestic Consumption Values recommended values of 2700 kWh per year, scaled to the new baseline of 2024. This is projected to decrease further, in line with the expected annual energy consumption reduction assumptions. In the near term, the TDCV values are trended out, however, from 2034 they are capped to reflect the uncertainty in further energy efficiency improvements from the present day.

Known Limitations

The domestic profile used for Profile Class 1 does not fully reflect the varying energy requirements of new domestic customers. Further subcategorising the domestic customer type by the size of house and number of electrical appliances could improve the granularity and accuracy of domestic customer behaviour.

The assumptions for the demand contribution and energy consumption reductions for domestic customers align with trends seen in the TDCV data. Further subcategorisation by customer type of the existing underlying demand could improve the assumptions for expected customer behaviour change for domestic customers.

Future Developments

With an increased number of domestic customers switching to smart meters and half-hourly metering, this data could be used to infer how customer behaviour changes with reference to price signals which a DNO does not directly impact. NGED plan to investigate the suitability of aggregated smart meter data to inform assumptions on the behaviour of existing and future domestic customers.

Non Domestic

Table 12: Table of distinct non-domestic technology types used in the DFES analysis, with description of the planning use class definition for each category

Technology	Subtechnology	Description of customer types	Units used in DFES volume projections
Non domestic	A1/A2	Shops, financial and professional services	Floorspace (metres squared) of new I&C developments
	A3/A4/A5	Restaurants, cafes, drinking establishments and hot food takeaways.	
	B1	Business (including offices)	
	B2	General industrial processes	
	B8	Storage and distribution	
	C1	Hotels	
	C2	Residential institutions (including secure residential institutions)	
	D1	Non-residential institutions	
	D2	Assembly and leisure	
	Sui Generis	Other customer types not covered by the categories above	

N.B. category C3/C4 (Dwelling and houses of multiple occupation) not included in the projections due to being covered by domestic projections.

Methodology

The DFES volumes project includes an analysis of all local authority development plans to identify new industrial and commercial developments. Each development is geographically allocated to an Electricity Supply Area where it would be most likely to connect to the distribution network.

Non-domestic developments are provided with units as m² of floor space in the development. There are ten difference categories used in the DFES volume analysis, which encompass different industrial and commercial customer types. These are consistent with the planning use classes, before they were updated in September 2020[12]. The units and categories of industrial and commercial customer were chosen as they are the most consistently used in local authority development plans and the Energy Performance Certificate (EPC) database.

For large non-domestic customers with an accepted connection offer to the NGED 33 kV, 66 kV or 132 kV networks, these customers are modelled as a distinct category and profiled based on the requested import capacity as per the connection offer.

Creating a sample of connected customers

To create representative profiles for each non-domestic customer type suitable for strategic network analysis, a demand profile per m² of development floorspace is required. This requires two datasets with the necessary information to be joined together as shown in Table 13.

Table 13: Summary of input data required for non-domestic customer behaviour analysis

Data source	Information required
NG asset management systems	• Meter Point Administration Number (MPAN) • Address
Energy Performance Certificate database[13]	• Address • Property use class (matching the list in Table 12) • EPC rating • Floor space (m²)

As the address is the only common field to join the two datasets, a bespoke Python string-matching program was developed match the different address fields for each customer. This uses an adaption of an algorithm published by Ratcliff and Obershelp (commonly known as the Getsalt Pattern Matching algorithm)[14]. This process generates a large sample of half-hourly metered customers with the required fields as in Table 13.

For the purposes of DFES analysis, it is assumed that new industrial and commercial customers connected to the network will have an EPC rating of C and above. This assumption is intended to remove the impacts of customers with low EPC ratings influencing the representative profiles for future non-domestic connections, and broadly aligns with proposals made in the Future Building Standard consultation[15].

Creating Representative Demand Profiles

For each customer in the sample above, half-hourly metering data is collected for the calendar year of 2019. Analysis of Valuation Office Agency (VOA) data on the number of non-domestic properties in each Local Authority was cross-referenced against the NGED geographic polygon datasets for Primary substations. This process creates a representative sample size of the number of customers of each non-domestic customer type connected to each Primary substation. The table below shows the total sample size available of customers used to generate non-domestic profiles, alongside the representative sample size for the average number of customers per non-domestic customer type connected to a Primary substation.

Table 14: Total sample size and representative sample size per Primary substation of customers used to derive non-domestic profiles

Property Use Class	Number of customers in sample	Representative sample size used
A1/A2	276	150
A3/A4/A5	68	65
B1	129	100
B2	64	60
B8	79	75
C1	60	30
C2	60	25
D1	69	35
D2	38	20
Sui Generis	9	5

For each customer type, the representative sample size was randomly selected from the input dataset. The total demand for all half-hourly periods across a year was extracted from metering data and normalised over the total floor space of the sample. For each of the seasons identified in the Representative Days section of this report, a daily demand profile was generated for each representative day using the following logic:

- **Peak demand representative day**: for each season studied, the maximum normalised value for the sample was extracted for each half hour; and
- **Peak generation representative day**: for each season studied, the minimum normalised value for the sample was extracted for each half hour; and zero export.

To ensure the worst-case network conditions were captured, the above process was repeated 1,000 times with different randomly selected input data for each customer type. The maxima and minima of all repeated samples taken was used to derive the demand profiles.

Profile Benchmarking

The representative profiles were benchmarked against a range of data sources to validate their suitability for use in network analysis, including similar data shared by other DNOs.

- **Non-domestic profiles used by NGED in previous strategic studies: NGED** has used non-domestic normalised around the industrial and commercial floorspace in previous strategic studies[16]. The profiles generated using the above process are similar when compared for network impact totals for the same input volume data. A key improvement is the ability to split the ‘Factory and warehouse’ customer type into distinct ‘General Industrial/B2’ and ‘Storage and Distribution/B8’ categories, as it is observed they follow different electrical profiles.
- **BSRIA Rules of Thumb[17]:** This document is for building services engineers to specify the electrical requirements for non-domestic buildings. The ‘rules of thumb’ for the after diversity maximum demand figures (of kW/m^2) compared favourably to the newly generated profiles. Any differences can be explained by the aggregate behaviour of a group of customers connected at a Primary substation level, rather than the individual customer demand.

Representative Day Profiles

A1/A2 (shops and retail)

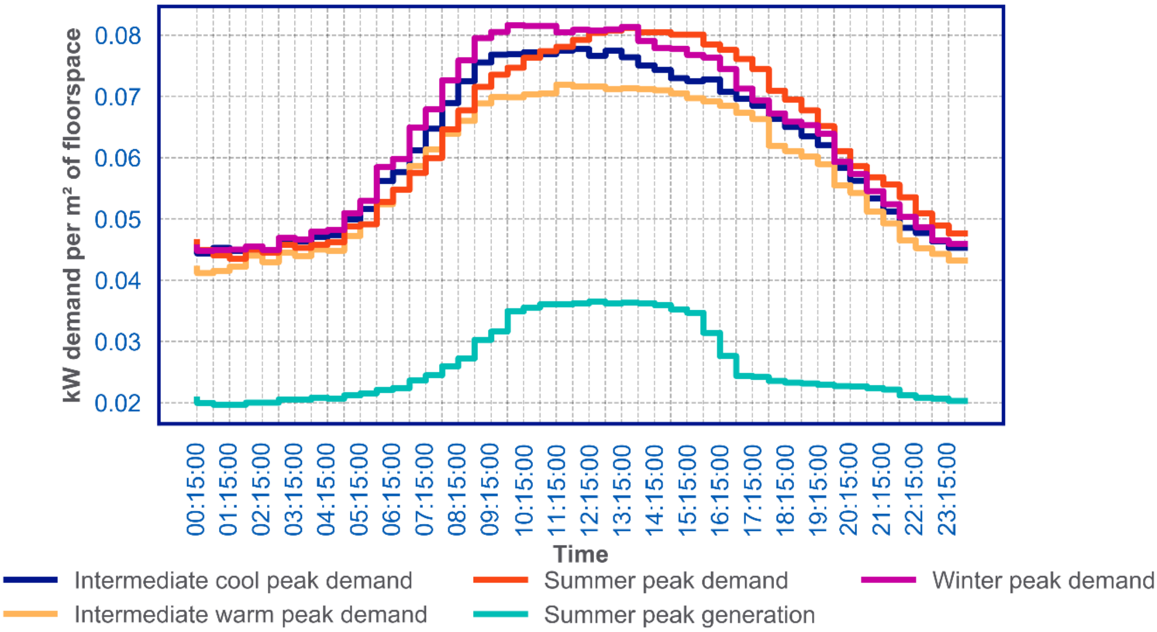

Figure 33: Representative A1/A2 non-domestic profiles

A3/A4/A5 (eating and drinking establishments)

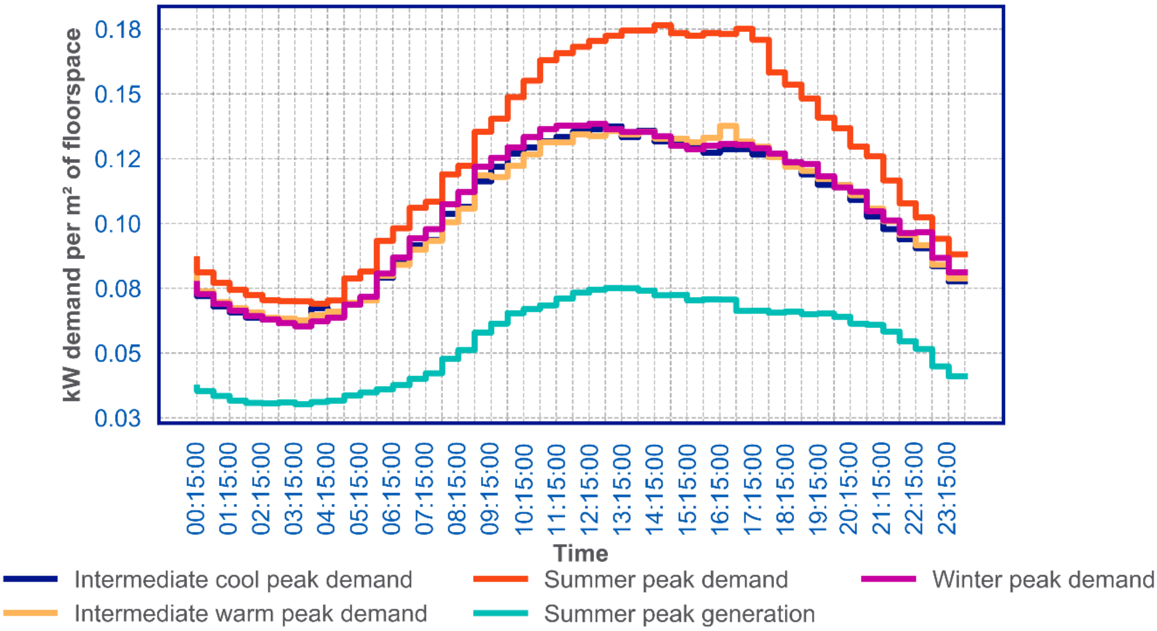

Figure 34: Representative A3/A4/A5 non-domestic profiles

B1 (office)

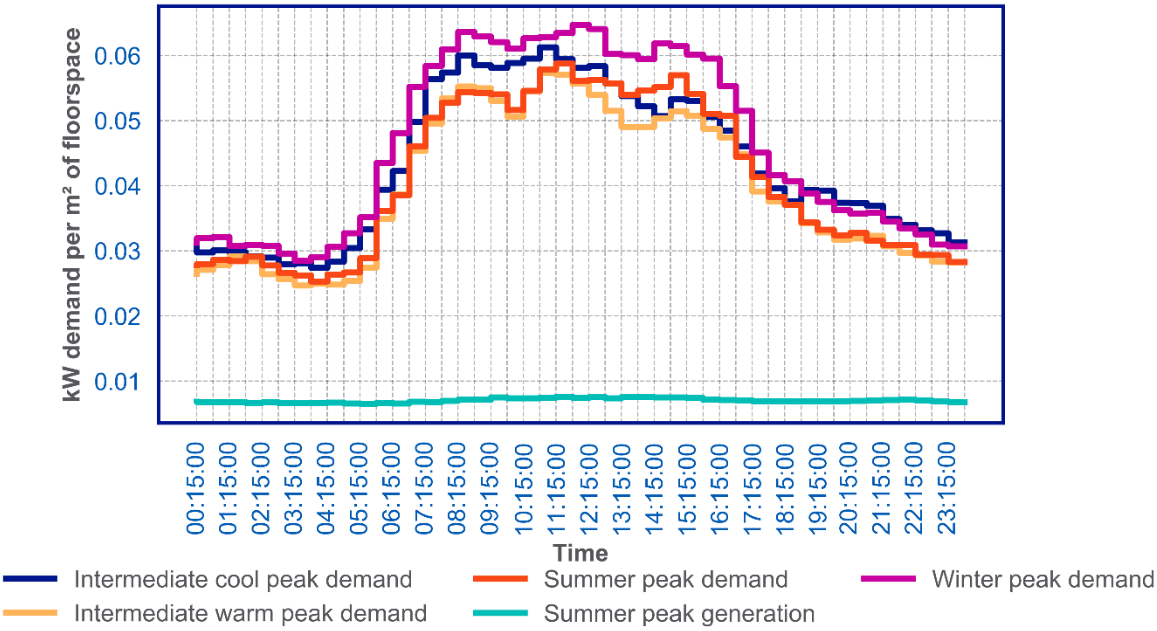

Figure 35: Representative B1 non-domestic profiles

B2 (general industrial)

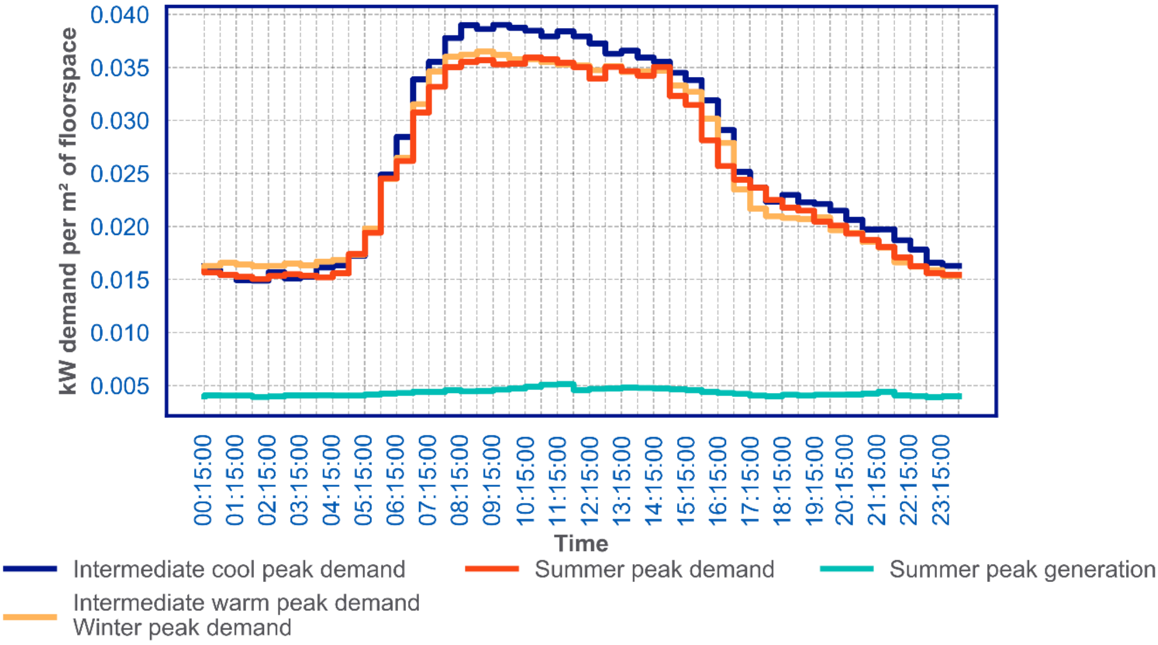

Figure 36: Representative B2 non-domestic profiles

B8 (storage and distribution)

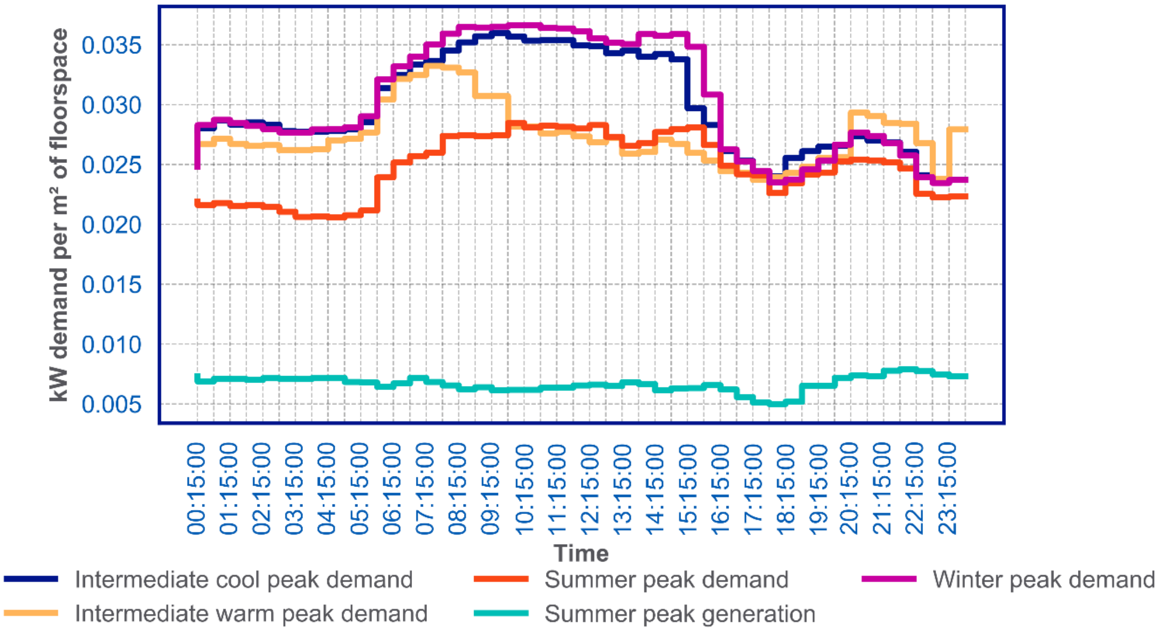

Figure 37: Representative B8 non-domestic profiles

C1 (hotel)

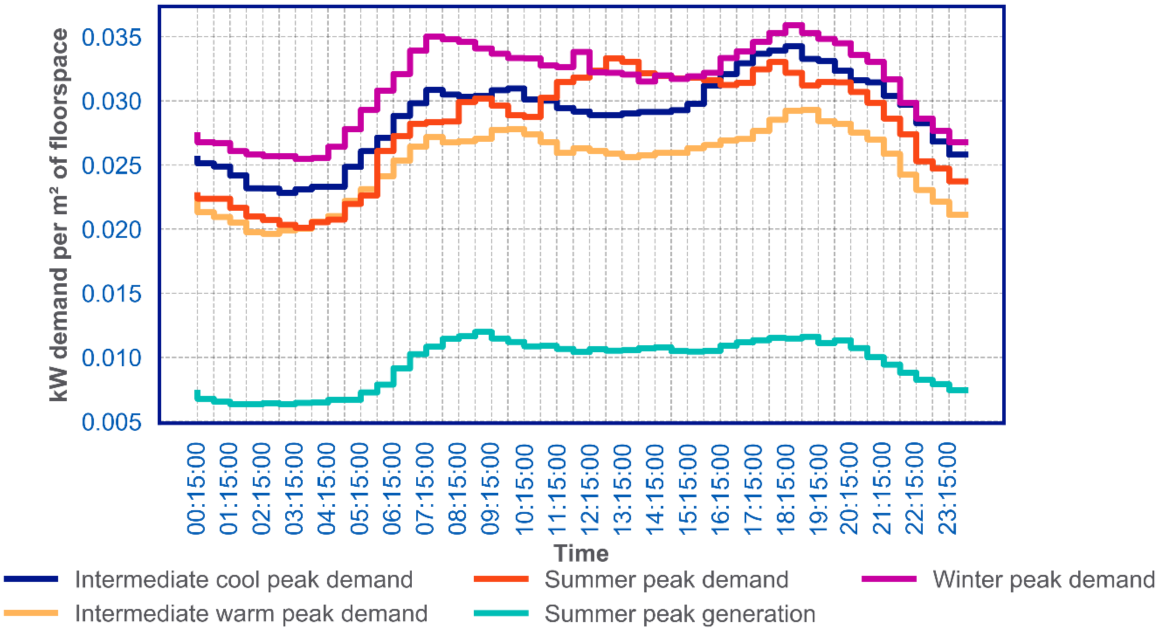

Figure 38: Representative C1 non-domestic profiles

C2 (residential institutions)

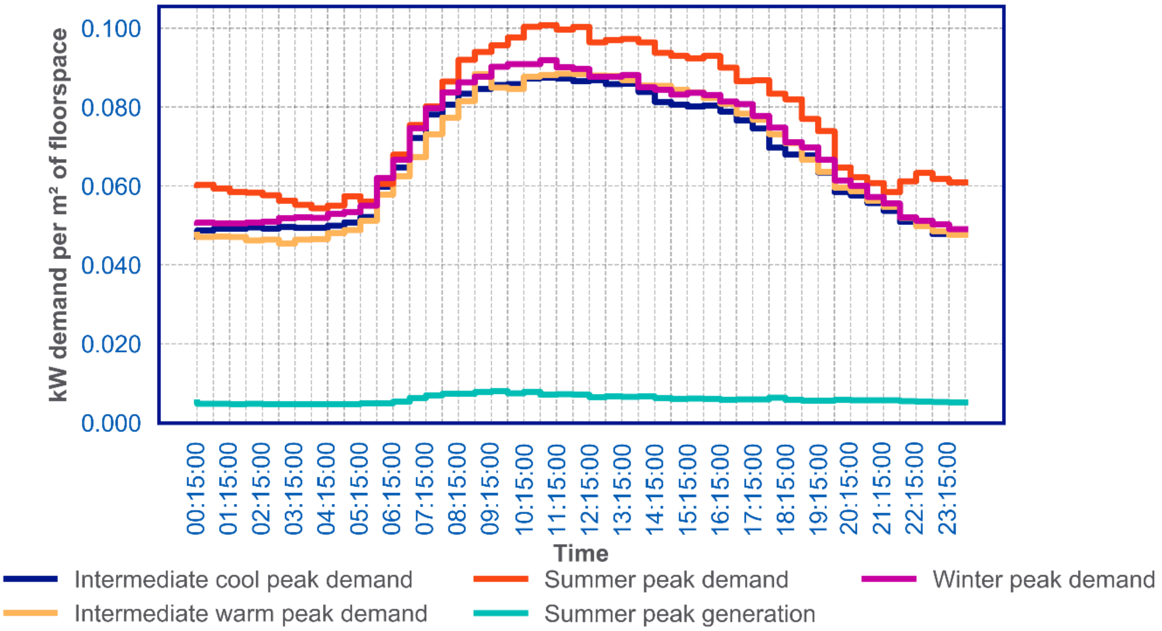

Figure 39: Representative C2 non-domestic profiles

D1 (non-residential institutions)

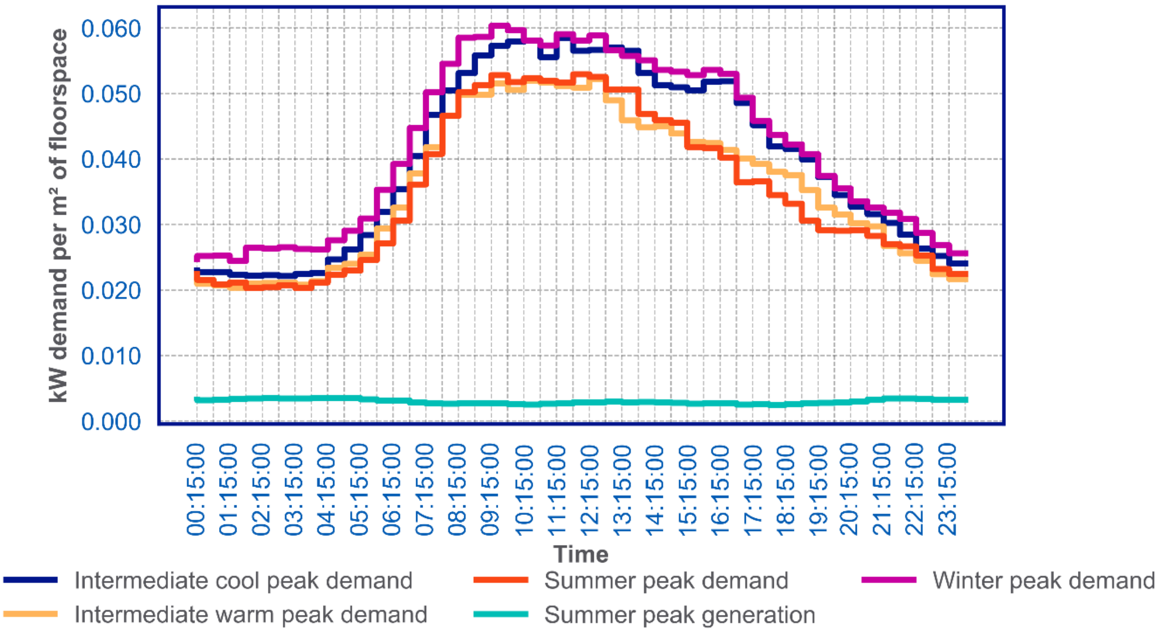

Figure 40: Representative D1 non-domestic profiles

D2 (assembly and leisure)

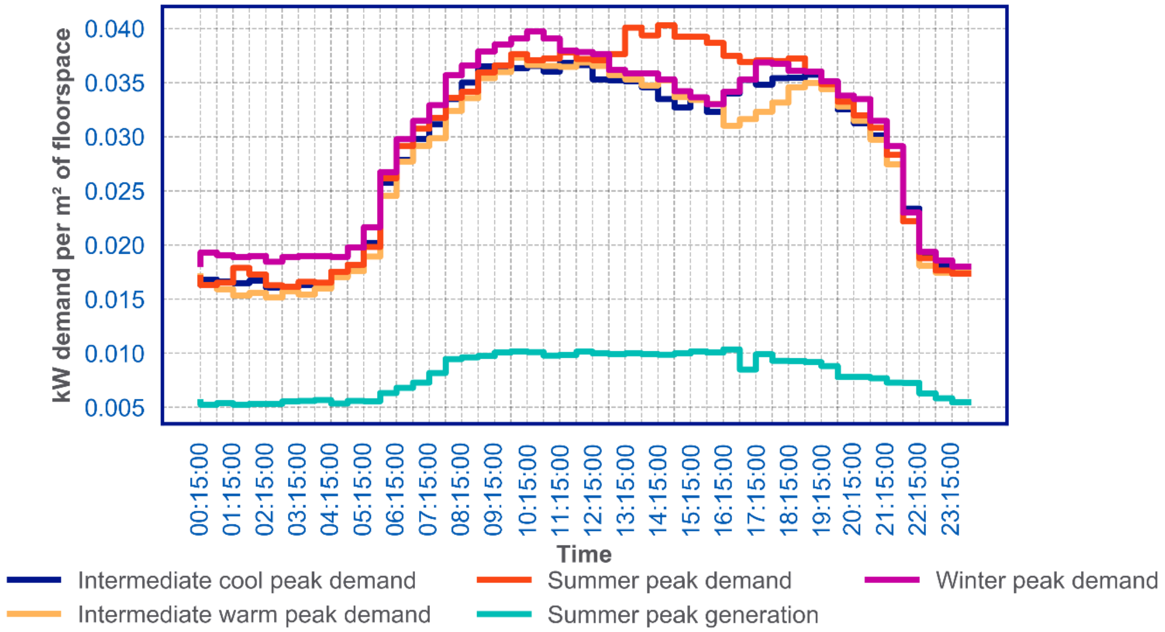

Figure 41: Representative D2 non-domestic profiles

Sui Generis

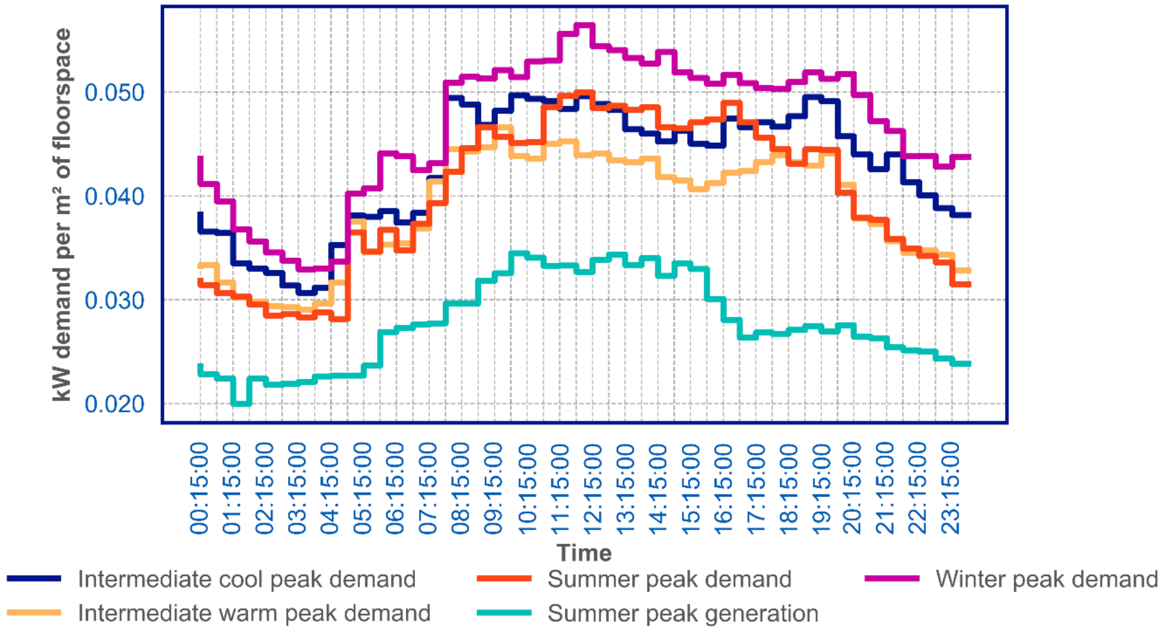

Figure 42: Representative Sui Generis non-domestic profiles

How will these profiles change over time

No flexed profile for non-domestic customers is used as part of the customer behaviour analysis. Whilst the market for industrial and commercial DSR is still relatively immature, suitable data to inform expected uptakes of load management for the purposes of 33 kV, 66 kV and 132 kV network analysis is not currently available for the representative days studied.

For the demand reduction due to energy efficiency measures, the same profile scaling figures as applied to the underlying demand shown in Figure 27 are used for new non-domestic customers. This assumption is made on the basis that a large proportion of the energy consumption across NGED is non-domestic and energy efficiency measures are expected to continue.

Energy Assumptions

This analysis was refreshed in DFES 2024 using updated data between 1st April 2023 and 1st April 2024. As part of the non-domestic profiling exercise, the years' worth of metering was collated for the sample and normalised over the total floorspace. An annual scaling factor for the floorspace to annual energy consumption in kWh was generated. To obtain total estimated annual energy consumption from new non-domestic customers, the values in Table 15 were used. The energy consumption for new non-domestic customers is expected to decrease further in line with the expected annual energy consumption reduction assumptions, with improvements in energy efficiency assumed to align with those in a domestic setting (Figure 31).

Table 15: Average scaling factor from floorspace (m^2) to total annual energy consumption (kWh) for each non-domestic customer type

Property Use Class	Scaling factor from development floorspace to total annual energy consumption (m^2 to kWh/year)
A1/A2	256.3
A3/A4/A5	586.8
B1	158.9
B2	110.0
B8	174.5
C1	131.0
C2	202.8
D1	106.0
D2	112.8
Sui Generis	308.6

Known Limitations

The non-domestic profiling exercise is reliant on the accuracy of the EPC database of non-domestic properties. There are some instances whereby the floorspace did not correlate to the floorspace of a customer connected to the NGED distribution network.

The electrification of industrial processes for existing customers is not captured as part of this analysis. As the profiles are based on existing customer metering data, this covers the existing penetration of electric heating and cooling for non-domestic customers.

Future Developments

As a large proportion of existing non-domestic customers switch to half-hourly settlement[18], half hourly data could be used to infer how customer behaviour changes with reference to price signals which a DNO does not directly impact. NGED plan to investigate the suitability of aggregated smart meter data to inform assumptions on the behaviour of existing and future non-domestic customers.

Some planning use classes have changed compared to our DFES subtechnologies; however, due to the cyclical nature of how local authorities produce local development plans, the majority of published data was still using the old planning use classes.

Electric Vehicles

Table 16: Electric vehicle and charger types used in the DFES analysis

Technology	Subtechnology	Units used in DFES volume projections
Electric vehicles	Hybrid bus and coach	Number of electric vehicles
	Hybrid car (autonomous)	
	Hybrid car (non-autonomous)	
	Hybrid HGV	
	Hybrid LGV	
	Hybrid motorcycle	
	Pure electric bus and coach	
	Pure electric car (autonomous)	
	Pure electric car (non-autonomous)	
	Pure electric HGV	
	Pure electric LGV	
	Pure electric motorcycle	
EV Charge Point	Car parks	Number of EV charge points
	Destination	
	Domestic off-street	
	Domestic on-street	
	En-route / local charging stations	
	En-route national network	
	HGV charge point	
	Fleet/Depot	
	Workplace	

Methodology

The DFES has been developed to include vehicle and charger projections for all NGED distribution licence areas. There are 12 vehicle and 9 charger types projected for all years and scenarios. Each vehicle and charger is geographically allocated to an Electricity Supply Area where it would be most likely to be registered or connect to the distribution network; noting that EVs will charge at multiple locations. All vehicle and charger types projected are given in Table 16. Out of the 12 vehicle types assessed, hybrid bus and coach, hybrid HGV, hybrid motorcycle and hybrid car (non-autonomous) were identified as not being credible vehicle types and the volumes for all years and scenarios remain at zero. They are included in the DFES projections volumes for completeness. All charger types are considered viable and the volumes connected increase under all scenarios.

The distribution of EVs in the near term is based on affluence, rurality, existing vehicle baselines and the distribution of on and off-street parking. However, in the late 2020s under all Net Zero scenarios uptake is assumed ubiquitous. This means that almost all consumers are assumed to have the same likelihood of adopting an EV.

Early EV forecasting typically sub-categorised vehicle types into Battery Electric Vehicles (BEV) and Plug-in Hybrids (PHEV). The majority of BEV and PHEV early adopters had access to off-street charging; meaning the majority of early charging data available was from residential off-street chargers. EV adoption has increased significantly in recent years and the type of vehicles and chargers available are more diverse. By including eight viable vehicle types in the projections, differences in annual mileage and energy are used to build a more representative energy model. The Department for Transport (DfT) and FES datasets were used to determine average mileage and energy figures for each vehicle subtechnology. More information on the energy assumptions for each vehicle type can be found in the Energy Assumptions section.

To assess the impact EVs will have on the NGED distribution network, profiles for all five representative days are required. These need to capture EV demand at existing peak demand periods and possible new peaks caused by the largescale adoption of EVs. There are two methods for profiling the impact of EVs:

1. **EV Profile** – Assign a profile to each EV; or
2. **Charger Profile** – Assign a profile to each charger

There are a number of limitations of directly profiling vehicles:

- **EV charging location** – EVs will use multiple charger types and locations to fulfil their energy requirement. Profiling an EV based on its registered location does not account for this. EVs registered at addresses without access to off-street charging will use a combination of work, slow/fast and rapid chargers to fulfil their energy requirements. These charger types may be located in a separate ESA and will have a notably different charging profile and utilisation.
- **Vehicle stock** – The total vehicle stock needs to be accurately represented when profiling EVs. This is more important as the volumes of electric LGVs and HGVs increase, as they will have a significantly different charging behaviour and energy requirement.
- **Multiple EVs to a charger** - Modelling 1 EV to a charger, does not assess the utilisation and diversity impact of multiple EVs on a house; particularly at peak demand periods.
- **Charger uptake** – The volumes and proportion of charger types available are projected to change under each scenario. Different charger categories have notably different charging behaviours, which is particularly important when profiling for network edge-cases.
- **EV to charger ratio –** By profiling each EV on a static profile it assumes the EV to charger ratio remains constant.

For the reasons described above, only assessing vehicles or chargers independently does not give sufficient information to determine the network impact of the EV transition. The DFES projections of vehicles and chargers allows the creation of a more representative EV model that accounts for scenario and year dependent energy requirement and the chargers that are available to deliver this energy.

This methodology has a number of benefits over directly profiling EVs:

- It accounts for the total vehicle stock yearly energy requirement
- It is profiling the chargers that are actually connected to the distribution network, based on location and type
- Factors in the vehicle to charger ratio and the utilisation of chargers

A number of projects, datasets and reports were assessed to determine the most appropriate profiles. The main projects used to derive and validate these profiles are:

- **Element Energy's EV Charging Behaviour Study (29th March 2019)** [19] - This project developed a set of annual charging demand profiles, covering all 8,760 hours within a year, based upon a dataset of over 8 million real-world charging events collected from major charge point operators.
- **Electric Nation**[20] - When launched, Electric Nation was the world's largest home smart charging trial with nearly 700 Electric Vehicle (EV) owners taking part in the project. The large-scale smart charging trial provided invaluable data on how EV owners charge their vehicle at home and included a trial looking at managed charging.

Aggregated smart meter data – We have used aggregated smart meter data from our customers with EV chargers connected to our network to feed into and validate our domestic EV charging analysis. Through this analysis, we identified that our customers are following our flexed profile more than previously known, due to the benefits of time of use tariffs. The smart meter data also confirmed the aggregate impact of EV chargers on peak demand, and the coincidence factors that should be used when factoring in diversity.

Charger Categorisation

The Element Energy model is one of the most comprehensive assessment of charging behaviour (~8 million transactions) within the UK. The charging behaviour demand profiles produced as part of this project were used as a starting point to produce charger specific profiles for the DFES EV Charge Point subtechnologies. The Element Energy work grouped all chargers into one of four categories:

- **Residential** - Charge points located at or near EV drivers' homes
- **Work** - Charge points installed in workplaces, for use by employees who commute to work using an EV
- **Slow/Fast Public** - Publicly accessible charge points, excluding those classified as Work or Residential.
- **Rapid Public** - Publicly accessible charge points with a charging capacity ≥43 kW

The mapping from the NGED charger subtechnologies to the Element Energy charger types are given in Table 17.

Table 17: Mapping of NGED EV Charge Point subtechnologies to corresponding Element Energy categorisations

Charger Grouping	NG Charger Subtechnology
Residential	Domestic off-street
	Domestic on-street
Work	Fleet/Depot
	Workplace
Slow/Fast Public	En-route / local charging stations
	Car parks
	Destination
Rapid Public*	En-route national network

*"The rapid public charger data was not made publicly available, as the relatively low sample size could be traced back to individual customers. As stated in the Element Energy report "this charger type classification provides an effective trade-off between distinctions in usage while ensuring each type has a large enough data volume".

The NGED DFES charger types are forecast at a more granular level to help inform interested stakeholders and aid in the future development of EV customer behaviour modelling. The profiles described below were created for the four overarching charging groups, and then applied to the more granular NGED charger types.

Normalised Profile Creation

The Element Energy dataset provides a whole yearly hourly profile for residential, work and slow/fast for each NGED distribution licence area. These profiles underwent detailed validation, including removal of erroneous charging events, correcting for increasing EV and charger stock and ensuring anomalously high and low demand were reflected in the final profiles. The final profiles used in this analysis are normalised hourly profiles that give a kW per kW installed capacity.

The process below was used to create the representative day profiles per charger category:

1. Group the yearly profiles from each NGED distribution licence area into the corresponding charger category.
2. Discount any licence area profiles that did not meet the Element Energy diversified threshold check. This is to exclude profiles that have an insufficient sample size to be statistically significant.
3. Assign the relevant season from the representative days to each day and hour within the year.
4. For each hour within a day, find the maximum across all licence areas within each season for all 3 available charger categories. This give a credible worst-case peak demand profile for each season.
5. For each half hour within a day, find the minimum across all licence areas for the summer season for all 3 available charger categories. This give a credible worst-case summer minimum demand profile.

The output of this process gave a profile for each representative day for the residential, work and slow/fast charger categories. These profiles are kW per yearly kWh. This approach enables the energy from a changing vehicle stock to be distributed across a year; accounting for increased utilisation and numbers.

The maximum for each licence area was taken and applied to all licence areas, rather than attempting to apply licence area specific diversity. This is because the South Wales profiles did not meet the diversified threshold for Work and Slow/Fast chargers. There is also a risk that any differences are due to uptake rate and sample size limitations, rather than actual licence area specific variances. Note there is not a significant difference between the fully diversified profiles.

Following the creation of the worst-case representative day profiles in kW/kWh units, they were then converted to per unit profiles, based on the methodology used to determine the volumes of EV charge points required, which involved energy assessments and charge-point apportionment. As the volumes methodology already includes this, the only aspects required to determine the energy passing through the charge point, is the assumed utilisation rate, and a conversion from power into energy, as per the formula below.

$$p.u.Charger\ profile\ (kW\ per\ kW\ of\ installed\ capacity) = \frac{Normalised\ profile\ \left(\frac{kW}{kWh}\right) *}{8760 * utilisation}$$

Due to the lack of available data on rapid charger utilisation, the profile for rapid chargers is modelled at unity (full import) for all demand representative days. This also extends to the eHGV charging profile. This does not represent how rapid chargers are likely to operate, but is a worst-case profile that will be re-evaluated as certainty increases with innovation projects or as roll out continues.

To account for residential smart charging, the Electric Nation managed charging trial data was analysed. The amount of energy time-shifted due to managed charging was calculated and this assumption was applied to the residential charger category to create a residential flexed profile. This final flexed profile is shown in Figure 44. It is important to note that the profile assumes no charging between 5-6pm, to enable the FES assumption of energy time-shifted at peak to be applied.

Representative Day Profiles

Residential EV Charge Point (unabated)

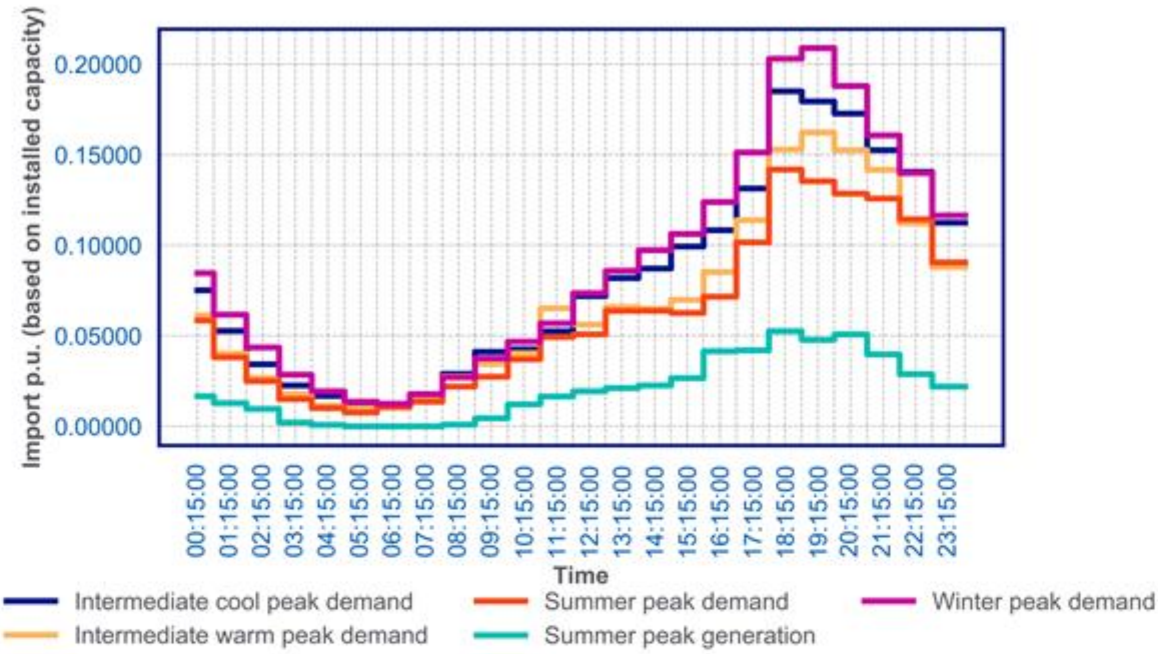

Figure 43: Residential unabated kW per kW installed capacity representative day charging profile

Residential EV Charge Point (flexed)

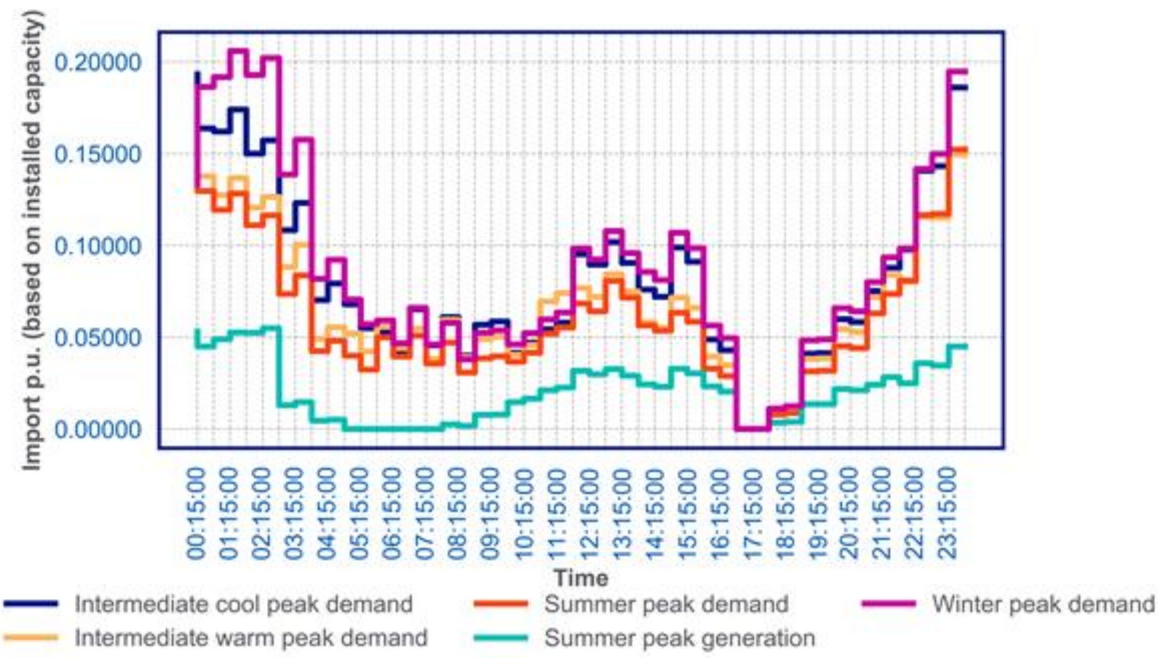

Figure 44: Residential managed charging (flexed) kW per kW installed capacity representative day charging profile

Workplace and fleet/depot EV Charge Point (unabated)

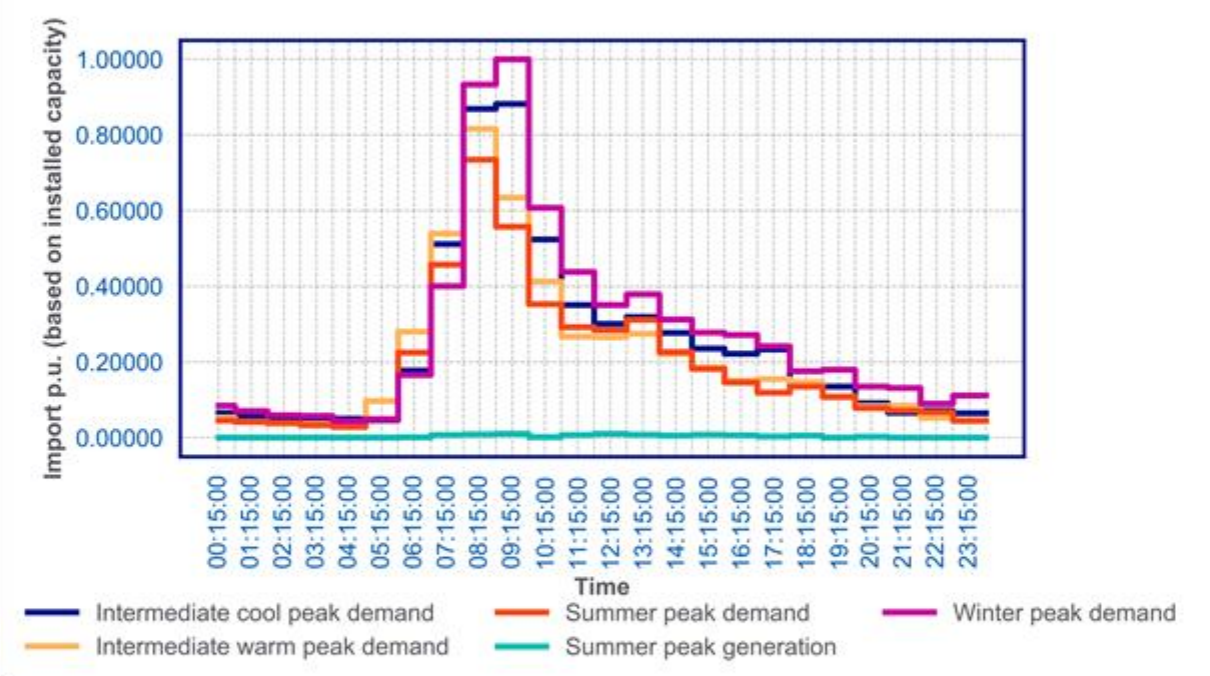

Figure 45: Workplace and fleet/depot unabated kW per kW installed capacity representative day charging profile

En-route / local charging stations EV Charge Points (unabated)

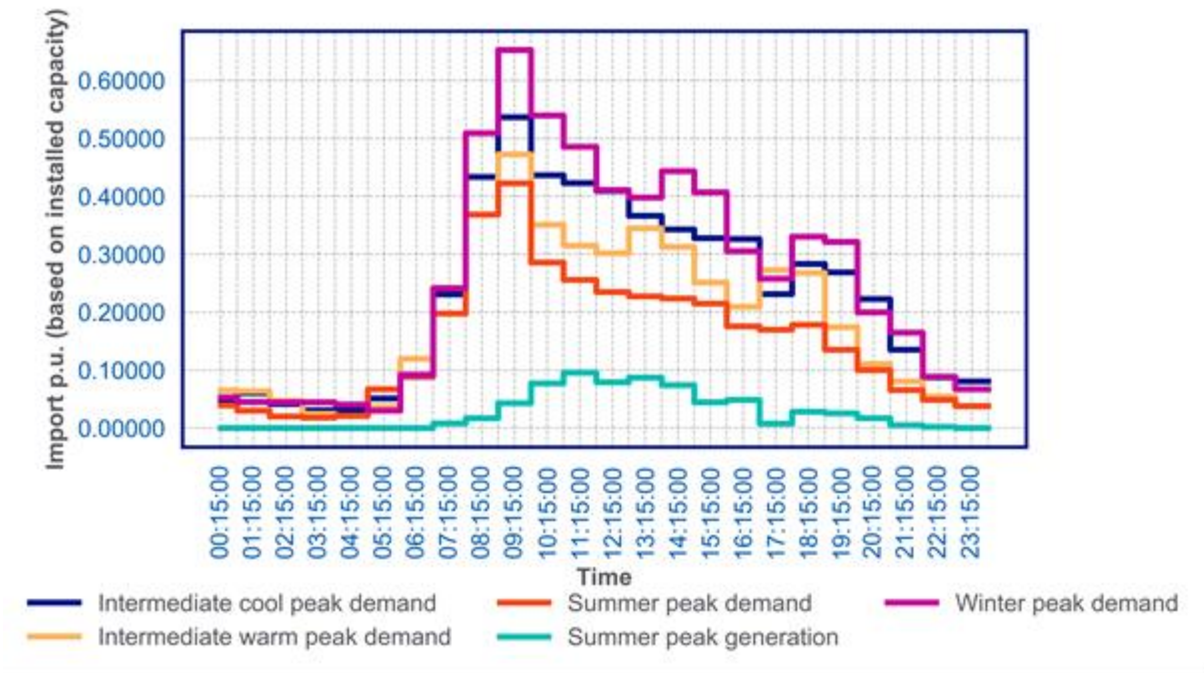

Figure 46: En-route / local charging stations unabated kW per kW installed capacity representative day charging profile

Car parks EV Charge Points (unabated)

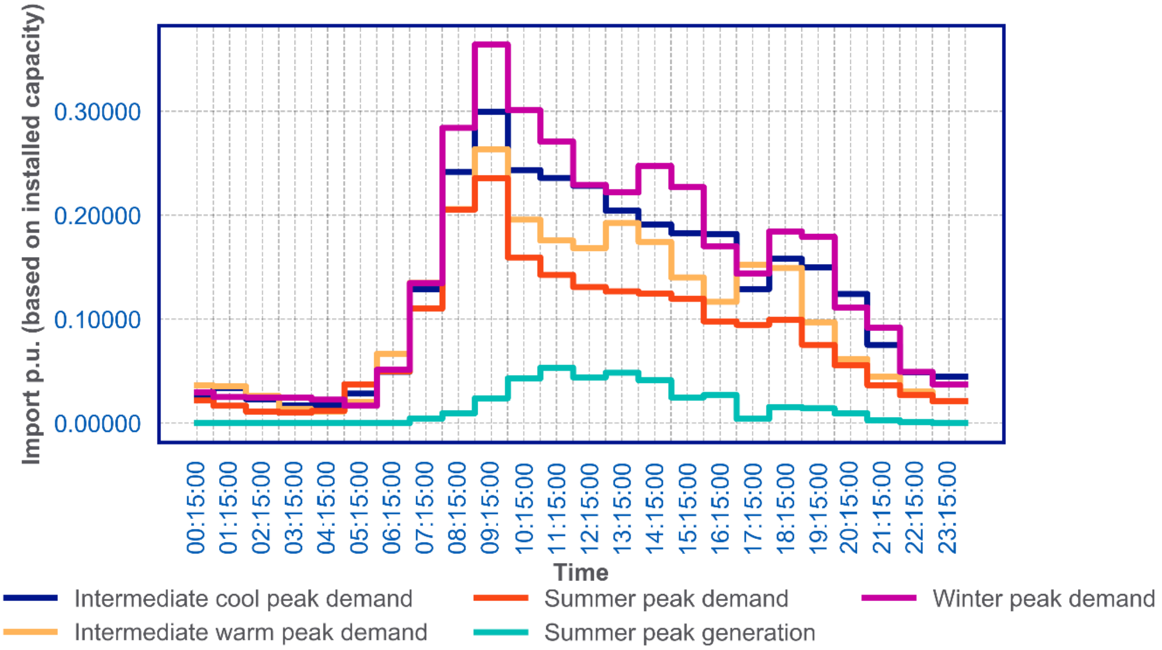

Figure 47: Car parks unabated kW per kW installed capacity representative day charging profile

Destination EV Charge Points (unabated)

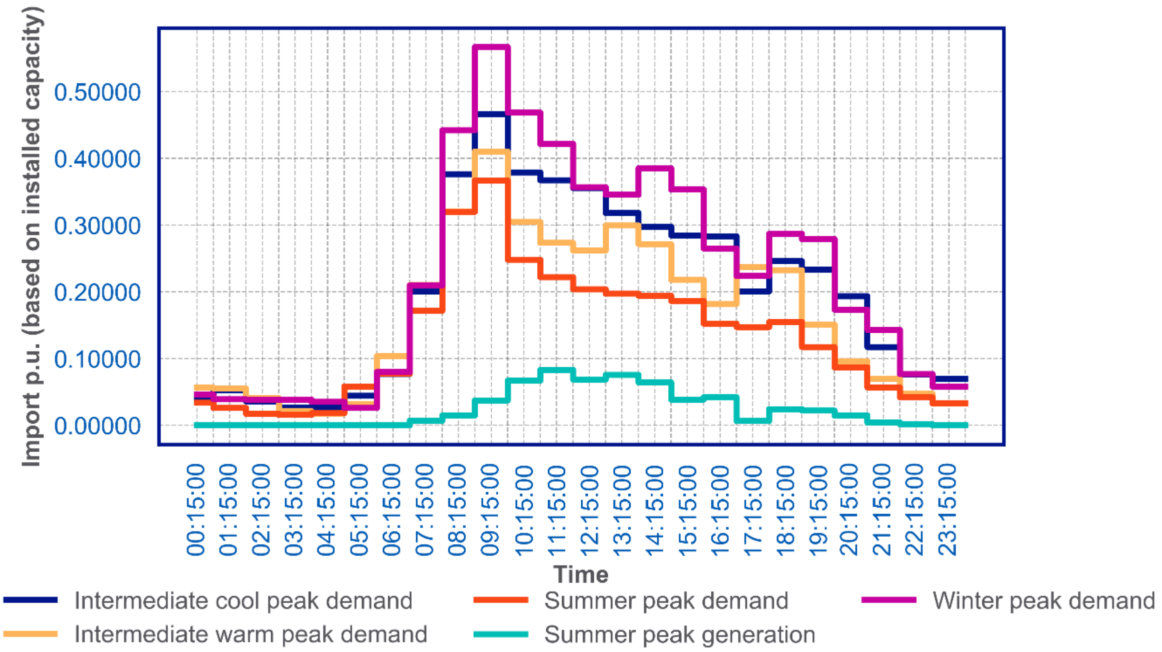

Figure 48: Destination unabated kW per kW installed capacity representative day charging profile

En-route national network and eHGV Charge Point (unabated)

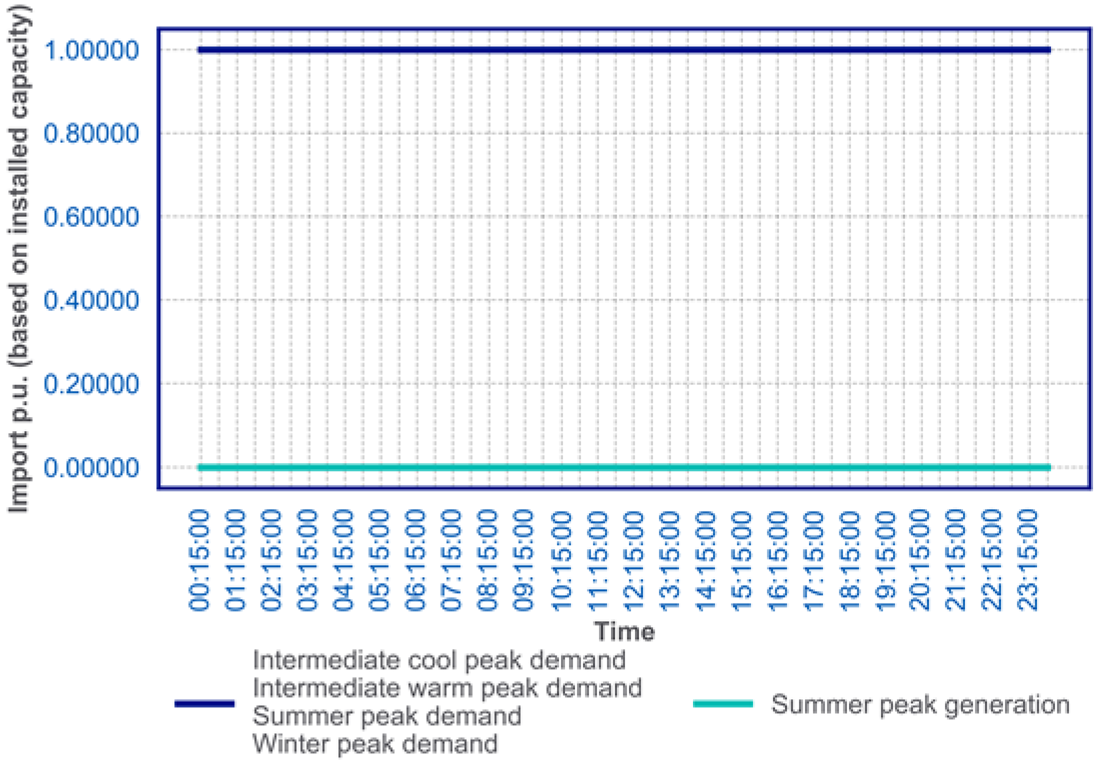

Figure 49: En-route national network and eHGV unabated kW per kW installed capacity representative day charging profile

How will these profiles change over time

As the profile looks at worst case day, some of the profiles are already are already peaking at the installed capacity of the charge-point based on the Element Energy model data. Additional evidence about the change of diversity as cars get more efficient is needed to provide more insight into future behaviours, such as shorter charge times due to advances in technologies or fewer charging events per day.

A review of Electric Nation Powered Up[21] was carried out for investigating the feasibility of incorporating the V2G behaviours into the analysis. This review found that due to the sensitivity of customers to pricing (which is supplied-led not as a result of a DNO flexibility contract) and the purpose of this modelling, additional understanding of customer behaviour is required to accurately incorporate V2G into the DFES analysis.

The proportion split between the unabated and flexed profile varies as shown in Figure 50 for each scenario. It is important to note that this is not representing DNO procured flexibility; we do not model procured flexibility (including V2G behaviour) at this stage of the DFES as it would potentially mask future constraints, and not flag the area for future procurement of flexibility.

Annual profile split of domestic EV charge points by scenario

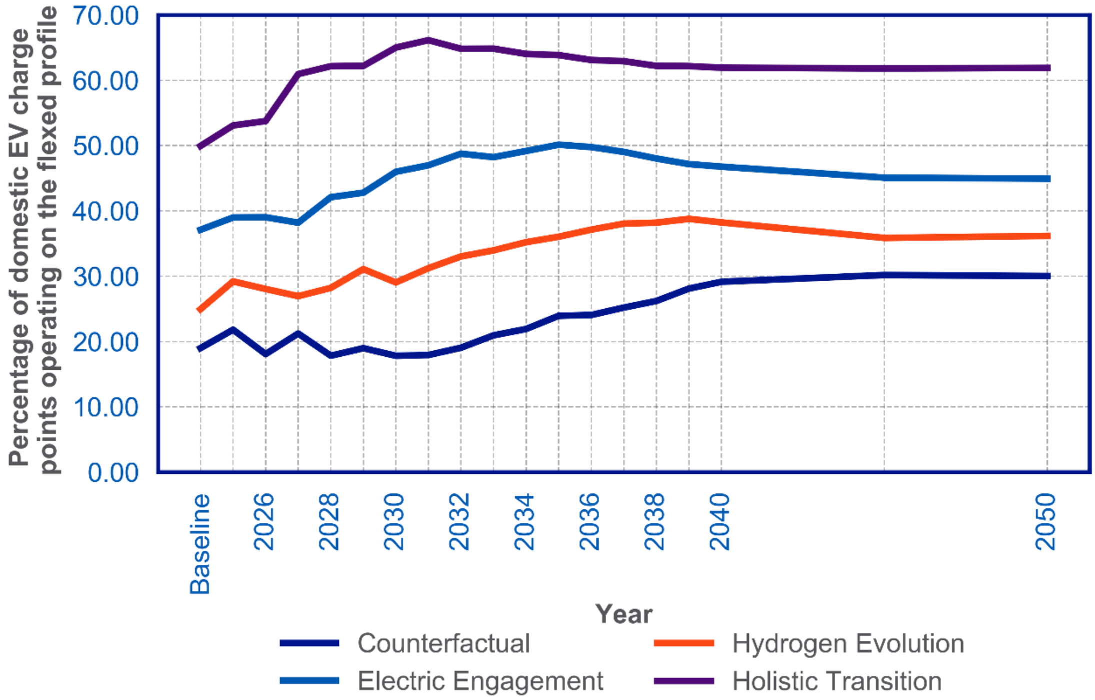

Figure 50: Profile split for domestic EV charge points across each scenario.

Energy Assumptions

The baseline energy assumptions per vehicle category are given in Table 18.

Table 18: Electric vehicle average annual mileage, kWh/mile and yearly energy requirement in Baseline year

Subtechnology	Average Mileage	kWh/mile (Baseline)	kWh/mile (2035)	kWh/mile (2050)	kWh per Year (Baseline)
Hybrid car (non-autonomous)	2,321*	0.28	0.26	0.26	650
Hybrid LGV	2,476*	0.48	0.47	0.47	1,181
Pure electric bus and coach	15,210	1.64	1.54	1.41	24,998
Pure electric car (autonomous)	7,736	0.28	0.26	0.26	2,168
Pure electric car (non-autonomous)	7,736	0.28	0.26	0.26	2,167
Pure electric HGV	33,899	1.33	1.25	1.14	45,103
Pure electric LGV	12,381	0.48	0.47	0.47	6,904
Pure electric motorcycle	4,800	0.12	0.12	0.11	569

*****Mileage when running on electric only

The efficiency improvements described in the above section are also applied for years after baseline.

Known Limitations

No modelling of Vehicle to Grid (V2G) has been assumed due to the uncertainty around behaviour at a granular substation level, in particular if V2G will resolve network constraints that do not align with system peak demand. In addition to the above uncertainties, it is currently being seen that the benefits of having a domestic battery are currently encouraging customers to adopt this technology, as opposed to V2G.

Customers charging directly from a 13A plug are not explicitly captured as a charger type. This is largely mitigated, as the total energy requirement of all EVs is captured and apportioned across the available chargers.

Profiles derived from the Element Energy model are only hourly, rather than half-hourly. Distribution networks are traditionally designed at a half-hour granularity. Benchmarking the residential off-street profiles against the Electric Nation profile shows that the hourly profile is largely representative of a full-diversified profile.

Customer behaviour is expected to change over time with the advancement of technologies, particularly for public charge-points. There is currently a lack of research and data available to inform how this behaviour may change over time; however, this will continue to be reviewed annually.

Future Developments

As more data becomes available, we will look to improve the modelling assumptions on autonomous vehicles. This includes understanding credible autonomous market models, including annual mileage and charging behaviour. This can include ways to better capture EV customers who are charging via 13A plugs, who do not have a dedicated EV charger. As more charging data becomes available, producing EV charging profiles at a higher granularity (half-hourly) will help identify any short duration peaks that will not be fully captured with an hourly profile. In addition, modelling the behaviour of domestic chargers where users are utilising EV Charge Point leasing applications.

Resistive Electric Heating

Table 19: Resistive electric heating technology types used in the DFES analysis

Technology	Subtechnology	Units used in DFES volume projections
Resistive electric heating	Direct electric heating	Number of customers with resistive electric heating
	Night storage heating	

Methodology

Resistive electric heating is a system using electricity to provide primary space heat and hot water to domestic buildings that is not driven by a heat pump. Typically, this is night storage heating or direct electric heating. This does not include heat networks.

The baseline number of resistive electric heating units is based on analysis of domestic heating technology types from EPC data, census data and NGED connected customers. The installation rate of direct electric heating in new builds is also based on local EPC data. Previous publications of national data shows that c.11% of new builds are heated by resistive electric heating, a proportion which has been relatively stable over recent years. The NGED DFES analysis of new build domestic properties is used to project increases in the number of resistive electric heating installations. Resistive electric heating has a higher running cost than a heat pump, they are assumed not to be the target of national policy to decarbonise domestic heating.

The customer behaviour assumptions for resistive electric heating and night storage are based on the Elexon profile classes[22]. They are consistent with the NGED Policy Document ST:SD5A (Design of Low Voltage Domestic Connections)[23]. This process is developed for the purposes of Low Voltage network design, and uses a statistical methodology consistent with that published in the ACE49 methodology[24]. For the application of these resistive heating profiles for use in strategic analysis of the EHV networks, a diversity level of 50 customers was chosen. This represents a credible usage profile for a single resistive electric heating installation, aggregated as part of a wider group of 50 domestic customers with night storage.

A limitation of the ACE49 methodology is it does not produce a half-hourly profile for all representative days assessed. To create a profile for all demand representative days, the ratio of HP energy requirement referenced to winter peak was used as an approximation for seasonal scaling.

Night storage

The Elexon profile class 2 represents domestic economy 7 customers. This is the profile class normally allocated to domestic customers with night storage. Profile class 2 includes the energy requirement for domestic demand, not just the night storage heating. To derive a night storage only profile, the delta between Elexon profile class 1 and profile class 2 was calculated. The profiles for night storage in the baseline year are shown in Figure 51.

Direct Electric Heating

The direct electric heating profile was created using a similar methodology to the night storage profile. The delta between profile class 1 and the unrestricted profile with electric heating was taken to create a direct heating only profile. The energy per installation for each year and scenario is detailed in the Energy Assumptions section.

Representative Day Profiles

Night storage profile

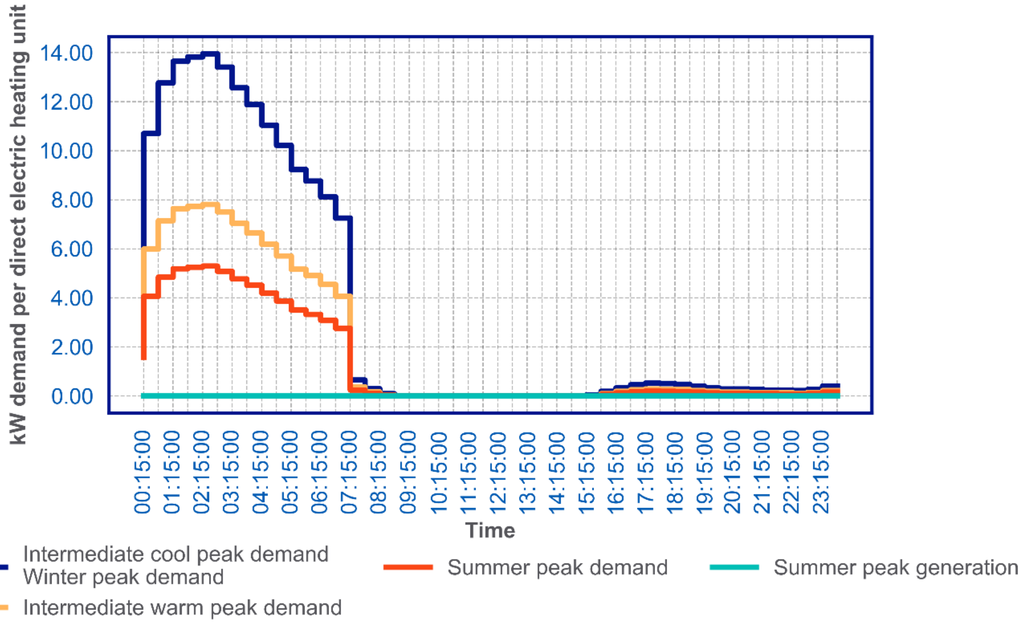

Figure 51: Night storage profile per installation in baseline year

Direct electric heating profile

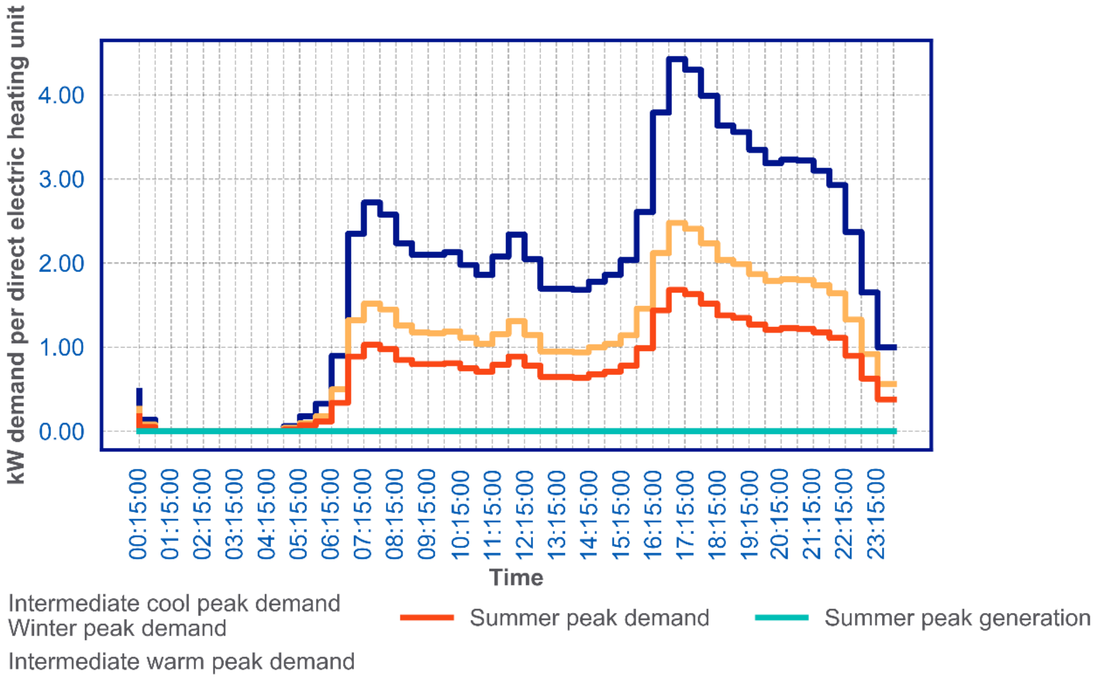

Figure 52: Direct Electric heating profile per installation in baseline year

How will these profiles change over time

The yearly energy requirement per installation is projected to reduce under all scenarios; more information can be found in the Energy Assumptions section. The ACE49 methodology used to derive both profiles are scaled around the yearly energy requirement per resistive electric heating customer. To account for how the reducing energy per installation will affect the MW profiles, a scaling factor based on the data Figure 53: Direct electric heating energy percentage change from baseline by scenario and Figure 54. The scaling factor is normalised around the baseline for each year and scenario and was applied to the profiles

Energy Assumptions

The yearly energy for direct electric heating and night storage broken down by year and scenario are taken from the FES data workbook[25]. The yearly energy is assumed to remain the same for direct electric heating and night storage. The yearly energy requirement is projected to reduce under all scenarios, due to improvements in existing and new housing stock thermal efficiency. The projected efficiency improvements in heating are shown in Figure 53 and Figure 54.

Annual energy consumption percentage change from baseline per direct electric heating customer

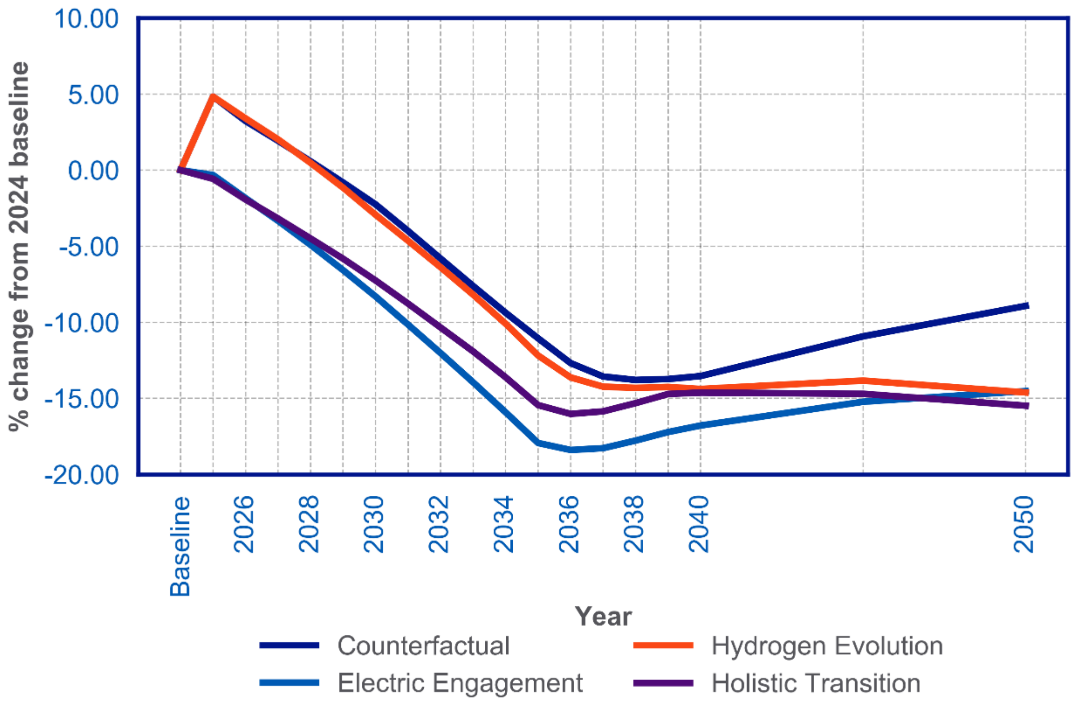

Figure 53: Direct electric heating energy percentage change from baseline by scenario

Annual energy consumption percentage change from baseline per night storage heating customer

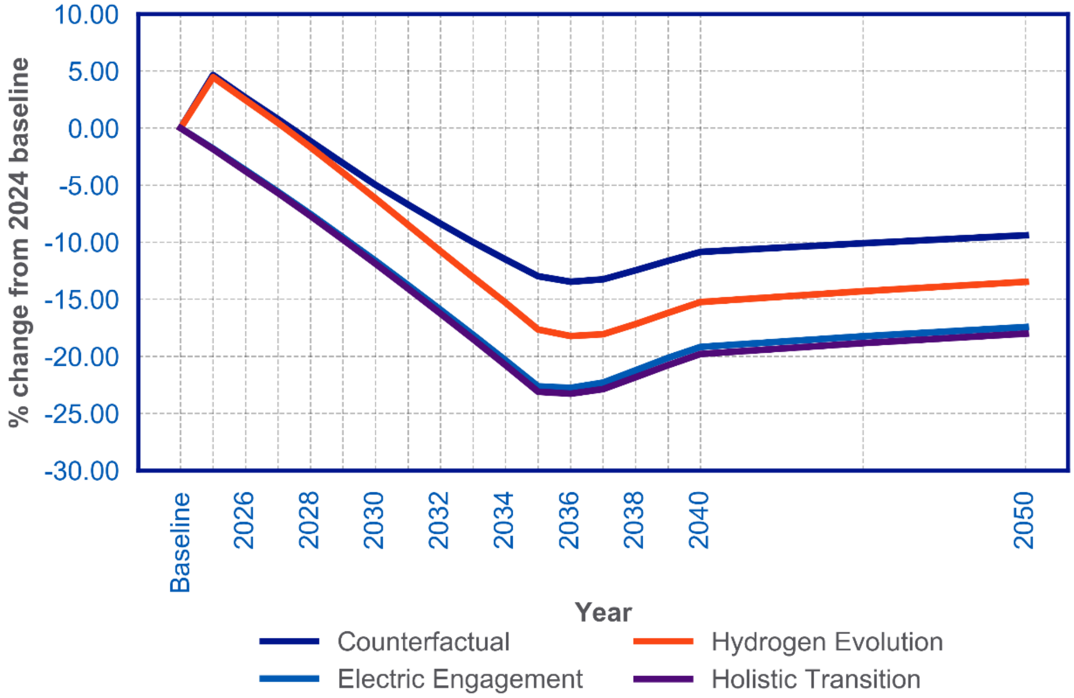

Figure 54: Night storage heating energy percentage change from baseline by scenario

Known Limitations

There are known limitations of these assumptions used for night storage and direct electric heating where the profiles do not currently vary by the archetype of house that they would be found on. Due to the varying thermal properties of different buildings, this could result in variations from the modelling used.

Future Developments

In future there is scope to integrate these heating profiles into a heat model that also includes both heat pumps and district heating, along with further categorisation into building types.

Heat Pumps

Table 20: Heat pump technology types used in the DFES analysis

Technology	Subtechnology	Units used in DFES volume projections
Heat pumps	Domestic - Hybrid	Number of heat pumps
	Domestic - Hybrid + thermal storage	
	Domestic - Non-hybrid ASHP	
	Domestic - Non-hybrid ASHP + thermal storage	
	Domestic - Non-hybrid GSHP	
	Domestic - Non-hybrid GSHP + thermal storage	
	District heating (non-bulk)	Number of customers on district heating scheme
	District heating (bulk)	
	Large scale heat pump for district heating	MW installed capacity

Methodology

Each heat pump connection is geographically allocated to an Electricity Supply Area where it would be most likely to connect to the distribution network. Heat pump volumes are provided in number of heat pumps. As described in the Domestic section, heat pumps are forecast independently to new domestic properties. This allows the retrofitting of heat pumps in the existing housing stock to be more accurately captured.

Ground Source Heat Pumps (GSHP) and Air Source Heat Pumps (ASHP) have been forecast separately, an addition compared to last year's analysis; however, it is expected that GSHPs will be less prevalent due to GSHPs space requirements for the ground source loop and cost of installation. It is worth noting that GSHPs do have a higher coefficient of performance, particularly at times of low ambient temperatures.

Recent developments in hybrid heat pumps, which work with a backup technology (primarily gas), have started to reduce some of the barriers and raise potential for much higher growth in the sector. As well as starting to make it a cost-effective option for an on-gas grid customer, a hybrid system also requires less disruptive change. The higher temperature heat can use existing radiators and the heat pump operates at times when it is most efficient (e.g., low electricity prices or moderate heat requirements), with back up sources taking over when it is not.

The majority of substations see a yearly peak demand during the winter or intermediate cool seasons, at times of cold ambient temperatures. The majority of heat pump energy demand is also within the winter and intermediate cool seasons, with a peak demand that is shown to correlate very closely with existing peak demand.

With non-hybrid heat pumps, all energy is provided via the electricity network, compared with hybrid systems that can switch between electricity and gas. At times of high network demand and low ambient temperatures, non-hybrid systems coefficient of performance can drop significantly. An additional electrical backup source is used where the non-hybrid heat pump is unable to maintain the required temperature. A hybrid system is able to switch over to its alternate fuel source at times of high electricity demand.

When determining the heat pump profiles, it was important to consider the coincident nature of existing peak demand and heat pump peak demand. The use of average or typical profiles does not capture the onerous network loading that will be seen for a 1-in-20 winter.

Non-hybrid Profiles

A review of available heat pump data was undertaken to determine the best source to derive edge-case heat pump profiles. The projects, data sources and reports evaluated include, but are not limited to:

- Electricity North West Limited Network Innovation Allowance (NIA) funded study: Managing the Impact of Electrification of Heat.[26]
- Customer-Led Network Revolution Insight Report[27]: Domestic Heat Pumps, dated January 2015. This included the associated TC3 datasets[28] with heat pump mean and standard deviation for a 48 half48-half hourly period for all months.
- Energy Policy report on “Decarbonising domestic heating: What is the peak GB demand?”[29]
- Applied Energy “The addition of heat pump electricity load profiles to GB electricity demand: Evidence from a heat pump field trial” (Applied Energy 204 (2017) 332–342) [30]
- NESO FES 2024 Report and Data workbook [31]
- Watson, S.D. et al, *Decarbonising Domestic Heating: What is the peak GB demand?* 2019, Energy Policy 126, p533-544 [29]
- Watson, S.D., K.J. Lomas, R.A. Buswell, *How will heat pumps alter national half-hourly heat demands? Empirical modelling based on GB field trials*, 2021, Energy and Buildings vol. 238. p110777[32][33]
- Daneshzand et al., *EV smart charging: How tariff selection influences grid stress and carbon reduction*, 2023, Applied Energy 348, p121482[34]

The non-hybrid heat pump profiles needed to capture the maximum electrical demand for all representative days. This includes demand from any electrical backup that may operate at times of extreme cold.

The Customer-Led Network Revolution TC3 dataset provide an average and standard deviation for a full 48 half hour period for each month in the year. This data enabled production of a half-hourly profile for each network capability season. It was determined that 3 standard deviations from the average was a credible peak, representing a cold period, where a large portion of electric backup heating is required. Based on literature reviews from more recent studies with larger sample sizes, the peak from this data was higher than would be expected, particularly for ground source heat pumps where the coefficient of performance is less influenced by external temperatures. The shape of the CLNR profiles was retained, but the scale of them altered to align with findings from these other studies. The unabated non-hybrid profiles are given in Figure 55.

The profiles with thermal storage represent properties that have storage methods to capture energy at times of low network demand, when electricity prices are lower. The thermal storage subtechnology profiles use the same underlying profiles as the profiles without thermal storage, but with less electrical demand during the morning and evening period. These were changed in DFES 2023 to include diversity of different tariffs during the evening peak, and the times of peak shaving with thermal storage aligned with the work carried out by Daneshzand et al.[34]. The non-hybrid thermal storage co-location profile is shown in Figure 57.

The profiles for GSHP and ASHP have different peak demands in cold weather, to account for the differences in CoP (Coefficient of performance) that are seen across the different technologies. Based on data from the Renewable Heat Premium Payment (RHPP) scheme, and subsequent analysis by Watson et al., the cold winter peak demand for an ASHP is 3.33 kW for ASHP, and 2.36 kW for GSHP systems. This RHPP data was recorded from 2013-2015, and the population within the sample is not representative of the current population of heat pumps installed across the UK.

More recently, data has been collected in the Electrification of Heat (EoH) demonstration funded by the Department for Energy Security and Net Zero (DESNZ – previously BEIS), between November 2020 and August 2022[35]. This data, alongside analysis carried out by Energy Systems Catapult[36] (ESC) has found that on the coldest day in the measured data, the CoP of the EoH (ASHP only) sample was 2.44 (mean coldest day temperature = -0.4C), which is a marked improvement on the RHPP data (where a mean outdoor temperature of -0.4C would be equivalent to an ASHP CoP of 2.05 based on the model created by Watson et al.[33]).

Due to the monitoring period of the winter of 2021/2022 not having a significant cold peak, unlike the RHPP data collection year of 2010, which was considered a very cold year, direct readings are not possible to use for estimating the heat pump COP on a 1-in-20 cold spell using the EoH data. Instead, some analysis was carried out by comparing the 2 datasets and COP relationships with outdoor temperature, and estimating the COP for the 1-in-20 cold spell using the formulae and processes described by Watson et al.[33]. These calculations indicated that the average COP of the current heat pump population in the UK under a 1-in-20 cold spell is 2.32, resulting in a peak demand per heat pump of 2.65 kW in a 1-in-20 cold spell. This is equivalent to the improvements in performance associated with the 'Good Performance' scenario that Watson et al. modelled, and shows significantly greater improvements in either the technology or energy efficiency of the housing stock than were expected to be seen in the period between the RHPP and EoH trials.

Further data collection should be done within the EoH trial to capture additional cold weather heat pump monitoring data to confirm these estimated values, and gather more data points to further develop understanding of GSHP systems under cold spells in the current UK housing stock.

Hybrid Profiles

Hybrid heat pumps are an emerging technology and there is still a level of uncertainty as to how they will operate. A hybrid system manages heat delivery from both a gas boiler, meaning the level of energy delivered from electricity can vary significantly dependent on mode of operation and price signals.

A key source of information on hybrid heat pump operation is the Freedom Project[37], which was a joint innovation project between National Grid, Wales & West Utilities and Passive Systems. It used air source heat pump and high-efficiency gas boiler hybrid system in 75 residential properties, the project has demonstrated the significant benefits that an integrated whole energy systems approach to deploying smart dual-fuel technologies can deliver.

The systems were operated in a range of different fuel price scenarios, including different ranges of gas pricing and with both fixed and variable rate electricity tariffs. When optimising for consumer cost with today's energy prices, the systems strongly favour gas boiler usage due to the very low cost of gas compared with electricity.

The FREEDOM Final Report states:

> *"The field trial demonstrated that hybrids can provide fully flexible loads with the ability to: constrain peak whole-home demand below the existing Elexon Profile Class 1 peak whilst still delivering 50% of the heat demand through the heat pump; enforce a capacity cap across a population, including a cap of zero ASHP demand; increase ASHP demand at times of plentiful low-cost renewable electricity; for the first time ever live carbon forecasts were used so that the ASHP could track grid carbon intensity and avoid times of high carbon peaking plant generation".*

Based on the FREEDOM project findings, hybrid heat pumps are modelled as running on gas for the Winter and Intermediate Cool Peak Demand representative days. Both of these representatives are focussed on extreme cold ambient temperatures, where the ASHP coefficient of performance will be greatly reduced and it is presumed that the heat pump control system and price signals will incentive gas sufficiently during these representative days.

Summer and intermediate warm representative days are profiled at 80% of the non-hybrid profile, accounting for hybrid systems that are still operating on gas even during less onerous periods. The profiles used for hybrid heat pumps can be found in Figure 59.

District heating profiles

The total heat demand of both domestic and non-domestic customers that would be connecting to a heat network has been assessed, and used to size heat pump energy centres in suitable locations.

Through using this methodology, the demand of district heating schemes is better captured. This is particularly true where a heat network extends across multiple primary substations, and the point of connection to the distribution network falls within only one of the primary electricity supply areas.

The heat network profile has been changed in 2024 to incorporate stakeholder engagement and model the impact of co-located thermal storage or booster systems under the high electrification scenarios. The installed capacity of these large-scale heat pumps has been determined through assuming 100% of the thermal peak demand has been met via the heat pump, however, through stakeholder engagement we have found that in real-world scenarios, this is unlikely to be the case due to costs. We have adapted the profiles to correct this and better replicate the real-world operation in the load sets used for network modelling.

Large-scale heat pumps for heat networks have been modelled differently across the different scenarios. The profile split functionality has been used to implement this in the data, through applying a low electricity demand profile in Counterfactual and Hydrogen Evolution, and a high electricity demand profile in Electric Engagement and Holistic Transition. Under scenarios with hydrogen or gas peaking boilers, the electrical demand for heat networks is far lower, due to the heat pump only being used for the baseload, and peaking being met through gas-powered booster systems (Figure 61). In electricity-intensive scenarios; however, heat pumps still only meet the baseload demand (~50% of the annual peak demand), and the remainder is met through electric boiler systems, with only a 100% efficiency (Figure 60)[38,39].

The cool seasons have been shaped in line with the demand profiles found in studies carried out by Fairheat[38,39] .The seasonal demand has been varied for the summer peak demand season, to reflect not only the reduction in space heating, but the increase in temperatures of inflowing water to properties, requiring less domestic hot water heating. The ratio of reduction was chosen based on a study by Dang et al.[40].

Representative Day Profiles

Non-hybrid air source heat pump profile

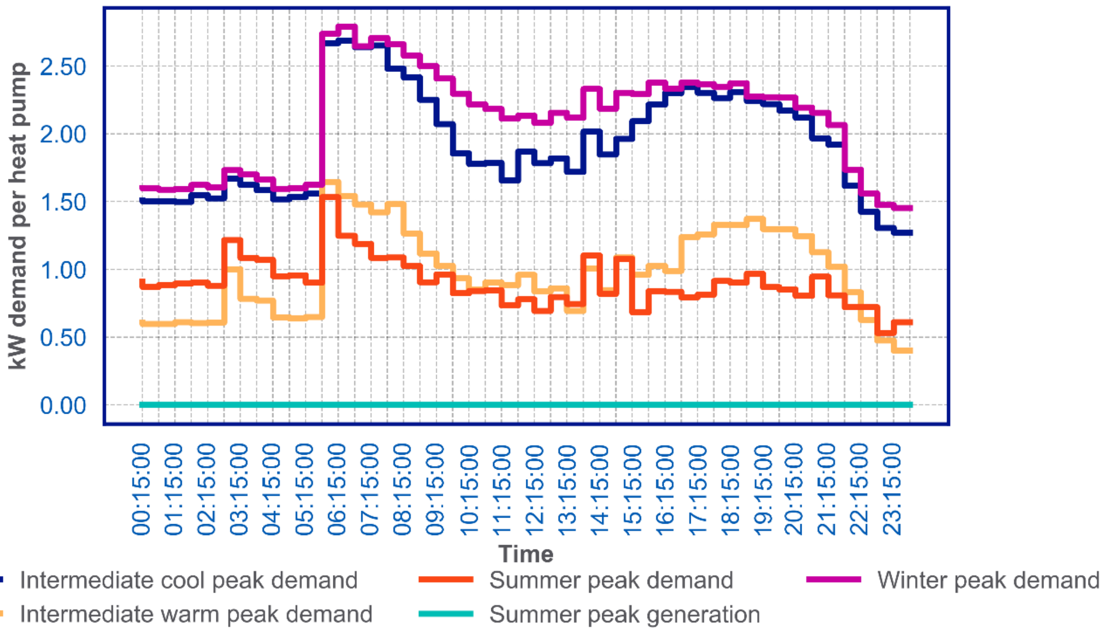

Figure 55: Non-hybrid air source heat pump profile in baseline year

Non-hybrid ground source heat pump profile

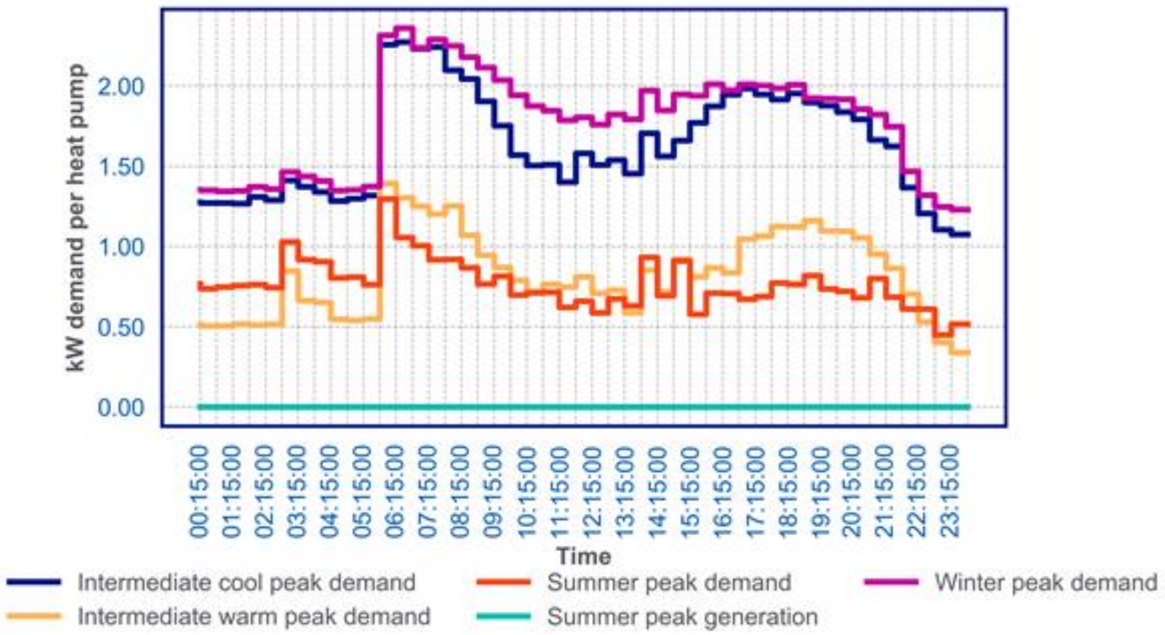

Figure 56: Non-hybrid ground source heat pump profile in baseline year

Non-hybrid air source heat pump profile with thermal storage

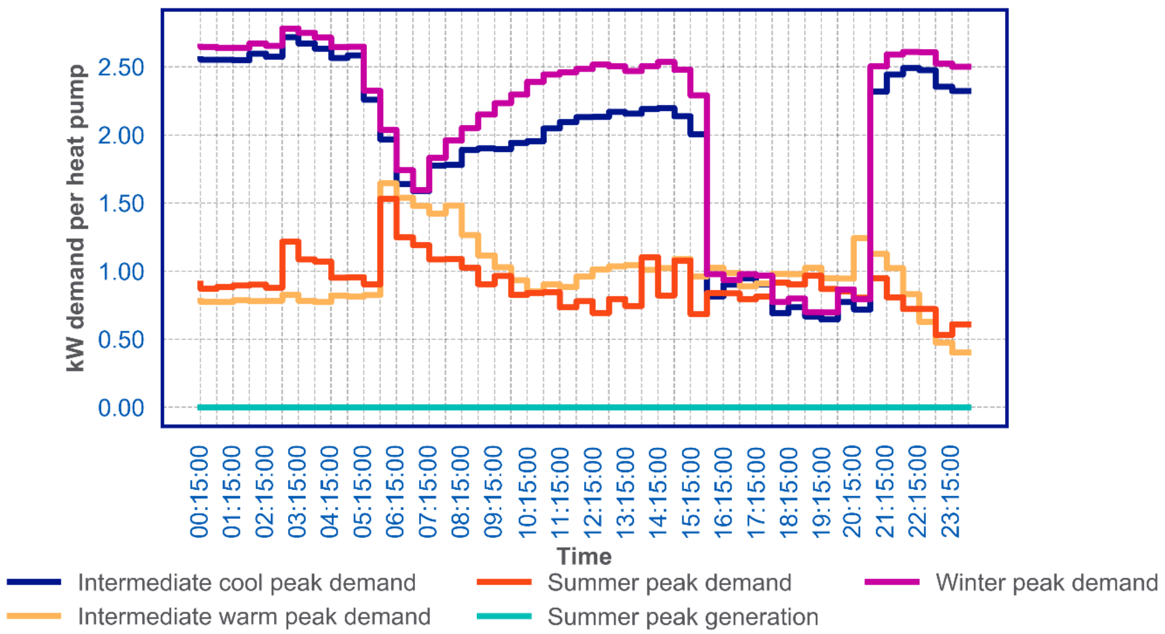

Figure 57: Non-hybrid air source heat pump with thermal storage profiles in baseline year

Non-hybrid ground source heat pump profile with thermal storage

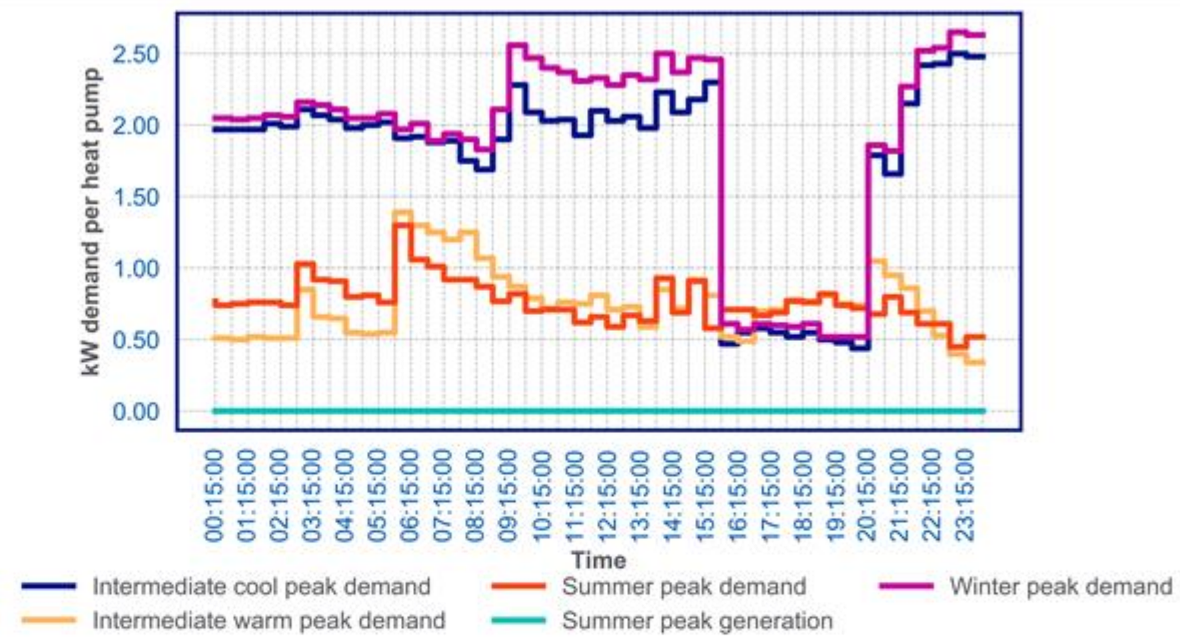

Figure 58: Non-hybrid ground source heat pump with thermal storage profiles in baseline year

Hybrid heat pump profile

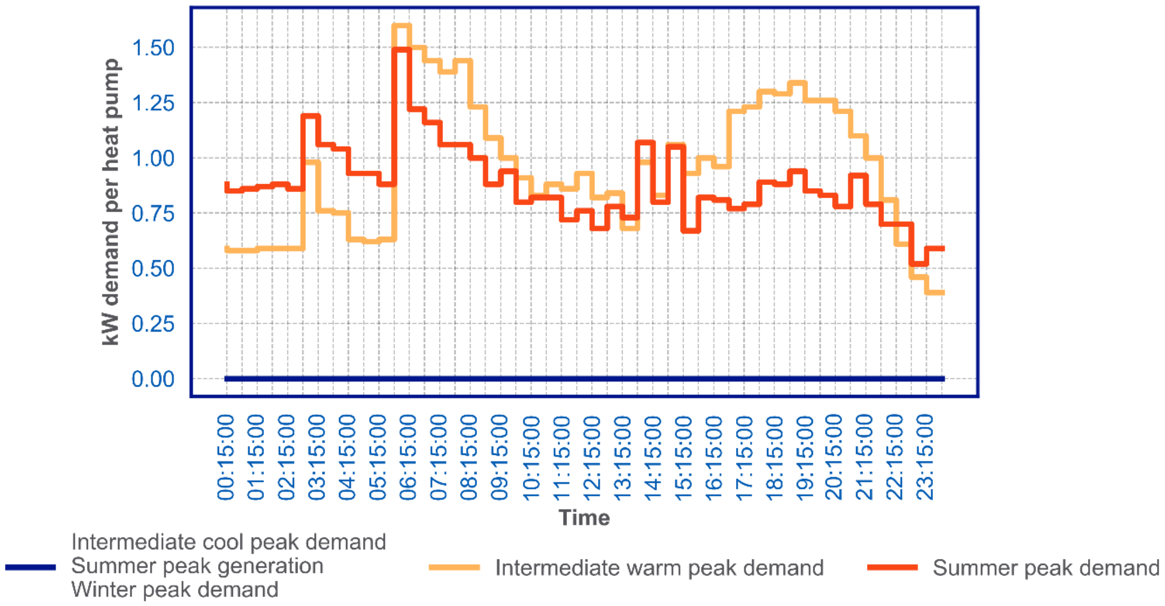

Figure 59: Hybrid heat pump in baseline year

Large scale district heating scheme heat pump profiles (electric booster system)

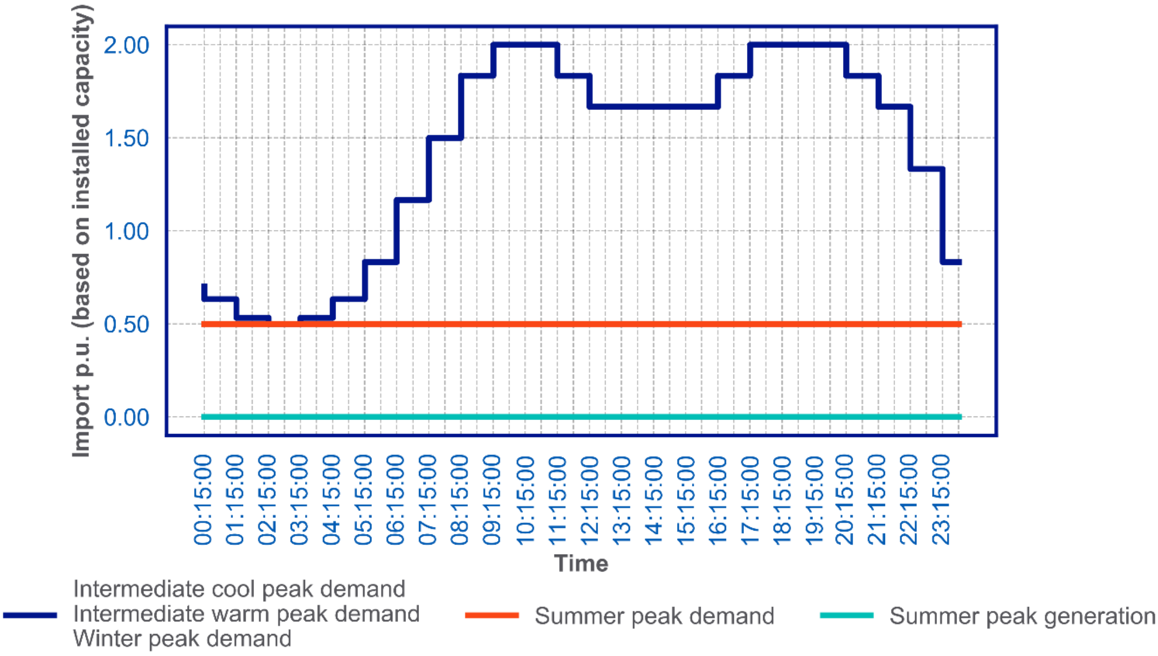

Figure 60: Representative heat pump profile of a large-scale district heating scheme with electric booster systems in baseline year

Large scale district heating scheme heat pump profiles (non-electric booster system)

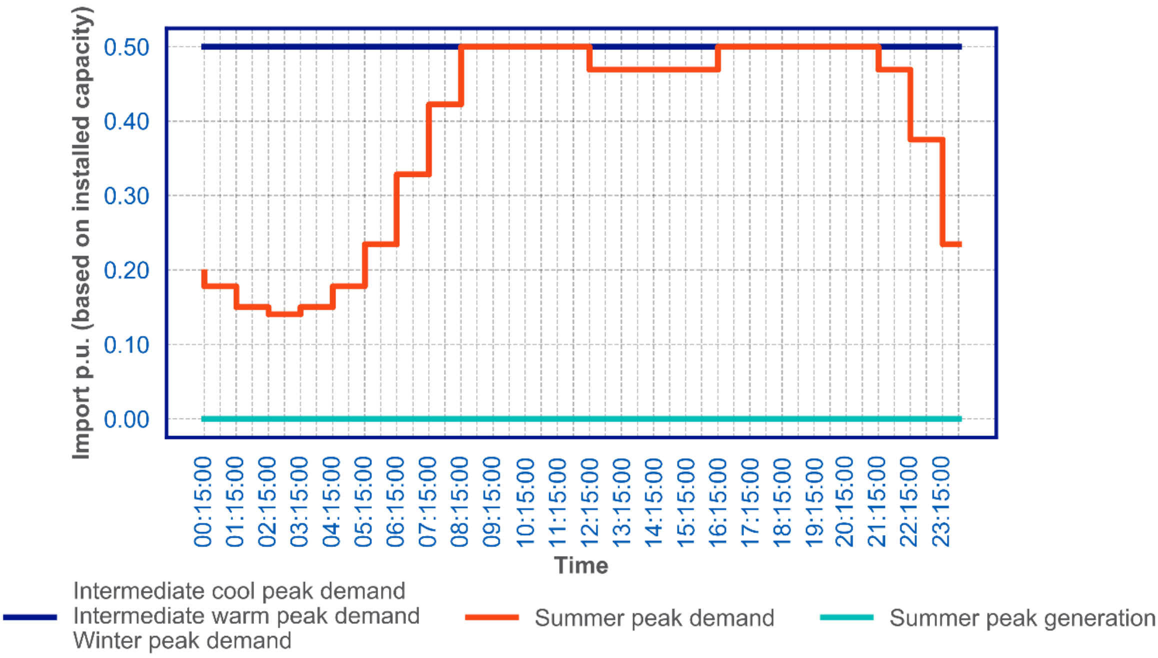

Figure 61: Representative flexed heat pump profile of a large-scale district heating scheme with non-electric booster systems in baseline year

How will these profiles change over time

The uptake of non-hybrid and hybrid systems vary significantly with each scenario. This has a notable impact when assessing the MW growth on the network, particularly for the Winter and Intermediate Cool Peak Demand representative days. Hybrid systems are able to switch to an alternate fuel source at times of high electricity demand; scenarios where a higher proportion of hybrid systems are forecast will have a reduced MW growth at times of high demand due to heat pumps.

The energy requirement of non-hybrid systems is forecast to reduce as the thermal efficiency of housing is improved and the coefficient of performance of heat pumps increases. The profiles are scaled to reflect changes in SPF and weather due to climate change, as shown in Figure 62.

Annual ASHP and GSHP peak demand percentage change from baseline

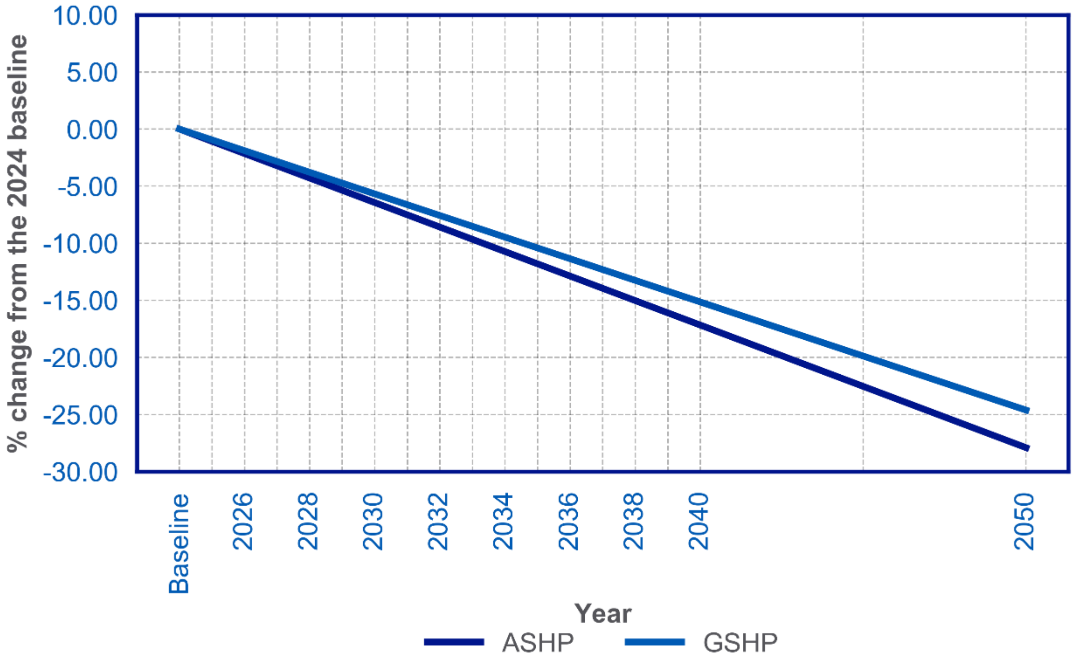

Figure 62: Expected percentage reduction in peak demand per ASHP and GSHP as a result of efficiency improvements

The reduction in peak demand is greater for ASHPs, as their efficiency is more significantly impacted during cold spells. GSHPs are not affected in the same way and so the technology conversion efficiency impact is not seen in the scaling factor.

Energy Assumptions

The energy requirements of non-hybrid (ASHP and GSHP) and hybrid heat pumps for each year and scenario were derived from the FES workbook. The variation in energy per heat pump in the near term are fairly substantial, so this has been highlighted as an area to review in DFES 2024 to find an alternative data source.

As described in the above section, these energy improvement figures were applied to the non-hybrid profiles to represent the reduction in peak MW requirement as housing stock thermal efficiency improves and coefficient of performance of heat pumps increases. This does not apply to the winter and intermediate cool hybrid profiles, where they are already assumed to be operating on an alternate fuel source.

Non-hybrid Air Source Heat Pump (and Non-hybrid Air Source Heat Pump co-located with thermal storage) annual energy consumption

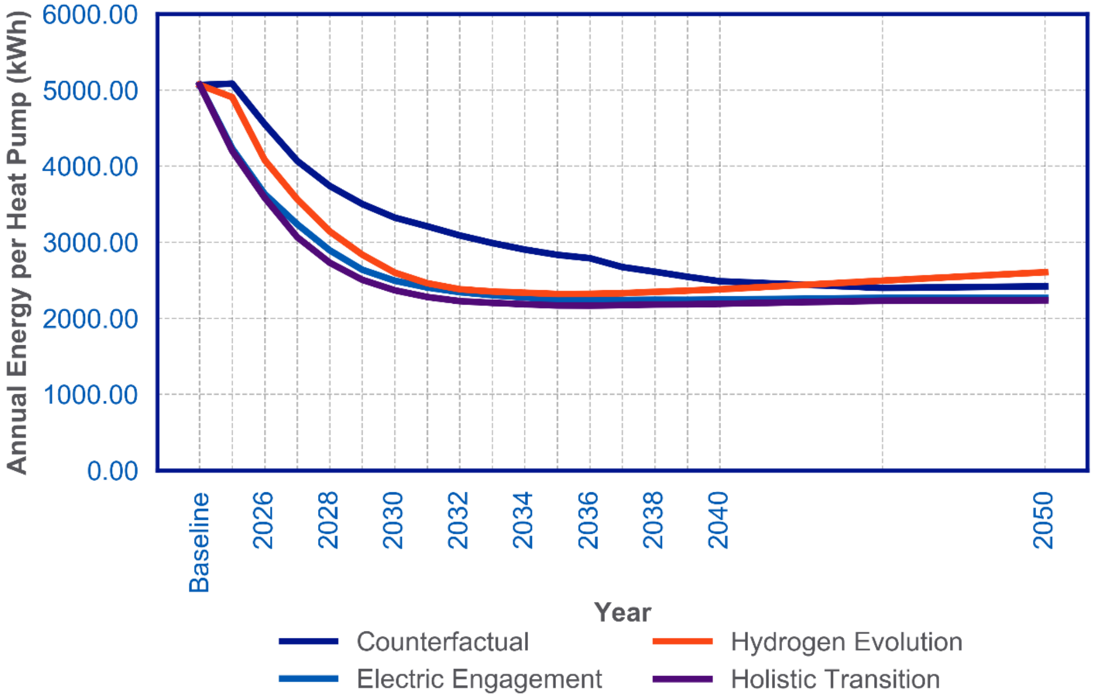

Figure 63: Yearly energy requirement per non-hybrid air source heat pump

Non-hybrid Ground Source Heat Pump (and Non-hybrid Ground Source Heat Pump co-located with thermal storage) annual energy consumption

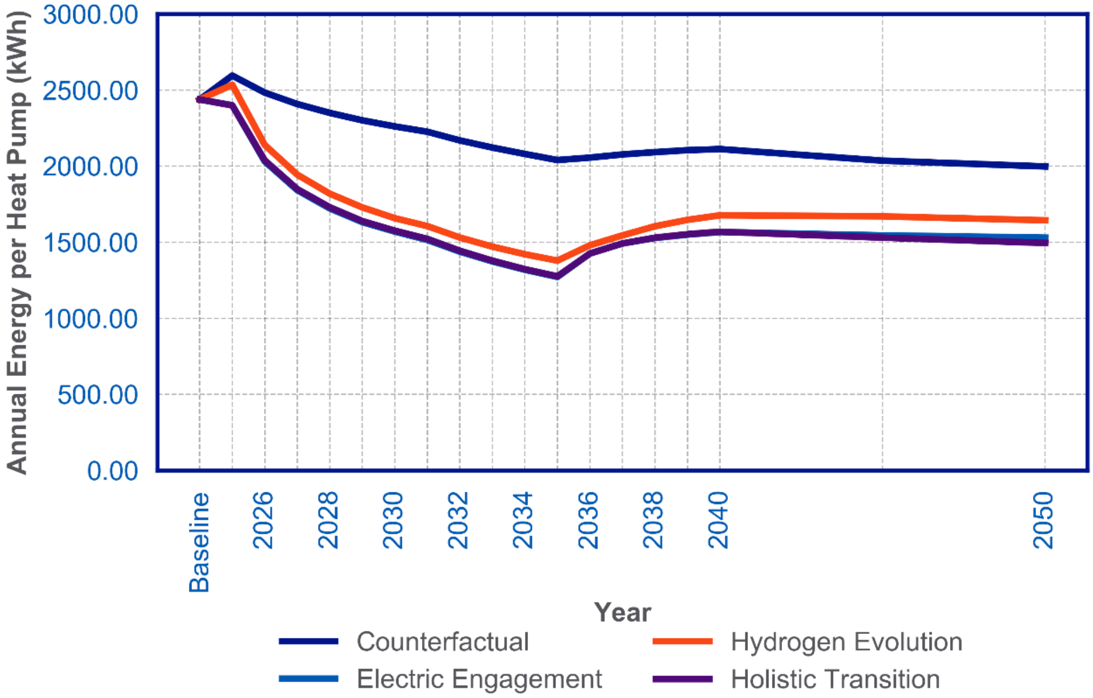

Figure 64: Yearly energy requirement per non-hybrid ground source heat pump

Hybrid Heat Pump annual energy consumption

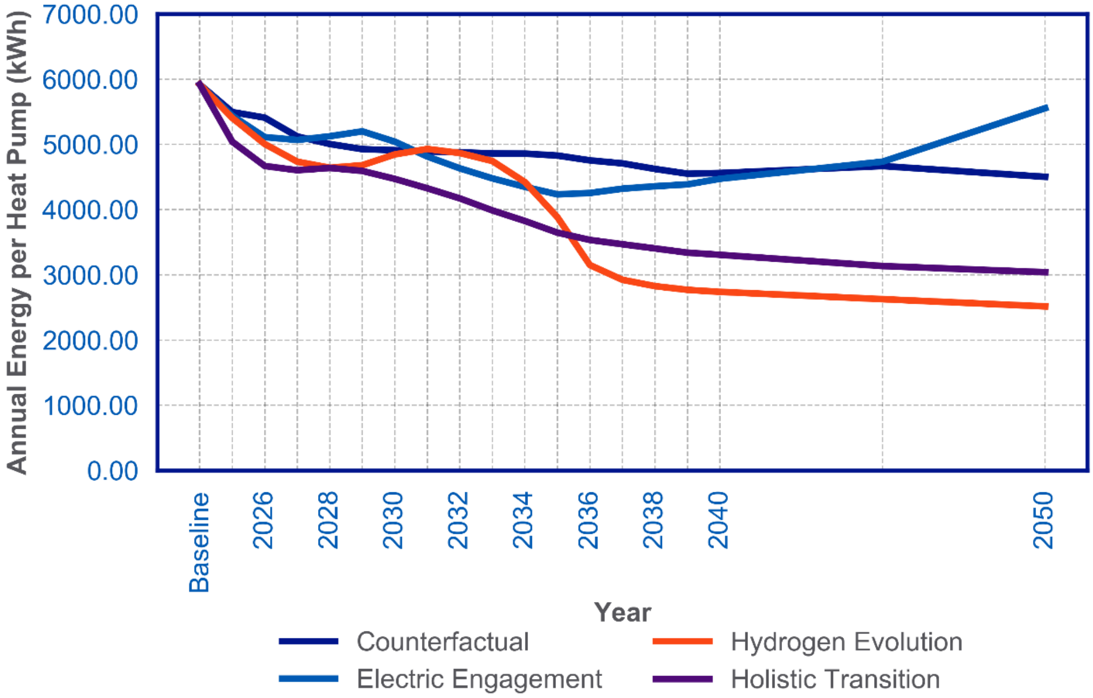

Figure 65: Yearly energy requirement per hybrid heat pump

Known Limitations

The current profiles used are produced from the CLNR project in shape, and the scale of them influenced through findings from various analyses of the RHPP dataset. The CLNR is a static dataset, and was a relatively small sample size, when looking at the number of properties with complete datasets. Through using RHPP analysis findings, this has improved the sample size from which the profiles were influenced, but carrying out bespoke analysis of the RHPP in house would help to better solve the specific questions that need answering when creating profiles for network analysis. Although there is significant benefit of using measured data to understand real-world customer behaviour, when it comes to emerging technologies, it is often the case that early adopters are not representative of the whole population. The larger sample size of the RHPP has helped to improve this; however, we will continue to review studies and publications of data that is continuing to be gathered to improve these assumptions.

Future Developments

We will continue to monitor the progress of existing projects, trials and business as usual processes for assigning customer behaviour for Heat Pumps suitable for network analysis of the EHV networks and update the assumptions as necessary.

Based on research findings, it is likely that the operating profile for GSHPs is more continuous than the behaviours associated with ASHPs. This should be investigated further and the profile of the two technologies not only differ in scale as they did this year, but also differ in shape to reflect usage trends.

Non-domestic Heating

Table 21: Non-domestic heating technologies

Technology	Subtechnology	Units used in DFES volume projections
Heat pumps	Non domestic - A1/A2	Floorspace (metres squared) of heated I&C buildings
	Non domestic - A3/A4/A5	
	Non domestic - B1	
	Non domestic - B2	
	Non domestic - B8	
	Non domestic - C1	
	Non domestic - C2	
	Non domestic - D1	
	Non domestic - D2	
	Non domestic - Sui Generis	
Resistive electric heating	Non domestic - A1/A2	Floorspace (metres squared) of heated I&C buildings
	Non domestic - A3/A4/A5	
	Non domestic - B1	
	Non domestic - B2	
	Non domestic - B8	
	Non domestic - C1	
	Non domestic - C2	
	Non domestic - D1	
	Non domestic - D2	
	Non domestic - Sui Generis	

Methodology

Since DFES 2023, non-domestic heating has been included within the scope, to determine additional demand that can be expected through non domestic premises converting their heating technology to heat pumps.

Initially, the present and future non-domestic building stock was determined in each of the four core scenarios, through incorporating local authorities' local development plans and applying windfall growth. Based on the scenario frameworks, these additional and existing buildings were then allocated heating technologies and conversion dates, to identify the m^2 of floorspace heated by either heat pumps or resistive electric heating in each of the scenarios.

To understand the power demand of these heating systems per m^2 of floorspace for each of these building categories, industry standard rule of thumb assumptions were used to first find the thermal heating demand, then conversion factors used to determine the electrical power required to generate the required heating[41].

Given that the optimal operation of heat pumps is a continuous profile, these profiles were kept flat, however the shape of the resistive electric heating profiles was varied throughout the 48 half hours to align with the occupancy of the buildings, and so mirrors the standard non-domestic profile.

Seasonal variation in non-domestic heating demand was applied through utilising the seasonal ratio from the domestic heat pump profiles.

Representative Day Profiles

A1/A2 non domestic heat pump heating demand per m² of floorspace

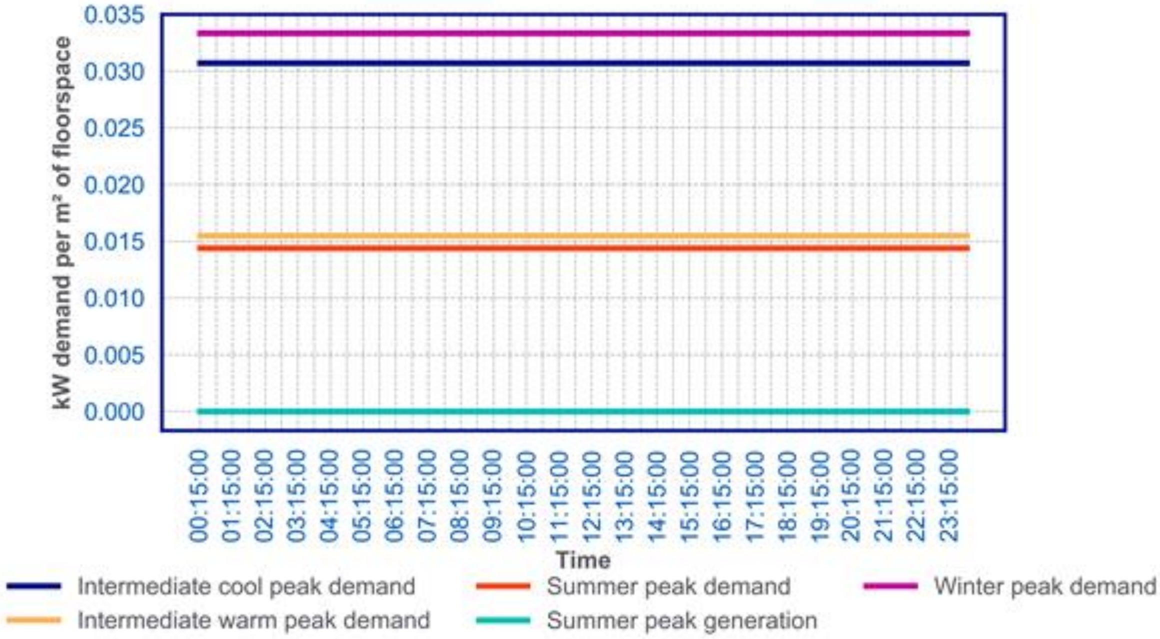

Figure 66: A1/A2 non domestic heat pump heating demand per m^2 of floorspace

A1/A2 non domestic resistive electric heating demand per m² of floorspace

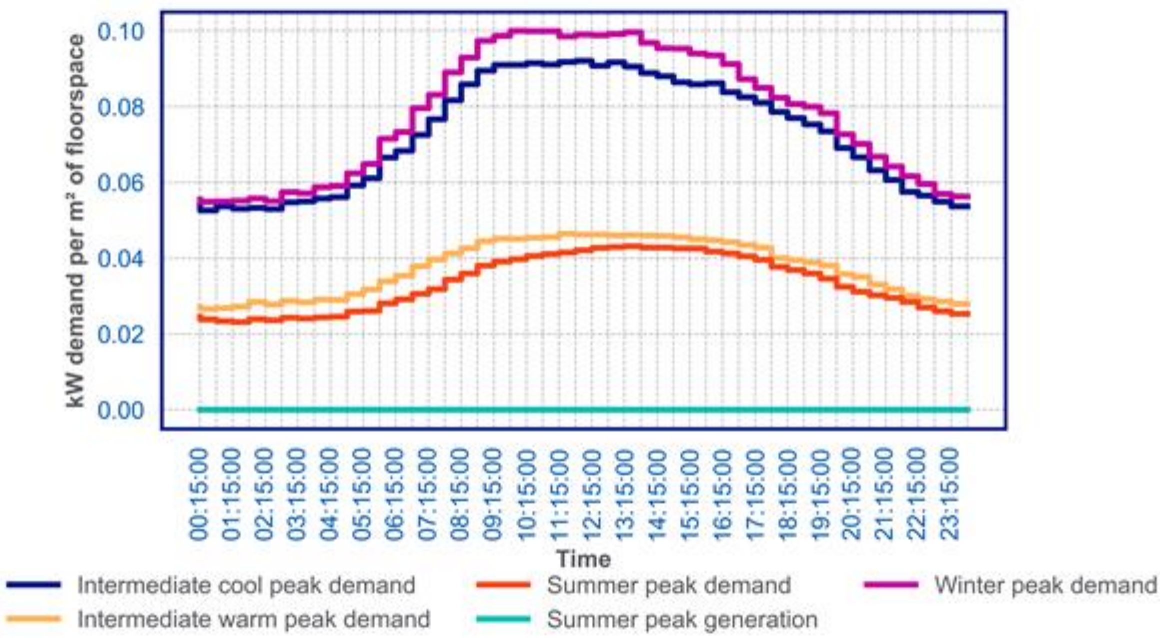

Figure 67: A1/A2 non domestic resistive electric heating demand per m^2 of floorspace

A3/A4/A5 non domestic heat pump heating demand per m² of floorspace

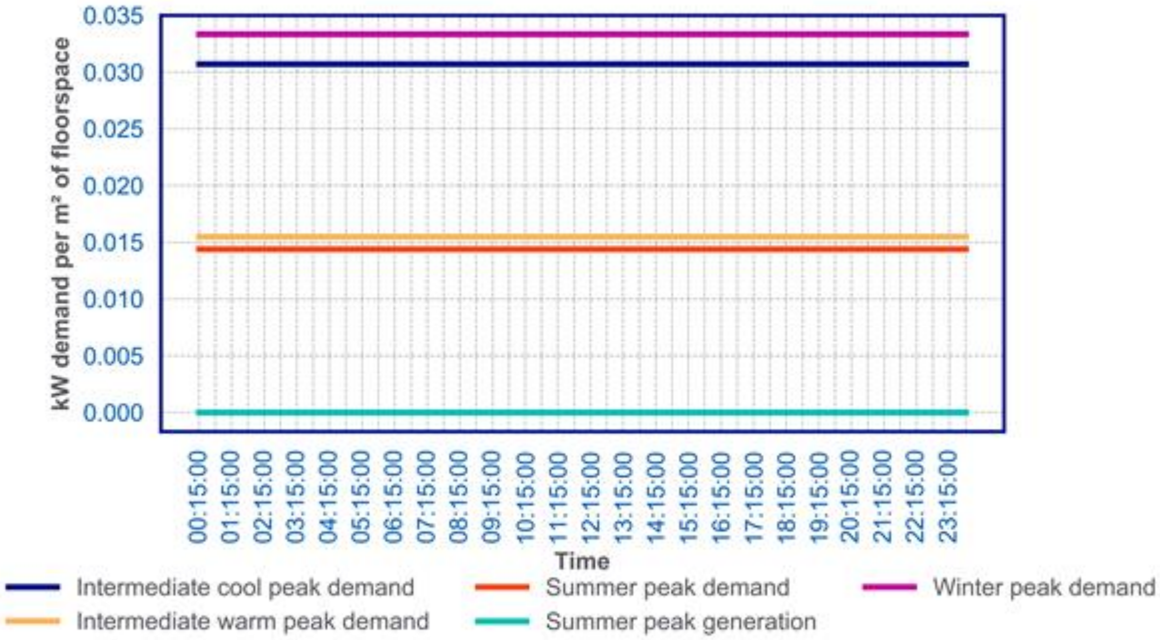

Figure 68: A3/A4/A5 non domestic heat pump heating demand per m² of floorspace

A3/A4/A5 non domestic resistive electric heating demand per m² of floorspace

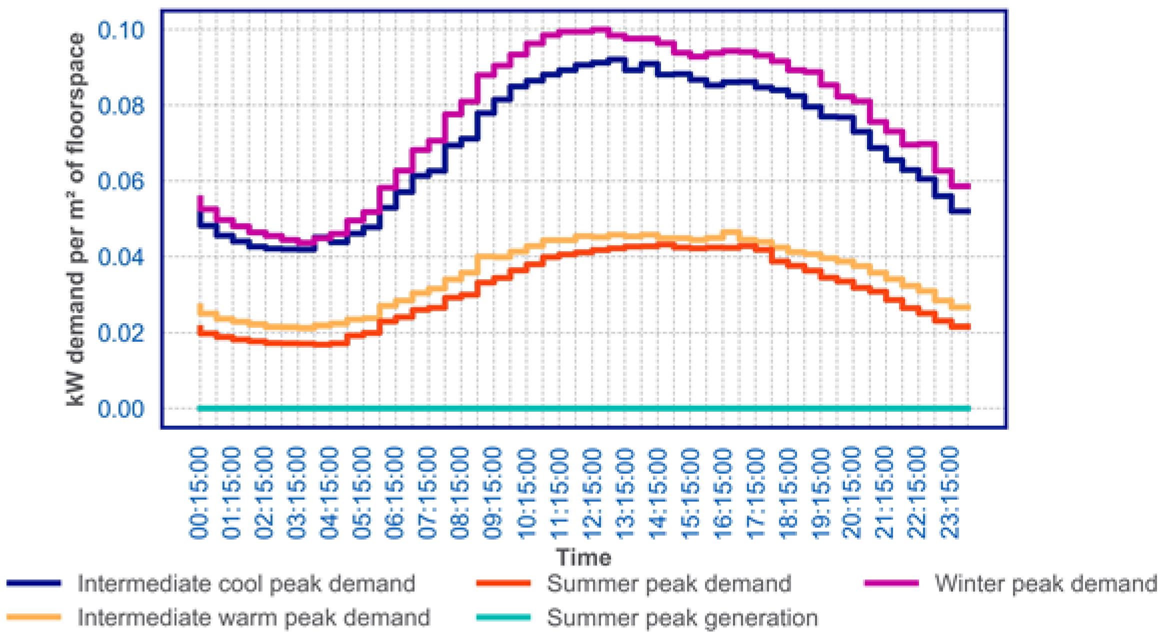

Figure 69: A3/A4/A5 non domestic resistive electric heating demand per m² of floorspace

B1 non domestic heat pump heating demand per m² of floorspace

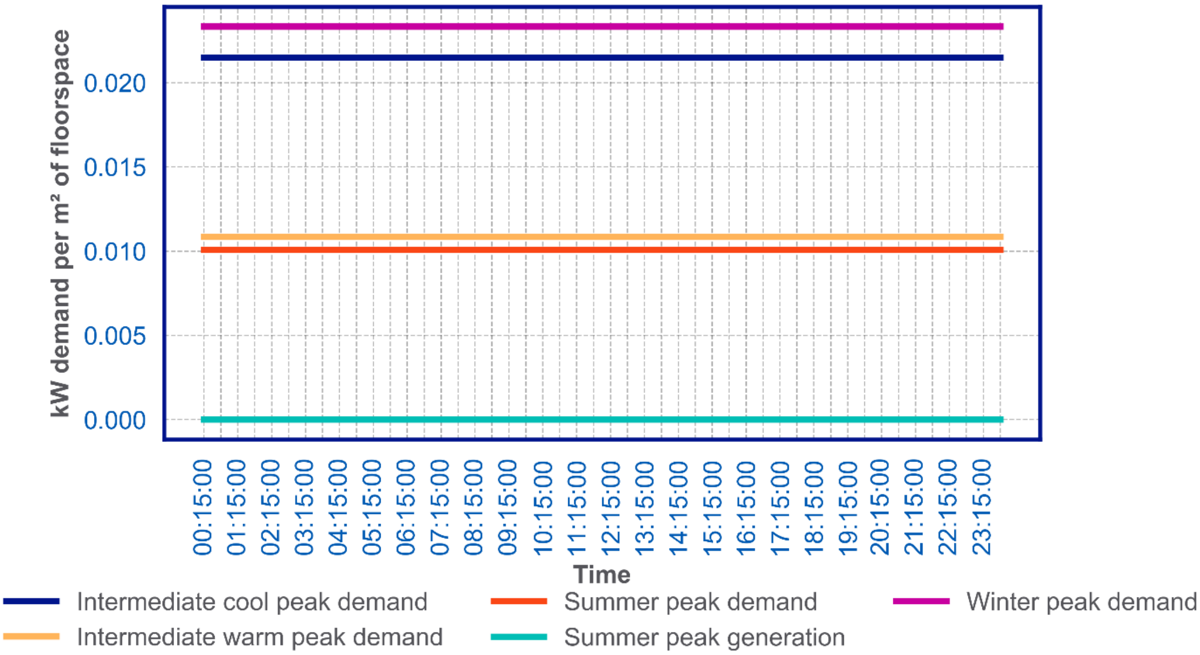

Figure 70: B1 non domestic heat pump heating demand per m² of floorspace

B1 non domestic resistive electric heating demand per m² of floorspace

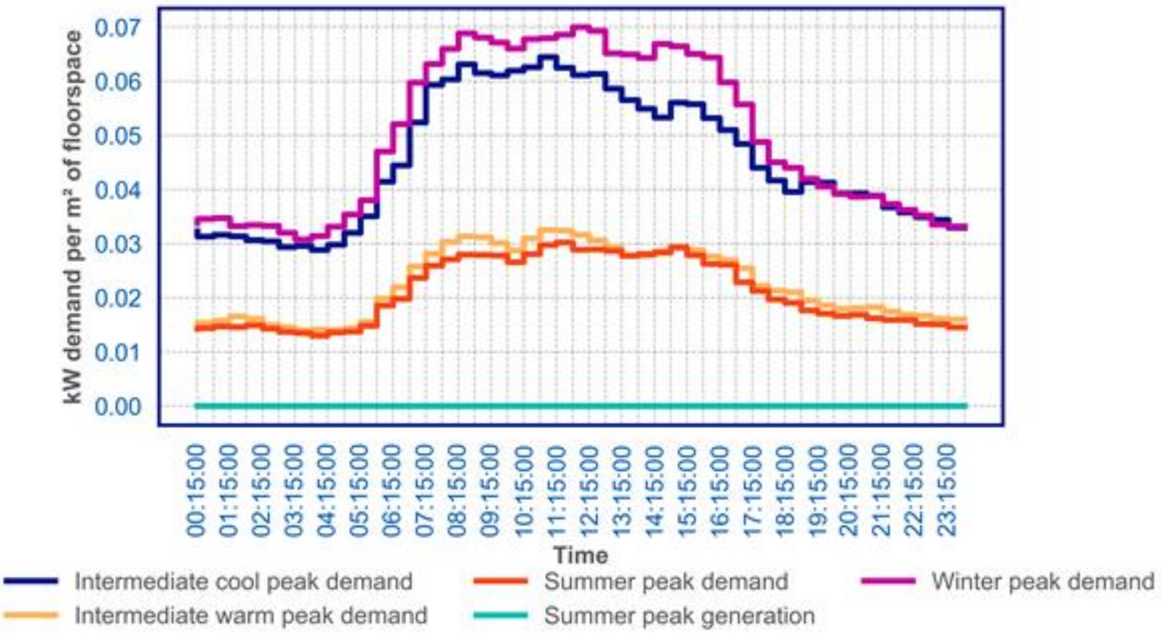

Figure 71: B1 non domestic resistive electric heating demand per m² of floorspace

B2 non domestic heat pump heating demand per m² of floorspace

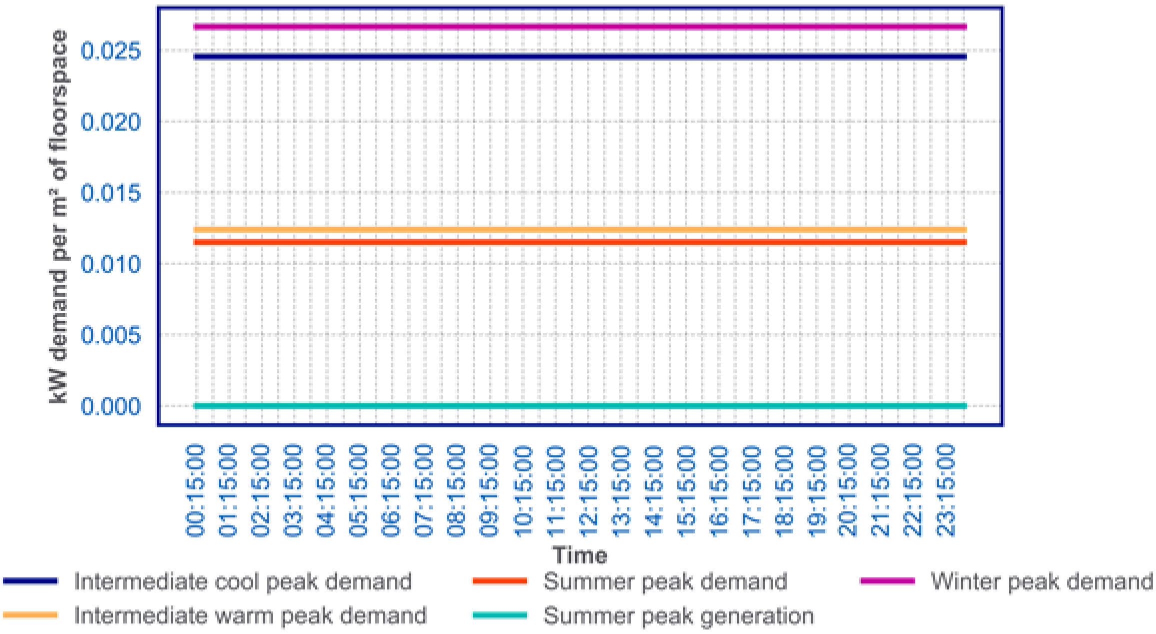

Figure 72: B2 non domestic heat pump heating demand per m² of floorspace

B2 non domestic resistive electric heating demand per m² of floorspace

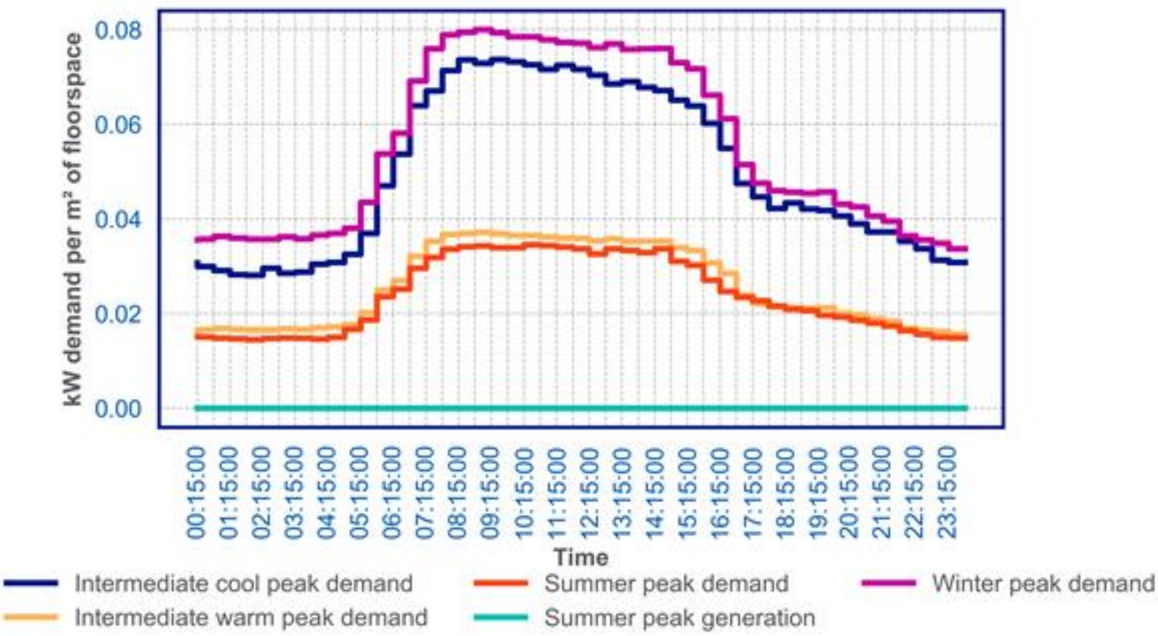

Figure 73: B2 non domestic resistive electric heating demand per m² of floorspace

B8 non domestic heat pump heating demand per m² of floorspace

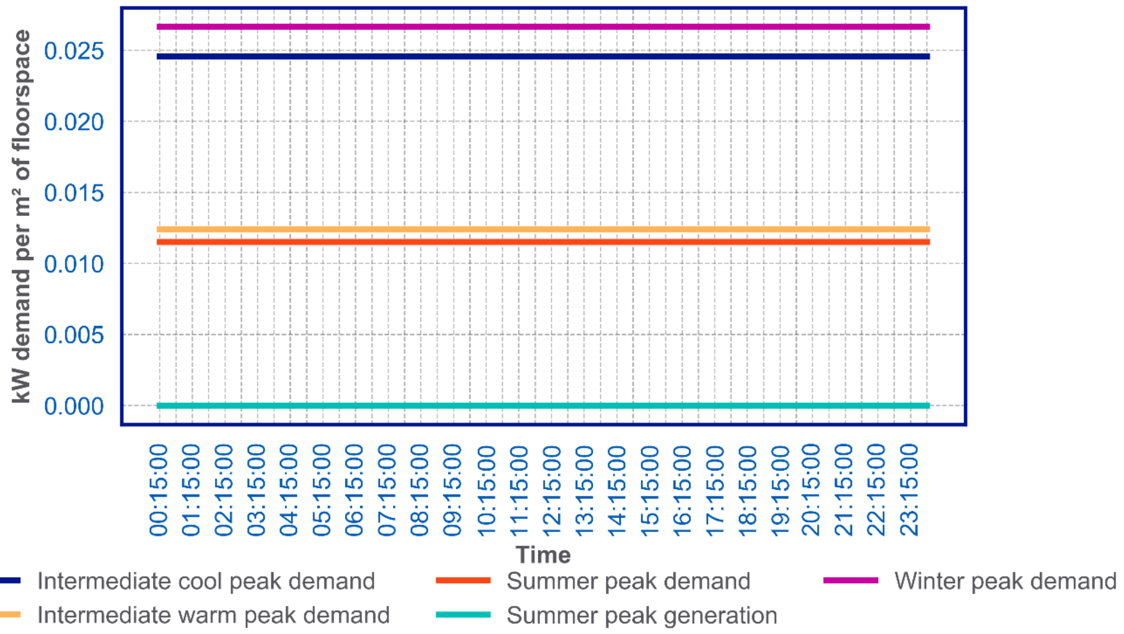

Figure 74: B8 non domestic heat pump heating demand per m² of floorspace

B8 non domestic resistive electric heating demand per m² of floorspace

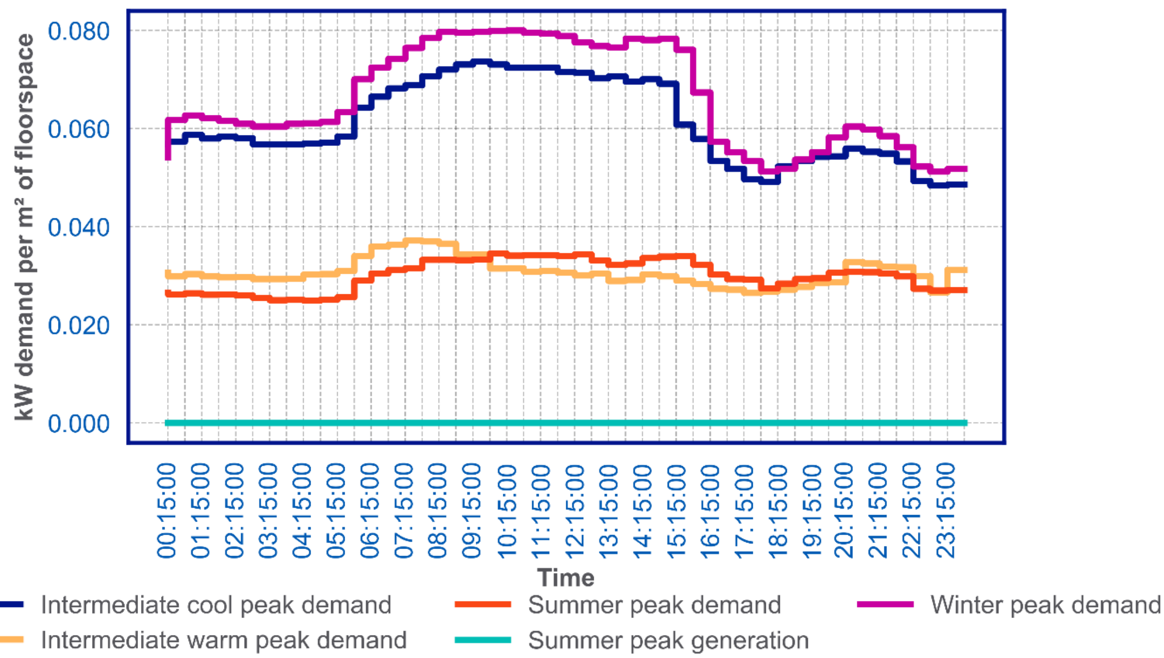

Figure 75: B8 non domestic resistive electric heating demand per m² of floorspace

C1 non domestic heat pump heating demand per m² of floorspace

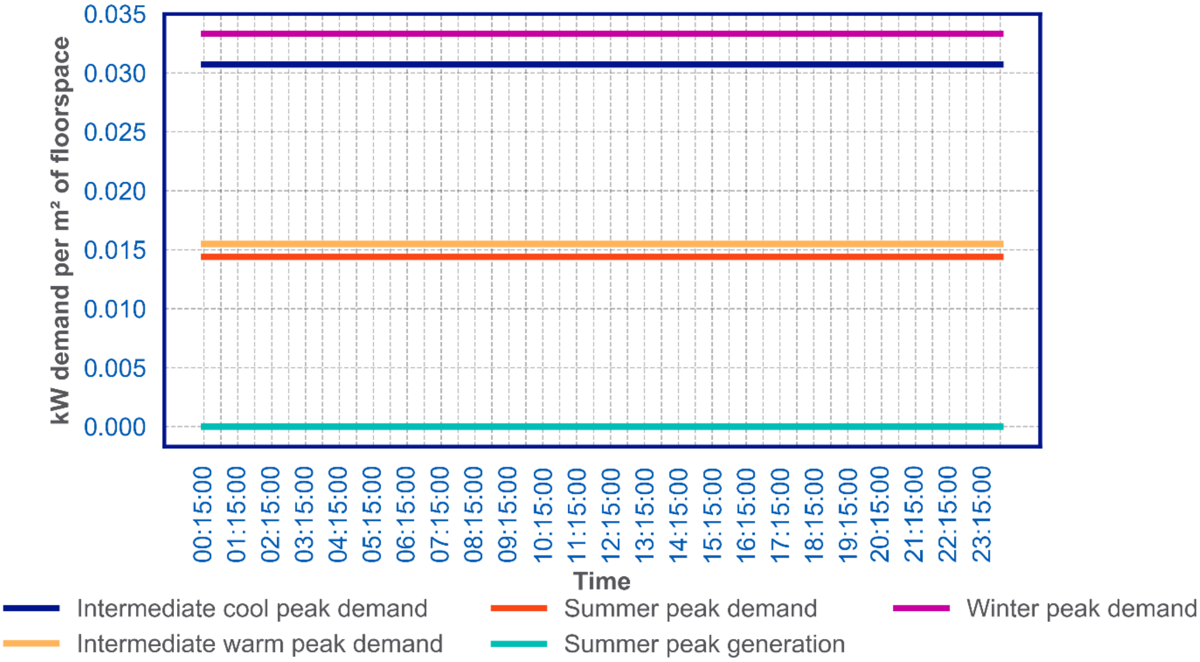

Figure 76: C1 non domestic heat pump heating demand per m² of floorspace

C1 non domestic resistive electric heating demand per m² of floorspace

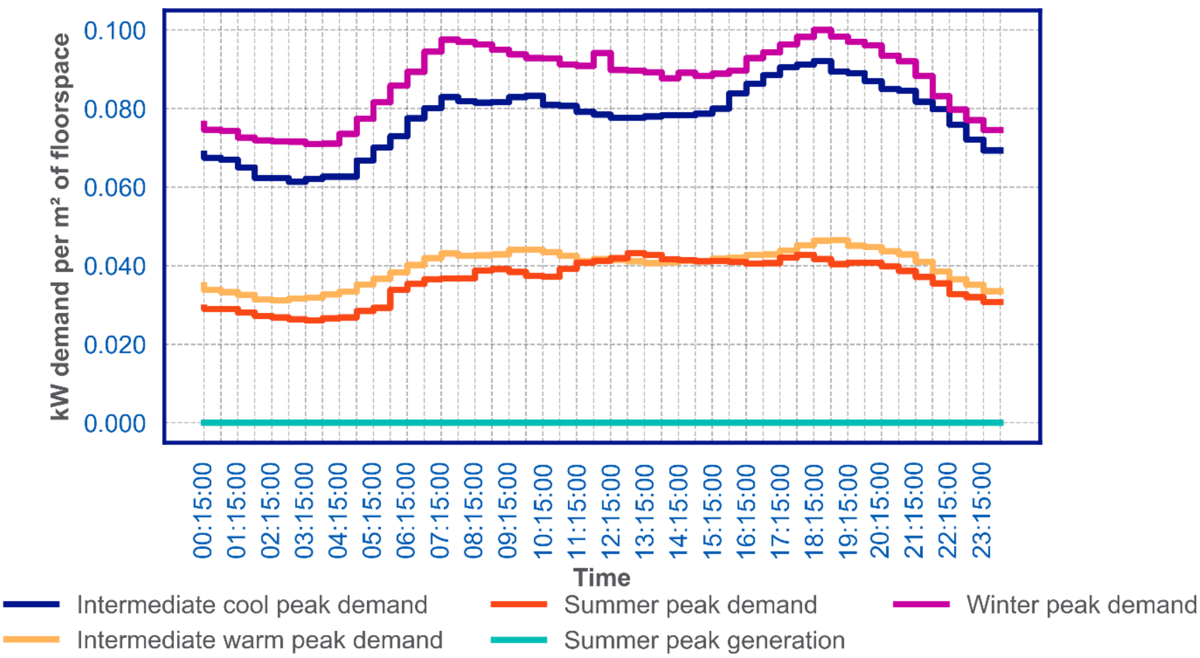

Figure 77: C1 non domestic resistive electric heating demand per m² of floorspace

C2 non domestic heat pump heating demand per m² of floorspace

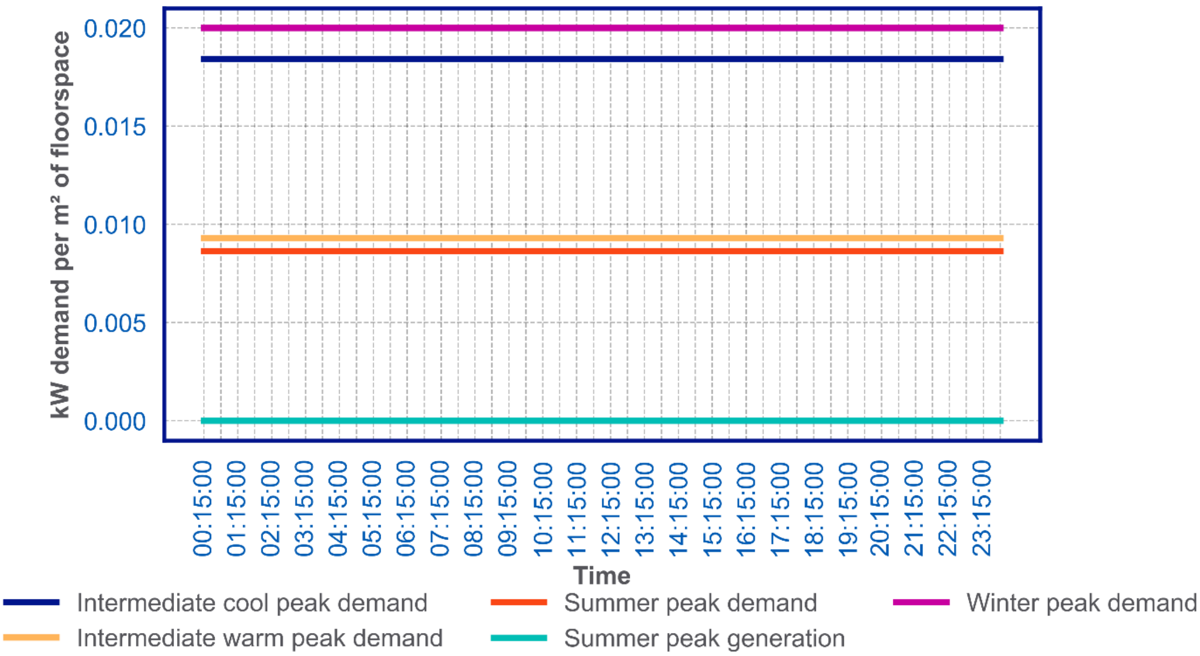

Figure 78: C2 non domestic heat pump heating demand per m² of floorspace

C2 non domestic resistive electric heating demand per m² of floorspace

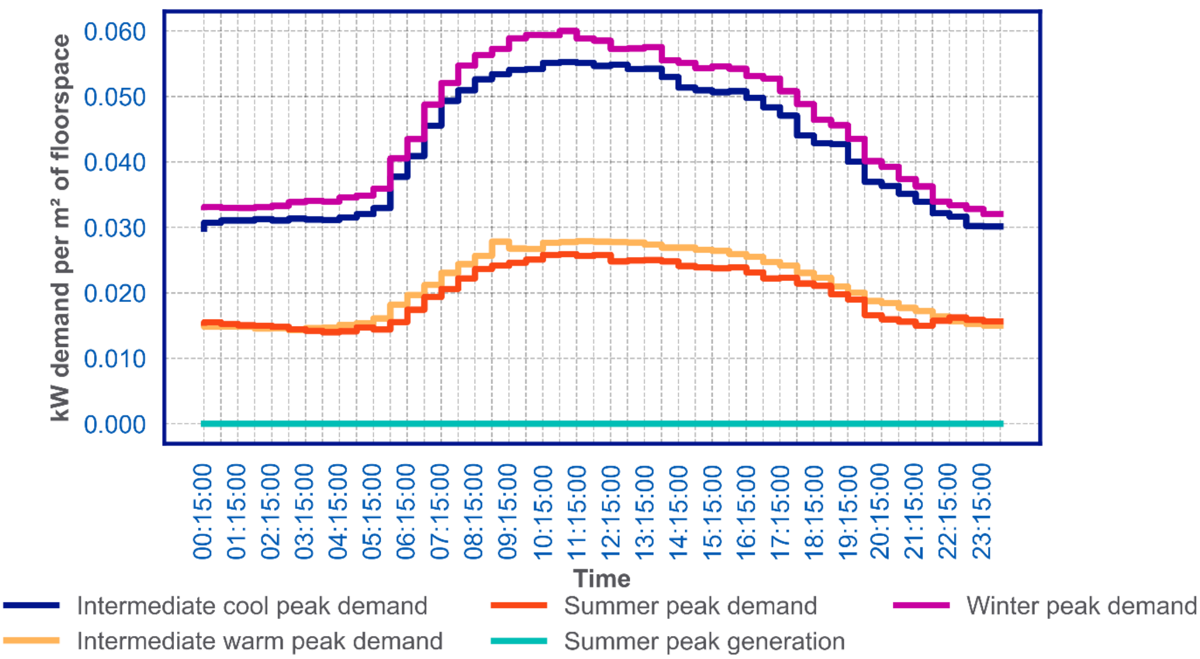

Figure 79: C2 non domestic resistive electric heating demand per m² of floorspace

D1 non domestic heat pump heating demand per m² of floorspace

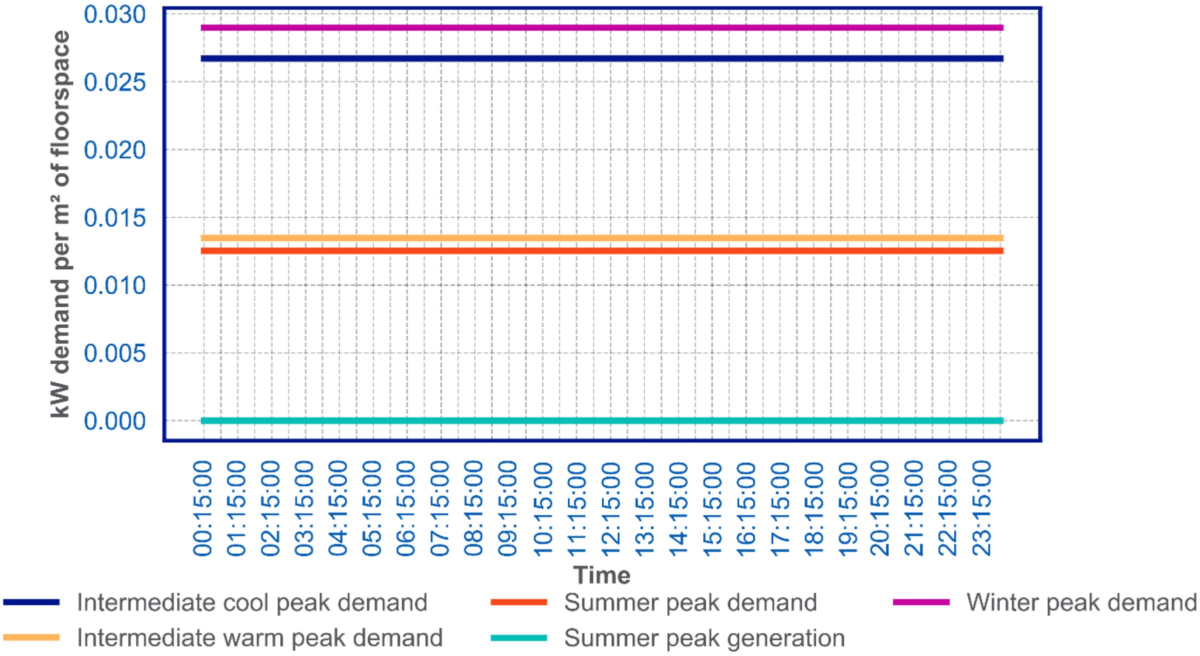

Figure 80: D1 non domestic heat pump heating demand per m² of floorspace

D1 non domestic resistive electric heating demand per m² of floorspace

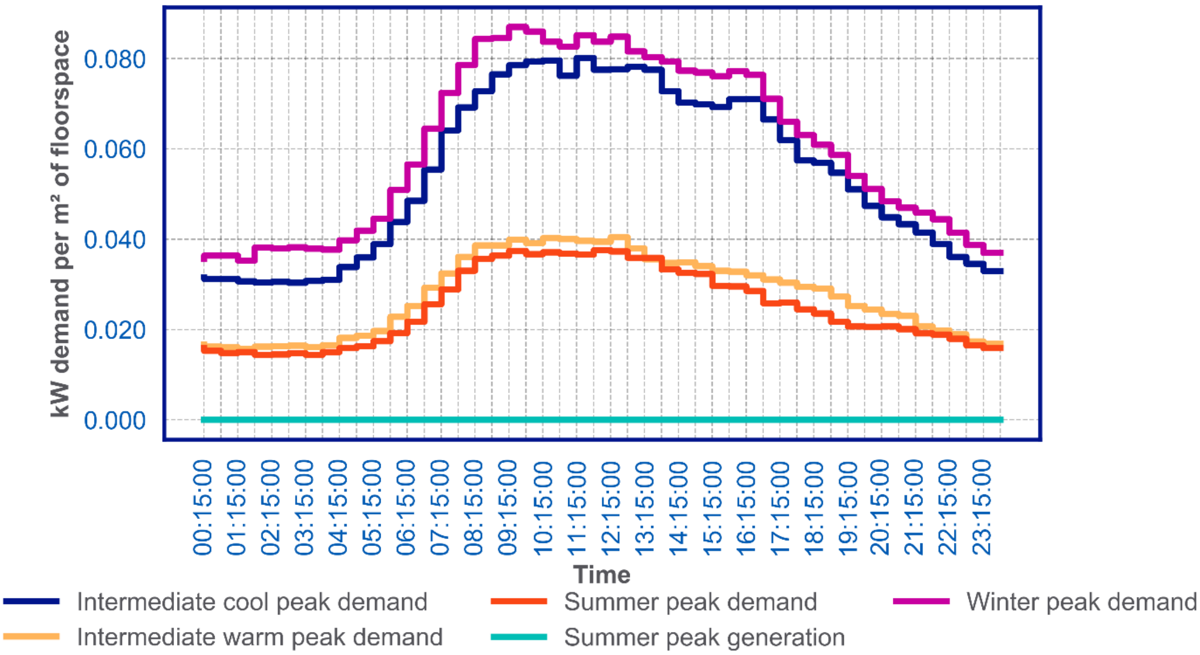

Figure 81: D1 non domestic resistive electric heating demand per m² of floorspace

D2 non domestic heat pump heating demand per m² of floorspace

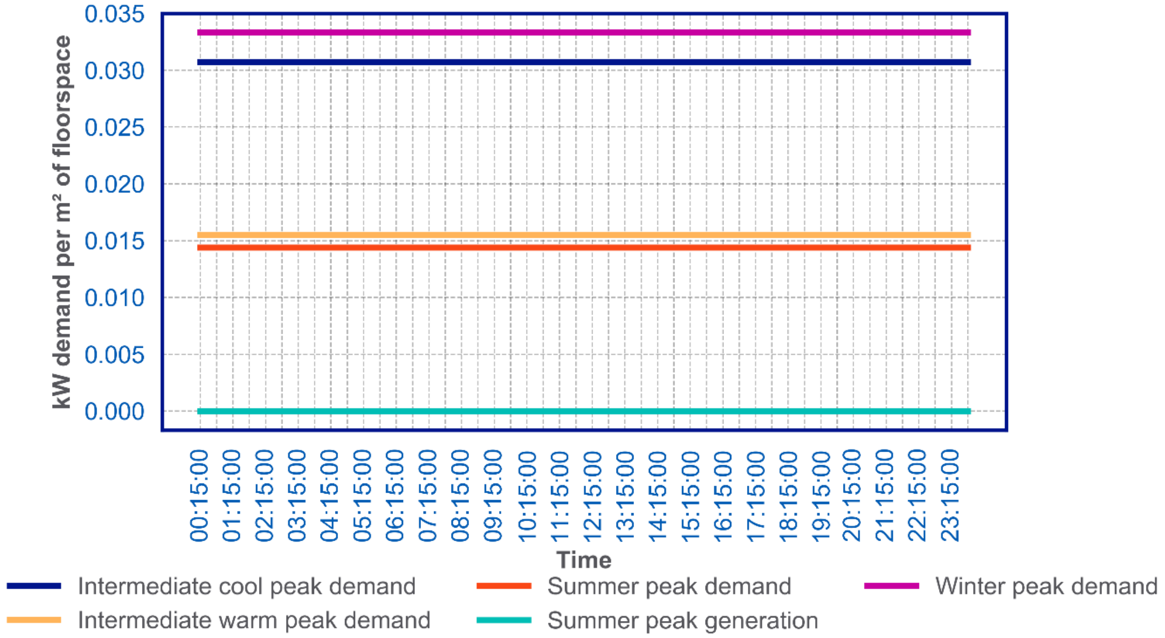

Figure 82: D2 non domestic heat pump heating demand per m² of floorspace

D2 non domestic resistive electric heating demand per m² of floorspace

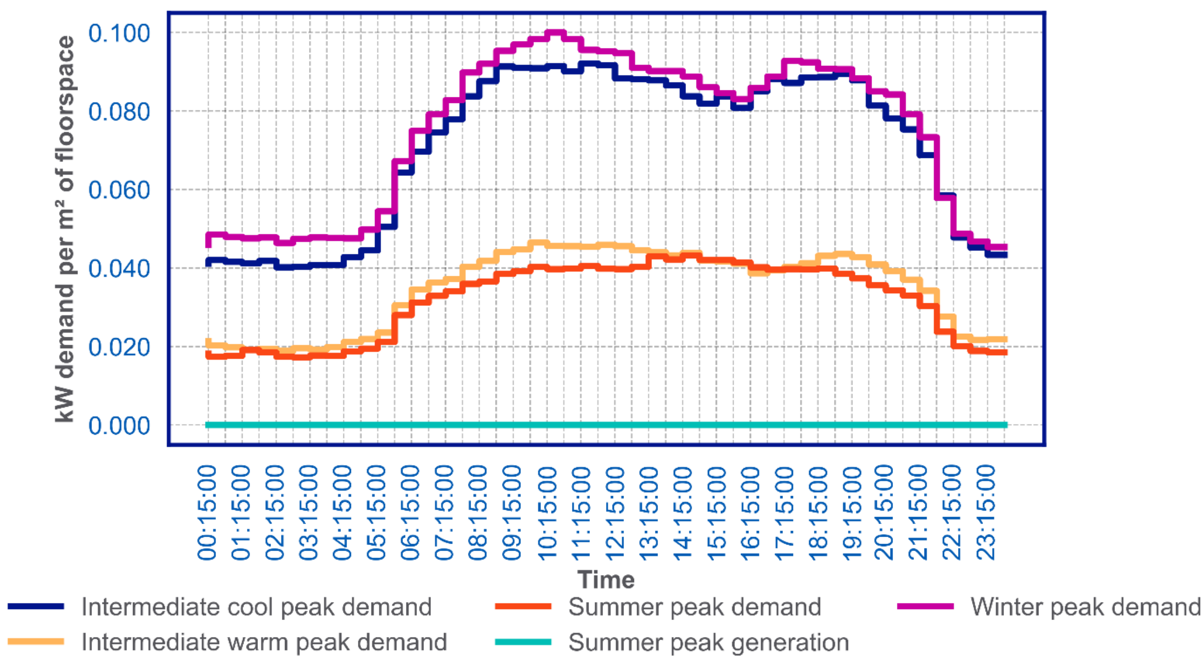

Figure 83: D2 non domestic resistive electric heating demand per m² of floorspace

Sui Generis non domestic heat pump heating demand per m² of floorspace

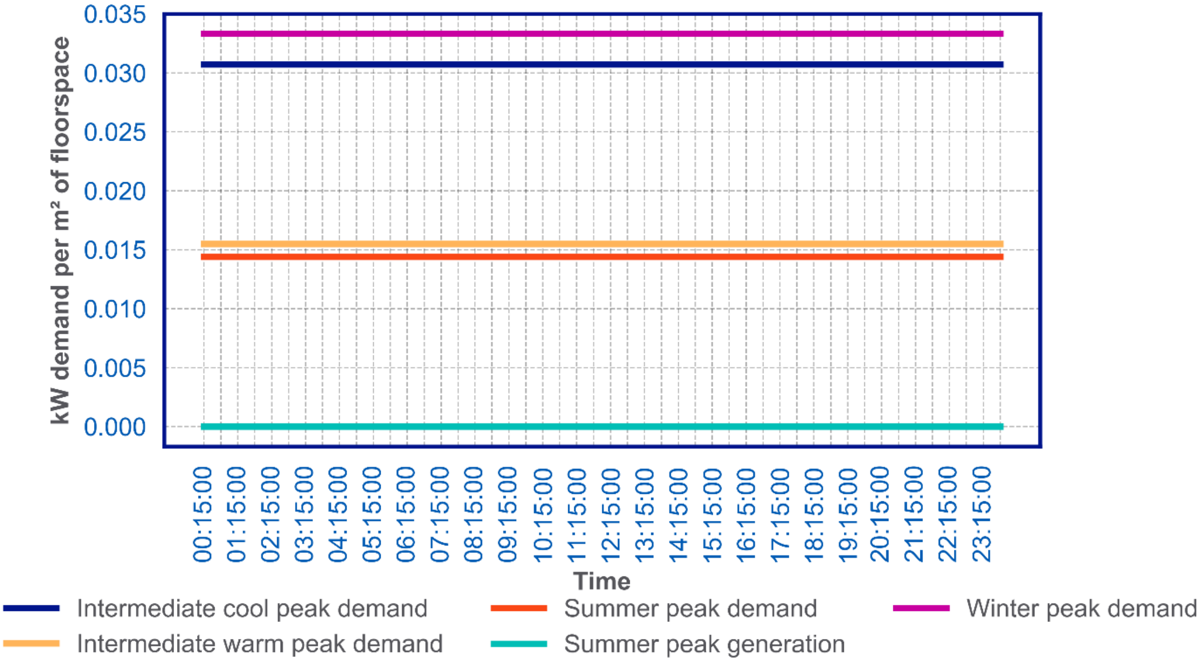

Figure 84: Sui Generis non domestic heat pump heating demand per m² of floorspace

Sui Generis non domestic resistive electric heating demand per m² of floorspace

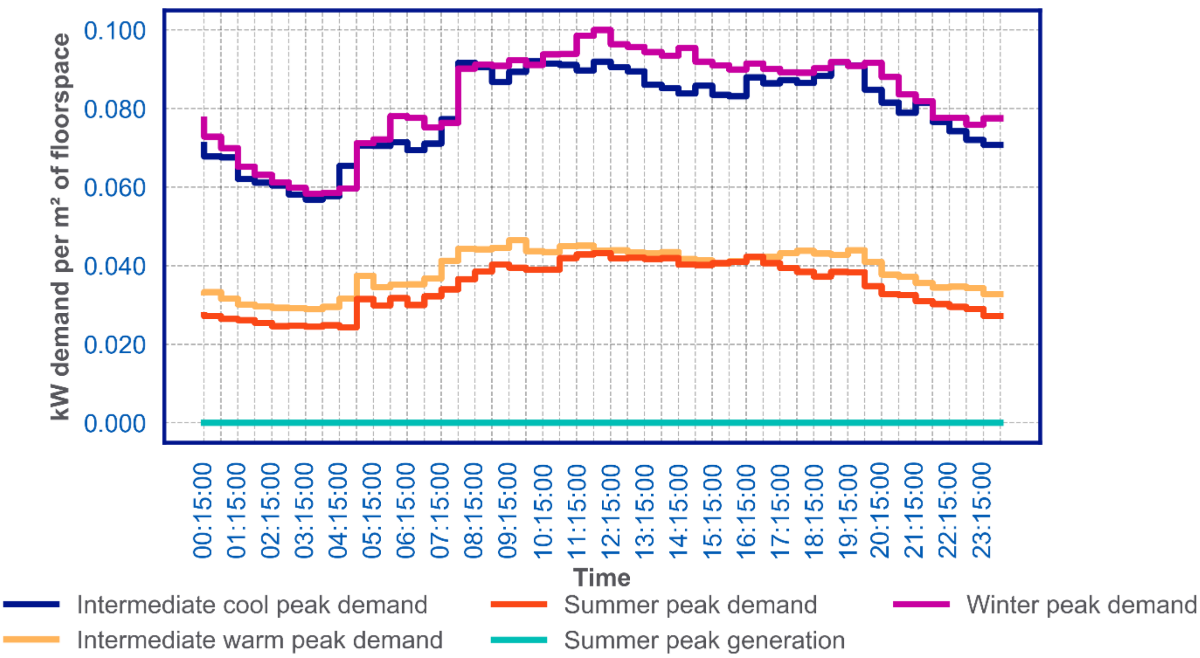

Figure 85: Sui Generis non domestic resistive electric heating demand per m² of floorspace

How will these profiles change over time

Due to thermal efficiency improvements of the building stock, there is a scaling factor applied over time to show the reducing peak demand of heating technologies. This is scaled according to the efficiency improvements recorded in the FES industrial and commercial heat pump energy consumption data.

Energy Assumptions

The energy assumptions for non domestic heating were taken from BSRIA Roles of thumb for the baseline values. Additional work will be done for DFES 2024 to find a more recent data source to inform the baseline values, as the most recent edition of BSRIA rules of thumb book is now over 10 years old. The baseline energy values were then scaled according to the FES industrial and commercial heat pump and resistive electric heating energy scaling factors[31]. This scaling factor was chosen due to similar factors impacting the improving energy efficiency in future years.

Known Limitations

As with the non-domestic baseline load, the main limitation of this methodology is the assumption that all buildings within a use class will use the same amount of heating per m^2 of floorspace. There is inevitably variation on a building-by-building level that this assumption does not capture.

A further limitation is the time of use of non-domestic heat pumps. They have currently been modelled as constant output throughout the day to represent the most efficient utilisation pattern of heat pumps, however, it is unlikely that this would be the case in real life operation.

The literature available for energy assumptions of non domestic buildings was unclear as to whether the quoted value was per m^2 of heated floorspace, or per m^2 of total floorspace of that building type. This should be investigated further to determine whether this can be improved.

Future Developments

As this is the first year of modelling non domestic heating, there are still further developments that we will be continuing to work on over the next year. Namely, this involves investigating the heat pump heating pattern of non domestic spaces, and to what extent heat pumps are run to maximise efficiency or to mirror occupancy. This may see the heat pump profile changing from being flat to being closer in resemblance to the non domestic resistive electric heating profile.

Another future development for the modelling of non-domestic heating is a new data source for the energy per m^2 for each building use class.

Air Conditioning

Methodology

Each air-conditioning unit is geographically allocated to an Electricity Supply Area where it would be most likely to connect to the distribution network. Air-conditioning volumes are provided in number of air-conditioners.

The daily profile for all of the demand representative days was assumed to be zero. The reasoning for this was that the peak demand representative days in winter, intermediate warm and summer all coincide with a cold day where domestic air conditioning was assumed not to be in use.

The profile for the Summer Peak Generation representative day was also modelled as zero for network assessments. This does not necessarily coincide with high ambient temperatures, particularly on networks with high wind penetration. There is a risk that modelling air-conditioning demand for the summer peak generation day will mask the worst-case condition.

Representative Day Profiles

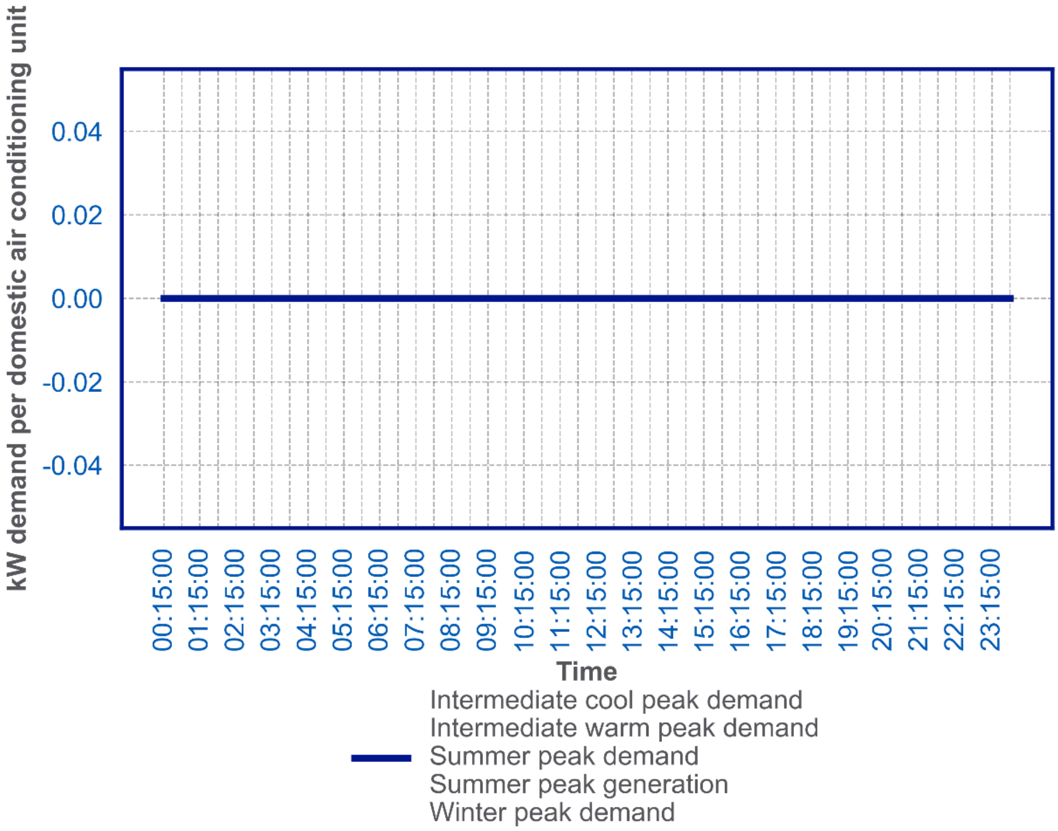

Figure 86: Representative air-conditioning profiles

How will these profiles change over time

These profiles do not change for any year and scenario.

Energy Assumptions

As described in the Methodology section, the air-conditioning demand is assumed as zero for all existing representative days. However, the overall energy is modelled as 500 kWh/year for each installation. This figure is taken from the FES workbook and is assumed to not change by year and scenario[31].

Known Limitations

The current representative profiles do not capture the minimum coincident air-conditioning demand at time of peak generation.

This air-conditioning technology currently only captures domestic installations. Non-domestic units are more prevalent and the impact is largely captured in the existing demand behaviour described in the non-domestic section.

As more domestic air-conditioning units connect, demand at times of high ambient temperature could cause a new network edge-case. Similar to hot countries with high levels of air-conditioning, the peak demand can actually occur at high ambient temperatures. All four demand representative days are currently focussed on peaks due to cold ambient temperatures.

Future Developments

We plan to undertake analysis on domestic and non-domestic air-conditioning operating behaviour. Focussing on existing behaviour at time of network peak and potential for new edge-cases to occur as uptake increases. Consideration of increased energy requirement as average temperature increases could also be reviewed.

Hydrogen Electrolysis

Methodology

Each hydrogen electrolysis plant is geographically allocated to an Electricity Supply Area where it would be most likely to connect to the distribution network. Hydrogen electrolysis volumes are provided in installed capacity (MW).

The daily profile for all of the demand representative days was assumed to be one. The reasoning for this was that the production of hydrogen from hydrogen electrolysis, although likely to be coincident with peaking renewable generation, is not limited to times of high renewable generation. As our modelling only took into account those hydrogen electrolysers that are directly connected to our network, not located behind the meter at weather dependent generation sites, there is increased likelihood of the demand not aligning with renewable generation peaks.

The profile for the Summer Peak Generation representative day was modelled as zero for network assessments. This is to remove the risk of worst-case conditions for the summer peak generation days being masked when hydrogen electrolysis is not guaranteed to be operating at times of high generation.

Representative Day Profiles

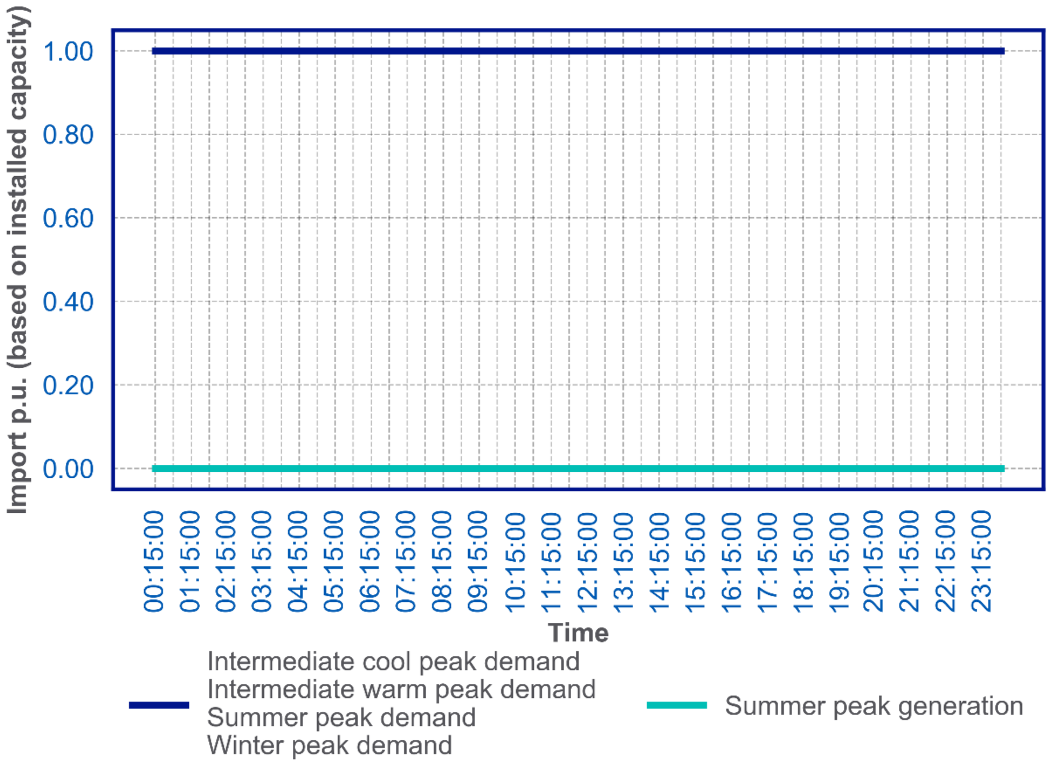

Figure 87: Representative hydrogen electrolysis profiles

How will these profiles change over time

These profiles do not change for any year and scenario.

Energy Assumptions

As described in the Methodology section, the hydrogen electrolysis demand is assumed as one for all existing representative days. Previously, the load factor was modelled as increasing[42], in line with hydrogen electrolysis using otherwise curtailed renewable energy; however, the overall energy has been modelled using 35% as the load factor. Based on an extensive literature review, the load factor has the potential to vary from 25% up to 95% depending upon the running style of the electrolysers, and the amount of storage available to the plant[42]. The selected load factor is constant across the scenarios.

Known Limitations

There is currently limited knowledge about the running of hydrogen electrolysers as they are in the early stages of development. As more hydrogen electrolysers are rolled out, we will be able to apply real-world use cases and data to our forecasting.

Future Developments

We plan to undertake agile analysis on the operating behaviour of hydrogen electrolysers and continue to develop the forecasts as the industry gains further insight into the operational workings of this new technology. Focussing on existing behaviour at time of network peak and potential for new edge-cases to occur as uptake increases.

Agricultural Machinery

The decarbonisation of agricultural machinery, and its resultant impact on the distribution network, is a new area of modelling for DFES 2024. On-site solar generation, fossil fuel electricity generation and anaerobic digestion electricity generation, which may all be located at farms, are already reflected as separate technologies in the DFES, as is building heat and road transport

Methodology

Agricultural demand is geographically allocated to an Electricity Supply Area where it would be most likely to connect to the distribution network, based on a number of spatial distribution factors, the most influential of which are current agricultural activities and the suitability of different farming models for electrification. More details on this methodology can be found in the DFES Technology Summary reports.

The daily profile for the demand representative days varies by season, in line with farming activities, particularly harvesting which peaks in our Summer and Intermediate Warm representative days. We have modelled the charging to happen in an 8-hour overnight period, however, it is likely that charging could also happen at other times as different vehicles may be using the same charger. The demand has been assumed to be linked not only with daylight hours, but with the operation of smart charging features of chare points. The utilisation of chargers for agricultural purposes is; however, quite uncertain due to lack of data about agricultural industry operating hours.

The profile for the Summer Peak Generation representative day was modelled as zero for network assessments. This is to remove the risk of worst-case conditions for the summer peak generation days being masked when agricultural vehicle charging is not guaranteed to be operating at times of high generation.

Representative Day Profiles

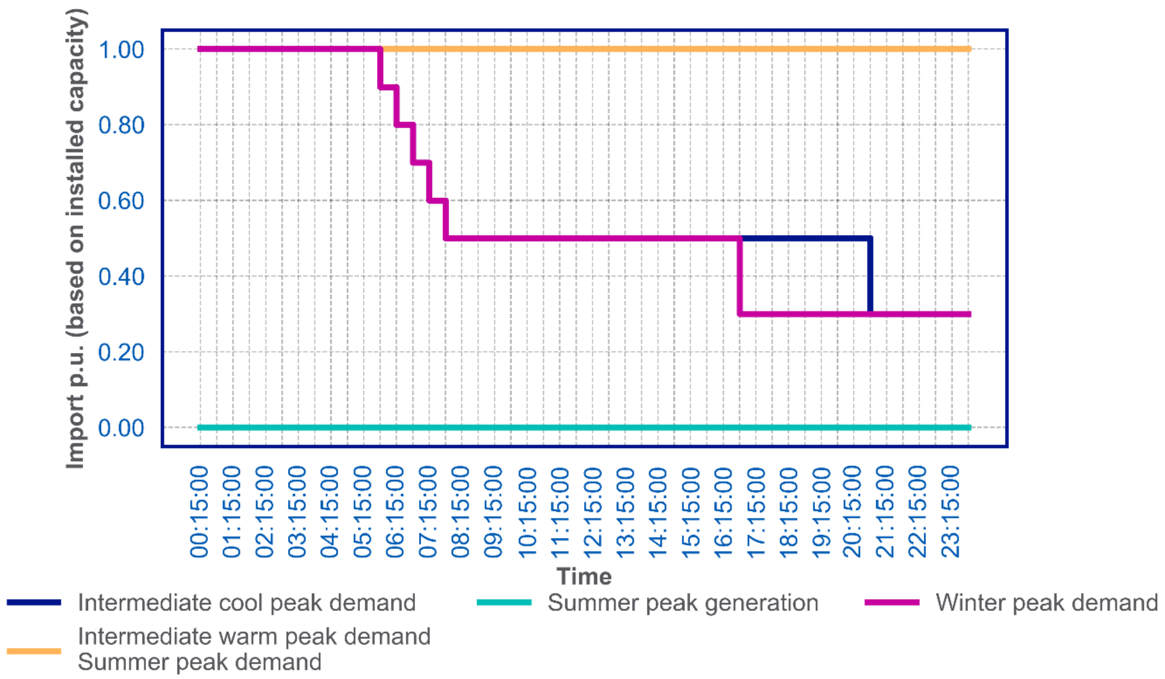

Figure 88: Representative agricultural machinery electricity demand profiles

How will these profiles change over time

These profiles do not change for any year and scenario as scenario variations have already been included when determining the roll out of agricultural machinery charging.

Energy Assumptions

The annual energy demand for farming in the UK was calculated using the CCC's Balanced pathways, and disaggregated down to local authority level. More details about this process and methodology can be found in the DFES 2024 Technology Summary Reports. It is assumed that the utilisation factor of the charge points is quite low, at just over 2%.

Known Limitations

There is currently limited knowledge about the how agriculture is likely to electrify as it is a hard to decarbonise sector, with large mobile machinery more likely to utilise biodiesel and other solutions as opposed to converting to battery electric vehicles. The operating profiles of these machines is also uncertain due to the lack of data around time of use, and particularly the high seasonality of farm work, where in harvest season the usage can be up to 16 continual hours. As more work is done in this space and real-world adoption begins, we will have more data available to inform our forecasting.

Future Developments

We plan to undertake agile analysis on the operating behaviour of electrified agricultural vehicles and machinery, and continue to develop the forecasts as the industry gains further insight into the operational workings of this new technology; focussing on existing behaviour at time of network peak and potential for new edge-cases to occur as uptake increases.

Aviation

The decarbonisation of the aviation sector, and its resultant impact on the distribution network, is a new area of modelling for DFES 2024. Existing demand, as well as electricity demand associated with on-site buildings and passenger EV charging is already modelled within the DFES, as well as on-site solar generation.

Methodology

Aviation demand is geographically allocated to an Electricity Supply Area where it would be most likely to connect to the distribution network, based on where current airports are located. Each of the airports across our licence areas were allocated an archetype, and the modelling informed by IBA, an aviation intelligence and advisory company, that was commissioned by National Grid Group to explore electricity use at UK airports.[43] More details on this methodology can be found in the DFES Technology Summary reports; however it should be noted that the forecast values reflect peak demand of the use of electricity on site, and the assumptions detailed below were used to convert this into demands that would be seen on the distribution network.

There are 3 key airport archetypes found across our licence areas; Large International, Regional, and Local airports. These airport archetypes have each been modelled differently in the analysis carried out by IBA, and reflect the movements of aircraft and airport support vehicles throughout the day. The airport vehicle portion of the profiles have been amended to reflect the time of charging, where Local Airports have been modelled to have their ground vehicles charge for 6.5 hours overnight, utilising smart charging, and the Regional and Large International airport archetypes have 60% of the ground support vehicle charging happening outside of operational hours (charging occurring between 22:00-04:30), and 40% of the charging happening throughout the remainder of the day.

The daily profile for the demand representative days varies by season, in line with aircraft movements reported by airports. This peaks in our Summer and Intermediate Warm representative days, in line with holiday season.

The profile for the Summer Peak Generation representative day was modelled as zero for network assessments. This is to remove the risk of worst-case conditions for the summer peak generation days being masked when Airport demand is not guaranteed to be operating at times of high generation.

Representative Day Profiles

Local airport (baseline)

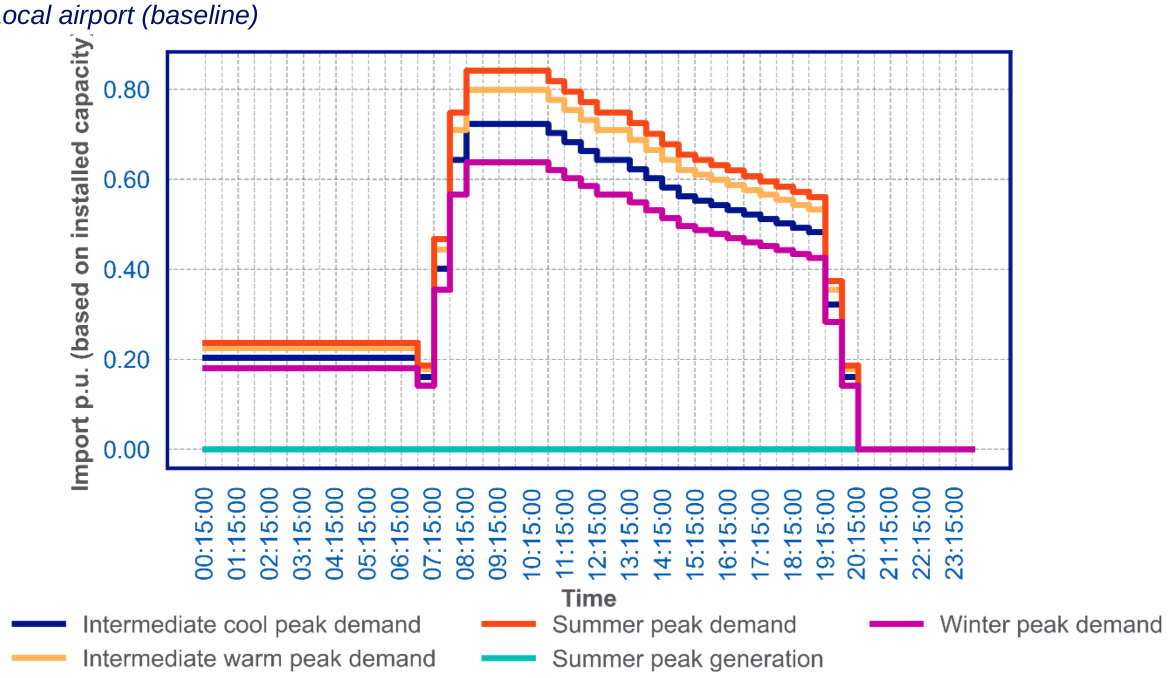

Figure 89: Representative Local Airport baseline profiles

Local airport (2050)

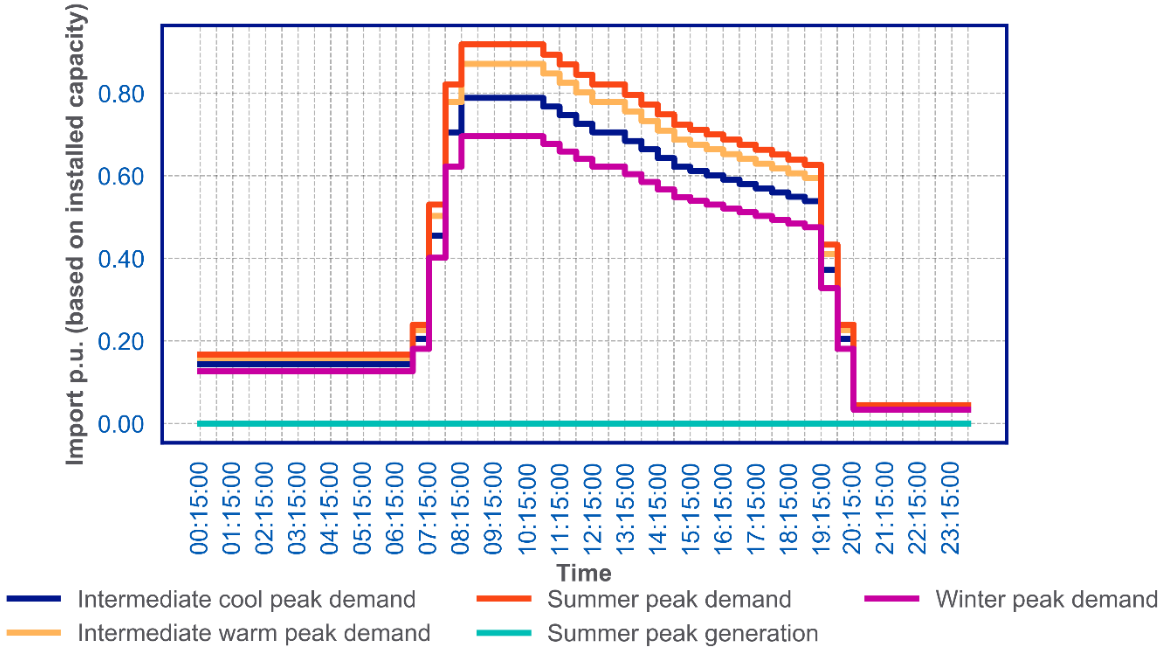

Figure 90: Representative Local Airport 2050 profiles

Regional airport (baseline)

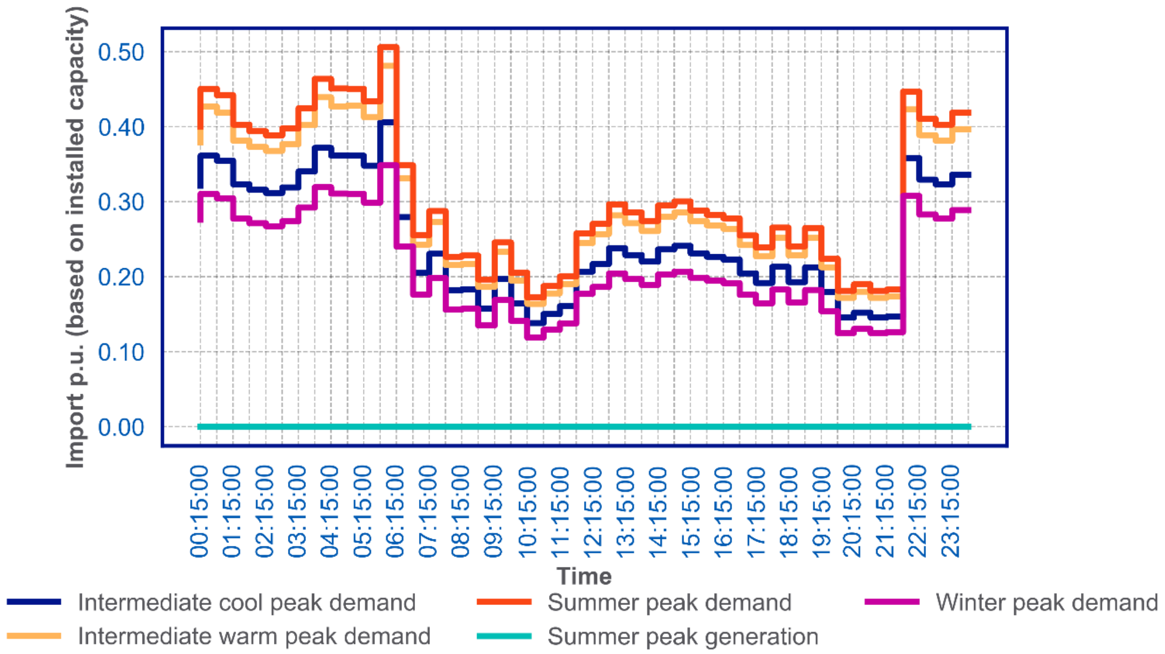

Figure 91: Representative Regional Airport baseline profiles

Regional airport (2050)

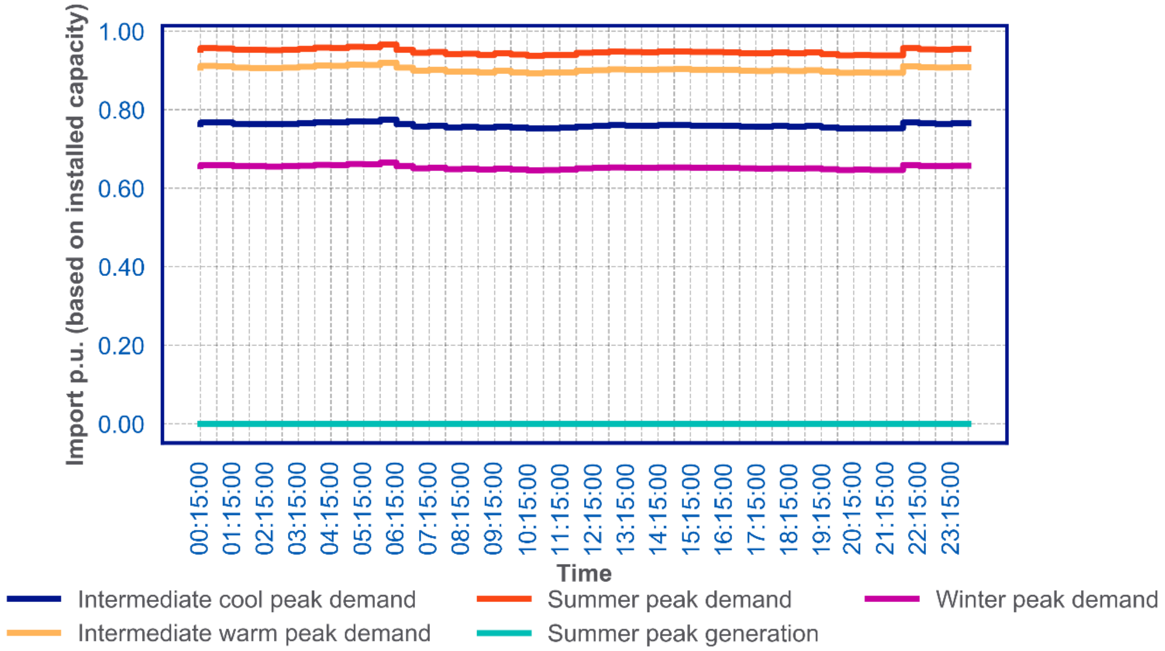

Figure 92: Representative Regional Airport 2050 profiles

International airport (baseline)

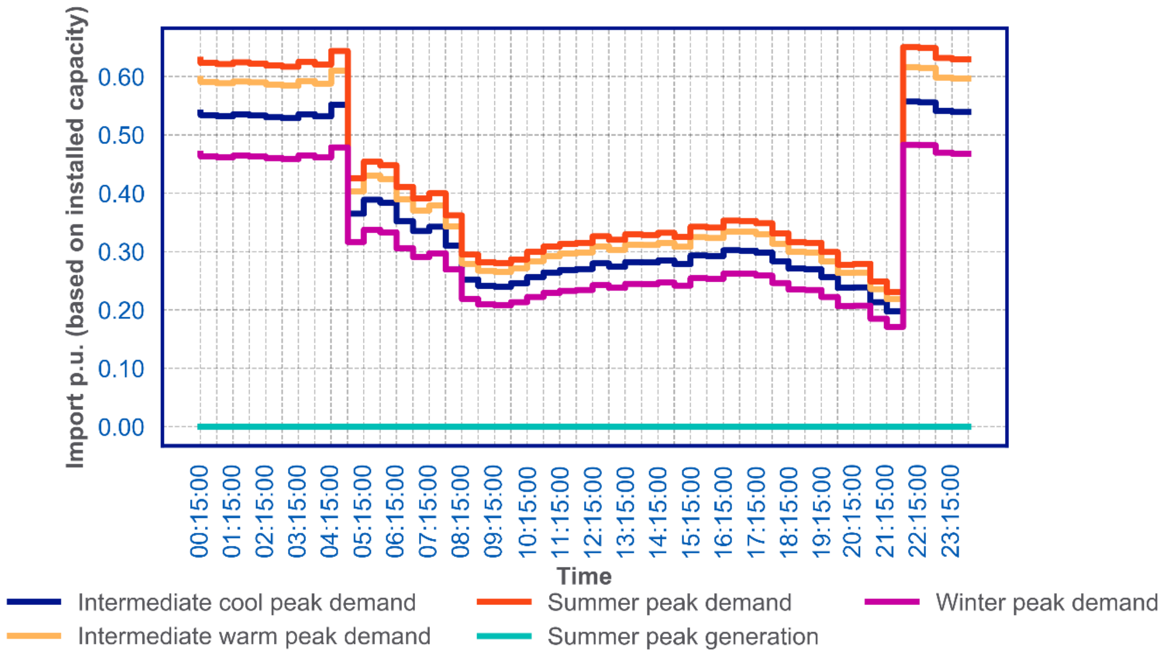

Figure 93: Representative International Airport baseline profiles

International airport (2050)

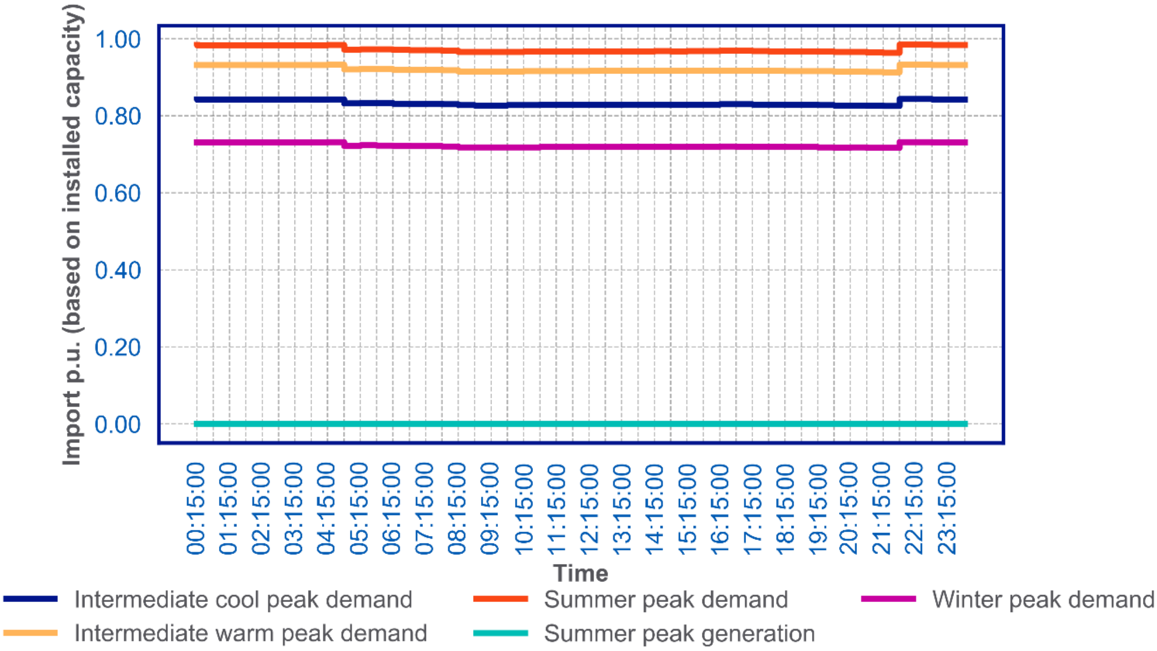

Figure 94: Representative International Airport flexed profiles

How will these profiles change over time

These profiles have been created such that they utilise the profile split functionality to replicate the changes in demand that will be seen between the baseline and 2050. The flexed profiles represent the demand in 2050, where there is hydrogen electrolysis co-located at airports. This makes the profiles more constant throughout the day, with a far higher utilisation factor. In the near term, the demand at airports is far more variable, with ground support vehicles making up the majority of increased power demand.

Energy Assumptions

The annual energy demand has been calculated based on the IBA analysis of existing aircraft movements and types, along with their fuel demand at the different airport archetypes of Major International, Large International, Regional and Local. This analysis studied the conversion of these archetype airports energy demand as they decarbonised, and so identified the electricity demand associated. This value is given per unit of aviation demand capacity and does not vary in future years, as higher rollout is captured through increasing aviation demand in DFES Part 1 - Volumes.

Known Limitations

There is currently limited knowledge about the how aviation is likely to electrify as it is a hard to decarbonise sector, with many uncertainties. The operating profiles of these sites is also uncertain due to the lack of data around time of use. It is important to NGED that we begin to have as much insight into these future demands as possible, which is why we have begun this analysis, despite there being a long way to go to further refine the workings. As more work is done in this space and real-world adoption begins, we will have more data available to inform our forecasting.

Future Developments

We plan to undertake agile analysis on the operating behaviour of airports as they decarbonise, and continue to develop the forecasts as the industry gains further insight into the operational workings of this new technology; focussing on existing behaviour at time of network peak and potential for new edge-cases to occur as uptake increases.

Maritime transport

The decarbonisation of the maritime sector, and its resultant impact on the distribution network, is a new area of modelling for DFES 2024. Electricity demand associated with on-site buildings and passenger EV charging is already modelled in the DFES, as well as on-site solar generation.

Methodology

Maritime demand is geographically allocated to an Electricity Supply Area where it would be most likely to connect to the distribution network, based on where current airports are located. The maritime modelling was split into two methods, one to calculate the peak demand of the ports, and the other to calculate the annual energy.

Future shore power peak demand was determined through analysis of the number of ship arrivals, the breakdown of these by vessel type and the categorisation of each port (major or minor) from the DfT's PORT data[44]. Projections for electricity demand at ports are based directly on the number of berths and the type of vessels these serve.

The method to determine future shore power annual electricity demand has been detailed in the Energy Assumptions section, found below.

It has been assumed that shore power demand could occur at any half hour within the representative day, therefore, the profile has been modelled as flat importing at 1 per unit across all representative days.

The profile for the Summer Peak Generation representative day was modelled as zero for network assessments. This is to remove the risk of worst-case conditions for the summer peak generation days being masked when maritime demand is not guaranteed at times of high generation.

Representative Day Profiles

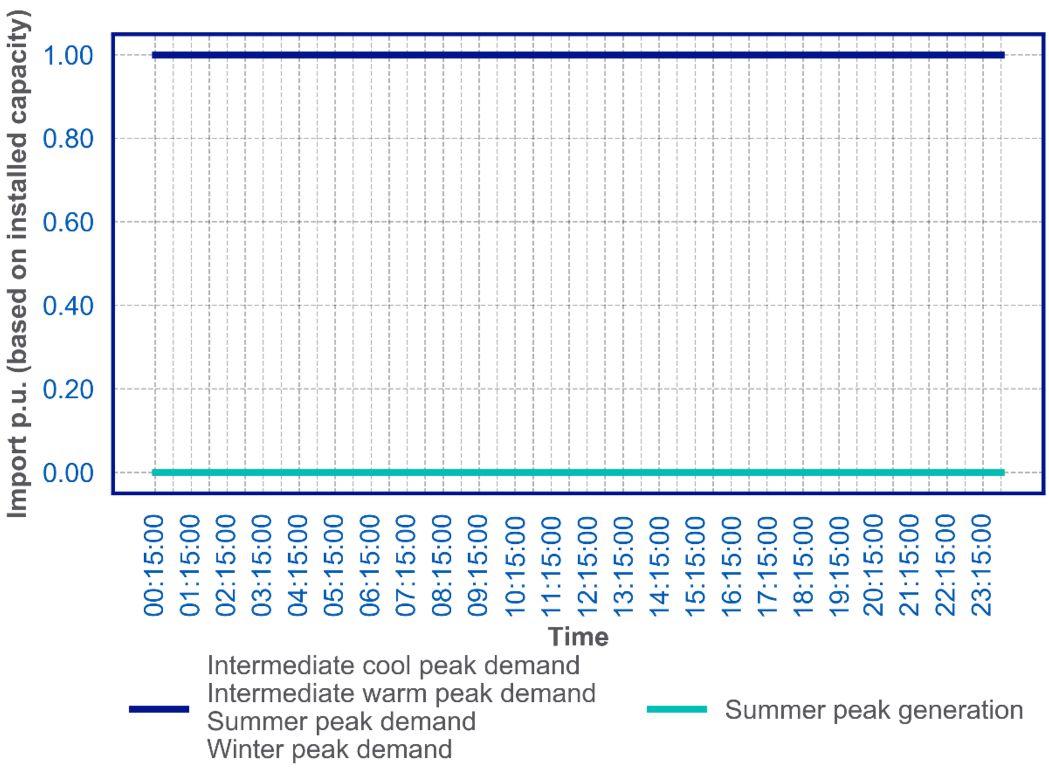

Figure 95: Representative maritime electricity demand profiles

How will these profiles change over time

These profiles do not change for any year and scenario as these variations have already been included when determining the roll out of maritime demand.

Energy Assumptions

The annual energy demand was calculated using National Grid analysis. The calculation was based on arrivals data disaggregated by port, vessel type and size. The demand of each arrival was calculated using the energy requirements of each ship type and size for propulsion and shore power, in addition to assumptions on refuelling rates and the uptake of electric propulsion and shore power via grid connections for the relevant scenario, Figure 96 shows the breakdown of annual electricity demand from each vessel type that would connect to NGED's network for shore power in 2050, where it can be seen that the majority of demand would be from other dry cargo vessels.

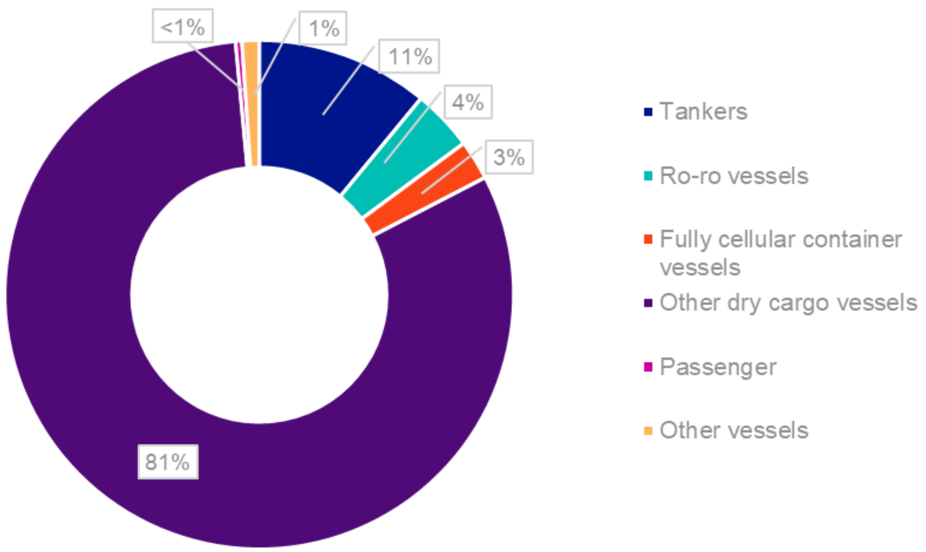

Figure 96 –NGED maritime shore power annual energy demand split by vessel type

By 2050, under a net zero compliant scenario with high degrees of electrification and a push to meeting renewable targets on time, the annual demand from shore powered vessels connected to the NGED network is forecast to be over 140 GWh. This represents ~60% of total demand at berth and is a result of the majority of ships connecting to the grid for shore power when at berth, as opposed to using diesel engines as is done currently.

Known Limitations

There is currently limited knowledge about the how maritime will electrify as it is a hard to decarbonise sector, with many uncertainties. The operating profiles of these sites is also uncertain due to the lack of data around time of use. It is important to NGED that we begin to have as much insight into these future demands as possible, which is why we have begun this analysis, despite there being a long way to go to further refine the workings. As more work is done in this space and real-world adoption begins, we will have more data available to better inform our forecasting.

Future Developments

We plan to undertake agile analysis on the electrification of maritime, which will likely be evolving as new policies continue to be released, such as the UK's 2024 proposal to expand the ETS to include all ship emissions at berth, which is likely to promote shore power[45].

Rail

The decarbonisation of rail, and its resultant impact on the distribution network, is a new area of modelling for DFES 2024.This analysis reflects the future electrification of railway lines, existing electrified lines are included in the underlying demand measured across our network.

Methodology

To identify locations for rail demand, the alongside proximity to transmission lines for existing, non-electrified railway lines. It was determined that where a proximal transmission line was available to connect to, this would be the preferred voltage for these demands. There are however a number of areas of our network that do not have transmission lines in the vicinity, and in these instances, it Is likely that the connection would be to the distribution network. Additional assumptions and methods can be found in the DFES 2024 Technology Summary Reports.

As train timetables are variable, it was deemed best to assume that the peak could occur at any half hour within the peak days being studied, resulting in a flat profile. The method to determine rail annual electricity demand has been detailed in the Energy Assumptions section, found below.

It has been assumed that shore power demand could occur at any half hour within the representative day, therefore, the profile has been modelled as flat importing at 1 per unit. across all representative days.

The profile for the Summer Peak Generation representative day was modelled as zero for network assessments. This is to remove the risk of worst-case conditions for the summer peak generation days being masked when rail demand is not guaranteed at times of high generation.

Representative Day Profiles

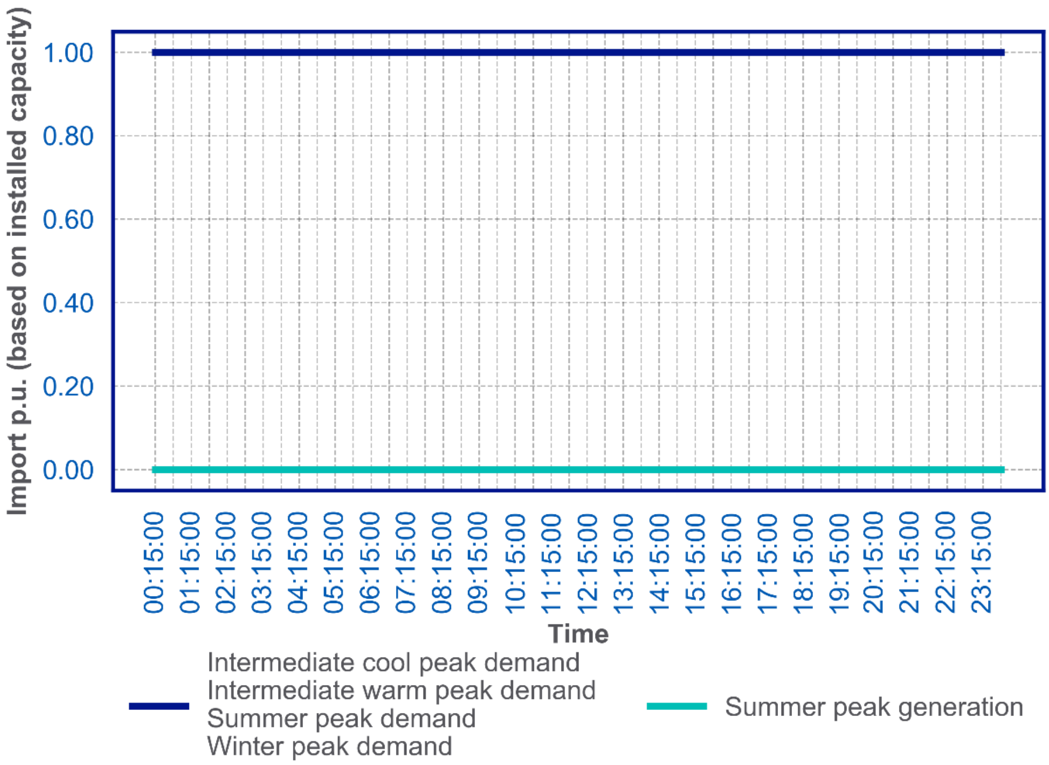

Figure 97: Representative rail electricity demand profiles

How will these profiles change over time

These profiles do not change for any year and scenario as these variations have already been included when determining the roll out of rail demand.

Energy Assumptions

The annual energy demand was calculated using annual train journey statistics, alongside assumptions regarding the energy demand per km that a passenger travels by rail[46]. This varies significantly by type of train and line, and so assumptions were aligned to recently electrified line data.

Known Limitations

There is currently limited available information on planned OHL rail electrification, particularly for smaller lines. The alternative options to OHL are still uncertain, and the exact location of grid connections for certain parts of rail network is variable.

Future Developments

We do not currently have plans to expand upon this development, but welcome feedback which we can incorporate into future analysis.

Summary of future developments

NGED welcome any feedback on the profiles presented in this document. Any improvements in the analysis used to create these profiles will be incorporated into future editions of the DFES process and strategic investment planning activities within NGED, with an annual review of each technology type planned. Publication of customer behaviour assumptions allows for transparency in the strategic investment planning activities, also to drive further discussion and data sharing between stakeholders to improve the assumptions used. Regional variations in profiles across the UK are expected and any differences in profile behaviour should be justified by the DNO. The list below covers some of the areas of focus for improvements to the DFES customer behaviour analysis in 2025:

- Further update and application of new national level policies into the customer behaviour assumptions of new domestic and non-domestic connections.
- Developing a greater understanding of the coincidence between demand behaviour of different technologies.
- Further extending the engagement with major energy users to better capture any anticipated changes in consumption and generation over a 7 year horizon.
- Investigation into using more granular profiles and energy efficiency assumptions based on existing customer breakdown within a smaller geographic area. This area of focus will utilise smart meter data to inform better assumptions on how customers react to price signals and how coincident price signals are to existing times of increased network loading.
- Engage with NESO as Regional Energy Strategic Plans are developed to aid increasing consistency across DNO planning assumptions
- Investigate where additional measured data (including smart meter data and data for specific customer types such as en-route national EV charging networks) is available, and further incorporate this into our analysis

Appendix A: Technology comparison to Open Networks building blocks

As part of the Open Networks projects led by the Energy Networks Association, distribution network operators proactively work with National Energy System Operator (NESO) to drive further standardisation between Future Energy Scenarios and Distribution Future Energy Scenarios processes. As part of the work delivered in 2020, common ‘building blocks’ were agreed between member companies. This allows for easy comparison between NESO and DNOs of the forecast volumes. A list of the technology types considered in our DFES analysis is included below, with the relevant building block number to which it refers.

Table 22: DFES technology to building block lookup

DFES technology	DFES subtechnology	Equivalent Building block ID number
Biomass & Energy Crops (including CHP)	-	Gen_BB010
CCGTs (non-CHP)	-	Gen_BB009
Geothermal	-	Gen_BB019
Hydro	-	Gen_BB018
Hydrogen-fuelled generation	-	Gen_BB023
Marine	Tidal stream	Gen_BB017
Marine	Wave energy	Gen_BB017
Non-renewable CHP	<1MW	Gen_BB001
Non-renewable CHP	>=1MW	Gen_BB002
Non-renewable Engines (non-CHP)	Diesel	Gen_BB005
Non-renewable Engines (non-CHP)	Gas	Gen_BB006
Nuclear SMR	-	Gen_BB020
OCGTs (non-CHP)	-	Gen_BB008
Other generation	-	-
Renewable Engines (Landfill Gas, Sewage Gas, Biogas)	-	Gen_BB004
Solar Generation	Commercial rooftop (10kW - 1MW)	Gen_BB012
Solar Generation	Domestic rooftop (<10kW)	Gen_BB013
Solar Generation	Ground mounted (>1MW)	Gen_BB012
Waste Incineration (including CHP)	-	Gen_BB011
Wind	Offshore Wind	Gen_BB014
Wind	Onshore Wind <1MW	Gen_BB016
Wind	Onshore Wind >=1MW	Gen_BB015
Storage	Co-location	Srg_BB001
Storage	Domestic Batteries (G98)	Srg_BB002
Storage	Grid services	Srg_BB001
Storage	High Energy User	Srg_BB001
Storage	Other	Srg_BB004

Domestic	-	Dem_BB001a
Non-domestic	A1/A2	Dem_BB002b
Non-domestic	A3/A4/A5	Dem_BB002b
Non-domestic	B1	Dem_BB002b
Non-domestic	B2	Dem_BB002b
Non-domestic	B8	Dem_BB002b
Non-domestic	C1	Dem_BB002b
Non-domestic	C2	Dem_BB002b
Non-domestic	D1	Dem_BB002b
Non-domestic	D2	Dem_BB002b
Non-domestic	Sui Generis	Dem_BB002b
Air conditioning	-	Lct_BB014
Agriculture	-	-
Aviation	Large International Airport	-
Aviation	Local Airport	-
Aviation	Regional Airport	-
Demand	Block load	-
Electric vehicles	Hybrid car (non-autonomous)	Lct_BB002
Electric vehicles	Hybrid LGV	Lct_BB004
Electric vehicles	Pure electric bus and coach	Lct_BB003
Electric vehicles	Pure electric car (autonomous)	Lct_BB001
Electric vehicles	Pure electric car (non-autonomous)	Lct_BB001
Electric vehicles	Pure electric HGV	Lct_BB003
Electric vehicles	Pure electric LGV	Lct_BB003
Electric vehicles	Pure electric motorcycle	Lct_BB001
EV Charge Point	Car parks	Lct_BB012b, LCT_BB013b
EV Charge Point	Destination	Lct_BB012b, LCT_BB013b
EV Charge Point	Domestic off-street	Lct_BB010b
EV Charge Point	Domestic on-street	Lct_BB010b
EV Charge Point	En-route / local charging stations	Lct_BB012b, LCT_BB013b

EV Charge Point	En-route national network	Lct_BB012b, LCT_BB013b
EV Charge Point	eHGV chargers	LCT_BB013b
EV Charge Point	Fleet/Depot	Lct_BB011b
EV Charge Point	Workplace	Lct_BB011b
Heat pumps	District heating	Lct_BB009
Heat pumps	Domestic - Hybrid	Lct_BB006
Heat pumps	Domestic - Non-hybrid ASHP	Lct_BB005
Heat pumps	Domestic - Non-hybrid GSHP	Lct_BB005
Heat pumps	Domestic - Hybrid + thermal storage	Lct_BB006
Heat pumps	Domestic - Non-hybrid ASHP + thermal storage	Lct_BB005
Heat pumps	Domestic - Non-hybrid GSHP + thermal storage	Lct_BB005
Heat pumps	Non domestic - A1/A2	-
Heat pumps	Non domestic - A3/A4/A5	-
Heat pumps	Non domestic - B1	-
Heat pumps	Non domestic - B2	-
Heat pumps	Non domestic - B8	-
Heat pumps	Non domestic - C1	-
Heat pumps	Non domestic - C2	-
Heat pumps	Non domestic - D1	-
Heat pumps	Non domestic - D2	-
Heat pumps	Non domestic - Sui Generis	-
Heat pumps	Large-scale heat pumps for district heating	-
Hydrogen electrolysis	-	Dem_BB009
Maritime	-	-
Rail	-	-
Resistive electric heating	Domestic - direct electric heating	-
Resistive electric heating	Domestic - night storage heaters	-
Resistive electric heating	Non domestic - A1/A2	-
Resistive electric heating	Non domestic - A3/A4/A5	-

Resistive electric heating	Non domestic - B1	-
Resistive electric heating	Non domestic - B2	-
Resistive electric heating	Non domestic - B8	-
Resistive electric heating	Non domestic - C1	-
Resistive electric heating	Non domestic - C2	-
Resistive electric heating	Non domestic - D1	-
Resistive electric heating	Non domestic - D2	-
Resistive electric heating	Non domestic - Sui Generis	-

Appendix B: Primary substation clustering

Methodology

In order for a computer to imitate the behaviour of a human manually grouping profiles, Machine learning (ML) techniques were used. ML can be defined as a field of study which allows computers to learn without being clearly programmed to do so

Specifically, *unsupervised* ML techniques can be used to produce profile groups for further human analysis. The term “unsupervised” refers to the ML algorithm working with unlabelled data. In this context of this project, a “label” would be a descriptor for a group of profiles with similar behaviours.

This section aims to give a high-level overview of the ML techniques used to produce the profile clusters; the reader should consult other reference material for an in-depth explanation of how the ML techniques work.

The starting point for devising the ML clustering methodology was to consider how a human would group similar demand profiles. An intuitive way of doing this would be to plot the demand profiles, and match those with similar profile shapes. For example, one group may consist of profiles with morning and evening peaks, and another group may consist of profiles with a midday peak. When creating these groups, a human would also consider the “context” of a profile peak. Peaks do not occur at the same time, but fall within a range. For example, the evening peak could fall between 5 pm to 7 pm.

Previous work within the company focused on an unsupervised technique known as k-means clustering and that used Dynamic Time Warping (DTW) as a metric to group the half-hourly data of Electricity Supply Areas (ESAs). Half-hourly data for “representative days” of the year was gathered and clustering performed on these data with the intention of inferring information about the ESAs from the similarity of clustering’s during these representative days.

The k-means algorithm is a hard-clustering process which produces non-overlapping clusters; soft-clustering is slightly different and produces clusters which may overlap. Points are assigned to the most probable cluster group. Soft-clustering can allow better grouping for “non-spherical” data, which is the case for clusters having different variances and co-variances.

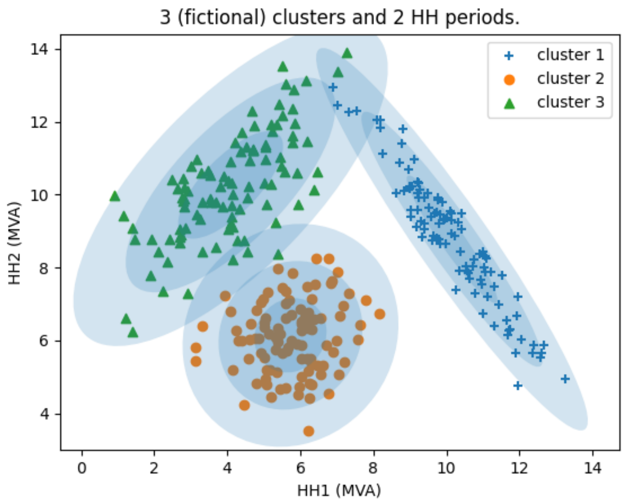

Figure 98: GMM applied to two (fictional) half-hour data.

In this approach a Gaussian Mixture Model (GMM) used the available HH-data for each ESA to produce clustering's. To avoid overfitting the number of clusters, k, a measure of cost/error is used: Akaike Information Criterion (AIC) or Bayesian Information Criterion (BIC) are typical (DTW method used the within-cluster-sum-of-squares measure for this purpose). The AIC or BIC is calculated for each fitted GMM model; because the initial step of GMM randomly assigns cluster centres there are small difference in final cluster centres, to account for this randomness the model is recalculated 10,000 times for each k and the minimum cost model noted. When cluster numbers are increased the AIC/BIC scores reduce and then increase, the optimal number of clusters (and model) will correspond to the minimum value of AIC/BIC.

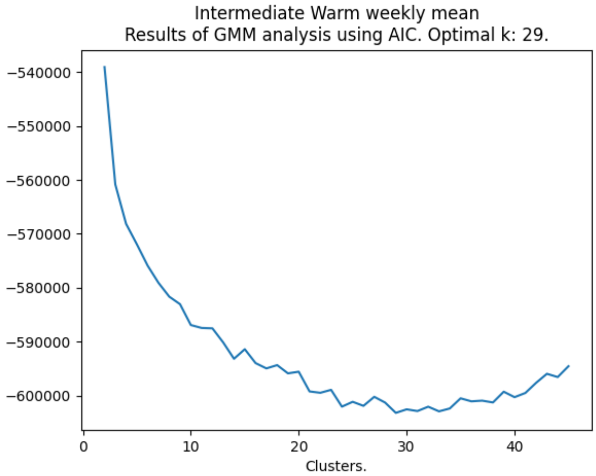

Figure 99: AIC values used to estimate k with GMM.

Prior to clustering the HH real power data for each site was converted to per-unit values based upon the maximum annual value for each site and GMM applied to the data with randomised initial cluster centres and the best models selected. Using AIC/BIC to calculate the optimal number of clusters resulted in a large number of seasonal groupings and the sparsity of ESAs withing similar groupings made regression using MPAN types, LCT types or generation types meaningless. A fixed value of 5 for each seasonal clustering was used.

The Adjusted Rand Index (ARI) can give some insight into how ESA behaviour is consistent across seasons, the ARI is calculated between pairs of seasons. If ESAs are mapped to the same clusters (in different seasons) there is good reason to believe that similar factors drive that behaviour. An ARI score of +1 indicates that the groupings are identical, whereas a score of 0 indicates a random assignment to clusters. The results ranged from 0.197 between Winter and Intermediate Cool through to 0.067 between Intermediate Warm and Summer minimum.

Once clustering was completed ESAs were grouped into similar five-seasonal groups (or classes) and regression was carried out for each using the proportion of MPAN types, LCT and generation types as estimators. Classes may be labelled, for example, “W2,S1,Sgen4,IC4,IW3” indicating an ESA is in the following groups: Winter 2, Summer 1, Summer generation 4, Intermediate Cool 4 and Intermediate Warm 3. 215 unique classes were discovered with the data set used; this number will vary should other HH data be used.

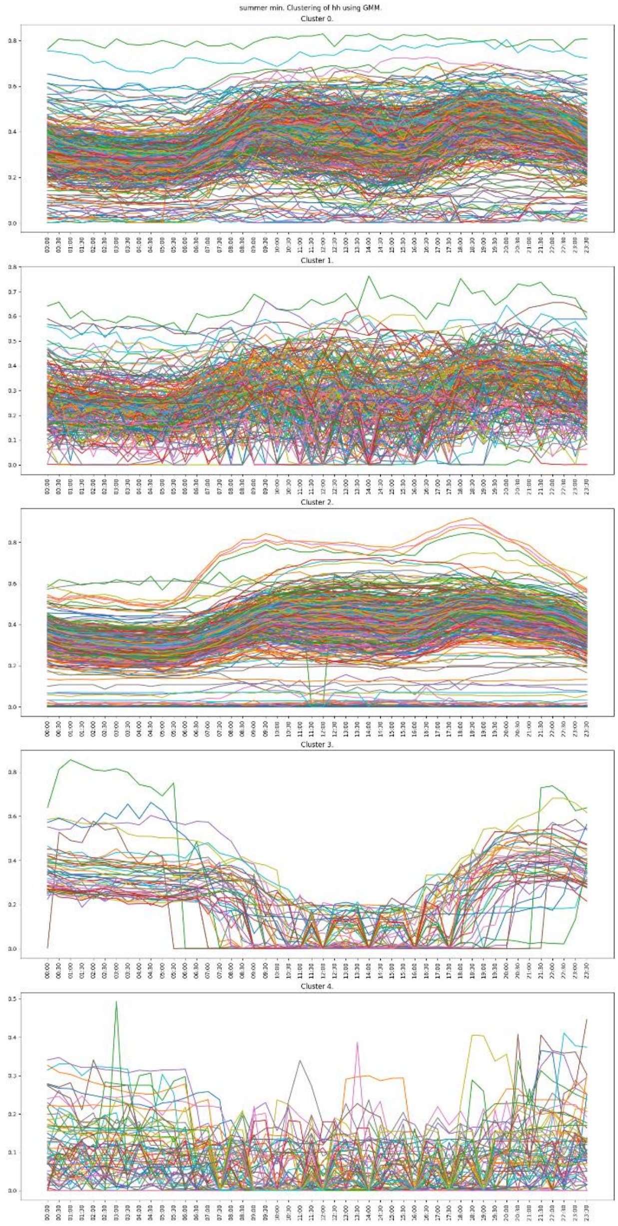

Figure 100: Clustering of ESAs using 5 clusters using Summer min, data per-unit HH data.

Stratified k-fold cross-validation was used to explore any underlying factors, and whether regression models might have some predictive use; the limited-memory Broyden-Fletcher-Goldfarb-Shannon (LBFGS) solver, using 5 folds and 1000 iterations was used for cross-validation. The proportions of MPANS, LCTs, Generators connected to each ESA were used as variables in the multinomial regression. Table 23 shows the results of the cross-validation of the models to predict the seasonal class of each ESA.

Both of the cross-validation measures have low standard deviation indicating that it is possible to construct linear regression models to predict the seasonal classes. The mean accuracy results range from 0.14 to 0.15 which is about 30 times better than chance. The Coefficient of determination scores (R2) are negative, indicating that the estimators are not too good at explaining the variance of the five-season-classes; but it should be noted that during the cross-validation many of the test sets were very small and this could result in differences between the means of the test and training data producing poor R2 scores. It is unclear whether a different regression model, or more pre-processing of the estimators and HH data, or another set of estimators, would explain the clustering classes better. The simplest linear regression model would use MPAN data as a predictor for seasonal classes.

Table 23: Results of cross-validation on regression models.

Estimators	Mean Accuracy	Accuracy SD	Mean R2	R2 SD
MPAN	0.136	0.007	-0.681	0.034
LCT	0.135	0.005	-0.651	0.024
GEN	0.146	0.011	-0.546	0.038
ALL	0.153	0.012	-0.542	0.040

Customer Behaviour assumptions

Glossary

Acronym	Term	Definition
–	Access Window	The period of spring, summer and autumn in which arranged outages are normally taken.
ANM	Active Network Management	The ENA Active Network Management Good Practice Guide summarises ANM as: Using flexible network customers autonomously and in real-time to increase the utilisation of network assets without breaching operational limits, thereby reducing the need for reinforcement, speeding up connections and reducing costs.
ASHP	Air Source Heat Pump	Type of Heat Pump that absorbs heat from outside air for the purposes of space heating and hot water.
BEV	Battery Electric Vehicle	Electric vehicle with a battery as the only means of propulsion
BSP	Bulk Supply Point	A substation comprising one or more Grid Transformers and associated switchgear
–	Demand	The consumption of electrical energy.
DSR	Demand Side Response	Ofgem led tariffs and schemes which incentivise customers to change their electricity usage habits
DfT	Department for Transport	The governmental department responsible for the transport network in England and part of Scotland, Wales and Northern Ireland which are not devolved.
DFES	Distribution Future Energy Scenarios	An annual process undertaken by Distribution Network Operations to forecast future growth on the distribution network
DG	Distributed Generation	Generation connected to a distribution network. Sometimes known as Embedded Generation.
DNO	Distribution Network Operator	A company licenced by Ofgem to distribute electricity in the United Kingdom who has a defined Distribution Services Area.
DSO	Distribution System Operator	National Grid Electricity Distribution’s DSO is responsible for a number of key outputs to help shape the future development of the distribution network.
DSOF	Distribution System Operability Framework	A document published by National Grid that assesses the technical issues facing Distribution Network Operators as they transition to Distribution System Operator (DSO).
DTW	Dynamic Time Warping	An algorithm to measure similarity between two time series
EV	Electric Vehicle	General term for a vehicle which uses electric motors as its method of propulsion.
ESA	Electricity Supply Area	Each ESA represents a block of demand and generation as visible from the distribution network. For the 2022 DFES studies, each ESA represents the geographic area supplied by a Primary Substation (which contains NG-owned distribution substations) providing supplies at a voltage below 33 kV, or a customer directly supplied at 132, 66 or 33 kV or by a dedicated Primary Substation.
ENA	Energy Networks Association	The Energy Networks Association is an industry association funded by gas or distribution or transmission licence holders.

EPC	Energy Performance Certificate	Rating scheme to summarise the energy efficiency of buildings.
ER	Engineering Recommendation	A document published by the Energy Networks Association.
EAC	Estimated Annual Consumption	An estimated rate of consumption, nominally expressed in kWh/year that is used in electricity settlement.
FCO	First Circuit Outage	P2/8 defines a First Circuit Outage as: *"a fault or an arranged Circuit outage…"* Also referred to as N-1 in some contexts.
FES	Future Energy Scenarios	A set of scenarios developed by Nation Grid to represent credible future paths for the energy development of the United Kingdom.
GB	Great Britain	A geographical, social and economic grouping of countries that contains England, Scotland and Wales.
GBSO	Great Britain System Operator	National Grid is the system operator for the National Electricity Transmission System (NETS) in Great Britain. Responsible for coordinating power station output, system security and managing system frequency.
GSP	Grid Supply Point	A substation comprising one or more Super Grid Transformers and associated switchgear
GSHP	Ground Source Heat Pump	Type of Heat Pump that absorbs heat from the ground for the purposes of space heating and hot water.
HP	Heat Pump	General term for a heating system that extracts heat from surroundings which can then be used to produce hot water or space heating.
HGV	Heavy Goods Vehicle	A large goods vehicle with a gross mass greater than 3500 kg
LGV	Light Goods Vehicle	Commercial vehicle with a gross mass of less than or equal to 3500 kg
LTDS	Long Term Development Statement	A document published by all DNO's to assist current and future users of the distribution network to identify and assess opportunities available to them for making new or addition use of the network.
ML	Machine Learning	A field of study which allows computers to learn without being clearly programmed to do so
MPAN	Meter Point Administration Number	Unique reference number used in Great Britain to identify electricity supply points, such as individual domestic residences
NGESO	National Grid Electricity System Operator	National Grid Electricity System Operator is the electricity system operator for Great Britain.
NDP	Network Development Plan	Requirement as part of Electricity Distribution Licence Condition 25B for Distribution Network Operators to cover the investments planned for the next 5 to 10 year period in relation to the 11 kV network and above.

NIA	Network Innovation Allowance	Funding scheme for innovation projects introduced as part of RIIO-ED1. For the RIIO-ED1 period, NGED requested the minimum 0.5% of total regulated income.
Ofgem	Office for Gas and Electricity Markets	Ofgem is responsible for regulating the gas and electricity markets in the United Kingdom to ensure customers' needs are protected and promotes market competition.
–	Open Networks	The Open Networks Project is a major energy industry initiative that will transform the way our energy networks work, underpinning the delivery of the smart grid. This project brings together 9 of UK and Ireland's electricity grid operators, respected academics, NGOs, Government departments and the energy regulator Ofgem. Note: Open Networks was previously known as the ENA TSO-DSO Project.
PV	Photovoltaic	Type of distributed generation which uses solar irradiance to generate electricity.
PHEV	Plug-in Hybrid Electric Vehicle	Electric vehicle with a battery and a supplementary engine, which is able to run on both modes of propulsion.
–	Primary Distribution	The sections of an electrical distribution network which provide the interface between transmission and Primary or Secondary Distribution. In National Grid's distribution network the 33kV circuits and Primary Substations are considered to be Primary Distribution.
–	Primary Substation	A substation comprising one or more Primary transformers and associated switchgear
–	Primary Transformer	A transformer that steps voltage down from 66 or 33kV to 11kV or 6.6kV
RDP	Regional Development Plan	A study which looks at the complex interaction between the distribution and transmission network, also between different distribution networks.
TDCV	Total Domestic Consumption Values	Industry standard values for the annual gas and electricity usage of a typical domestic customer
V2G	Vehicle to Grid	Where a plug-in EV can export to the power grid.
VOA	Valuation Office Agency	UK government body responsible for the valuation of properties for the purpose of council tax and for non-domestic rates in England and Wales
NG	National Grid Electricity Distribution	A Distribution Network Operator (DNO) that is licenced by Ofgem to distributed electricity in the East Midlands, West Midlands, South West, and South Wales regions of United Kingdom.

Table of Units

Term	Definition
kV	Kilovolt, a unit of Voltage (x103)
LV	This refers to voltages up to, but not including, 1kV
HV	Voltages over 1kV up to, but not including, 22kV
EHV	Voltages over 20kV up to, but not including, 132kV
kW	Kilowatt, a unit of Power (x103)
MW	Megawatt, a unit of Active Power (x106)
MVA	Mega volt-ampere, a unit of Apparent Power (x106)
MVAr	Mega volt-ampere (reactive), a unit of Reactive Power (x106)
kWh	Kilowatt hour, a unit of energy (x103). Equivalent to a constant 1kW of Active Power delivered for an hour

[1] ACE Report no.49, *Report on Statistical Method for Calculating Demands and Voltage Regulations on LV Radial Distribution Systems*, Energy Networks Association, 1981.

[2] Engineering Recommendation P2 Issue 8, *Security of Supply*, Energy Networks Association, 2023

[3] Engineering Recommendation P27 Issue 2, Current rating guide for high voltage overhead lines operating in the UK distribution system, Energy Networks Association, 2020;

[4] Energy Networks Association, Engineering Recommendation P2 Issue 8, p9, 2023

[5] Ofgem, *Open letter on changes to licence conditions as a result of the transposition of the Clean Energy Package,* 8th December 2020; https://www.ofgem.gov.uk/system/files/docs/2020/12/electricity_directive_open_letter_0.pdf

[6] National Grid Electricity Distribution Innovation, *Assessment of Climate Change Event Likelihood Embedded in Risk Assessment Targeting Electricity Distribution (ACCELERATED),* 2023, https://www.nationalgrid.co.uk/innovation/projects/assessment-of-climate-change-event-likelihood-embedded-in-risk-assessment-targeting-electricity-distribution-accelerated

[7] National Grid, *RIIO-ED2 Business Plan 2023-2028,* 2021; https://yourpowerfuture.nationalgrid.co.uk/downloads/40290

[8] Elexon, *Load Profiles and their use in Electricity Settlement,* 2018; https://www.elexon.co.uk/documents/training-guidance/bsc-guidance-notes/load-profiles/

[9] National Grid, Standard Technique: SD5A/6, Design of Low Voltage Domestic Connections, 2022;

[10] Energy Networks Association, *ACE Report no.49*, p5

[11] Ofgem, *Decision for Typical Domestic Consumption Values 2023*, 2023; https://www.ofgem.gov.uk/publications/decision-typical-domestic-consumption-values-2023 (Accessed November 2023)

[12] Planning Portal, *Change of Use – Use Classes,* 2020; https://www.planningportal.co.uk/info/200130/common_projects/9/change_of_use

[13] Ministry of Housing, Communities and Local Government, *Energy Performance of Buildings Data* [Data set], https://epc.opendatacommunities.org/ (Accessed 13th September 2019)

[14] Python Software Foundation, *difflib – Helpers for computing deltas,* 2020; https://docs.python.org/2/library/difflib.html (Accessed 19th August 2020)

[15] Ministry of Housing, Communities and Local Government, Future Buildings Standard: Consultation on changes to Part L (conservation of fuel and power) and Part F (ventilation) of the Building Regulations for non-domestic buildings and dwellings; and overheating in new residential buildings, 2021; https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/956037/Future_Buildings_Standard_consultation_document.pdf

[16] National Grid, *Shaping Subtransmission East Midlands*, 2020; https://www.nationalgrid.co.uk/downloads-view/134116

[17] Hawkins, G, (2011). Rules of Thumb – Guidelines for building services (5th edition). BSRIA

[18] Ofgem, *Modification Proposal: Balancing and Settlement Code (BSC) P272: Mandatory Half-Hourly Settlement for Profile Classes 5-8,* 2014; https://www.elexon.co.uk/wp-content/uploads/2012/02/P272D.pdf

[19] Element Energy, *Electric Vehicle Charging Behaviour Study, Final Report for National Grid ESO,* 2019; https://www.smarternetworks.org/project/nia_ngso0021/documents

[20] National Grid, *Electric Nation,* 2019; https://www.nationalgrid.co.uk/projects/electric-nation

[21] National Grid, *Electric Nation – Powered Up,* 2020; https://www.nationalgrid.co.uk/projects/electric-nation-powered-up

[22] Elexon, Load Profiles and their use in Electricity Settlement, p41

[23] National Grid, Standard Technique: SD5A/5, Design of Low Voltage Domestic Connections, p41

[24] Energy Networks Association, *ACE Report no.49*, p5

[25] NESO, *FES Data Workbook 2024 v03*

[26] Electricity North West Lid, *NIA ENWL001 – Demand Scenarios with Electric Heat and Commercial Capacity Options,* 2017 https://www.enwl.co.uk/globalassets/innovation/enwl001-demand-scenarios--atlas/enwl001-closedown-report/nia-enwl001-closedown-report-final.pdf

[27] Northern Powergrid, *Customer Led Network Revolution Insight Report: Domestic Heat Pumps,* 2015; http://www.networkrevolution.co.uk/wp-content/uploads/2015/01/CLNR-L091-Insight-Report-Domestic-Heat-Pumps.pdf

[28] Northern Powergrid, *Customer Led Network Revolution TC3 Dataset,* [Data set] 2014 http://www.networkrevolution.co.uk/wp-content/uploads/2015/01/TC3-Dataset_December-2014.xlsx (Accessed July 2019)

[29] Watson, S.D. et al, *Decarbonising Domestic Heating: What is the peak GB demand?* 2019, Energy Policy 126, p533-544

[30] Love, J et al., *The addition of heat pump electricity load profiles to GB electricity demand: Evidence from a heat pump field trial*, 2017, Applied Energy 204, p332-342

[31] NESO, *FES Data Workbook 2024 v03*

[32] Watson, S.D., K.J. Lomas, R.A. Buswell, *How will heat pumps alter national half-hourly heat demands? Empirical modelling based on GB field trials*, 2021, Energy and Buildings vol. 238. p110777

[33] Watson, S.D. Crawley, J., Lomas, K.J., Buswell, R.A., *Predicting future GB heat pump electricity demand*, 2023, Energy and Buildings vol. 286. p112917

[34] Daneshzand et al., *EV smart charging: How tariff selection influences grid stress and carbon reduction*, 2023, Applied Energy 348, p121482

[35] Energy Systems Catapult, DESNZ, *Electrification of Heat Demonstration Project Summary Report,* Electrification of Heat Demonstration Project, 2024

[36] Energy Systems Catapult, DESNZ, *Heat Pump Performance Data Analysis Report,* Electrification of Heat Demonstration Project, 2024

[37] National Grid, *FREEDOM: Flexible Residential Energy Efficiency Demand Optimisation and Management,* 2019; https://www.nationalgrid.co.uk/projects/freedom

[38] Hiscock, E., *Hourly Load Modelling for Heat Pump and Thermal Store Sizing in a Hybrid Energy Centre*, FairHeat, 2023

[39] Adamson, J., *Optimising electric peaking plant capacity with oversized thermal stores*, FairHeat, 2023

[40] Dang, L.M., Lee, S., Li, Y. et al. *Daily and seasonal heat usage patterns analysis in heat networks*. Sci Rep 12, 9165 (2022). https://doi.org/10.1038/s41598-022-13030-6

[41] Hawkins, G. and Building Services Research and Information Association, *Rules of thumb: guidelines for building services*, Bracknell: Bsria, 2011

[42] BEIS, *Hydrogen Production Costs 2021*, 2021

[43] https://www.iba.aero/

[44] DfT, *Port freight annual statistics 2023: Overview of port freight statistics and useful information*, 2024

[45] UK ETS scope expansion: maritime sector, Open Consultation, November 2024

[46] Department for Energy Security and Net Zero, Greenhouse gas reporting: conversion factors 2022, Greenhouse gas reporting: conversion factors 2022 - GOV.UK, [Accessed December 2024]

Disclaimer

Registered Office: Avonbank, Feeder Road, Bristol BS2 0TB

nationalgrid.co.uk

nationalgrid DSO