Produced for the National Infrastructure Commission in partnership with EA Technology Ltd

Work Package 1: Electricity Distribution Network Capacity Analysis

Scenario development and load profile selection

November 2024

About Sponsor

This project was carried out for the National Infrastructure Commission. The Commission provides government with impartial, expert advice on major long term infrastructure challenges.

About Regen

Regen is an independent centre of energy expertise with a mission to accelerate the transition to a zero-carbon energy system. We have 20 years' experience in transforming the energy system for net zero and delivering expert advice and market insight on the systemic challenges of decarbonising power, heat, and transport.

Regen is also a membership organisation, managing the Regen members network and the Electricity Storage Network (ESN) – the voice of the UK storage industry. We have over 150 members who share our mission, including clean energy developers, businesses, local authorities, community energy groups, academic institutions, and research organisations across the energy sector.

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Date	November 2024

Contents

Section 1:

Purpose of this document

This document contains the outputs from Work Package 1 (WP1) of the Electricity Distribution Network Capacity Analysis, carried out by Regen and EA Technology Ltd for the National Infrastructure Commission (NIC).

The NIC is undertaking a study on the policy decisions necessary to make the electricity distribution network fit for net zero.[1] To support this study, the NIC commissioned Regen and EA Technology to analyse potential future distribution network loads and their potential impact on the network.

The project is split into two work packages. During WP1, the project develops several future load scenarios using the national Electricity System Operator's (ESO) Future Energy Scenarios (FES) 2023 scenarios as a primary input and identified a set of load profiles and assumptions, including the potential impact of demand flexibility.

Work Package 1, documented in this report, contains:

- Scenario development for the assessment of network capacity (Section 2: Scenario Development)
- An evidence review of technology profiles and network flexibility potential (Section 3: Load Profiles)

In Work Package 2 (WP2), the distribution network impacts of the scenarios and sensitivities developed in WP1 are analysed using network capacity modelling tools developed by EA Technology. The modelled output from WP2 is intended to give the NIC an evidence base to look at the potential need for network investment across all GB distribution networks and for a number of case study network archetypes.

[1] Electricity distribution networks study, NIC, 2024

Section 2:

Scenario Development

Technology uptake scenario development for the assessment of network capacity

2.1. Summary and context

This section details the set of technology uptake scenarios agreed upon with the NIC, with justification on scenario design and data inputs. It is supported by a separate data workbook.

The network capacity analysis and modelling carried out in WP2 requires two sets of data inputs developed in Work Package 1:

- Scenario uptake volumes for key network loads, such as number of EV chargepoints, heat pump uptake or capacity of solar generation
- Daily half-hourly demand and generation profiles for each technology/demand load detailed in Section 3: Load Profiles .

2.1.1. Scenario development approach

The analysis uses the Consumer Transformation scenario from the ESO's FES 2023 as the core input for all technologies where available.[2] Where technology data is not available in Consumer Transformation, or where modifications are made, these are documented and summarised in sections 2.2 to 2.6.

The FES is an industry-recognised scenario framework which is heavily used across the energy industry for a range of applications, including underpinning energy network investment. The FES process has evolved in response to over a decade of stakeholder feedback and is a highly mature framework with data granularity to Grid Supply Point (GSP) level for many technologies. Each FES scenario has its own framework of interconnected assumptions around the approach taken to achieve net zero carbon emissions and the future of the energy system.

The FES Consumer Transformation scenario is used in this analysis because it meets the UK's 2050 net zero target and interim carbon budgets with high levels of electrification, and is in broad alignment with the NIC's Second National Infrastructure Assessment[3].

The Consumer Transformation scenario projects very rapid deployment of electric low-carbon technologies, such as electric vehicles and heat pumps, alongside rapid growth in renewable electricity generation. The ESO characterises the scenario with the following description:

[2] Future Energy Scenarios, ESO, July 2023

[3] Second National Infrastructure Assessment, National Infrastructure Commission, 2023

"The net zero target is met in 2050 with measures that have a greater impact on consumers and is driven by higher levels of consumer engagement. They will have made extensive changes to improve their home's energy efficiency and most of their electricity demand will be smartly controlled to provide flexibility to the system. A typical homeowner will use an electric heat pump with a low temperature heating system and an Electric Vehicle (EV). The system will have higher peak electricity demands managed with flexible technologies including energy storage, Demand Side Response (DSR) and smart energy management."

Future Energy Scenarios 2023 [4]

The detailed approach for each technology and load source connected to the distribution network is documented in the following sections of this report.

To meet their licence conditions, Distribution Network Operators all develop regional future energy scenarios to inform their network planning and investment. These projections, known as Distribution Future Energy Scenarios, include granular projections of future loads to regional and individual network asset level[5].

2.1.2. Technology and load source scope

Table 1 shows the technology scope of the analysis as agreed with the NIC at the start of the project. The key areas of focus of the study are heat and transport electrification, and their respective capacities to provide system flexibility. The impact of underlying building demands and some emergent industrial and commercial (I&C) demands are also considered, alongside the impacts of distributed generation and storage technologies.

Table 1: Demand and generation technologies in the analysis. The analysis includes the main generation technologies expected to connect to the distribution network.

Sector	Subtechnology
Road Transport (electric vehicle chargepoints)	Domestic off-street
	Workplace (incl. fleets)
	Public slow and fast (up to 50kW)
	Public rapid (over 50kW)
Heat	Domestic heat pumps (Air source and ground source)

[4] FES 2023 report (page 7), ESO, July 2023

[5] Distribution Future Energy Scenarios, Regen

Sector	Subtechnology
	Non-domestic heat pumps
	Direct electric heating incl. night storage
	Heat networks (district heat)
Industrial and commercial demand	I&C demand
	Electrolysis
	Data centres
Domestic	Underlying domestic demand
Generation and storage	Small-scale solar (Up to 1 MW per installation)
	Small-scale storage (Up to 1 MW per installation)
	Grid-scale solar (Over 1 MW)
	Wind
	Grid-scale storage (Over 1 MW)
	Dispatchable generation

Table 2 summarises some potential drivers of demand which are not included in this analysis.

Table 2: Demand technologies not included in the analysis

Industrial and commercial demand	Agriculture
	Non-road transport (such as aviation, shipping, off-highway machinery, rail)
	Industrial process electrification
	Heavy industrial sites
Domestic demand	Domestic air conditioning

Table 3 summarises the definitions of voltage tiers used throughout this study. Voltage tiers above EHV are not considered in the analysis.

Table 3: Definition of voltage tiers

Voltage tier	

Low voltage (LV)	All voltage levels up to and including 1kV. Typically 230V single phase and 415V three phase.
High voltage (HV)	All voltage levels above 1kV up to and including 20kV.
Extra high voltage (EHV)	All voltage levels above 20kV up to, but not including, 132kV.

2.1.3. Sensitivity analysis

Several sensitivity cases are defined to test the distribution network impact of different combinations of input parameters. These are outlined Table 4 below and described in more detail in the relevant technology sections.

Table 4: Summary of sensitivity cases. Note: further sensitivities are defined in Work Package 2.

	Name	Flexibility and winter conditions	Heat technology uptake rate
1	FES 23 CT - high flex	Higher levels of flexible operation of EVs, heat pumps and energy storage with typical winter conditions (see Section 2.3)	Higher heat pump adoption (FES 2023 Consumer Transformation)
2	FES 23 CT delayed HP - high flex		Delayed heat pump adoption (Regen modification to Consumer Transformation)
3	Lower HP - high flex		Lower heat pump adoption with higher electric resistive heating (High Heat Pump scenario from Aurora Energy Modelling for Second National Infrastructure Assessment)
4	FES 23 CT - low flex	Lower levels of flexible operation of EVs, heat pumps and energy storage with typical winter conditions (see Section 2.3)	Higher heat pump adoption (FES 2023 Consumer Transformation)
5	FES 23 CT delayed HP - low flex		Delayed heat pump adoption (Regen modification to Consumer Transformation)
6	Lower HP - low flex		Lower heat pump adoption with higher electric resistive heating (High Heat Pump scenario from Aurora Energy Modelling for Second National Infrastructure Assessment)
7	Winter stress test	Winter stress test: higher heating demand with lower flexibility availability (see Section 3.3)	Higher heat pump adoption (FES 2023 Consumer Transformation)
8	Lower I&C demand	Testing the impact of I&C demand reduction (see Section 3.4)	Higher heat pump adoption (FES 2023 Consumer Transformation)
9	High data centre deployment	Testing the impact of very high data centre deployment with higher flexibility availability (see Section 2.4)	Higher heat pump adoption (FES 2023 Consumer Transformation)
10	High initial small-scale	Testing the impact of higher small-scale	Higher heat pump adoption (FES 2023 Consumer Transformation)

	Name	Flexibility and winter conditions	Heat technology uptake rate
	storage deployment	storage deployment with higher flexibility availability (see Section 2.5)	

2.2. Transport

2.2.1. Summary

The adoption of Electric Vehicles (EVs) is expected to increase rapidly under all net zero scenarios. The corresponding deployment of EV chargepoints of various archetypes (domestic, workplace, public, etc.) will significantly impact the electricity distribution network.

The FES 2023 Consumer Transformation scenario is used as the core data input for this sector. This scenario projects very rapid deployment of electric vehicles of all vehicle types representing the upper bound of plausible deployment. It is aligned with a 2030 requirement for all new vehicles to be low carbon[6].

Successively, Regen's DFES transport model is used to estimate the grid-facing capacity of EV chargepoints that are required to deliver the FES Consumer Transformation scenario's EV growth and subsequent electricity demand for road transport.

Table 5: EV charging assumptions

Assumption	Detail
Scope	The analysis includes EV chargepoints for electric road vehicles. It does not include off-highway vehicles, such as agricultural or industrial machinery.
Data sources	1. Projections of energy consumption (TWh) by vehicle type are taken from the ESO's 2023 FES using the Consumer Transformation scenario.[7] 2. EV chargepoint capacity projections are developed using Regen's DFES transport model, informed by stakeholder and DNO feedback.

[6] Paragraph 3.80, Autumn Budget 2024v, HM Treasury, October 2024

[7] Future Energy Scenarios, ESO, July 2023

Assumption	Detail
Chargepoint categorisation	Chargepoints are categorised into four chargepoint archetypes as defined in the FES: • Domestic off-street • Workplace (including fleets) • Public slow and fast (up to 50kW) • Public rapid (including eHGV chargepoints)
EV chargepoint energy consumption	Regen's transport model includes assumptions on the proportional distribution of electricity demand by EV chargepoint archetype, based on stakeholder and DNO engagement in the delivery of DFES studies. These assumptions are summarised in Table 7.
Average EV chargepoint utilisation	Regen's transport model includes assumptions on the projected average annual utilisation rate of individual EV chargepoint archetypes based on stakeholder and DNO engagement in the delivery of DFES studies. These assumptions are summarised in Table 7.
Voltage tiers	Voltage tiers are allocated as documented in Table 8.

2.2.2. Approach and capacity projection methodology

Regen's DFES transport model estimates EV chargepoint capacity for each chargepoint archetype to meet the overall EV growth scenario and subsequent electricity demand.

The model takes two approaches:

1. **Non-domestic chargepoints:** The ESO's 2023 FES projections of EV uptake and subsequent electricity consumption are converted to EV chargepoint capacity based on assumptions of annual average EV chargepoint utilisation trends (capacity factor), split by vehicle and EV chargepoint archetypes. These assumptions have been derived for Regen's DFES studies from stakeholder engagement and DNO feedback.
2. **Domestic off-street chargepoints:** Domestic EV chargepoint uptake is modelled based on EV uptake in households with off-street parking. It is assumed most households with an EV and available off-street parking install an EV chargepoint (84% of EV drivers, including those without a driveway, have access to a chargepoint according to ZapMap survey[8]).

Table 6: EV chargepoint capacity formula.

Summarised formula to estimate non-domestic EV chargepoint capacity in the Regen transport model
$EV\,charger\ capacity\ (GW) = \dfrac{\begin{bmatrix} FES\ Consumer\ Transformation \\ annual\ EV\ energy\ consumption (GWh) \end{bmatrix} \times \begin{bmatrix} Proportion\ of\ annual\ EV\ energy \\ allocated\ to\ EV\ charger\ (\%) \end{bmatrix}}{[24 \times 365\ (hours)] \times [Utilisation\ rate\ (\%)]}$ Note: these variables vary by EV archetype, EV chargepoint archetype and over time.

[8] ZapMap EV Charging Survey, ZapMap, 2022

2.2.3. Electricity consumption projections by electric vehicle archetype

For this study, Regen's DFES transport model uses the ESO's 2023 FES transport electricity consumption by EV archetype and over time. Each vehicle archetype's electricity consumption was then distributed to EV chargepoint archetypes. This is illustrated in Figure 1 below.

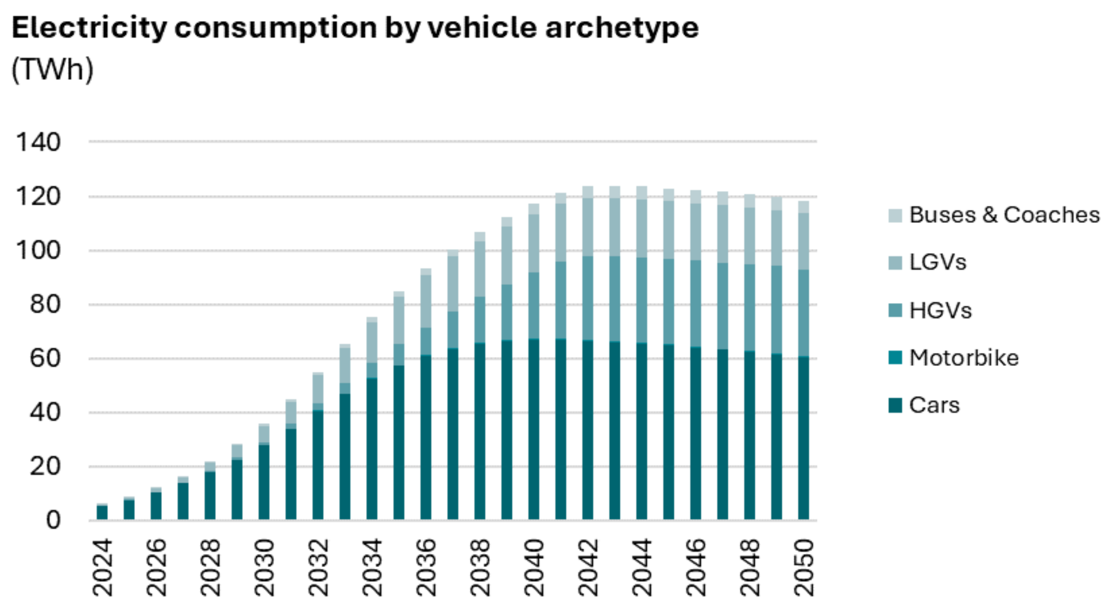


Figure 1: Annual road transport electricity consumption by vehicle archetype from the ESO's 2023 FES Consumer Transformation scenario

2.2.4. Electricity consumption by chargepoint archetype

Regen's DFES transport model estimates EV chargepoint capacity by allocating an assumed annual utilisation rate to each EV chargepoint archetype's estimated annual electricity consumption. The formula for this is presented and described in section 2.2.2. Figure 2 and Figure 3 illustrate the estimated electricity consumption at each EV chargepoint archetype. Table 7 summarises the assumed utilisation rates in 2050.

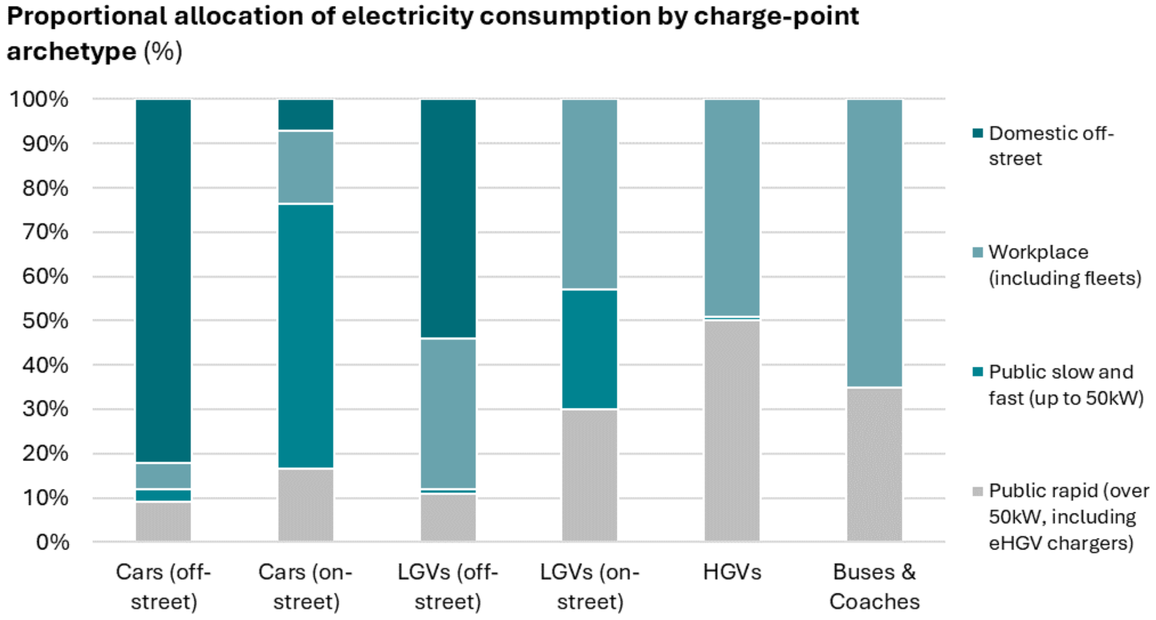


Figure 2: Regen transport model example of the annual proportion of EV energy consumption associated with each EV chargepoint archetype (applied to Consumer Transformation, 2050)

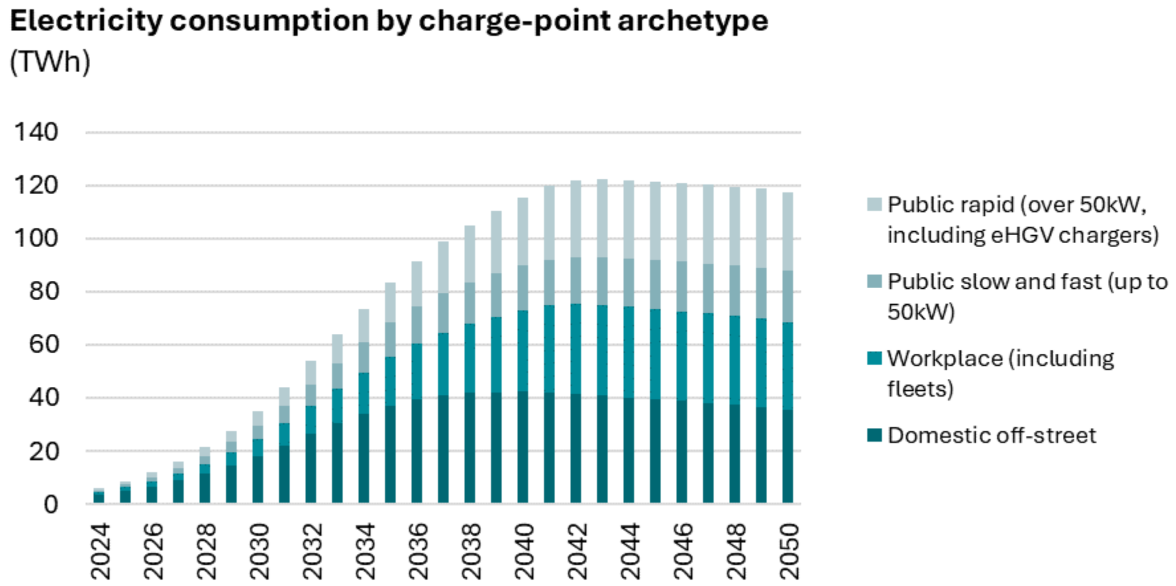


Figure 3: Road transport electricity consumption by EV chargepoint archetype from Regen's DFES transport model, based on the ESO's 2023 FES Consumer Transformation road transport electricity consumption

Table 7: Regen transport model average annual EV chargepoint utilisation rates for the Consumer Transformation scenario

Subtechnology	Utilisation rate	2021	2025	2030	2035	2040	2045	2050
Domestic off-street	N/A	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Workplace (including fleets)	Assumed medium utilisation	12%	15%	20%	25%	30%	32%	31%
Public slow and fast (up to 50kW)	Assumed low utilisation	7%	9%	12%	15%	18%	20%	20%
Public rapid (over 50kW, including eHGV chargepoints)	Assumed high utilisation	13%	16%	22%	29%	37%	41%	41%

2.2.5. Results: Projections of chargepoint capacity

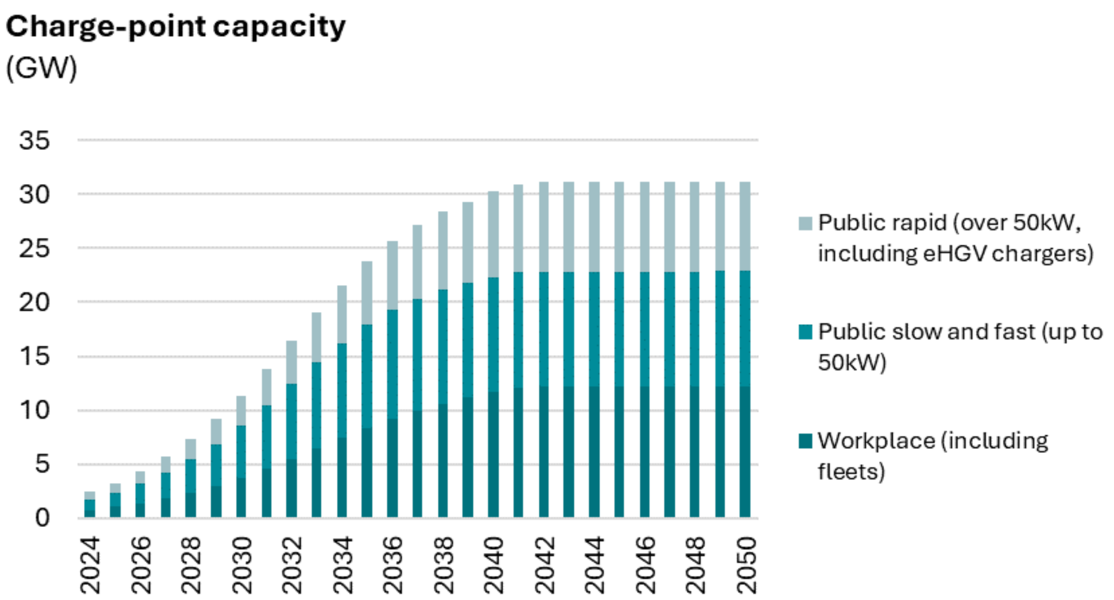


Figure 4: EV chargepoint grid-facing capacity for non-domestic EV chargepoint archetypes from Regen's DFES transport model

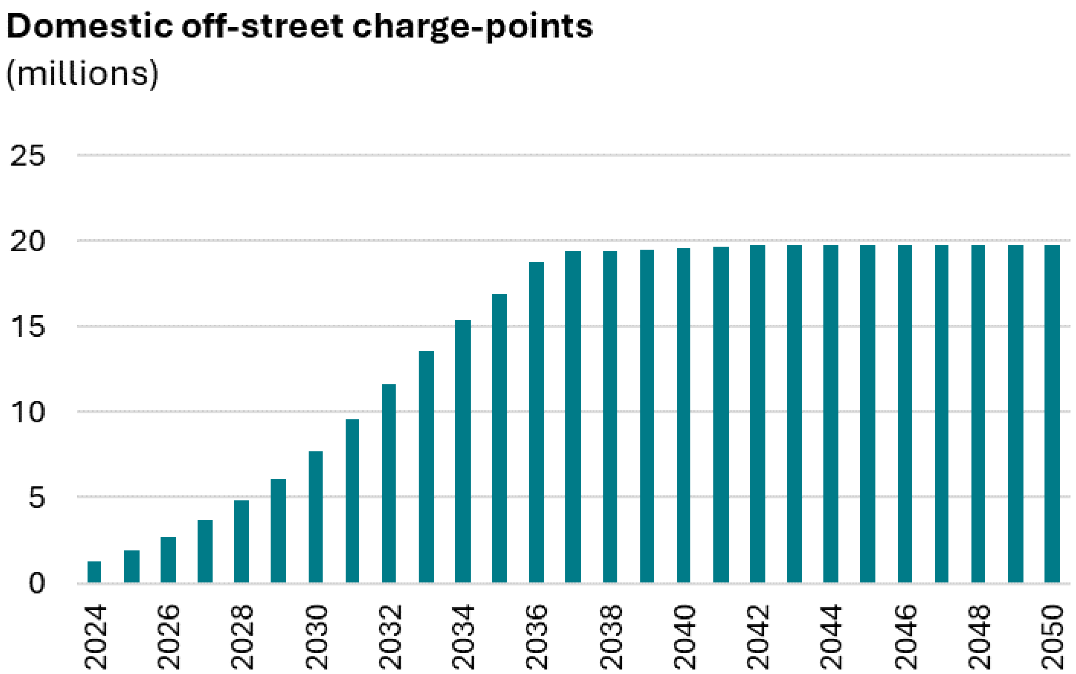


Figure 5: Domestic off-street EV chargepoints from Regen's DFES transport model. Each chargepoint has a capacity of 7.36 kW.

2.2.6. Voltage tier capacity allocation

Table 8: EV chargepoint voltage tier allocation

Technology	LV	HV	Notes
Domestic off-street	✓		In practice, all domestic chargepoints connect at LV level.
Workplace (including fleets)	✓		In reality, some fleet/depot chargepoints will have sufficient capacity to warrant a connection at HV level. Assuming all chargepoints of this archetype connect at LV is a conservative simplification.
Public slow and fast (up to 50kW)	✓		In reality, some public chargepoints under 50kW will connect at HV. Assuming all chargepoints of this archetype connect at LV is a conservative simplification.
Public rapid (over 50kW, including eHGV chargepoints)		✓	For public rapid chargepoints (50kW+), the capacity is assumed to connect at HV. This assumption has been made to conservatively model the upper range of network impact. In reality, some chargepoints will connect at EHV, 132kV or even transmission-level sites (depending on the availability of local grid infrastructure). The proportion of capacity connecting at each tier is highly uncertain. DNOs do not publish their pipelines for demand (as they do for generation). The impact of this assumption is that the modelled HV impact will be higher than in reality.

2.2.7. Comparison with other evidence

Baseline comparison: the projections of public chargepoint capacity from this analysis for the end of 2024 are in broad agreement with data published by ZapMap[9]. The source data is shown in Table 9 and a comparison is shown in Table 10.

[9] EV charging statistics 2024, ZapMap, July 2024

Table 9: Public chargepoint data from ZapMap, accurate to July 2024.

Capacity	Number of chargepoints	Assumed capacity per chargepoint (kW)	Approximate installed capacity (MW)
Less than 8 kW	39,424	7.36	290
8 to 49 kW	14,251	22	314
50 to 149 kW	7,373	100	737
Over 150 kW	5,721	150	858

Table 10: Public chargepoint capacity derived in this analysis compared with approximate capacity derived from ZapMap data.

Chargepoint archetype	Capacity projection for end of 2024 (MW)	Approximate capacity derived from ZapMap data in **Table** 9 (MW)
Public slow and fast (up to 50kW)	966	604
Public rapid (over 50kW, including eHGV chargers)	684	1,595

Projection comparison: to Regen's knowledge, this is the first time that GB-wide projections of EV chargepoint capacity have been developed and so there are no existing capacity projections to compare to.

The EU's Alternative Fuelling Infrastructure Regulation (AFIR) requires 1.3 kW of publicly available charging infrastructure per battery electric car or van (and 0.8 kW per plug-in hybrid car or van).[10] As shown in the comparison in Table 11 below, this requirement would represent greater capacity than projected in this analysis.

[10] Alternative Fuels Infrastructure Regulation, April 2024

Table 11: Comparison of EU AFIR requirements applied to GB against projections developed in this analysis.

	2024	2030	2035	2040	2045	2050
EU requirement for cars and vans applied to FES Consumer Transformation electric vehicle uptake (GW)	3.0	17.8	39.4	47.2	47.2	47.2
Projections of public chargepoint capacity in this analysis for all vehicle archetypes (GW)	1.7	7.7	15.4	18.6	19.0	19.0

2.3. Heat

2.3.1. Heat summary

The decarbonisation of heat by 2050 is anticipated to be one of the main sources of additional electricity demand on Great Britain's electricity system. Almost 90% of the nation's homes are currently heated by some form of fossil fuel, and a significant proportion of these will need to electrify to achieve net zero. [11]

This analysis tests the impact of heat electrification on distribution network infrastructure by analysing multiple potential heat technology uptake scenarios, alongside the potential for renewable heat to act as a source of demand-side response.

The low-carbon heat technologies considered in this analysis included:

- Domestic air-source heat pumps (ASHP)
- Domestic ground-source heat pumps (GSHP)
- Non-domestic heat pumps
- Electric resistive heating
- Electric storage heating
- District heat networks

The network impacts of each technology are tested using EA Technology's Transform model in WP2. Three heat uptake scenarios vary the rate of heating technology uptakes and the overall technology mix. All scenarios used are derived from external published sources, as described in

[11] Census 2021 Table TS046 (Central Heating), Office of National Statistics, Accessed via Nomis, June 2024

Section 2.1.1, and achieve full heat decarbonisation by 2050. FES Consumer Transformation is used as the baseline heat uptake scenario, as is the case with other technologies. As in FES, total heating technology counts reconcile to the total building stock (for domestic and non-domestic sectors), meaning an implicit assumption of one heating unit per building.

2.3.2. Heat scenario definition

Three heat technology uptake scenarios are used in this analysis:

1. **FES Consumer Transformation:** Consumer Transformation scenario from the ESO Future Energy Scenarios 2023
2. **Delayed Heat pump Uptake**: a modified version of the FES 2023 Consumer Transformation scenario
3. **Lower Heat Pump Uptake:** High Heat Pump scenario from Aurora Energy's analysis for the Second National Infrastructure Assessment (NIA2)

These are described in more detail in this subsection. Figure 6 shows the relative percentage uptake of heat pumps in the nation's building stock under the three scenarios.

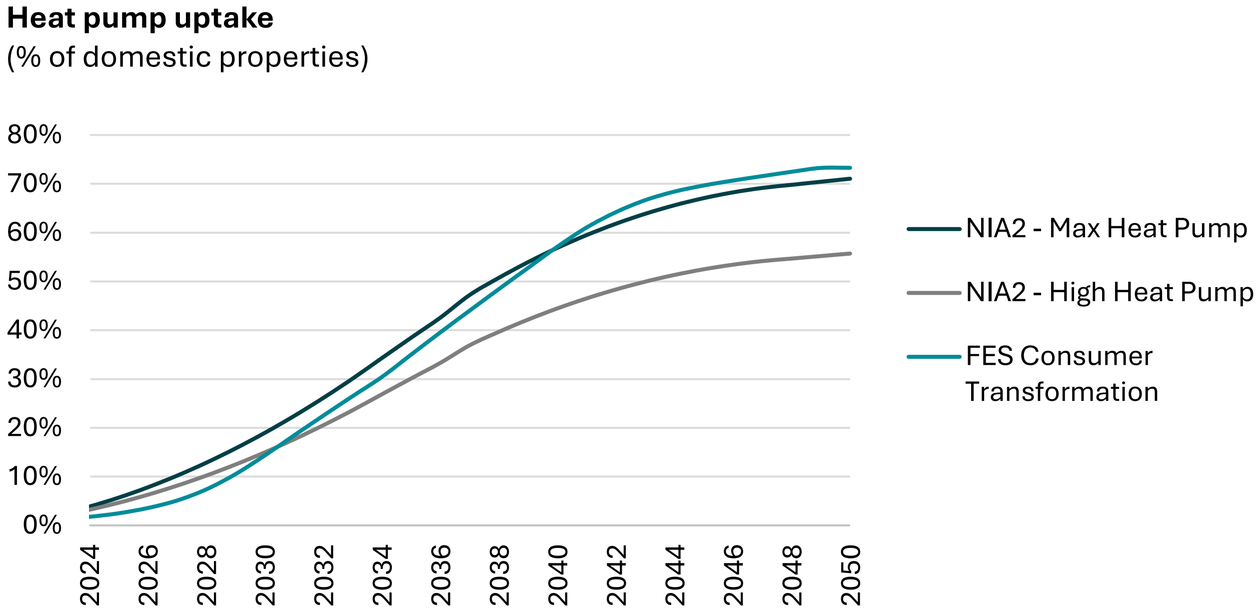


Figure 6: Comparison of heat pump uptake in FES Consumer Transformation, NIA2 Max Heat Pump and NIA2 High Heat Pump

The 'High Heat Pump' scenario from Aurora Energy's analysis for NIA2 is used in the sensitivity analysis rather than the more ambitious 'Max Heat Pump' scenario for the following reasons:

- FES 2023 Consumer Transformation and the NIA2 'Max Heat Pump' scenario follow very similar trajectories in percentage uptake terms.[12] As such, the ambition of the NIA2 analysis is broadly represented by the Consumer Transformation scenario, which acts as the baseline for heat pump uptake in this study.
- NIA2 'High Heat Pump' still represents an ambitious, net zero compliant heat pump uptake scenario but with a lower overall final proportion of heat pumps in 2050 than Consumer Transformation.
- In both NIA2 scenarios, the major alternative technology is direct electric heating, while FES favours district heat uptake.

Therefore, the use of NIA2 'High Heat Pump' as a sensitivity case investigates the impacts of achieving heat electrification but with greater reliance on less efficient heating technology (direct electric heating) when compared with Consumer Transformation. The intention of the sensitivity is to understand the impact of reduced heat pump uptake relative to Consumer Transformation, not the relative impacts of district heat and direct electric heating – use of 'Max Heat Pump' would not achieve this.

Table 12: Heat scenario definition

Scenario	Scenario Description
FES Consumer Transformation Heat pump uptake relative to other scenarios: High Source: ESO Future Energy Scenarios, Consumer Transformation scenario	For this scenario, the uptake of all sources of electrical heat demand is sourced from the Consumer Transformation scenario as standard. Consumer Transformation represents a high-ambition, high-electrification 'scenario world' in which electricity delivers almost all heat demands by 2050. This provides a reasonable basis for assessing the high levels of demand growth that may be experienced by distribution networks due to heat decarbonisation.
Delayed Heat Pump Uptake Heat pump uptake relative to other scenarios: Delayed, but reaches the same level as Consumer Transformation by 2050	This heat uptake scenario is a modification of FES Consumer Transformation, in which the 2050 end state is unchanged but the path to system decarbonisation is slightly different. Relative to Consumer Transformation, heat pump uptake is delayed, with uptake replaced by district heat connections. District heat electrical loads will connect to the HV network, displacing a high volume of LV-connected heat pumps in clustered regions.

[12] This is significant because the NIA2 analysis covers England only, and so scaled trends are required for Great Britain level analysis.

Scenario	Scenario Description
Source: FES 2023 Consumer Transformation, modified by Regen for this analysis	This minor modification to Consumer Transformation enables a reasonable sensitivity analysis of delayed heat pump uptake due to policy decisions, which may lead to an increase in local centralised heat delivery infrastructure, such as district heat, while still arriving at a fully decarbonised building stock in 2050 in compliance with net zero targets. Technology types in the 'Delayed Heat Pump Uptake' scenario remain consistent with Consumer Transformation. Key assumptions used in its development (i.e. modification of Consumer Transformation) are described in detail below.
Lower Heat Pump Uptake Heat pump uptake relative to other scenarios: Central Source: Second National Infrastructure Assessment (NIA2) – 'High Heat Pump' scenario (Aurora Energy)	This scenario comes from data produced by Aurora Energy as evidence for the National Infrastructure Commission's second National Infrastructure Assessment (Energy Sector Modelling, Project B – Decarbonising Heating Systems: evidence and options).[13] The 'High Heat Pump' scenario represents a future with rapid heat decarbonisation, with significant electrification. More consumers use direct electric heating than in Consumer Transformation. Full heating stock electrification is achieved by 2050 and the scenario is compliant with legally binding net zero targets. Assumptions used by Aurora Energy throughout their heat analysis are consistent with those used by the Committee on Climate Change during the creation of scenarios for the Sixth Carbon Budget.[13] Note that the data developed by Aurora Energy covers England only, as building stock policy is a devolved issue and, therefore, does not fall under the remit of the NIC outside England. To enable a comparison between the NIA2 scenario and FES, the relative breakdown of heating stock is applied to the total FES building stock for Great Britain. It is possible that differences in the building stock in Wales and Scotland may lead to a slightly different mix of heating technologies; however, this is not possible to deduce directly from the available data.

[13] Aurora Energy Systems modelling, Project B (Data and report) Aurora Energy for National Infrastructure Commission, 2023

Scenario development approach for ‘Delayed Heat Pump Uptake’ scenario

Relative to Consumer Transformation, heat pump uptake has been replaced by district heat connections in the ‘Delayed Heat Pump Uptake’ scenario, used for sensitivity analysis. Heat network expansion and development see a rapid increase sooner rather than the rapid growth seen in the mid-2030s under the unmodified Consumer Transformation scenario.

This is possible under a near-term policy environment which does not support heat pump adoption for individual homeowners, but which does prioritise and accelerate the development of heat networks.

The difference in heat pumps between Consumer Transformation and the Delayed Uptake scenario peaks in the mid-2030s at around 1.6 million units (see Figure 10 in section 2.3.3). This amounts to an approximate doubling of heat network uptake connections, which is considered to be a reasonable upper limit when modifying an already ambitious scenario.

The methodology used to modify the Consumer Transformation and create the Delayed Heat Pump Uptake scenario is as follows:

- Heat network and heat pump uptake until 2026 remains unchanged from Consumer Transformation.
- Heat network connection growth in Consumer Transformation sees a significant increase in rate around 2035. In the ‘Delayed Heat Pump Uptake’ scenario, this level of heat network uptake seen from 2035 has been brought forward by 5 years to 2030.
- To smooth the uptake curve, quadratic interpolation has been used between the 2026 value and the new 2030 value.
- The same gradient is kept from 2030 until the maximum market penetration seen in Consumer Transformation (18.9%) is reached. This occurs by 2046 instead of 2050.
- Subsequent growth in heat network connections is in line with building stock growth, but does not exceed the percentage level of Consumer Transformation.
- This process creates a heat network trend with an identical uptake gradient to that modelled in the FES, but brought forwards by five years.
- As discussed above, the additional heat network connections each year are offset by removing units from the heat pump trend, so that the total number of heat systems is unchanged.
- All heating system uptakes besides district heat and heat pumps are unaltered from Consumer Transformation.

The Delayed Uptake scenario also has an identical 2050 end state to Consumer Transformation. This analysis has only altered the uptake rates of electrified low-carbon technologies, meaning the scenario still complies with net zero by 2050.

It is assumed that all new heat network connections in this scenario are powered by electricity. This assumption is supported by FES scenarios, the Aurora Energy analysis for the 'High Heat Pump' scenario and the Committee on Climate Change’s Sixth Carbon Budget Dataset, which indicates that future heat network growth will be electrified (see Figure 13).[2,13,14] While no emissions analysis is conducted for this scenario, heat pumps are being replaced by other forms of electrified heat. Large-scale electrified heat networks are likely to be operated by heat pumps, leading to similar or lower energy consumption due to the efficiency of large systems, particularly GSHPs. Consequently, the emissions pathway in this scenario is likely still aligned with the Sixth Carbon Budget targets, despite potential differences from the FES Consumer Transformation report.

A system benefit of heat networks is their potential to locally reduce electricity network congestion by displacing individual electrified heating systems. Therefore, for the sensitivity analysis in WP2, it is assumed that all additional heat network connections will connect at HV. Whilst this is a simplification, it acts as a useful way to investigate the sensitivity of the network to clusters of lower sustained heat pump uptake at LV, relative to Consumer Transformation.

2.3.3. Heat pumps

Heat Pump subtechnologies

The ESO's 2023 FES provides projected uptake trends for a variety of heat pump types. These have been simplified for the purposes of the distribution network analysis for the NIC, as described in Table 13.

Table 13: FES heat pump types mapped to simplified subtechnologies for this analysis

Heat pump subtechnology (FES)	**Heat pump subtechnology used in this analysis**	**Detail**
Domestic ASHP	Domestic ASHP	-
Domestic GSHP	Domestic GSHP	-
Domestic hybrid (ASHP + electric resistive)	Domestic ASHP	The majority of hybrid heat pumps in Consumer Transformation are of this type. Since all heat demand for these systems is delivered by electricity, considering them as standard ASHPs does little to impact the total electricity requirement. It is worth noting that, in reality, the overall efficiency of such a heating system would be

[14] Sixth Carbon Budget supporting data ('Buildings Additional Data'), Committee on Climate Change, December 2020

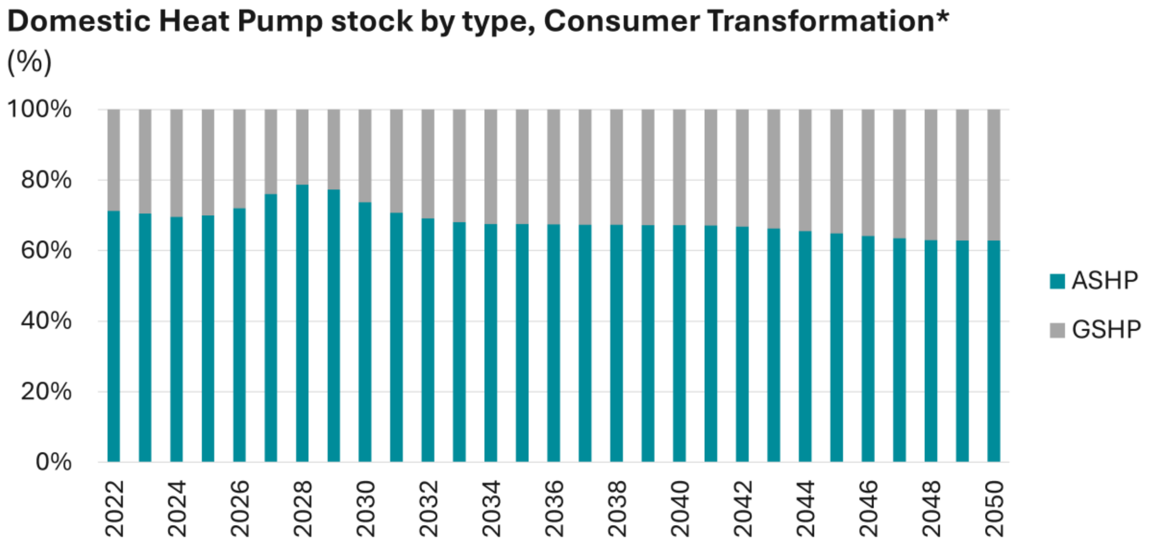
Heat pump subtechnology (FES)	Heat pump subtechnology used in this analysis	Detail
		lower than that of a non-hybrid ASHP due to the provision of a portion of the system's heat from a direct electric boiler. However, the impact of this inefficiency is captured in the range of the sensitivity analysis via the NIA2 'High Heat Pump' scenario (see Table 12), which includes a significantly higher share of direct electric resistive heating systems than Consumer Transformation. Direct electric systems are significantly less efficient than ASHPs, as their efficiency cannot exceed 100%. Therefore, they are also less efficient than hybrid systems, which use heat pumps and electric resistive boilers. As such, the peak demand growth seen in the NIA2 'High Heat Pump' scenario is likely to exceed that of Consumer Transformation, even with hybrid systems explicitly modelled.
Domestic hybrid (ASHP + hydrogen boiler)	-	Consumer Transformation contains no hydrogen-backed hybrid heat pumps.
Domestic hybrid (ASHP + biofuel boiler)	Domestic ASHP	Though present in Consumer Transformation, these hold a minor overall share of the technology mix throughout the scenario (market share peaks at 1.6% in 2050). Therefore, the materiality of including these heat pumps is deemed to be low.
Non-domestic ASHP	Non-domestic	The total quantity of non-domestic heat pumps of all types in FES is dwarfed by domestic heat pumps (Consumer Transformation projects c.960,000 non-domestic heat pumps in total by 2050 and c.23.8m domestic heat pumps).
Non-domestic GSHP		
Non-domestic hybrid (ASHP + electric resistive)	Non-domestic	

Heat pump subtechnology (FES)	Heat pump subtechnology used in this analysis	Detail
Non- domestic hybrid (ASHP + biofuel boiler)	Non-domestic	As such, all types of non-domestic heat pumps have been grouped together for simplicity, as the materiality of the split is likely to be minor in relation to the impact of domestic heat pumps.
Non-domestic hybrid (ASHP + hydrogen boiler)	-	Consumer Transformation contains no hydrogen-backed hybrid heat pumps.

Meanwhile, Aurora Energy's NIA2 heat pump analysis provides data on the following categories of heat pumps.[13] Assumptions based on FES data have been used to arrive at a set of heat pump categories that are aligned between scenarios.

Table 14: NIA2 Heat Pump types and assumptions in this analysis

Heat pump archetype (NIA2)	Heat pump archetype used in this analysis	Reasoning/methodology
Domestic	Domestic ASHP and Domestic GSHP	The split between air-source and ground-source systems is based on their respective shares of total heat pumps seen in FES Consumer Transformation. The split is plotted below in Figure 7.
Non-domestic	Non-domestic	As discussed in Table 13, non-domestic heat pumps are not split by system type in this analysis.

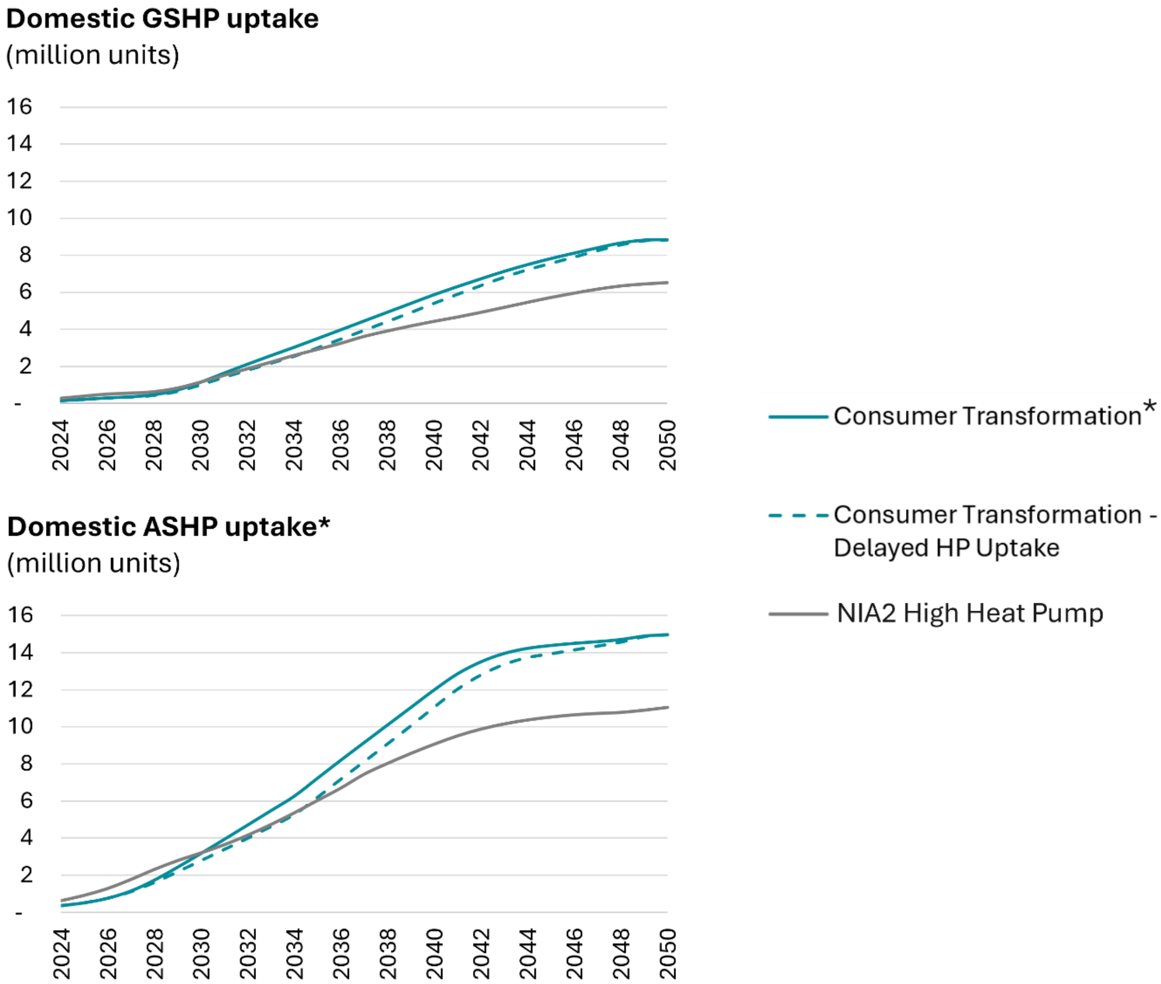


* **Note:** FES Consumer Transformation data has been simplified here, with hybrid heat pumps counted as ASHP as described above. The majority of hybrid heat pumps in FES Consumer Transformation are electrically backed, making this a reasonable approximation in terms of electrical load.

Figure 7: Domestic heat pump stock breakdown between air source and ground source systems. Note that hybrids have been aggregated with ASHPs, as described in Table 13.

Heat pump scenario comparison

The comparative uptake of domestic ASHPs and GSHPs is shown below in Figure 8. Figure 9 shows the level of non-domestic heat pump uptake in the three scenarios. All types of non-domestic heat pumps present in FES data (ASHP, GSHP and hybrids) are aggregated together.



* **Note:** The number of ASHPs displayed for Consumer Transformation is an aggregation of ASHP and hybrid heat pump units in the original FES data, as described.

Figure 8: Domestic heat pump uptake scenarios. Top: Ground-source heat pumps; Bottom: Air-source heat pumps

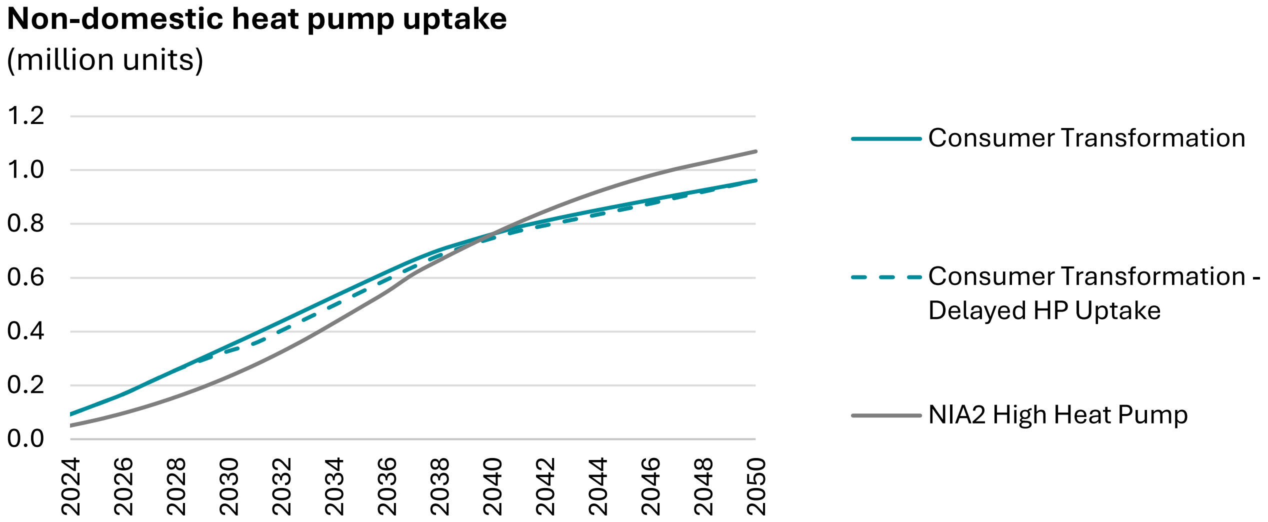


Figure 9: Non-domestic heat pump uptake (all types).

Figure 10 shows the difference in heat pump uptake between Consumer Transformation and the Delayed Uptake scenario. The difference varies through time, with over one million fewer heat pumps in the Delayed Uptake scenario each year from 2032 to 2042. This reduction in uptake first kicks in after 2026, with the same total number of heat pumps reached by 2050. The difference is made up of electrified district heat connections, as described in Section 2.3.2.

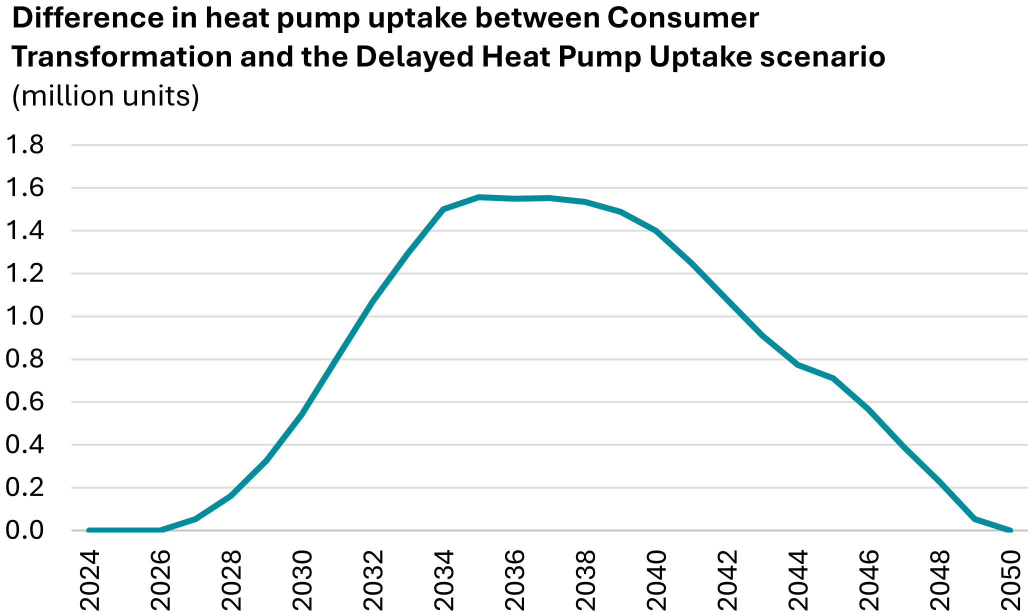
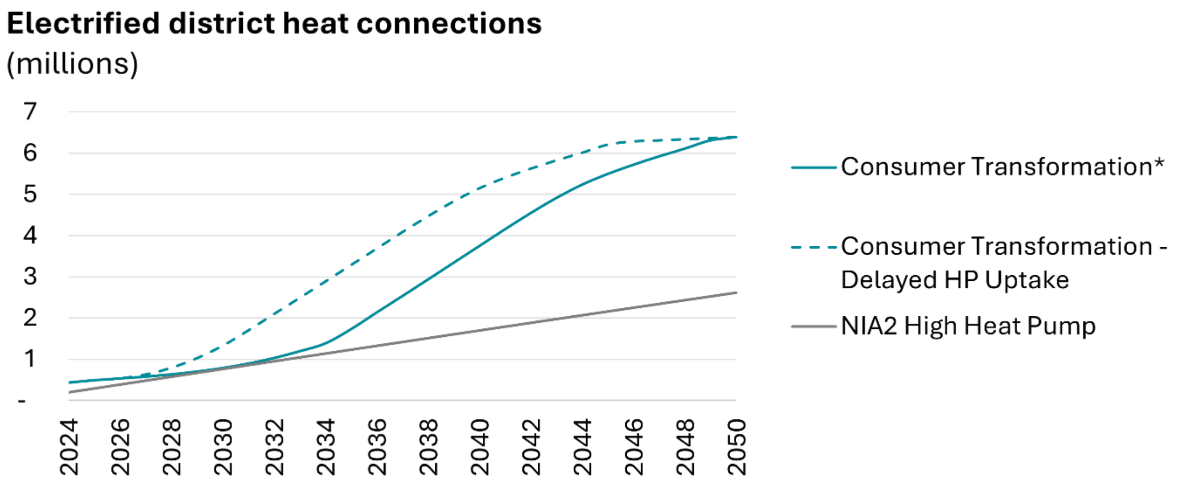


Figure 10: Difference in heat pump uptake (all types of heat pumps) between the FES Consumer Transformation scenario and the Delayed Heat Pump Uptake scenario.

2.3.4. District heat networks

Summary

Figure 11 shows the uptake of electrified district heat across domestic and non-domestic buildings in the three scenarios. The additional heat network connections seen in the 'Delayed Heat Pump Uptake' scenario relative to Consumer Transformation are equal to the heat pumps removed (see Figure 10 above).



* **Note:** The number of electrified district heat connections displayed for Consumer Transformation here is not directly from FES, but is a combination of FES district heat totals and the fuel mix from Aurora Energy's NIA2 analysis, as described above.

Figure 11: Electrified district heat network connections (domestic and non-domestic)

District heat networks (also known as district heating or heat networks) supply heat from a central source to consumers, avoiding the need for individual boilers or electric heaters in every building. Uptake varies significantly between sources. As described in Table 12, the NIA2 'High Heat Pump' scenario has lower district heat uptake than Consumer Transformation, instead relying more heavily on direct electric heating as an alternative to heat pumps.

Voltage tier

As described in Section 2.3.2, electric heat networks are assumed to connect at HV level. Therefore, when adopted in favour of distributed electrified heat sources in this analysis, heat networks displace connected capacity from the LV network, which may lead to lower LV network impact.

Fuel mix

The fuel mix of heat networks is uncertain and varies between sources (FES[2], NIA2[13] and the Sixth Carbon Budget[14]); however, all are in agreement that future heat networks will primarily be electrically backed.

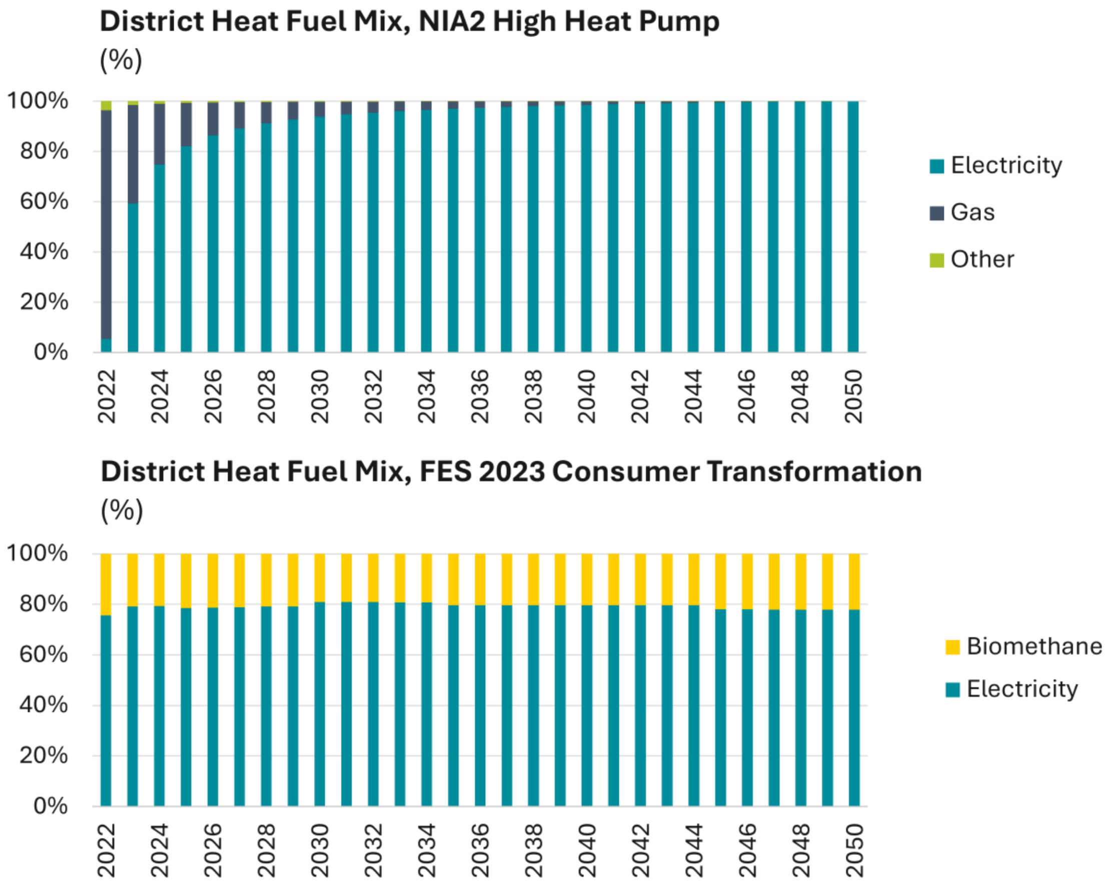


Figure 12: Breakdown of district heat fuel mix. Top: NIA2 'High Heat Pump' scenario; Bottom: FES 2023 Consumer Transformation.

Figure 12 compares the modelled fuel mix of district heat seen in the NIA2 'High Heat Pump' and FES Consumer Transformation scenarios. The Consumer Transformation figures are derived from Table ED3 of the FES dataset, which provides figures for annual energy use by district heat fuel source at a national level. [15] There are several important points to be noted:

- In FES Consumer Transformation, a high proportion of existing district heat connections are already electrified with the remaining energy coming from biomethane, which continues to 2050. Very little variation in the fuel mix is reported between 2022 and

[15] FES Data Workbook V003, Table ED3, ESO, July 2023

2050. This is not consistent with data seen elsewhere, such as from the second National Infrastructure Assessment or the Climate Change Committee's (CCC's) Sixth Carbon Budget.

- In NIA2 data, the majority (91%) of existing heat networks are gas powered, with a small number of electrically driven (5%) and 'other' (4%) heat networks. Growth is only seen for electrically driven heat networks in this scenario.

Therefore, NIA2 fuel splits are used to disaggregate the connections in Consumer Transformation (and by extension, the 'Delayed Heat Pump Uptake' scenario) as they are deemed more reliable than the data found in FES. The CCC's analysis shows that growth in heat networks results in increased electrification (shown in Figure 13), supporting this methodology decision.

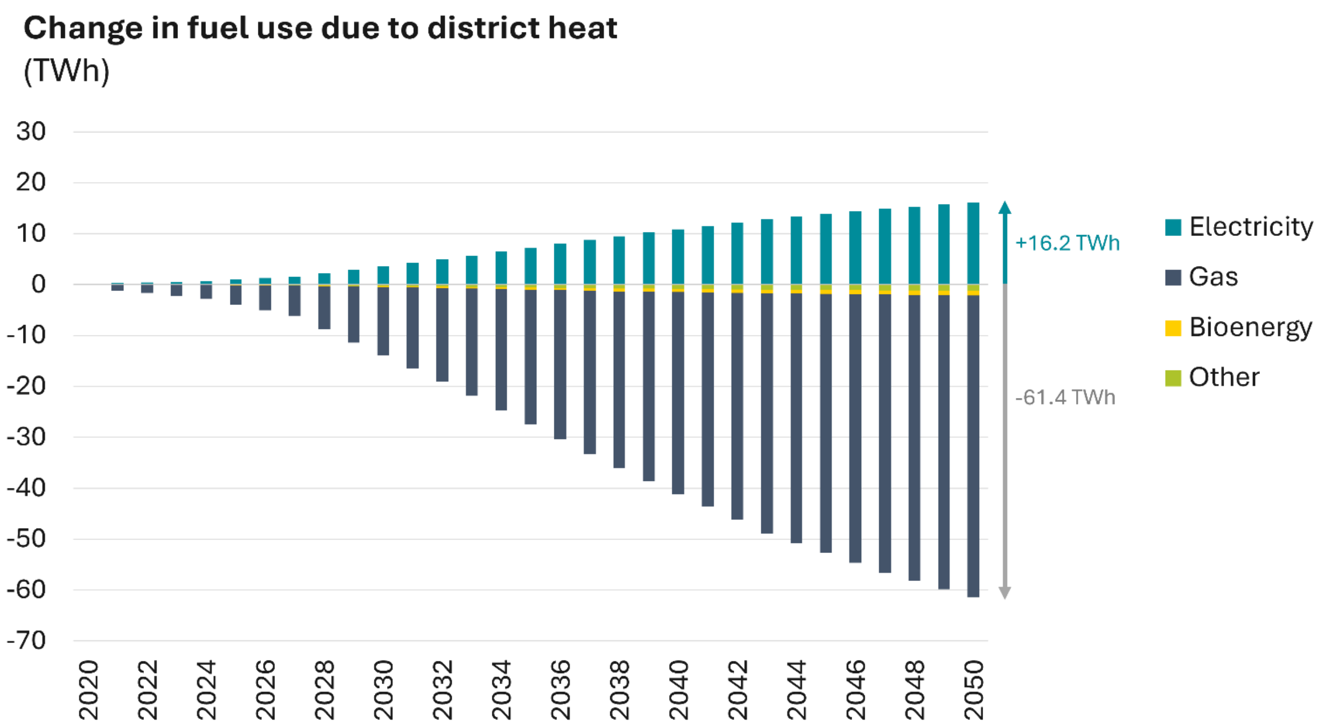


Figure 13: Change in energy use due to district heat by source (CCC's sixth Carbon Budget, Balanced Net Zero Pathway)

Baseline uptake

There is uncertainty around the baseline number of district heat connections. Table 15 shows significant variation between sources on the total number of district heat connections currently in operation.

Table 15: Total district heat connections reported in different sources

Source	Date	Number of district heat connections	Note
FES, Consumer Transformation[2]	2023	544,000	Base year = 2022 For Great Britain
NIA2 'High Heat Pump' scenario[13]	2023	68,000	Base year = 2022 England only
Census 2021 (Office of National Statistics (ONS)) [16]	2021	217,000	Year = 2021 England only for direct comparison with the NIA2 'High Heat Pump' scenario. *(The census does not cover Scotland, so a comparison with the FES figure for GB is not possible).*

In all scenarios, the heat network connections grow very significantly by 2050, reducing the overall impact of variations in the baseline. Nonetheless, baseline discrepancies between scenarios may impact results. However, the impact on results is unlikely to be significant because this analysis sources the fuel mix from NIA2 where a low proportion of total heat network connections are electrified in the base year.

[16] Census 2021, ONS

2.3.5. Direct electric heating

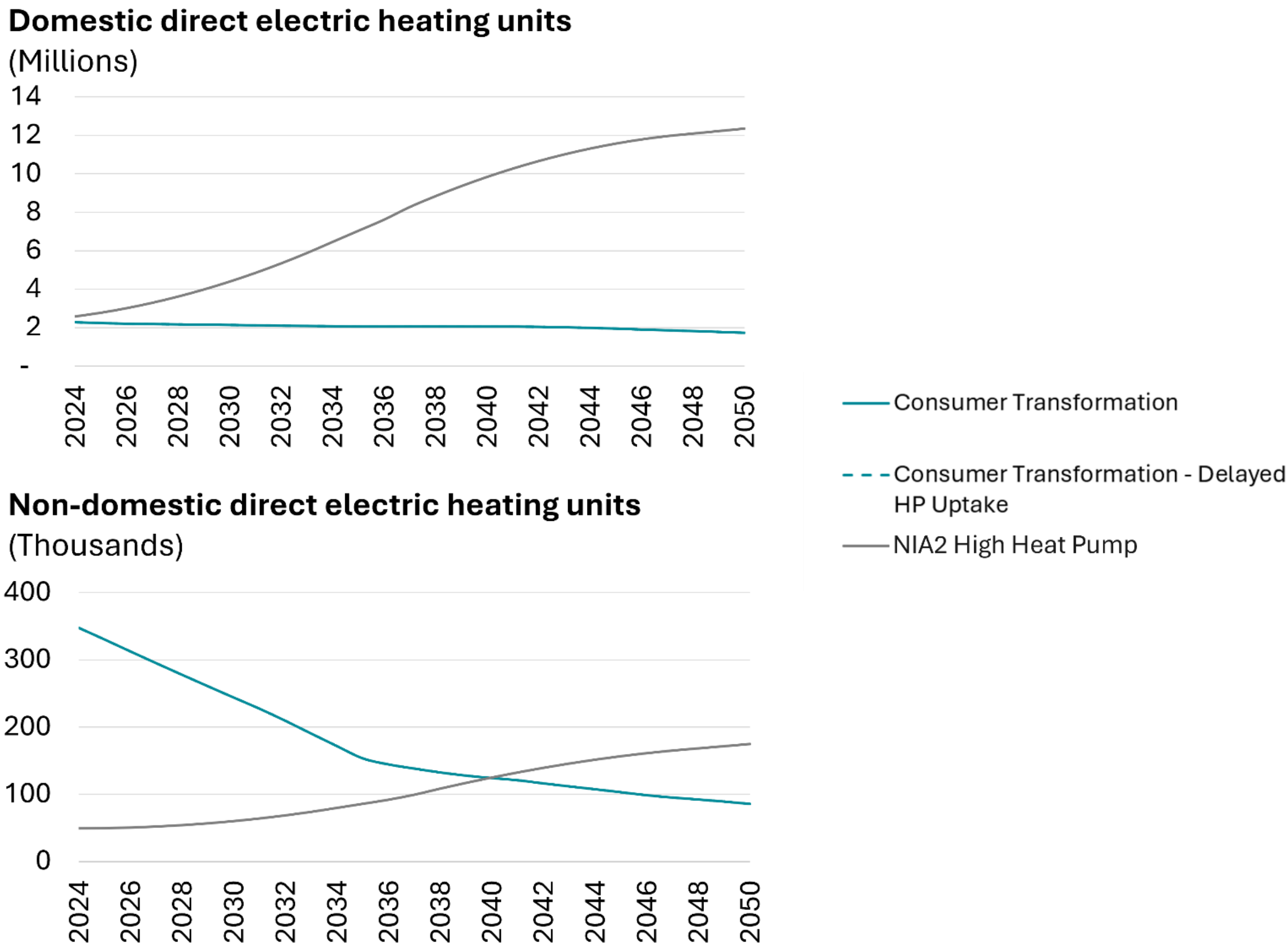
Direct electric heating refers to the use of electric boilers, electric resistive heaters and electric storage heaters to deliver heat to a building.

FES data provides uptake curves for electric resistive and electric storage heaters, while NIA2 provides data only for 'electric heating'. Aurora Energy's documentation of the NIA2 project suggests that this refers to electric resistive heating only, which is maintained as an assumption for this analysis.[13,17] It should be noted that this may lead to significant network impacts compared with the other scenarios for two reasons:

- The NIA2 'High Heat Pump' scenario used in this analysis assumes a lower penetration of heat pumps than Consumer Transformation. The shortfall in heat pumps is generally accounted for by additional electric resistive heaters, especially in space-constrained homes.
- The NIA2 'High Heat Pump' scenario has significantly more direct electric systems each year than Consumer Transformation. A high number of these are storage heaters in FES, which implies a degree of flexible demand due to heating the thermal store at non-peak times. The NIA2 'High Heat Pump' scenario lacks this diversity and it is likely that peak growth due to heat will be more pronounced under this scenario as a result.

The NIA2 'High Heat Pump' scenario is scaled up (as with all the other heat technologies, as described in Table 12) so that the total number of systems reconciles to the equivalent total from FES. Aside from this, the direct electric heating uptake forecasts are unmodified from the source. There is no difference between direct electric heating uptake seen in Consumer Transformation and the 'Delayed Heat Pump Uptake' scenario because the only technologies varied between the two are heat pumps and district heat. Meanwhile, the NIA2 'High Heat Pump' scenario does not include storage heating, as described above. Scenarios are shown below (in aggregate for domestic and non-domestic) in Figure 14.

[17] Decarbonising heating systems: evidence and options (B) - Energy sector modelling to support the second National Infrastructure Assessment, Aurora Energy for National Infrastructure Commission, 2023



Note: Figures shown are an aggregation of electric resistive and night storage heaters. Consumer Transformation (FES) and the Delayed HP Uptake scenario have equal direct electric heating uptake. There are no night storage heaters in the NIA2 High Heat Pump scenario.

Figure 14: Direct electric heating scenarios (electric resistive and night storage total). Top: domestic uptake; Bottom: non-domestic uptake

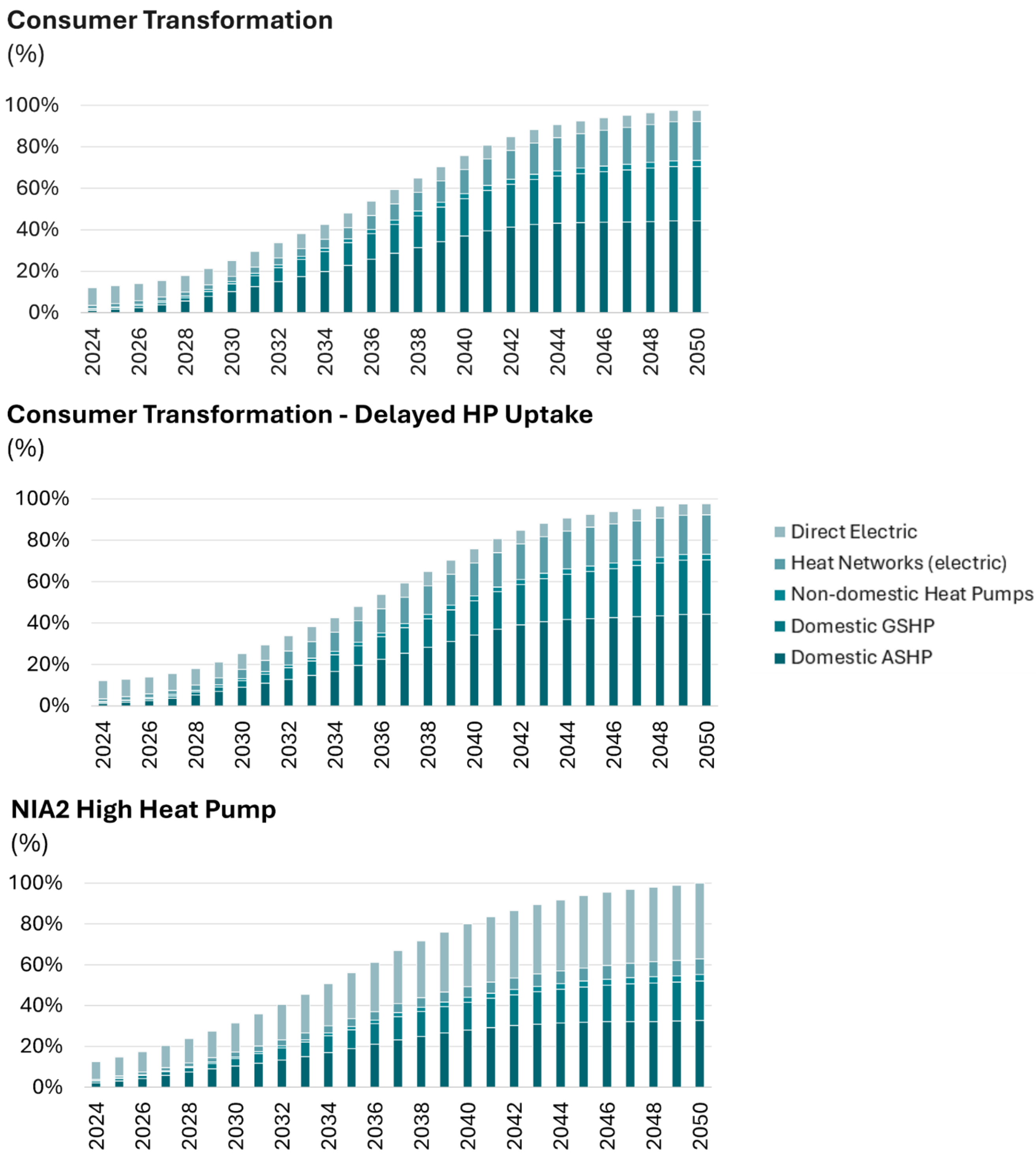
2.3.6. Overall heating technology mix

The heat scenarios also contain projections for the number of connections for non-electrified heat sources. These additional technologies are summarised in Table 16. For the purposes of this study, the behaviour and relative uptake of each of these is unimportant, as they will not derive energy from electricity networks. As such, the technologies below are aggregated into a single category in the dataset accompanying the project: 'Other (non-electrical)'. This enables a clear view of the overall level of heat electrification anticipated in each scenario in a given year.

Table 16: Non-electrical heat technologies included in the source datasets

Technology	FES	NIA2	Note
Gas boiler	✓	✓	-
Oil boiler	✓	✓	-
Biofuel boiler	✓		-
Biomass boiler	✓		-
Biomass CHP	✓		-
Community	✓		Large, multi-occupancy buildings fed by a single boiler/furnace that provides central heating and Domestic Hot Water (DHW). The majority of these are fed by fossil fuels, and Consumer Transformation predicts no growth, with almost all phased out by 2050. They represent a very small share of overall heating connections (peaking at 0.64% in 2022 and declining thereafter).
Hydrogen boiler	✓	✓	Both sources include hydrogen boilers as a technology category. However, in the scenarios used in this study, neither FES nor NIA2 model uptake.
District heat (gas)	✓	✓	FES building blocks contain aggregate district heat connection counts. As discussed in Section 2.3.4, NIA2 splits are used to disaggregate FES connections into electrically powered, gas powered and 'other' district heat networks.
District heat (other)	✓	✓	

Figure 15 shows the overall heating technology mix in the three scenarios used for this analysis. The small quantity of non-electrified heating systems in 2050 in the Consumer Transformation and 'Delayed Heat Pump Uptake' scenarios consist of a small number of gas boilers, biofuel boilers, biomass boilers & CHP, oil boilers and shared community systems. In total, this accounts for around 795,000 heating systems, of which 767,000 are low-carbon (biofuels and biomass). The NIA2 'High Heat Pump' scenario achieves 100% electrification in 2050.



Note: Modifications and simplifications have been made to the source data from FES and the 2nd National Infrastructure Assessment to arrive at the final scenarios shown here and used in the analysis. These are described throughout section 2.3. The remainder each year represents all types of non-electrified heating.

Figure 15: Overall heating technology breakdown in each scenario

2.4. Industrial and commercial

2.4.1. Industrial and commercial underlying demand

In this analysis, underlying demand refers to industrial and commercial electricity demand for appliances, lighting, computing etc. Demand growth in this sector is driven by increases in building stock, informed by data published under the FES 2023.[18] Underlying demand does not cover demand due to emergent low-carbon technologies, such as heat pumps – the demand for which is captured elsewhere with technology sector-specific assumptions.

EA Technology's Transform model, used in WP2, accepts voltage-level inputs for aggregated I&C underlying demand. Approximately 75% of the total I&C customer count is allocated to LV, and the remainder to HV. This assumption was developed by EA Technology during the Transform model's inception.[19]

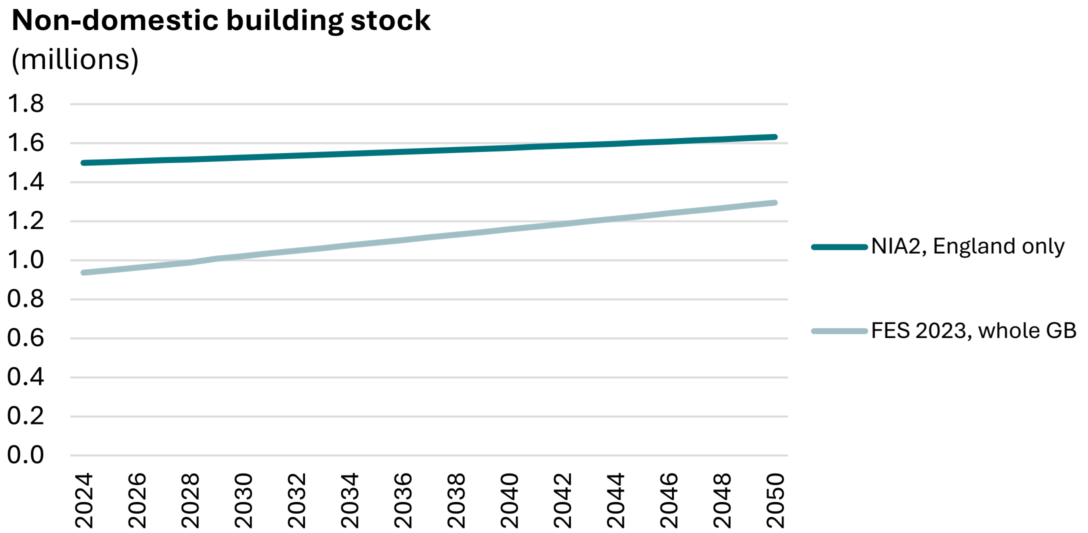


Figure 16 shows the total number of I&C buildings in Great Britain, taken from FES 2023 Consumer Transformation. It is compared to the non-domestic building stock trend (England only) developed by Aurora Energy for NIA2.

[18] Future Energy Scenarios, ESO, July 2023

[19] P172, Assessing the Impact of Low Carbon Technologies on Great Britain's Power Distribution Networks version 3.1, EA Technology for Energy Networks Association ,July 2012

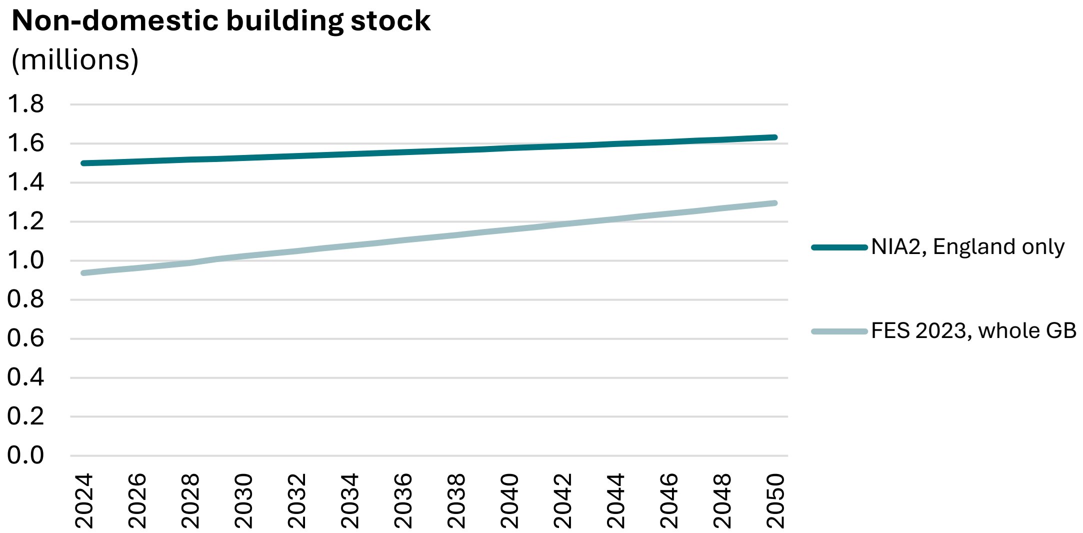


Figure 16: I&C Building growth projection

The existing numbers of non-domestic customers are lower in the FES than stated in the Non-Domestic National Energy Efficiency Data Framework (ND-NEED), which states 1.76 million non-domestic buildings in England and Wales (not including Scotland) in 2022.[20] Similarly, building stock in the FES is significantly lower than in the Aurora Energy modelling for NIA2. However, the FES building stock trend is used in the analysis to ensure consistency with other technology uptake data, particularly heat technologies, which reconcile to FES building totals.

Comparing FES peak demands with the low building stock numbers implies a high peak demand per non-domestic connection (see section 3.4.1). As such, and in order to retain building counts from FES for the reasons described above, non-domestic loads in Transform have been calibrated such that the overall industrial and commercial underlying peak demand is equal to that reported in FES Consumer Transformation in the base year.

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[20] Non-Domestic National Energy Efficiency Data Framework, DESNZ, 2022

2.4.2. Hydrogen Electrolysis

Hydrogen is currently produced at scale via the reformation of fossil gas with carbon dioxide released into the atmosphere. In the future, hydrogen will be produced either via electrolysis, where water is split into component molecules of hydrogen and oxygen using electricity, or via the reformation of fossil gas with carbon capture and storage. The deployment of hydrogen electrolysis is a potentially disruptive source of electricity demand on the electricity distribution network.

Projections of installed capacity

Table 17: Electrolyser capacity assumptions

Assumption	Detail
FES input scenario	Electrolyser capacity is sourced from ESO's FES 2023 Consumer Transformation scenario.[21] The FES Consumer Transformation scenario assumes a future with higher fuel consumption switching from fossil fuels to electrification and targeted use of hydrogen in some sectors. Significant variance exists between different FES scenarios, reflecting the level of uncertainty in this emerging sector.
Scenario-specific hydrogen demand assumptions	In the medium term, shipping, power generation, and industrial activity are all significant hydrogen demand sectors. In the long term, shipping demand will grow to become the largest sector and a small amount of demand will come from aviation, in addition to power generation and industry. Hydrogen is not used for space heating.
Scenario-specific hydrogen supply assumptions	Hydrogen production and demand are matched at a regional level because hydrogen distribution networks are assumed to be less developed. The FES does not publish which technologies (distribution electrolysis, transmission electrolysis, steam reformation etc.) supply each demand sector.
Data post-processing	The FES projections imply a reduction in electrolyser capacity on the distribution network from 2025 to 2026. This is highly unlikely because very few electrolysers have reached end of life. The data was processed such that capacity could not reduce year on year.
Voltage tiers	Electrolysers could connect at HV, EHV or 132kV voltage tiers depending on their project capacity. As there are currently relatively few distribution-connected electrolysis projects, and these projects are typically smaller pilot projects, there is little evidence available to reliably estimate how

[21] Future Energy Scenarios, ESO, July 2023

	much capacity will connect at each tier. Therefore, for this analysis, electrolysers are assumed to connect at the HV level (voltage tiers are defined in Table 3 summarises the definitions of voltage tiers used throughout this study. Voltage tiers above EHV are not considered in the analysis. Table 3). Common electrolyser capacities are over 1 to 10 MW, too large for LV.[22] This assumption has the impact of overestimating the HV network impact of electrolysers because, in reality, some plants will connect at EHV or 132kV level.

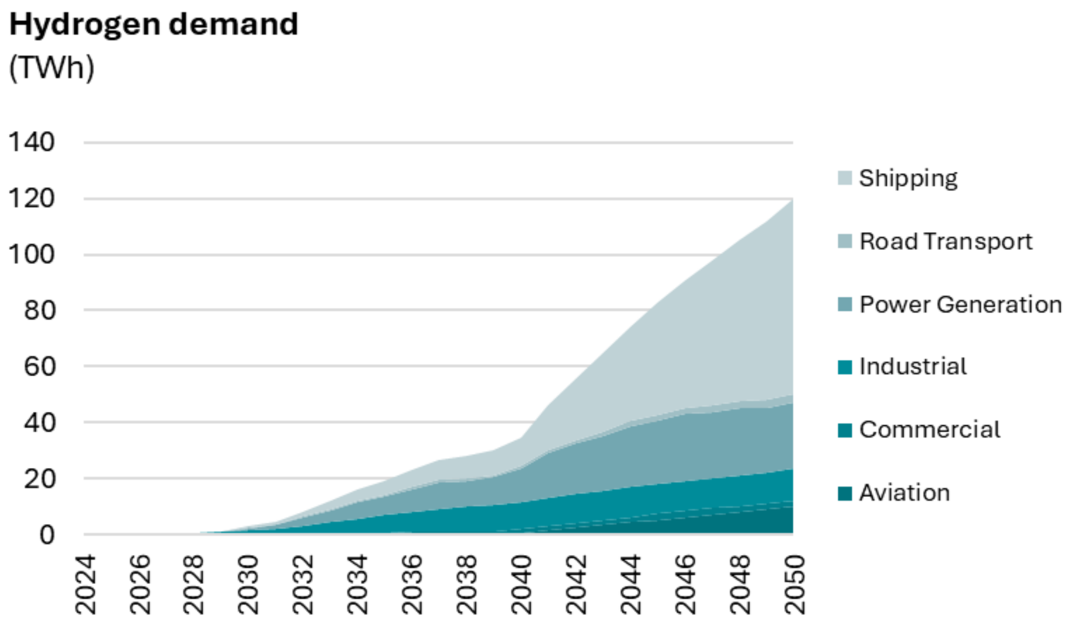

Figure 17: Hydrogen demand by sector (FES 2023 Consumer Transformation)

[22] 1.3 Suitability of electrolyser for large-scale hydrogen production, Assessment of electrolysers report, Scottish Government, 2022

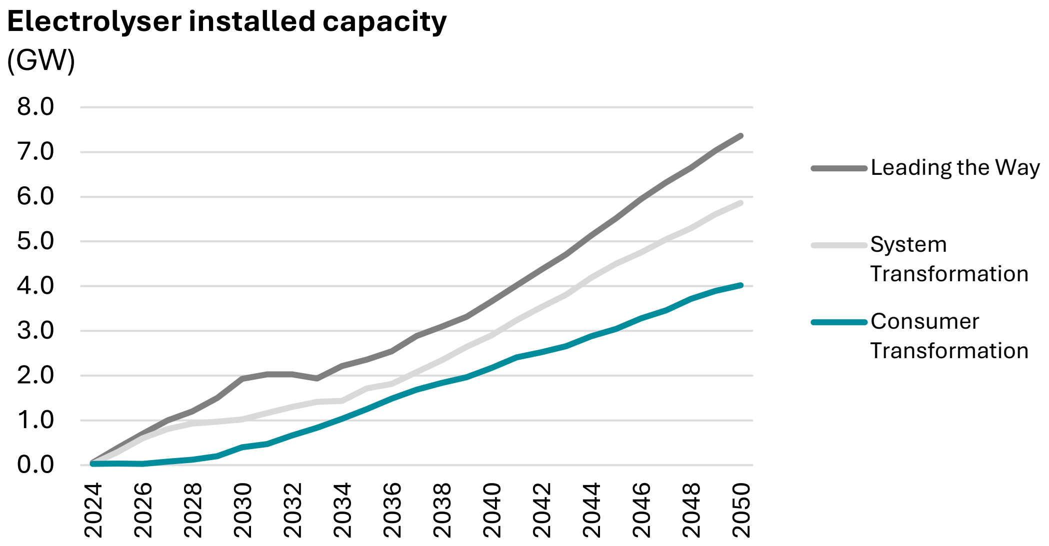

Figure 18: FES 2023 net zero scenario projections of electrolyser capacity installed on the distribution network across GB

Table 18: FES 2023 Consumer Transformation electrolyser capacity projection detail

Year	Distribution connected electrolyser capacity (MW)	Share of total incl. transmission connected (%)
2023	22	100%
2025	37	100%
2030	398	55%
2035	1,253	36%
2040	2,173	34%
2045	3,045	20%
2050	4,021	17%

Comparison with other evidence

- The DNOs National Grid Electricity Distribution (NGED) and Scottish and Southern Electricity Networks (SSEN) publish installed electrolyser capacity in their DFES.[23,24] In

[23] Distribution Future Energy Scenarios, NGED, 2023

[24] Distribution Future Energy Scenarios, SSEN, 2024

their 2023 DFES, only 3.5 MW of capacity was connected across the six licence areas covered by these network operators.

- In 2023, the UK government introduced a target of 6 GW of electrolyser capacity by 2030,[25] which is significantly higher than the projected 0.73 GW by 2030 across both transmission and distribution in the FES Consumer Transformation scenario.
- The projection of electrolyser capacity in the Consumer Transformation scenario is significantly lower than the other two net zero FES 2023 scenarios (Leading the Way and System Transformation). This reflects the higher demand in those scenarios from residential, transport and industrial sectors that is not present in the Consumer Transformation scenario world.

2.4.3. Data centres

As demand for digital services and associated computing power continues to grow, continued increases in data centre capacity in Great Britain are expected. According to the ESO, data centres currently account for 2.5% of electricity demand (TWh, annual) and this could increase to 6% by 2030.[26]

The ESO's FES includes a projection of data centre energy consumption (TWh, annual) but not installed capacity (GW). Consumption is split between transmission and distribution connected data centres: currently around 60% of energy consumption is attributed to distribution connected sites. The ESO's projection is based heavily on stakeholder input – there is currently no central authority responsible for recording data centre capacity in Great Britain.

Due to the significant uncertainty around data centre capacity, an additional higher uptake sensitivity has been included using the FES 2024 scenario with highest data centre energy consumption (Holistic Transition).

[25] Hydrogen Production Delivery Roadmap, Department for Energy Security & Net Zero, December 2023

[26] Data Centres, ESO, 2022

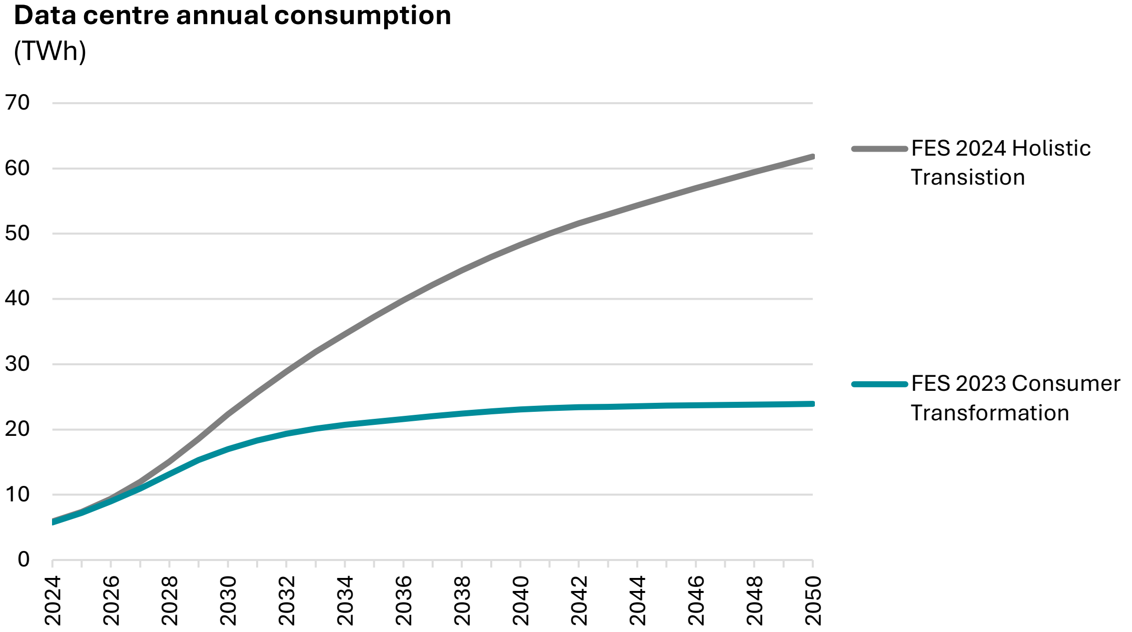

Figure 19: FES projections of data centre energy consumption on electricity transmission and distribution networks

Projections of installed data centre connection capacity

For the distribution network analysis, a projection of data centre capacity has been developed by combining the FES projections of energy consumption and estimates of the data centre load factor.

The core assumption is that data centre installed capacity rises in proportion to projections of energy consumption from the FES. The shaded range in Figure 20 illustrates the sensitivity of the projections to model inputs (described in Table 19).

Table 19: Data centre projection assumptions and input parameters

Assumption/input parameter	Detail
FES input scenario	The FES 2023 Consumer Transformation scenario projects rapid data centre energy consumption growth, with demand tapering in the 2030s. The FES projections of data centre demand vary significantly between scenarios.
Additional sensitivity	The FES 2024 Holistic Transition scenario has been used as an input for sensitivity analysis to model a very high data centre deployment case.
Assumed load factor	An average annual load factor of 35% has been assumed. Analysis carried out by UK Power Networks (UKPN), shared with Regen for this project, found that data centres on its

	network had an average utilisation of 30 to 40%. The shaded range in Figure 20 shows the sensitivity to 30% and 40% load factors.	
Share of data centre energy consumption at distribution level (from FES 2023 Consumer Transformation)	2024	44%
	2025	38%
	2026	33%
	2027	30%
	2028 to 2050	29%
Voltage tiers	For this analysis, data centres are assumed to connect at EHV level to reflect the very large (up to 100 MW) individual capacities of connections. Voltage tiers are defined in Table 3 summarises the definitions of voltage tiers used throughout this study. Voltage tiers above EHV are not considered in the analysis. Table 3.	

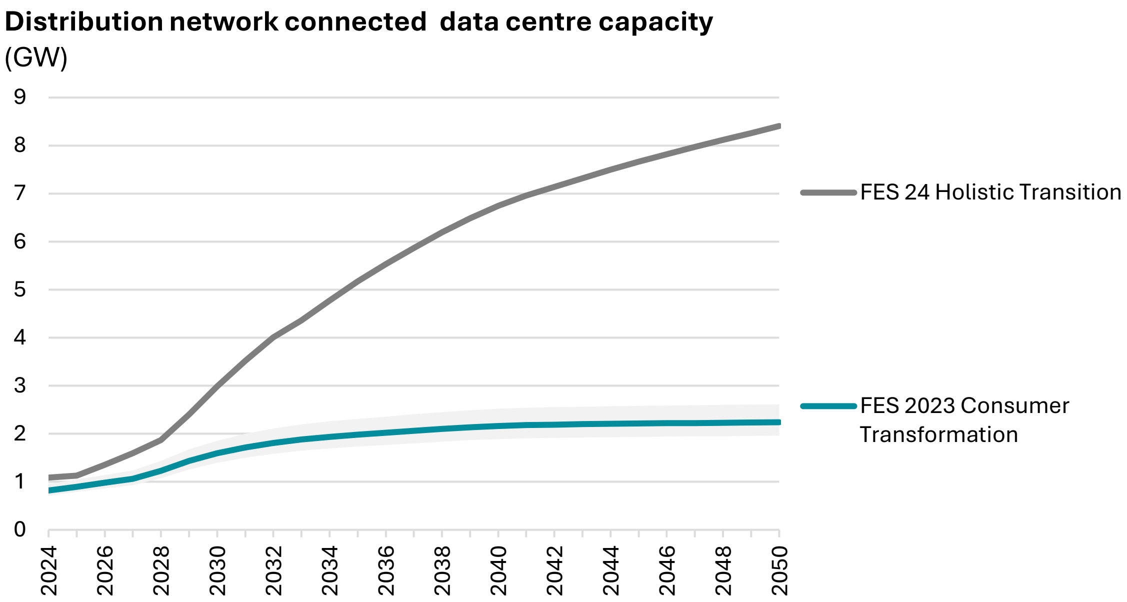

Figure 20: Projection of installed data centre capacity on the distribution network across GB. The shaded range illustrates the sensitivity of projections to assumed load factors of 30 and 40%.

Table 20: Projection of distribution network connected data centre capacity (Regen analysis)

	Distribution connected capacity (GW)	**Distribution connected capacity (GW)**
Scenario input	FES 2023 Consumer Transformation	FES 2024 Holistic Transition (sensitivity)
2024	0.82	1.09
2030	1.59	2.99
2040	2.16	6.74
2050	2.24	8.41

Comparison with other sources of evidence for data centres

Comparison to other projections is challenging due to limited public data and a lack of distribution/transmission connection data tagged for data centres.

Baseline comparison: DNO data suggests that data centre capacity on the distribution networks could be slightly higher than the analysis finds but may also be concentrated into some hot spot areas.

- SSEN has experienced rapid growth in data centre capacity in its Southern licence area, along the M4 corridor especially. SSEN's DFES, developed by Regen, provides evidence of 400 MW of existing installed capacity in the SSEN Southern licence area.[27]
- UKPN has shared connections data with Regen for this project, providing evidence of 450 MW of capacity.
- Other DNOs have not shared data centre capacity. Most data centre activity is focused in London and the surrounding areas, operated by UKPN and SSEN.

Near-term comparison: DNO connections data suggests significant growth in capacity, potentially higher than the analysis projects.

- SSEN's DFES cites 1 GW of projects with accepted grid connection agreements.[28]
- UKPN's DFES cites 1.6 GW of data centre capacity with connection agreements across all three UKPN licence areas.[29] The updated analysis shared with Regen for this project suggests that UKPN now has 2.5 GW of projects with grid connection agreements.
- Projects with grid connection agreements do not always connect (there is often a level of attrition); however, further projects could also apply to connect.

[27] Southern Licence Area DFES, SSEN, 2024

[28] Southern Licence Area DFES, SSEN, 2024

[29] UKPN DFES (3.1.4), UKPN, 2024

Long-term projections: ESO highlights that data centre capacity will increase in the long-term but there is significant uncertainty to what extent.[30] It is worth noting that the range of FES 2023 data centre energy consumption projections (shown in Figure 19) has remained similar to the range projected in ESO's research note, published in March 2022. Since publication, significant developments in artificial intelligence have occurred that may lead to higher future data centre demand. This justifies the inclusion of a high-growth sensitivity for data centres based on the FES 2024 projections.

[30] Data Centres, ESO, 2022

2.5. Generation and storage

Summary

In all net zero FES scenarios, generation and storage capacity on the distribution networks is expected to increase significantly. The FES 2023 Consumer Transformation scenario projection sees combined generation and storage capacity on distribution networks increasing from around 46 GW in 2024 to over 130 GW in 2050.[31]

This report section details the input assumptions made in collaboration with the NIC using the FES 2023 Consumer Transformation scenario as a base.

Scope

The analysis includes all the main forms of generation and storage technologies connected to the electricity distribution network. Storage includes batteries, compressed air, liquid air, and pumped hydro. Bi-directional V2G charging is covered in the transport section and thermal storage is covered in the heat section.

Projections of installed generation and storage capacity (GW) are taken from the ESO's 2023 FES Consumer Transformation scenario. Installed capacity has been filtered to distribution connections only.

Technology categorisation

Technologies are grouped into categories with similar load profiles and characteristics. A breakdown is shown in Table 21.

Table 21: Technology categorisation, mapping from FES[32]

Category	FES technology	FES Building Block ID	Technology detail
Dispatchable generation	Non-renewable CHP	Gen_BB001	>=1MW
	Non-renewable CHP	Gen_BB002	<1MW
	Micro CHP	Gen_BB003	Domestic (G98/G83)
	Renewable engines (landfill gas, sewage gas, biogas)	Gen_BB004	
	Non-renewable engines (diesel) (non-CHP)	Gen_BB005	

[31] Future Energy Scenarios, ESO, July 2023

[32] Building Block Definitions tab, Future Energy Scenarios Data Workbook, ESO, July 2023

Category	FES technology	FES Building Block ID	Technology detail
	Non-renewable engines (gas) (non-CHP)	Gen_BB006	
	Fuel cells	Gen_BB007	
	OCGTs (non-CHP)	Gen_BB008	
	CCGTs (non-CHP)	Gen_BB009	
	Biomass & energy crops (including CHP)	Gen_BB010	Includes biomass conversions
	Waste incineration (including CHP)	Gen_BB011	
	Marine	Gen_BB017	Tidal stream, wave power, tidal lagoon
	Hydro	Gen_BB018	Excludes pumped hydro
	Geothermal	Gen_BB019	
	Hydrogen fuelled generation	Gen_BB023	Hydrogen
Grid-scale solar	Solar generation	Gen_BB012	Large (G99)
Grid-scale storage	Batteries	Srg_BB001	Batteries
	Pumped hydro	Srg_BB003	Pumped hydro
	Other	Srg_BB004	Other
Small-scale solar	Solar generation	Gen_BB013	Small (G98/G83)
Small-scale storage	Domestic batteries (G98)	Srg_BB002	Domestic batteries (G98)
Wind	Wind	Gen_BB014	Offshore wind
	Wind	Gen_BB015	Onshore wind >=1MW
	Wind	Gen_BB016	Onshore wind <1MW

A limitation of this categorisation is that the dispatchable category contains a wide range of sub-technologies (mostly fossil and other dispatchable sources). In particular, marine generation (tidal stream, wave power, tidal lagoon) has been categorised as dispatchable but contains sub-technologies that may not behave like other dispatchable sources (i.e. tidal lagoons can be operated like dispatchable sources). The impact of this is deemed to be low, as marine generation currently makes up only 0.3% (53 MW) of capacity in this category and is projected to grow to only 2.0% (276 MW) by 2035 and 3.2% (356 MW) by 2050. With such a small projected capacity, this generation technology does not warrant separating out from the main categories.

The wind category contains small and large onshore installations, as well as offshore wind. Offshore wind makes up a small but not insignificant proportion of current total distribution-connected wind capacity (7% currently, with the FES projecting this reduces to 5% by 2035). Offshore wind installations typically have higher capacity factors than onshore installations (i.e. generating more power throughout the year). Offshore wind installations are likely to connect to 132kV networks which are not modelled in the network capacity analysis.

Allocation of storage and generation across voltage tiers

Voltage tiers are determined from an analysis of all six DNO's Embedded Capacity Registers (ECRs).[33] Future projections of installed capacity are allocated to voltage tiers in proportion to the capacity (for each technology group) found in the ECRs.

Baseline capacity is allocated using analysis of existing sites and future capacity is allocated using analysis of pipeline sites in the ECRs. The ECRs provide the most up-to-date and publicly available project-level data for existing and future sites connected to the distribution network.

The analysis assumes that attrition (projects with offers that ultimately do not progress towards connection) occurs equally across voltage tiers. There is no assumption that one tier experiences higher attrition than another. This may not be the case in reality, but has been made in the absence of evidence to suggest that pipeline projects experience higher attrition at one voltage tier over another.

A limitation of the ECRs is that the voltage tier tagging can be inaccurate. The impact of this is greatest at LV, because most LV-connected sites have small individual generation capacities, so a few wrongly tagged large sites can skew the voltage breakdown significantly. The ECR data is cleaned by removing sites deemed to be wrongly tagged to LV (sites both connected at LV and with capacities greater than 1MW). LV networks generally cannot support generation with export capacities greater than 1 MW. Once cleaned, the data suggests very low levels of LV deployment for dispatchable and wind technologies, so these are assumed to connect at higher voltage tiers.

Capacity allocated to 132 kV is not included in the network capacity analysis as EA Technology's Transform model used in WP2 includes tiers up to Extra-High Voltage (EHV) only.

Table 22: Summary of voltage tier allocation

Subtechnology	Voltage tier	Existing capacity	Future capacity	Assumption
Dispatchable	132 kV	25%	6%	

[33] Embedded Capacity Registers, ENA databases

Subtechnology	Voltage tier	Existing capacity	Future capacity	Assumption
	EHV	37%	50%	LV-connected generation makes up a very small proportion (<1%) of dispatchable generation. All capacity is assumed to connect at HV, EHV and 132 kV.
	HV	38%	44%	
	LV	0%	0%	
Grid-scale solar	132 kV	6%	37%	Grid-scale solar is assumed to connect at HV, EHV and 132kV whilst small-scale solar connects at LV.
	EHV	65%	39%	
	HV	29%	24%	
	LV	0%	0%	
Grid-scale storage	132 kV	36%	53%	Grid-scale storage is also assumed to connect at HV, EHV and 132kV, whilst small-scale storage connects at LV.
	EHV	47%	28%	
	HV	17%	19%	
	LV	0%	0%	
Wind	132 kV	18%	16%	LV-connected generation makes up a very small proportion (<1%) of wind generation. All capacity in these categories is assumed to connect at HV, EHV and 132 kV.
	EHV	60%	76%	
	HV	22%	8%	
	LV	0%	0%	

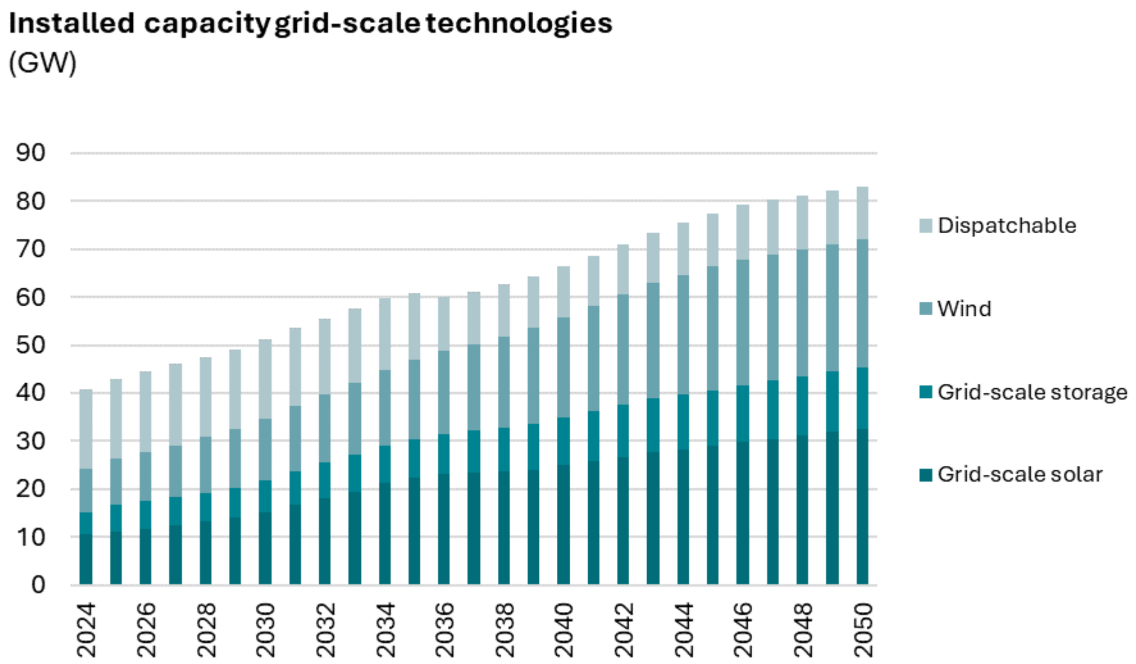

Figure 21: Grid-scale generation and storage capacity projections from the FES 2023 Consumer Transformation scenario

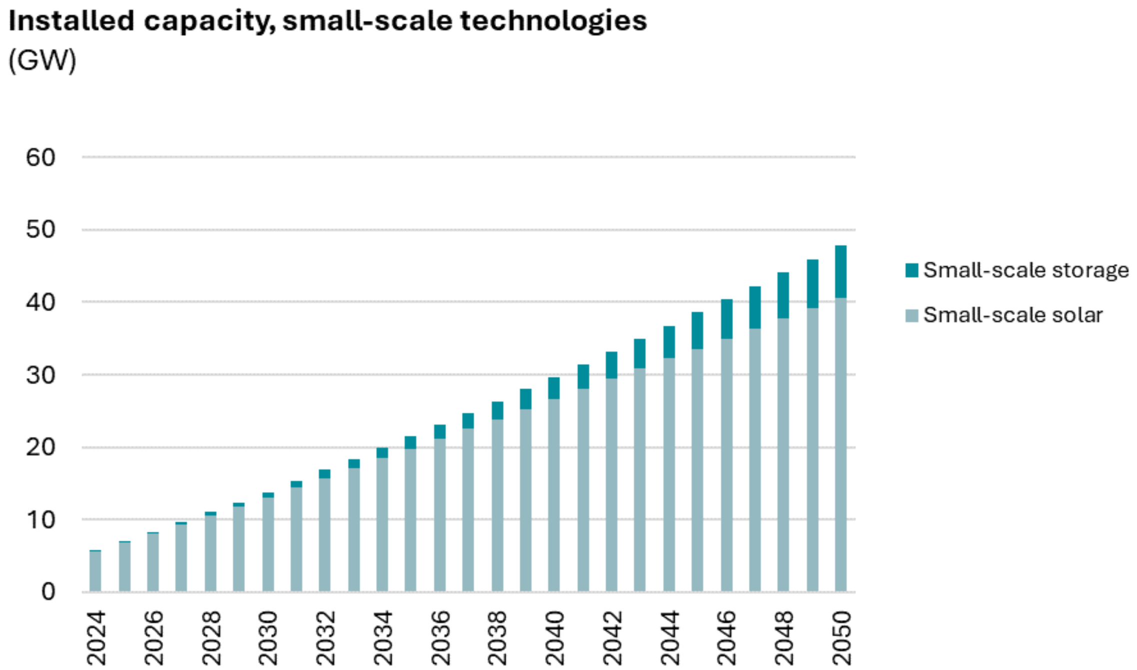

Figure 22: Small-scale generation and storage capacity projections from the FES 2023 Consumer Transformation scenario

2.5.1. Comparison with other evidence

Grid-scale storage

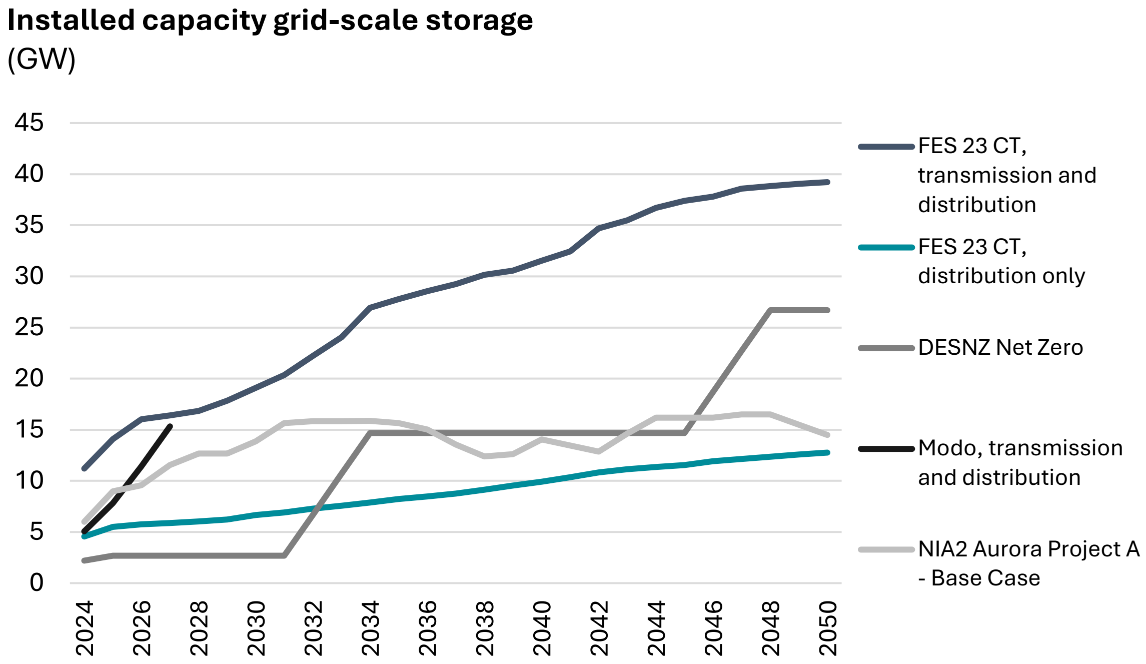

Figure 23: Comparison of capacity projections of grid-scale storage technologies, connected to both distribution and transmission

The rate of storage growth is uncertain. Nevertheless, all scenarios suggest that there will be a significant increase in both short and long-duration storage. There is a very large pipeline of storage projects within the connection queue so there is potential for storage capacity to grow very rapidly.

Figure 23 compares projections for storage capacity from several sources:

- FES Consumer Transformation (including both transmission and distribution)
- FES Consumer Transformation (distribution only – as used in this analysis)
- DESNZ Net Zero projections, Annex I (transmission and distribution) [34]
- NIA2 Aurora energy sector modelling, Project A Base Case (transmission and distribution) [35]

[34] Energy and emissions projections Annex I, Department for Energy Security and Net Zero, 2023

[35] Project A, NIA2 Aurora energy sector modelling, 2023

- Modo projections (transmission and distribution, battery storage only)[36]

The FES Consumer Transformation projections for storage across both transmission and distribution networks are significantly higher than the other projections. Near-term projections from Modo, energy storage industry analysts, align most closely with the FES projections.[37] This comparison suggests that, in the 2020s, FES Consumer Transformation projections of grid-scale storage are higher than industry analysts expect.

The projections of storage capacity are derived in different ways by the ESO for small-scale and grid-scale categories. Small-scale storage increases exponentially, with increasing shares of behind-the-meter solar generation incorporating battery storage systems due to an assumed reduction in battery prices. Grid-scale storage increases more linearly after an early growth spurt. Across all six DNOs' ECRs there is 74 GW of grid-scale storage capacity in the pipeline; this is significantly more than is anticipated to connect to the network.

Wind

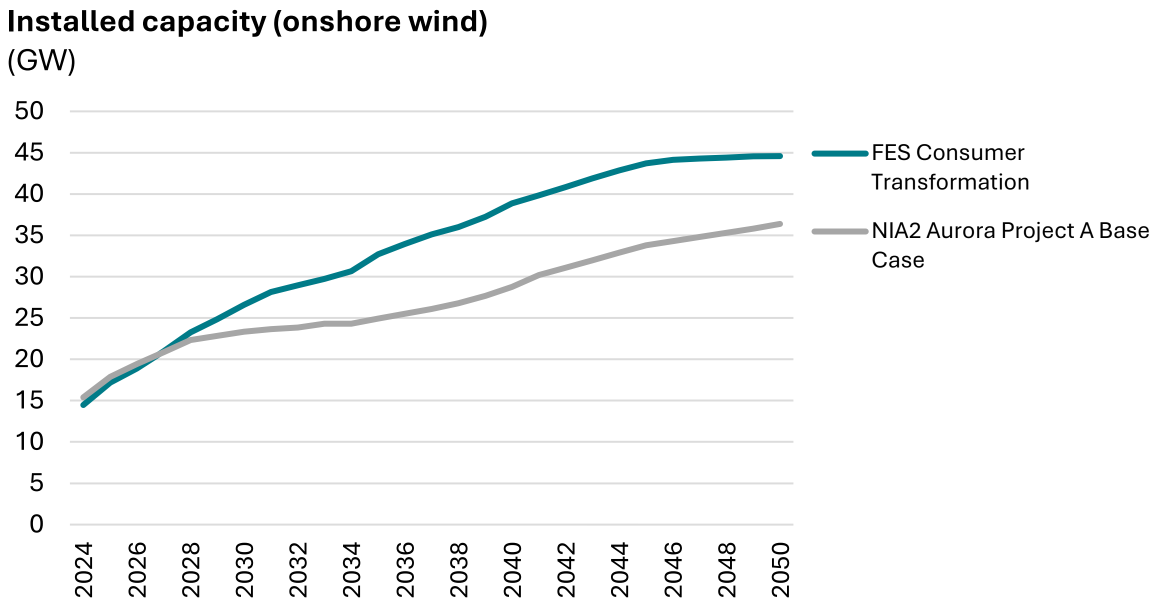

Figure 24: Comparison of onshore wind capacity projections across both transmission and distribution from FES Consumer Transformation with NIA2 Aurora Project A Base Case results

The FES Consumer Transformation projections for total onshore wind capacity (including transmission) broadly align with the results from the NIA2 Aurora Energy Sector Modelling (Base

[36] GB Battery Pipeline Report, Modo, May 2024

[37] GB Battery Pipeline Report, Modo, May 2024

Case). FES projections are higher in the long term. Capacity projections are not available at a distribution level from the Aurora analysis.

The DESNZ scenario projection for 'renewables' aligns with the FES Consumer Transformation projections for wind and solar combined (installed across transmission and distribution networks)[38]. DESNZ data does not include individual technology projections (or the share connected at distribution level), so comparison at a technology level is not possible.

Solar

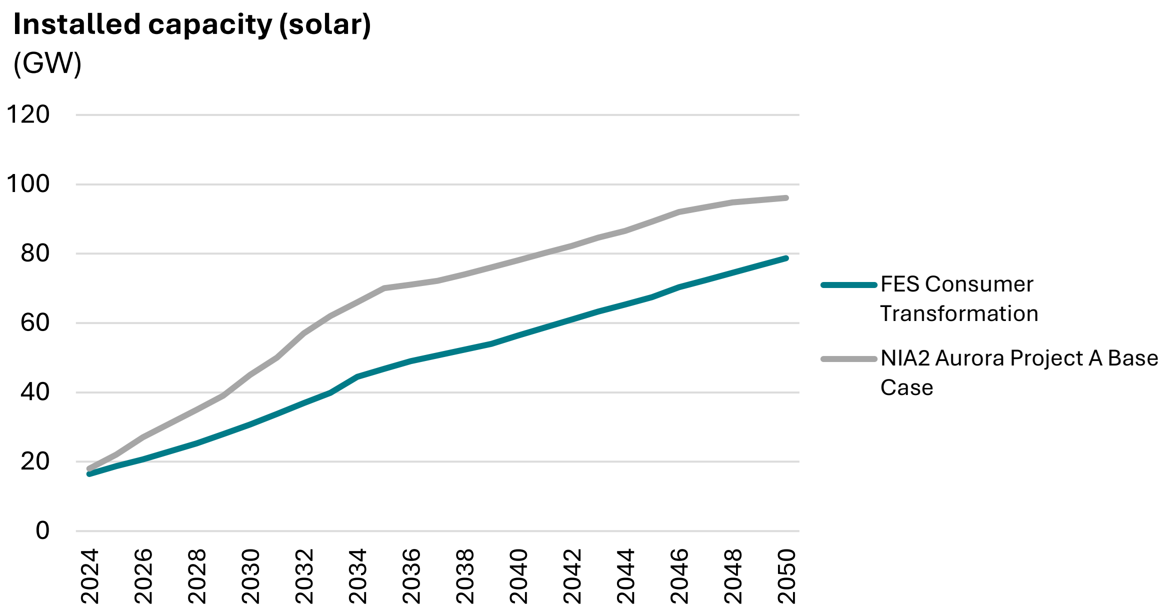

Figure 25: Comparison of solar capacity projections across both transmission and distribution from FES Consumer Transformation with NIA2 Aurora Project A Base Case results

The FES Consumer Transformation projections for total solar capacity (including transmission and small-scale generation) are broadly aligned with the results from the NIA2 Aurora Energy Sector Modelling. However, the FES projections are lower throughout the period to 2050. Capacity projections are not available at distribution level from the Aurora analysis.

Small-scale solar

The FES 2023 Consumer Transformation projections of small-scale capacity include near-term installation rates of around 1,250 MW per year for solar. According to MCS data,[39] 190,000

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[38] Energy and emissions projections Annex I, Department for Energy Security and Net Zero, 2023

[39] MCS data dashboard, Micro Certification Scheme, 2024

small-scale solar installations were made in 2023 with an average capacity of 4.99 kW each; this would suggest 950 MW installed, slightly lower than the FES Consumer Transformation scenario projects in the near term. Note: not all solar installations are MCS certified. Over the period to 2050, FES Consumer Transformation annual small-scale solar installations grow very modestly to 1400 MW per year.

Small-scale storage

Limited evidence is available for comparing small-scale storage projections. MCS does not publish the same installation data for battery storage as it does for solar. An industry report produced by SolarPower Europe suggests that at the end of 2023, 1.1 GWh of domestic battery energy storage capacity was installed.[40] Assuming a ratio of power to energy storage capacity of 1:1, this would correspond to 1.1 GW – much higher than the FES 2023 Consumer Transformation projection of 90 MW for the same period. To check this, Regen contacted small-scale solar and battery installers. These responded and estimated that, at the time of writing, over 50% of their installs come with a battery (some installers quoted rates as high as 95%), with battery and solar capacities roughly matched.

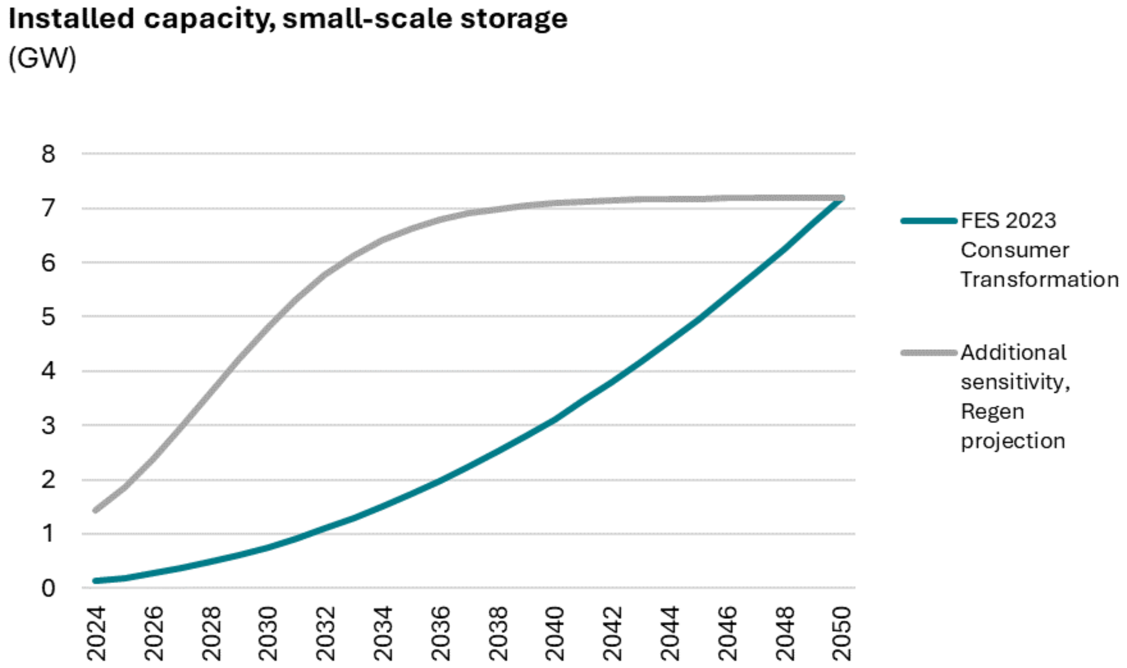

Figure 26: Installed capacity of small-scale storage systems in FES 2023 Consumer Transformation and an additional sensitivity developed by Regen.

Given this uncertainty, an additional sensitivity with significantly higher small-scale storage baseline capacity and faster growth is included in the analysis. The additional projection was developed by increasing the baseline installed capacity to 1.1 GW at the end of 2023 and assuming deployment follows an s-curve (defined with a logistic function) with installed capacity reaching the same levels seen in FES 2023 Consumer Transformation by 2050.

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[40] Battery storage markets in Europe 2023 (Page 21), European Market Outlook for Battery Storage 2024-2028, SolarPower Europe

2.6. Domestic underlying demand

Domestic underlying demand refers to electricity demand for domestic appliances, lighting, computing etc. In this analysis, demand growth in this sector is driven by building stock growth, which, for the purposes of this study, is informed by data published under the FES 2023.[41] Underlying demand does not cover demand due to emergent low-carbon technologies, such as heat pumps, the demand for which is captured elsewhere with technology sector-specific assumptions. The number of domestic properties increases in the FES at an average rate of 124,000 properties per year, from 29 million in 2022 to 32.5 million in 2050.

Table 23: Domestic underlying demand assumptions

Assumption	Detail
FES input scenario	Numbers of domestic properties in Great Britain are sourced from the ESO's 2023 FES. The number of domestic properties does not vary with the FES scenario. The data is sourced from Table BB1 in the FES data workbook (Building block ID: Dem_BB001a).
Voltage tiers	All properties are assumed to connect at LV level.

Table 24: Number of domestic properties sourced from ESO's FES 2023

Year	Number of properties (million)
2022	29.01
2024	29.26
2030	30.00
2035	30.62
2040	31.23
2045	31.85
2050	32.46

[41] Future Energy Scenarios, ESO, July 2023

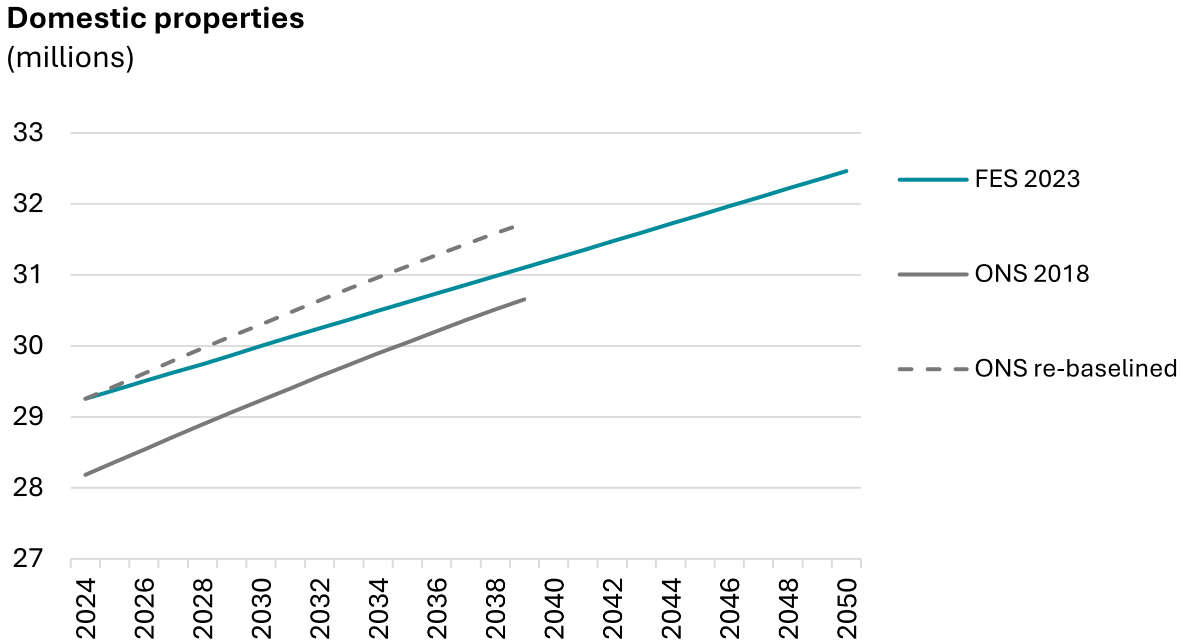

Figure 27: Domestic property projections. The dashed line shows the rate of property growth from ONS 2018 projections, re-baselined to start at the same number of properties as FES 2023 to enable comparison of growth.

Comparison with other evidence

Baseline comparison: The FES baseline data aligns with the government's sources for existing properties. Combined, the government's sources suggest that there were 29.1 million dwellings across Great Britain in 2021:

- 24.9 million dwellings in England[42]
- 1.47 million dwellings in Wales[43]
- 2.67 million dwellings in Scotland[44]

The baseline numbers of properties are similar to those used in the NIA2 energy sector modelling (which found 29.1 million properties as of 2020).[45]

Projections comparison: The FES domestic building stock increases at an average annual rate of 124,000 up to 2050. This is relatively low compared to historic rates of house building (on average 195,000 homes were built per year across Great Britain in the five years before 2022-

[42] Census, ONS, 2021

[43] Census, ONS, 2021

[44] Households and Dwellings in Scotland, National Records of Scotland, June 2021

[45] Aurora – Energy sector modelling Project B. Report slide 22, National Infrastructure Commission, 2023

23[46]). Rates of building new domestic properties are higher in ONS's most recent projections from 2018 (average 166,000 per year,[47] higher than the 124,000 average in the FES). Annual additions reduce over time in the ONS projections, from 0.19 million in 2024 to 0.14 million in 2039 (the last year of the projections). A comparison is shown in Figure 28.

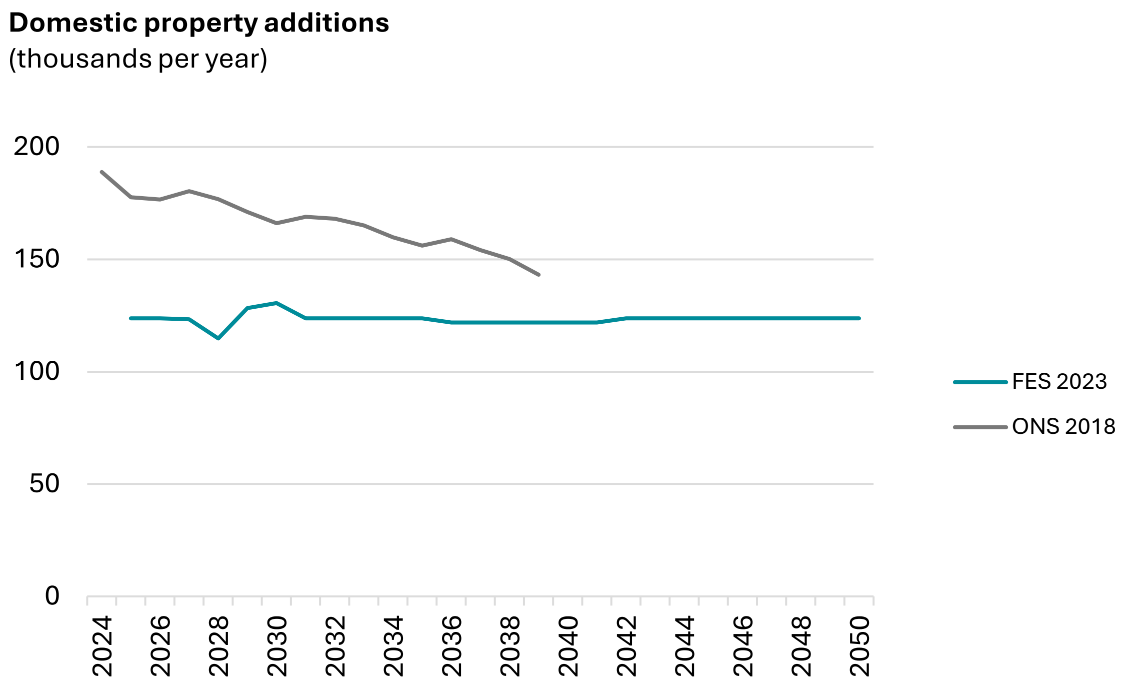

Figure 28: Comparison of rates of new domestic property additions across Great Britain.

[46] House building, UK: permanent dwellings started and completed by country, ONS, 2024

[47] Household projections, ONS, 2018 (most recent available)

Section 3:

Load Profiles

An evidence review of technology load profiles and network flexibility potential

3.1. Summary and context

This section details the review of technology load profiles used in the network capacity analysis conducted in WP2.

The key data outputs of this work package are daily half-hourly demand and generation profiles for each technology for three seasonal 'representative' days that represent the most onerous network conditions expected on the electricity distribution network.

The network capacity analysis uses these load profiles combined with the projected uptake volumes developed in Section 2:..

Table 25: Demand and generation technologies included in the analysis

Sector	Subtechnology
Road Transport (electric vehicle chargepoints)	Domestic off-street
	Workplace (incl. fleets)
	Public slow and fast (up to 50kW)
	Public rapid (over 50kW)
Heat	Domestic heat pumps (Air source and ground source)
	Non-domestic heat pumps
	Direct electric heating incl. night storage
	Heat networks (district heat)
Industrial and commercial demand	I&C demand
	Electrolysis
	Data centres
Domestic	Underlying domestic demand
Generation and storage	Small-scale solar (Up to 1 MW per installation)
	Small-scale storage (Up to 1 MW per installation)
	Grid-scale solar (Over 1 MW)
	Wind
	Grid-scale storage (Over 1 MW)
	Dispatchable generation

3.1.1. Representative days

EA Technology's proprietary network capacity modelling tool, Transform, models three 24-hour demanding network loading periods throughout the year. Three daily load profiles are selected for each technology to cover the range of conditions that the network could be expected to handle without loss of supply.

The three representative days are defined as follows:

- **Winter peak demand**, with minimum coincident generation – an assessment of the network's capability to meet peak winter demand conditions when demand is high and generation is low
- **Intermediate cool peak demand,** with minimum coincident generation – an assessment of the network's capability to meet demand conditions outside of winter and summer
- **Summer peak generation,** with minimum coincident demand – an assessment of the network's capability to handle generation output.

Seasons are defined as follows:

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

3.1.2. Profile selection approach

Distribution Network Operators (DNOs) were invited to respond to a Request for Information (RFI) with 48 half-hourly load profiles for each of the three seasonal days described for a subset of technologies. The data items requested are summarised in Table 26.

Table 26: Summary of data items requested in RFI to DNOs.

Technology group	Technology	Information requested	
		48 half-hourly profiles	Uptake data
EV chargepoints	Domestic, off-street	✓	
	Workplace (incl. fleets)	✓	
	Public slow & fast (≤50kW)	✓	
	Public rapid (>50kW)	✓	
Heat	Domestic ASHP	✓	
	Domestic GSHP	✓	
	Non-domestic heat pumps	✓	
	Direct electric heating	✓	
	Domestic night storage	✓	
	Heat networks (district heat)	✓	

Generation and storage	Small scale storage	✓	
	Small-scale solar		
	Grid-scale storage	✓	
	Grid-scale solar		
	Wind		
	Dispatchable generation	✓	
I&C demands	I&C underlying demand		
	Electrolysis	✓	
	Data Centres	✓	✓

As a starting point, profiles have been sourced from National Grid Electricity Distribution (NGED). This is for several reasons;

- The technology categorisation NGED uses in its DFES aligns closely with the FES and matches that used in this study
- NGED has a near-comprehensive set of load profiles for the technology scope of this study
- NGED profiles had been used recently by EA Technology with the network capacity models used in this analysis.

A comparison of the DNO profiles shows that, as expected, there are differences across all profiles. This is especially notable where deployment of Low Carbon Technologies (LCTs) is relatively nascent, where the evidence base is comparatively immature and/or energy loads have been subject to change. An example of change is the rapid development of grid-scale storage business models over the past 18 months. It is also noted that several technologies have been the subject of new trials and evidence gathering by the DNOs, which are now being reflected in updated profiles. A limitation is that the modelling uses a snap-shot of current load profiles when it is expected that network user behaviour and profiles will change over the course of the net zero transition.

Where there are significant differences between the profiles (and where subtechnologies can appropriately be compared) a comparison is provided. For these profiles, the project conducts additional research to determine the most appropriate profile to use for the purposes of this study, with assumptions and supporting evidence provided for those decisions. Where there is a significant range in possible operating behaviour this is explored via sensitivity analysis, described in more detail in section 3.1.7.

3.1.3. Diversity

Diversity is a measure of the non-correlation of group demand. In simple terms, it is the principle that large groups of customers are less likely to use energy at the same time. A common example is that not all households boil their kettle simultaneously, and if they did, network capacity would be exceeded. Diversity increases as the group size increases and/or if demand behaviour is less correlated. Diversity reduces non-linearly with smaller group sizes and/or if demand behaviour begins to correlate, for example, because of an external factor – a time of use tariff price signal or the end of a football game.

Similar principles apply for generation. Although there will be a clear correlation between variable renewable generation and wind speeds and solar irradiance, even solar and wind farms in close proximity there will be some degree of diversity.[48]

The profiles presented here have been developed to assess the network capability of EHV networks. For most technologies, this means that a large group of customers are expected to connect below this voltage tier, and therefore, the load profiles are diversified. As such, they do not represent the load of an individual customer, which would be highly variable, but the load of the group of customers connected under that point in the EHV network.

In WP2 for lower voltage network analysis, such as LV feeders, where smaller group sizes are typical,[49] load diversity is reduced (i.e. loads are increased) to reflect the higher loads per customer that these network assets experience.[50]

3.1.4. Flexibility

Energy system flexibility refers to adjustments to supply and demand to ensure that energy flows are balanced. From an electricity network point of view, flexibility refers to supply or demand adjustments that maintain operating parameters such as power or voltage within certain limits. Historically, flexibility has largely been provided on the supply side (for example, with dispatchable generation increasing output during peak demand periods) but now demand-side flexibility is increasingly being deployed.

This study assumes two separate categories of flexibility services:

1. Implicit flexibility (customer-led):
2. Explicit flexibility (network operator procured):

Implicit flexibility (customer-led):

This includes changes in energy use behaviour taken by customers in response to a variety of signals or technological changes.

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[48] Regen has looked at the system benefits of a more diversified offshore wind portfolio in the 2023 study Go West

[49] Trials such as Electric Avenue and Electric Nation have shown high levels of EV charging diversity with groups containing 20, 30 and 100 domestic EV chargepoints – a low average group demand per EV chargepoint. However, groups with 5 or fewer, as might be connected to an LV feeder, display less diversity.

[50]Section 4.4 Diversity, Work Stream 3, Assessing the Impact of Low Carbon Technologies on Great Britain's Power Distribution Networks, Energy Networks Association on behalf of Smart Grids Forum, 2012

For distribution networks, this includes behaviour changes in response to:

- Time-of-use tariffs, where trends in wholesale prices are passed onto customers via tariffs
- Tariff innovations based on smart metering and remote control such as dynamic wholesale price trackers
- Demand side response procured at the national level by the Electricity System Operator (which would be explicit for the ESO).

Explicit flexibility (network operator procured):

This includes flexibility services, including demand side response (DSR), procured and instructed by Distribution System Operators (DSOs). This form of flexibility is not accounted for in the load profiles and is a solution to network constraints modelled in Work Package 2.

The load profiles provided in this document incorporate behaviour changes from implicit flexibility but not explicit flexibility. An important assumption has been made that periods of high demand on the distribution networks are correlated with implicit price signals to turn down demand. Whilst this has been the case historically, and is a reasonable assumption for representative day analysis, it is possible that a high demand period could coincide with low energy prices (stimulating further demand) if renewable generation levels are also very high. In the future, with high levels of renewable energy, a peak (winter) demand could correspond with high levels of generation. The overall energy supply would be in balance, so there would be no implicit price signal to reduce demand and DNOs may need to call upon explicit flexibility services to manage network constraints.

Further, profiles which contain a specific period of demand turndown, such as for domestic heat pumps with thermal storage, are based on current typical network loading and market dynamics. These are likely to change when sufficient flexible LCT demand comes online, meaning the implicit flexibility modelled via the load profiles here may not be representative of future behaviour.

3.1.6. Units

The units of measurement for load profiles vary by technology, depending on the units of uptake, so the combined output of uptake and load profiles is measured in kW or MW. In some cases, the load profiles were provided in units normalised by annual consumption (i.e. kW per kWh) so an assumed annual consumption was used to derive a profile in units of kW.

Table 27: Example units of LCT uptake and load profiles

Technology	Uptake units	Load profile units	Resultant units
Domestic heat pumps	Number of heat pumps	kW per heat pump	kW
Solar generation	MW installed capacity	MW per MW installed capacity	MW

3.1.7. Sensitivities

Table 28 summarises the sensitivity cases tested in the analysis. Note this refers to the same sensitivities as in Table 4 in section 2.1.3, and is included here for ease of reference.

Table 28: Summary of sensitivity cases.

	Name	Flexibility and winter conditions	Heat technology uptake rate
1	FES 23 CT - high flex	Higher levels of flexible operation of EVs, heat pumps and energy storage with typical winter conditions (see Section 2.3)	Higher heat pump adoption (FES 2023 Consumer Transformation)
2	FES 23 CT delayed HP - high flex		Delayed heat pump adoption (Regen modification to Consumer Transformation)
3	Lower HP - high flex		Lower heat pump adoption with higher electric resistive heating (High Heat Pump scenario from Aurora Energy Modelling for Second National Infrastructure Assessment)
4	FES 23 CT - low flex	Lower levels of flexible operation of EVs, heat pumps and energy storage with typical winter conditions (see Section 2.3)	Higher heat pump adoption (FES 2023 Consumer Transformation)
5	FES 23 CT delayed HP - low flex		Delayed heat pump adoption (Regen modification to Consumer Transformation)
6	Lower HP - low flex		Lower heat pump adoption with higher electric resistive heating (High Heat Pump scenario from Aurora Energy Modelling for Second National Infrastructure Assessment)
7	Winter stress test	Winter stress test: higher heating demand with lower flexibility availability (see Section 3.3)	Higher heat pump adoption (FES 2023 Consumer Transformation)
8	Lower I&C demand	Testing the impact of I&C demand reduction (see Section 3.4)	Higher heat pump adoption (FES 2023 Consumer Transformation)
9	High data centre deployment	Testing the impact of very high data centre deployment with higher	Higher heat pump adoption (FES 2023 Consumer Transformation)

	Name	Flexibility and winter conditions	Heat technology uptake rate
		flexibility availability (see Section 2.4)	
10	High initial small-scale storage deployment	Testing the impact of higher small-scale storage deployment with higher flexibility availability (see Section 2.5)	Higher heat pump adoption (FES 2023 Consumer Transformation)

3.2. Transport

3.2.1. Transport summary

This section defines load profiles and flexibility behaviour for EV chargepoints for use in network capacity analysis conducted in WP2. Load profiles were selected for the four chargepoint categories shown in Table 29 (as defined in Section 2:).

The network analysis in WP2 models the loads of chargepoints, not electric vehicles, with multiple vehicle archetypes mapping to each chargepoint archetype – for example, many commercial vehicles are charged at domestic chargepoints and private cars are charged at a mixture of private and public chargepoints.

For the majority of chargepoint archetypes, the load profiles provided by NGED are used as the default due to ease of use and because these map one-to-one with the Regen Transport model used to generate GB level capacity projections of EV chargepoints. Profiles provided by DNOs for domestic off-street chargepoints are shown in Figure 29 for comparison.

Where NGED's profiles are replaced, other assumptions and supporting evidence are provided for those decisions.

These load profiles were derived and validated by NGED using three key projects:

- Electric Vehicle Charging Behaviour Study, Element Energy[51] - this project developed a set of annual charging demand profiles for National Grid ESO, covering all 8,760 hours within a year based upon a dataset of more than 8 million real-world charging events from major chargepoint operators
- Electric Nation[52] - this large-scale smart charging trial, which involved nearly 700 EV owners across Great Britain, provided data on how EV owners charge their vehicles at home and included a trial looking at managed charging
- Aggregated smart meter data analysis carried out by NGED.

This section also defines high and low flexibility sensitivity cases, which test the requirements for network capacity under the same chargepoint uptake conditions but with different modes of chargepoint operation.

[51] Electric Vehicle Charging Behaviour Study, Element Energy for National Grid ESO, March 2019

[52] Electric Nation, NGED, 2019

Table 29: Definition of EV chargepoint categories and summary of high and low flexibility sensitivities

Chargepoint category (FES building block)	**Regen transport model EV chargepoint archetype**	**High flexibility sensitivity**	**Low flexibility sensitivity**
Domestic off-street	Domestic off-street no chargepoint Domestic off-street with chargepoint	Three profiles for each representative day: 1. Non-managed charging 2. Managed charging 3. Bi-directional charging (V2G and V2H)	Two profiles for each representative day: 1. Non-managed charging 2. Managed charging
Workplace (including fleets)	Fleet/depot Workplace	Single profile for each representative day	Single profile for each representative day
Public slow and fast (up to 50kW)	Car parks Destination Domestic on-street	Single profile for each representative day	Single profile for each representative day
Public rapid (over 50kW, including eHGV chargepoints)	En-route/local charging stations En-route HGV chargepoint En-route national network	Single profile for each representative day	Single profile for each representative day

As with other LCTs, the use of EVs and charging behaviour is subject to change and evolution. The largest trial data available from the Electric Avenue and Electric Nation studies dates back to 2018-2019. Chargepoint operators and companies like ZapMap are now analysing real-life charge behaviour and have begun to provide this data to network companies on a fee-pay basis.

While new data will help networks develop more accurate load profiles, it is still the case that the market is developing rapidly. For example, many energy supply companies offer two-rate tariffs for EV charging, and some now offer dynamic tariffs. The off-peak price offered on two-rate tariffs is around 7 to 9 p/kWh (30-40% of the average price-capped unit rate), which provides a significant incentive to charge during overnight off-peak periods.[53][54] Overnight EV charging is, therefore, a common feature of network profiles. However, dynamic tariffs, where prices track changes in the wholesale electricity price every half-hour, are also being introduced and may shift the focus of charging to periods of high generation, which could occur during periods typically associated with higher demand.

In summary, it is expected that EV charge behaviour will continue to evolve and change, and (aided by smart technology) will generally become more sophisticated, responding to tariffs that are more sensitive to electricity price signals. This could work for the benefit of distribution networks, shifting peak loads to off-peak periods, but could also have a negative impact in terms of diversity loss and synchronised charging that could result from market price signals.

The chargepoint profiles in this study and the sensitivity analysis capture current trends but do not fully capture the complexity and uncertainty surrounding future charging behaviour.

3.2.2. Domestic off-street chargepoints

Charging management approaches and associated load profiles

Domestic off-street chargepoints can be operated in various ways to suit different users. In this analysis, the different chargepoint management types are grouped into three categories to include the variety of approaches that can be used to charge vehicles. These are outlined in Table 30.

Table 30: Definition of different charging management approaches for off-street domestic chargepoints

Management type	Approaches included in management type	Approach definition
1. Non-managed charging	N/A	The charging session begins immediately when plugged in
2. Managed charging (externally and user-managed)	Off-peak charging (via time-of-use tariffs)	Charging is scheduled for off-peak times when electricity prices are lower
	Smart charging	Supplier controls charging schedule whilst meeting user requirements (such as minimum range by a certain time)

[53] Electric vehicle energy tariffs, MoneySavingExpert, 2024

[54] Energy price cap (1st July to 30 Sept 2024), Ofgem, 2024

Management type	Approaches included in management type	Approach definition
	Dynamic price tracking	Charging occurs when wholesale prices (and other price signals) are lowest
3. Bi-directional charging	Vehicle-to-home (V2H)	Energy is exported from the vehicle to power devices in the home, displacing imports
	Vehicle-to-grid (V2G)	Energy is exported from the vehicle to the grid. The network models used in this study do not differentiate between V2H and V2G

Comparison of load profiles provided by DNOs

DNOs provided load profiles for the four chargepoint categories defined in Table 29. All DNOs responded with information on domestic off-street chargepoints. The load profile data provided is shown in Figure 29.

It should be noted that UKPN profiles are not displayed in Figure 29 because the approach they use to model charging load is not directly comparable. The UKPN methodology differs significantly, and is based on the proportion of users plugging their vehicle in each half hour. Additional assumptions and user archetyping are then applied to arrive at a final charging load. This methodology (which is embedded in UKPN load models) was developed through UKPN's innovation projects 'Recharge the Future' and 'Shift'.[55, 56] Granular modelling assumptions were not shared with Regen by UKPN and so comparable UKPN profiles (i.e. in units of kW) are not included in this analysis.

Two DNOs, Northern Powergrid (NPg) and Electricity North West (ENW), provided load profiles normalised by annual energy consumption. Load profiles in units of kW are derived by multiplying the normalised profiles by estimated annual consumption at each domestic chargepoint, as derived in Regen's chargepoint capacity analysis, described in section 2.2.2. The estimated annual consumption (per domestic off-street chargepoint and averaged from 2024 to 2050) is 2,310 kWh per chargepoint.

As would be expected for domestic chargepoints, the profiles exhibit increased charging loads outside of the working day, with peak loads overnight. The profiles exhibit a similar overall

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[55] Recharge the Future, Element Energy for UK Power Networks, 2018

[56] Project Shift, Baringa for UK Power Networks, 2022

shape but there is a range in the timing and quantum of profile peak loads. Load profiles provided do not vary by season (apart from those provided by NGED).

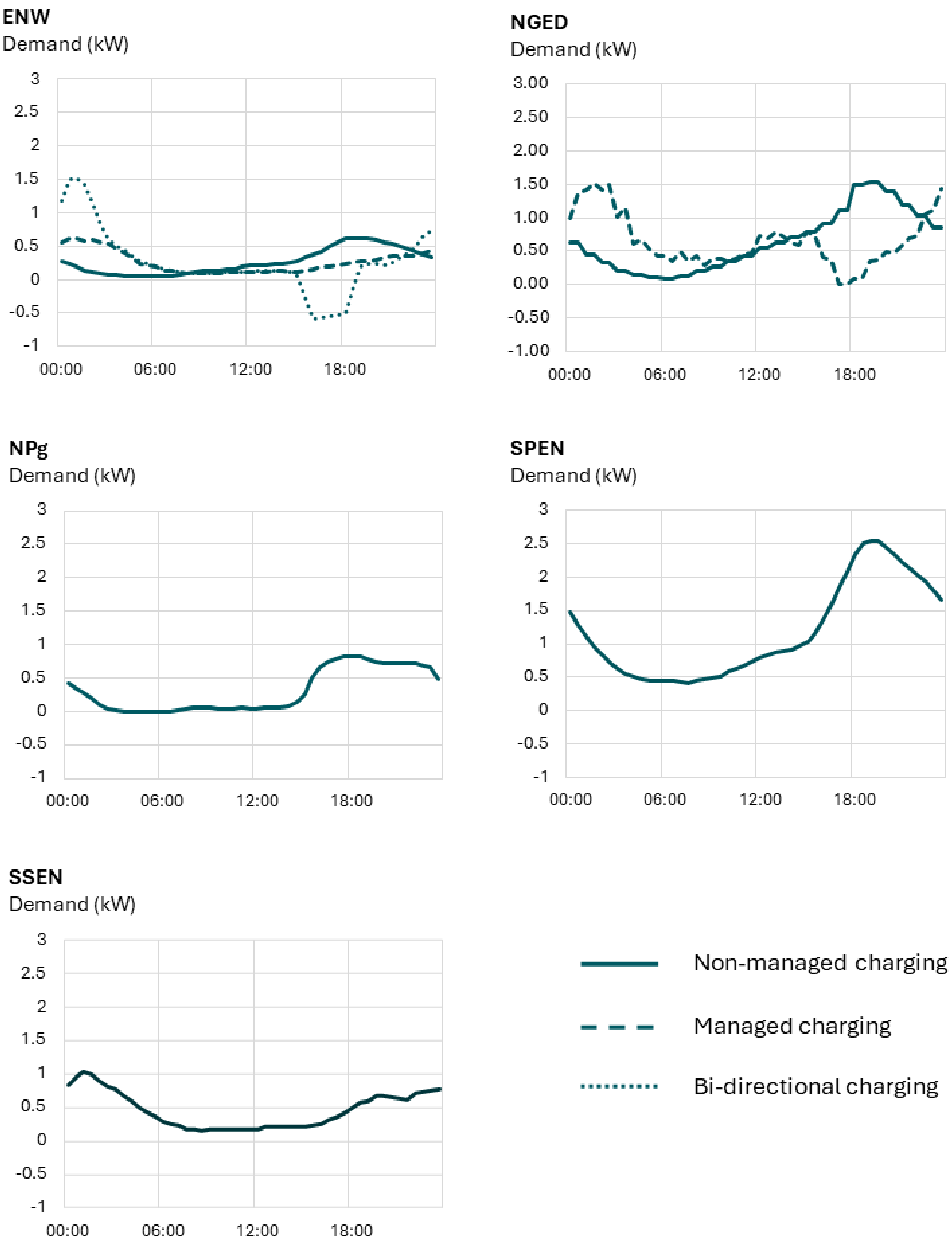

Figure 29: Comparison of load profiles for domestic off-street chargepoints (rated to 7.36kW) provided by DNOs for winter peak demand conditions. Dashed lines show managed charging profiles. ENW dotted line shows bi-directional profile. UKPN data not shown due to different data format.

Selected load profiles for domestic off-street chargepoints

Load profiles for both non-managed and managed chargepoints were sourced from NGED. The managed charging profiles are smoothed to remove noise by using a moving average – for each half-hourly period, the average of the proceeding, current and following half-hourly data points were taken.

For bi-directional chargepoints, this study uses a flat export profile for peak demand days to reflect that bi-directional charging could export at any time during the day. The quantum of export is defined using the profile provided by ENW.

The level of bi-directional export is adjusted between high and low flexibility sensitivities by varying the proportion of chargepoints operating under different modes described in Table 30.

The summer peak generation profiles are much lower than peak demand days. This is testing the network against low demand and high levels of generation, causing export-related constraints. For bi-directional charging on these days, it is assumed that there would be little incentive to export or displace imports, so the same profile has been used for both bi-directional and managed charging types.

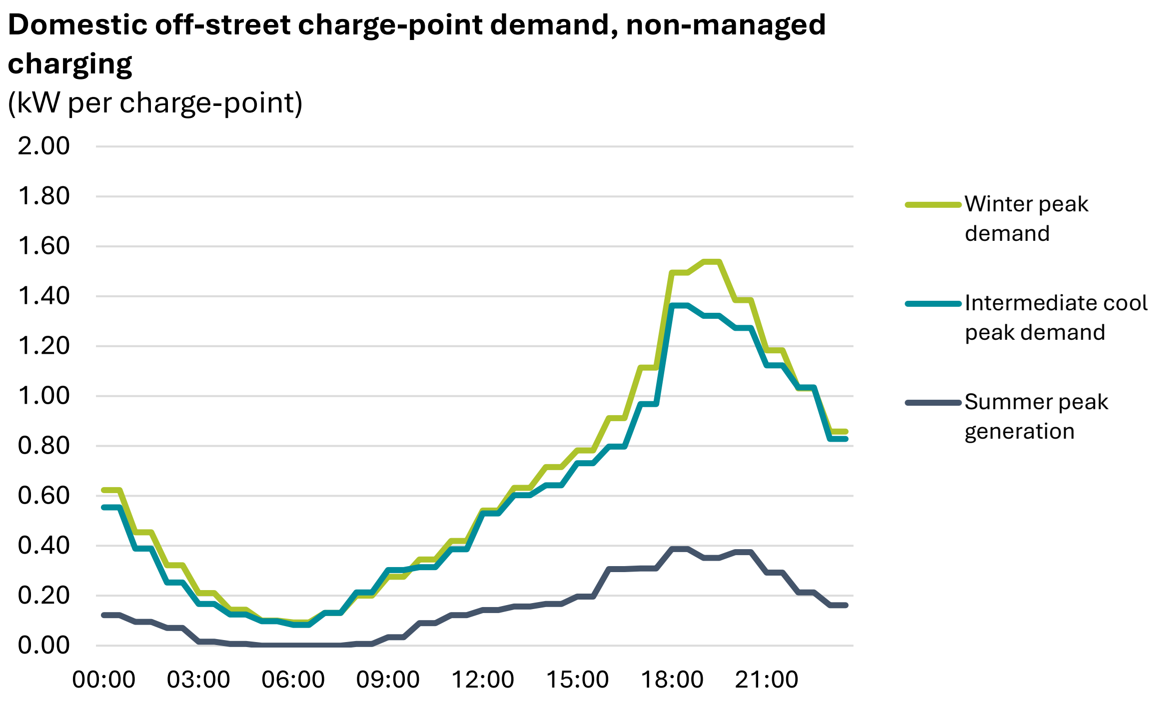

Figure 30: Load profiles for domestic off-street chargepoints, non-managed operation

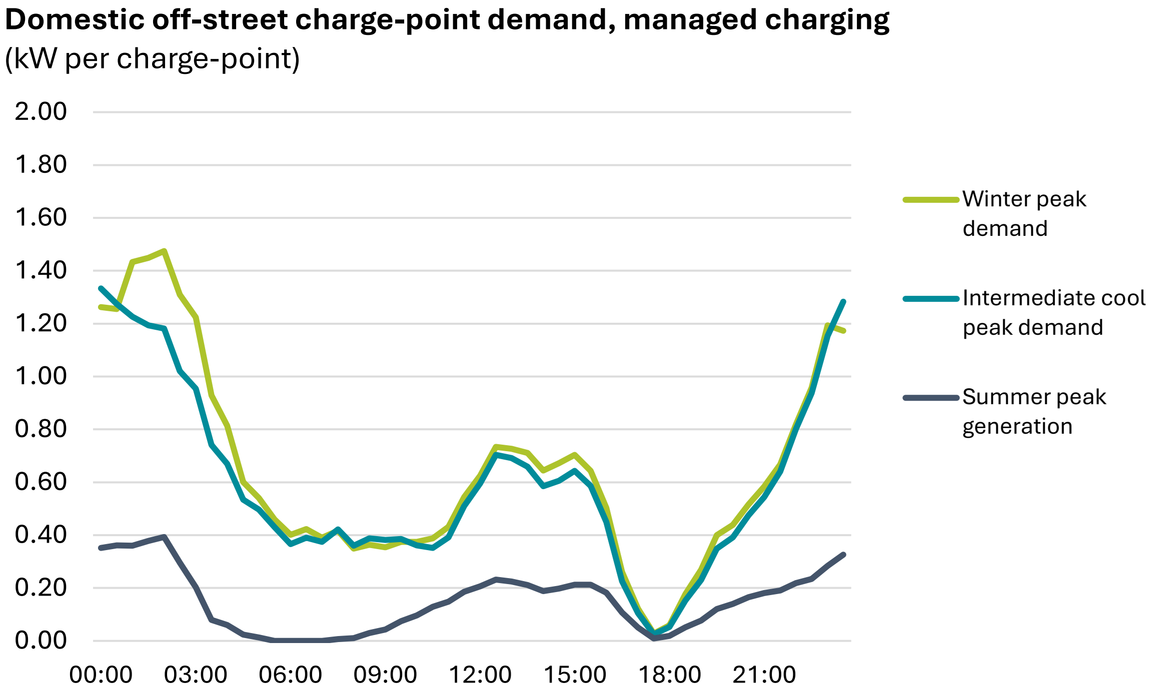

Figure 31: Load profiles for domestic off-street chargepoints, operating with managed charging

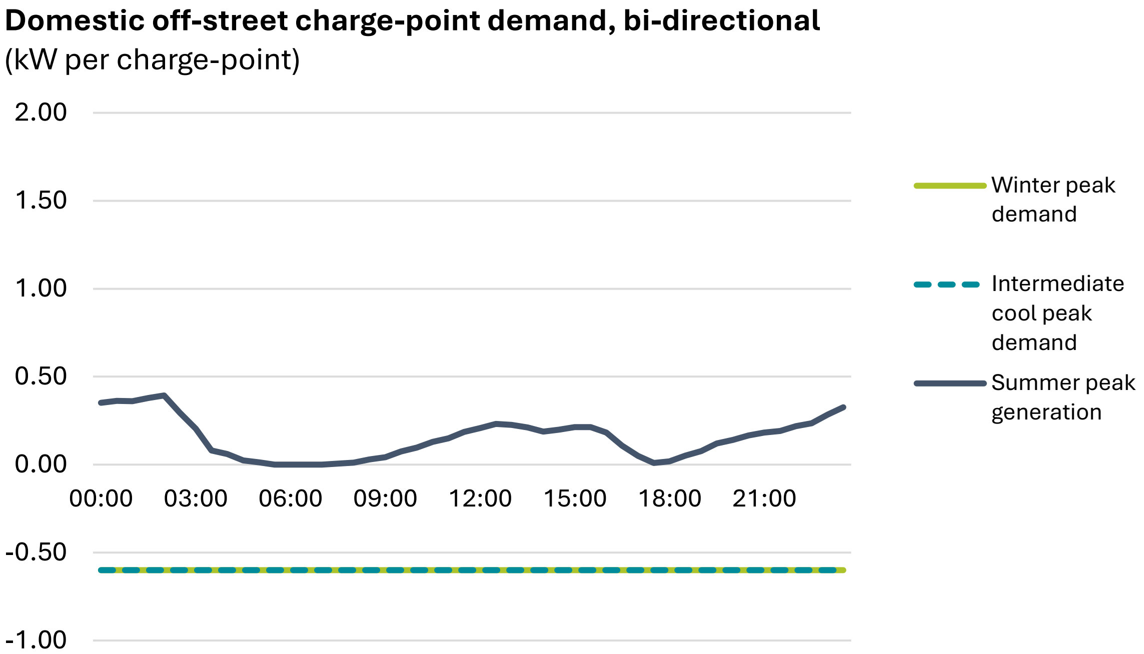

Figure 32: Load profiles for bi-directional domestic off-street chargepoints

High flexibility sensitivity for domestic off-street chargepoints

The high flexibility sensitivity follows the FES 2023 Consumer Transformation assumption framework, with high levels of consumer engagement and flexibility adoption. Derivation of the split of chargepoints operating via modes defined in Table 30 is outlined below:

1. **Non-managed charging:** The adoption of non-managed charging is sourced from UKPN's DFES.[57]
2. **Managed charging:** The adoption of managed charging is defined as the remainder of chargepoints after non-managed and V2G have been accounted for.
3. **Bi-directional charging:** Rates of V2G adoption are sourced from the FES 2023 Consumer Transformation scenario (Tab EC.13).[58] To date, the uptake of bi-directional charging has been very low, as reflected in the FES Consumer Transformation scenario. Currently, the dominant charging protocol (CCS) does not yet support V2G and whilst CHAdeMO, another charging protocol, has bi-directional capabilities, it is equipped on a few new vehicles.

[57] Flexibility Scenarios (document download here, Tab: EV smart charging and V2G), DFES 202, UKPN

[58] FES 2023, ESO, 2023

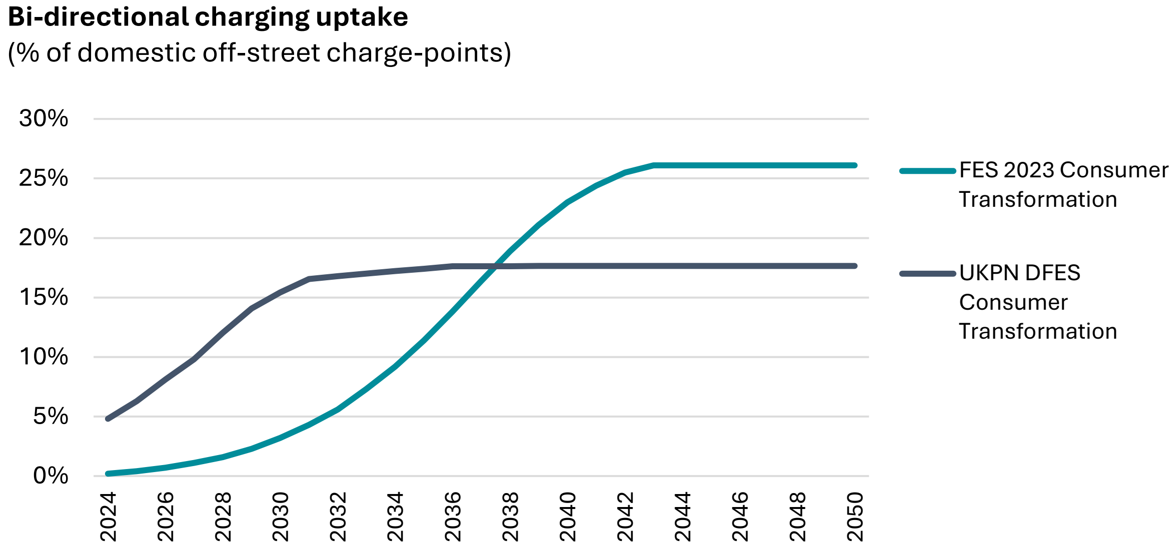

Figure 33: Comparison of FES 2023 Consumer Transformation and UKPN DFES Consumer Transformation bi-directional charging adoption

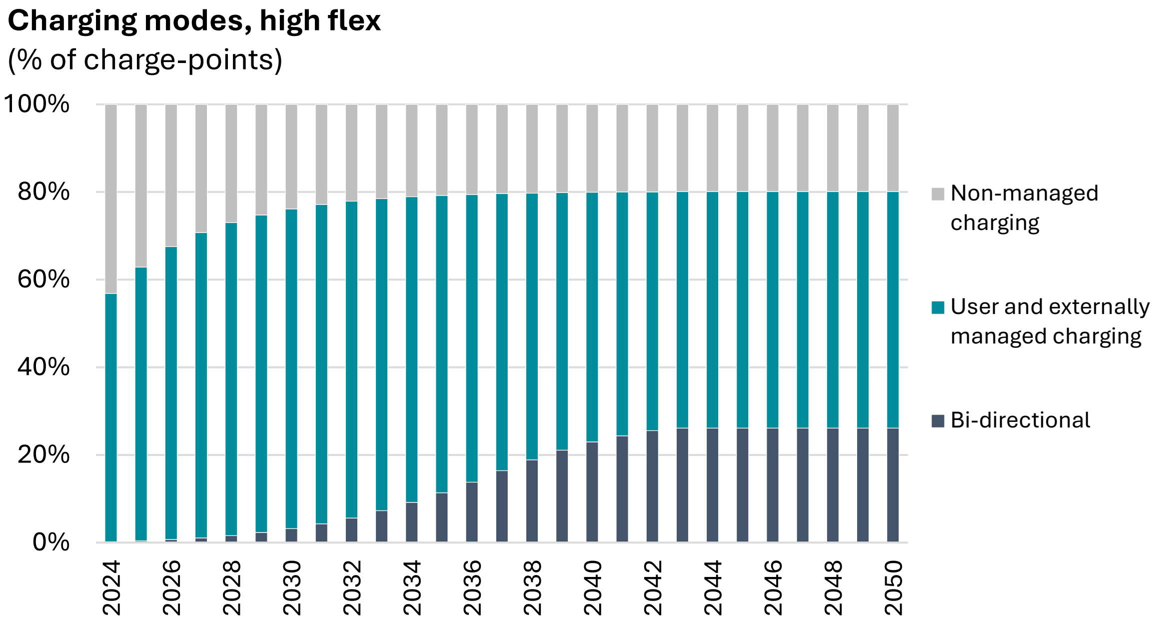

Figure 34: Breakdown of charging management approaches for the high flexibility sensitivity

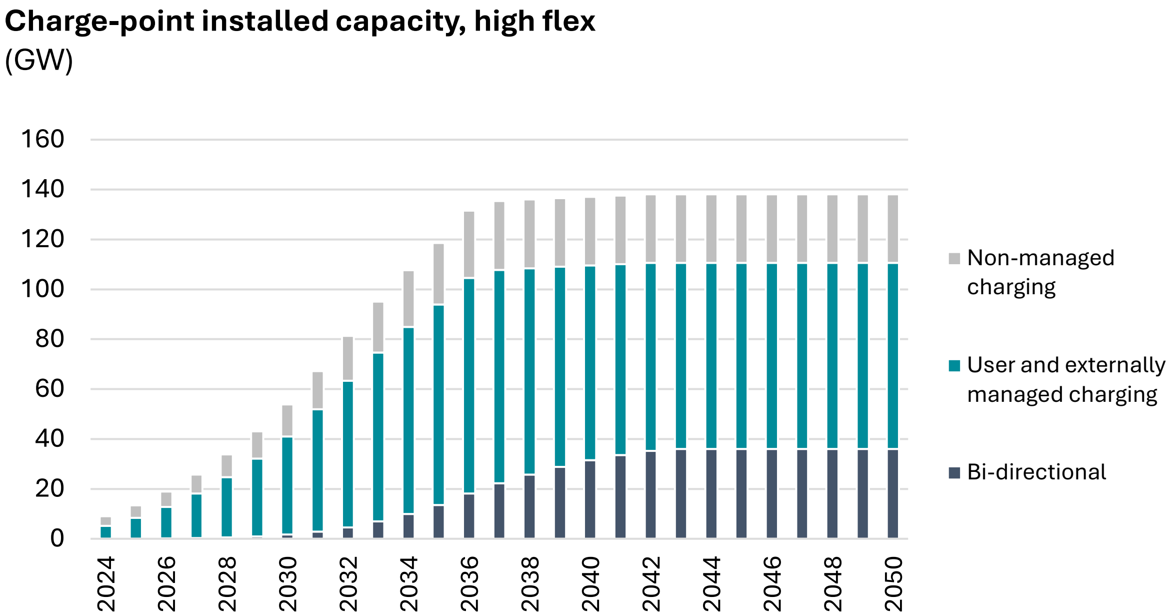

Figure 35: Total installed domestic off-street chargepoint capacity split by management approach for the high flexibility sensitivity. Assumes 7.36kW installed capacity per chargepoint

Low flexibility sensitivity for domestic off-street chargepoints

The low flexibility sensitivity assumes that flexible use of domestic off-street chargepoints is more limited. Specific assumptions are outlined below:

1. **Non-managed charging:** The adoption of non-managed charging is assumed to remain at current levels with the shift to managed or bi-directional modes from 2024. The level of adoption is defined from UKPN's DFES (Consumer Transformation scenario) as a static 43.1% share to 2050.
2. **Managed charging:** The adoption of managed charging is defined as the remainder of chargepoints after non-managed and V2G have been accounted for.
3. **Bi-directional charging:** It is assumed that bi-directional charging technology does not reduce in cost sufficiently for consumers to justify purchasing bi-directional enabled chargepoints, so uptake remains at 0% to 2050.

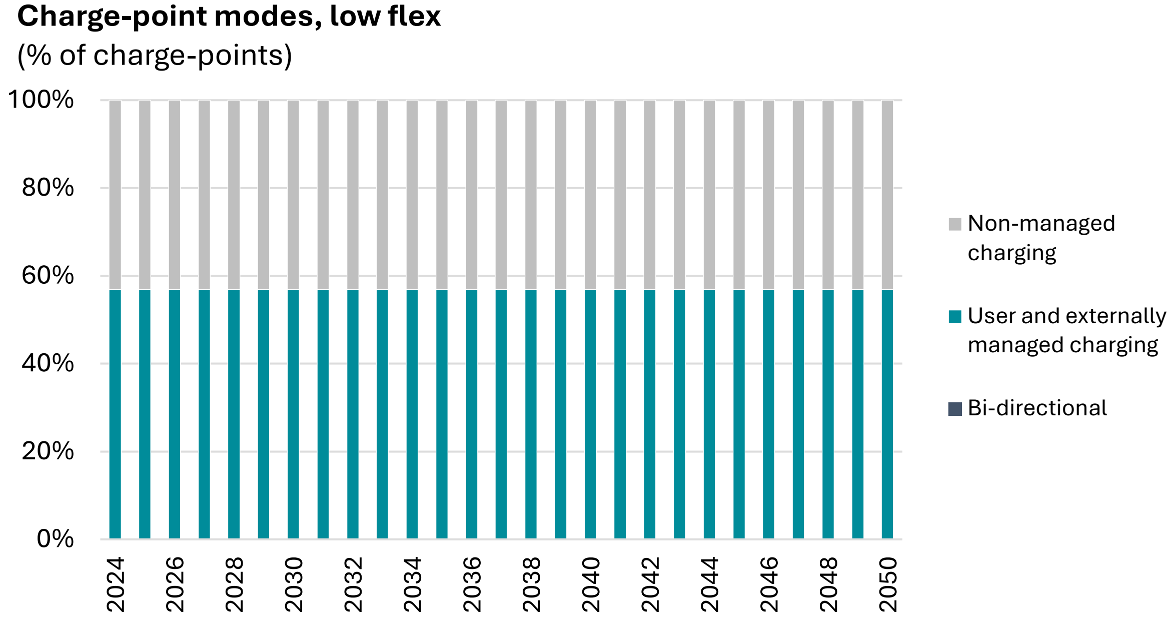

Figure 36: Breakdown of charging management approaches for the low flexibility sensitivity

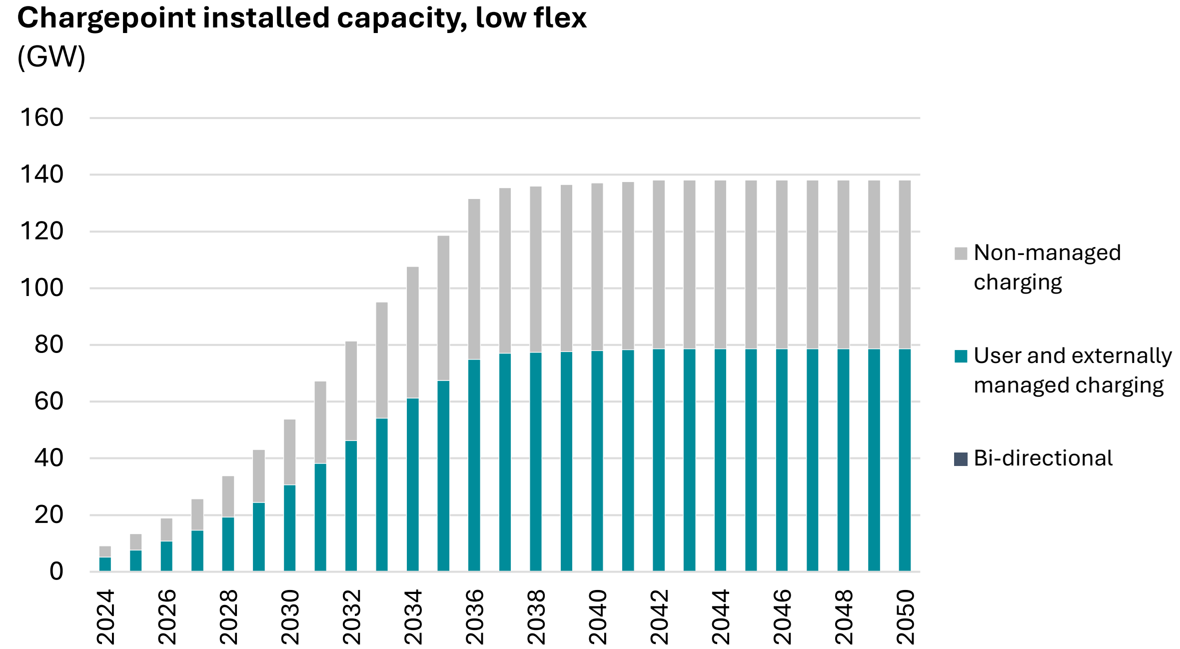

Figure 37: Total installed domestic off-street chargepoint capacity split by management approach for the low flexibility sensitivity. Assumes 7.36kW installed capacity per chargepoint

Limitations of approach for domestic off-street chargepoints

There are several limitations that should be noted:

- **Tariff development:** The managed charging profiles exhibit some demand in the early morning. Whilst this charging behaviour is evident today, in a future with electrified heat it is likely that price signals deter this behaviour (heating loads are less flexible and will occur in the early morning)
- **Charging modes:** The adoption of different charging modes is highly uncertain. This is particularly relevant for bi-directional charging which has not seen significant adoption beyond trials to date. The proportion of chargepoints operating in non-managed mode is high in both flexibility sensitivities (43% in low sensitivity and settling at 20% in the high flex sensitivity). A similar proportion (22%) of customers have never switched energy suppliers, suggesting that low levels of consumer engagement in their charging arrangements are not unreasonable to assume [59]
- **Bi-directional charging mode:**
    - Adoption of bi-directional V2G and V2H technology is highly uncertain and subject to a number of technical and commercial factors that could lead to a dramatically higher or lower uptake and to variation in charging behaviour. The use of two flexibility sensitivities with different rates of uptake aims to capture this uptake uncertainty.
    - The profiles used for bi-directional charging are highly uncertain and may overstate the network benefit of this technology by not modelling any import during the peak demand day. Users will need to import the exported energy either before or after the export period. This could have a negative network impact, although it is unlikely to occur during a peak period. In practice, the availability of bi-directional charging would vary depending on the price signal to consumers, the time of day and the number of vehicles that are at home and ready to charge.
    - Other uptake barriers include the cost of a bi-directional chargepoint, which in 2022 was £3,700 more than a unidirectional chargepoint, and domestic export limit of 3.68kW for a domestic single-phase connection.[60]

[59] Consumer perceptions of the energy market, Ofgem, 2018

[60] OVO energy and Nissan V2G trial, Ofgem, 2022

3.2.3. Workplace (including fleets)

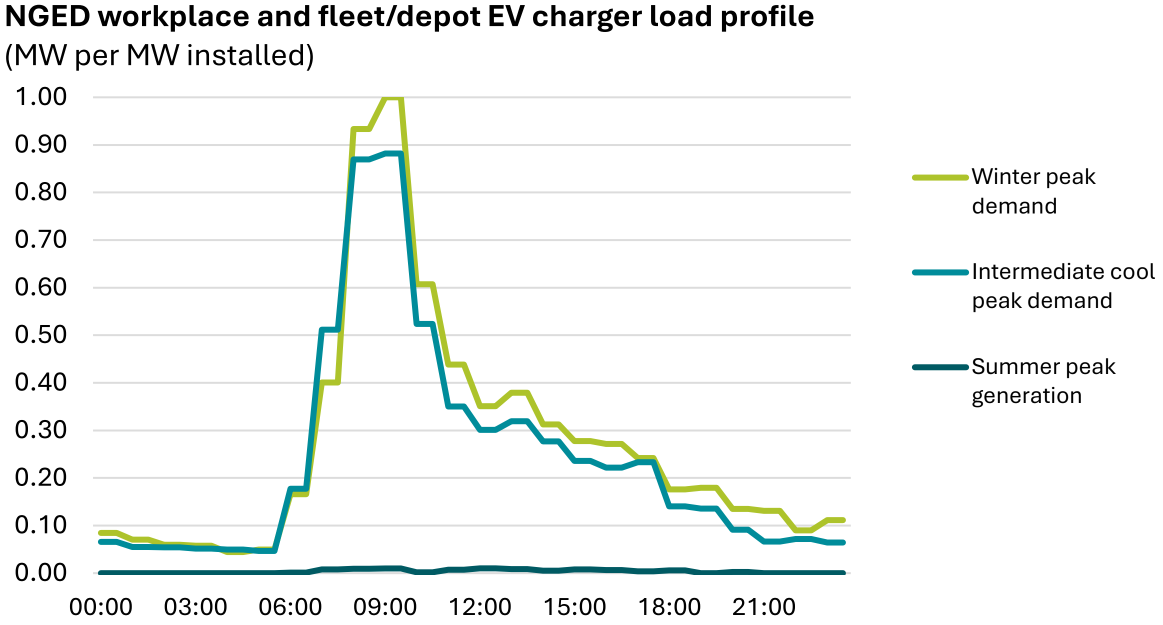

Figure 38: Load profiles provided by NGED for both workplace and fleet/depot chargepoints

This chargepoint category includes two archetypes; workplace chargepoints and depot-based chargepoints for fleets. These archetypes are likely to experience different charging behaviour, with workplace chargepoints experiencing higher loads during the working day and fleet/depot chargepoints experiencing higher loads outside of fleet operating schedules.

Many datasets and profile models have not differentiated between workplace and fleet/depot charging. For example, the load profiles for fleet/depot and workplace based chargepoints provided by NGED were the same, with peak charging events coinciding with the start of the working day.

Comparison against results from Optimise Prime, an innovation project focused on fleet electrification, shows that fleet charging profiles are more likely to feature higher levels of overnight charging driven primarily by depot based vehicles.[61] The project results also show that load profiles are application and depot specific, with load peaks following the end of shifts.

In this analysis, a separate worst-case flat profile is used in the absence of a fleet/depot charging profile based on real-world charging data. A new profile for the combined chargepoint archetype is generated by weighting the two individual profiles in proportion to the split of installed capacity (see Table 31 and Table 32).

[61] Final Learning Report, Optimise Prime, February 2023

Table 31: Assumed fleet/depot chargepoint flat profiles for representative days

	Demand (MW per MW installed) for all half-hourly periods
Winter peak demand	1.00
Intermediate cool peak demand	1.00
Summer peak generation	0.00

Table 32: Split of capacity used to generate a weighted average profile

FES building block	Regen transport model EV chargepoint archetype	Split of installed capacity (average from 2024 to 2050 from Regen projections)
Workplace incl. fleets	Fleet/depot	44.6%
	Workplace	55.4%

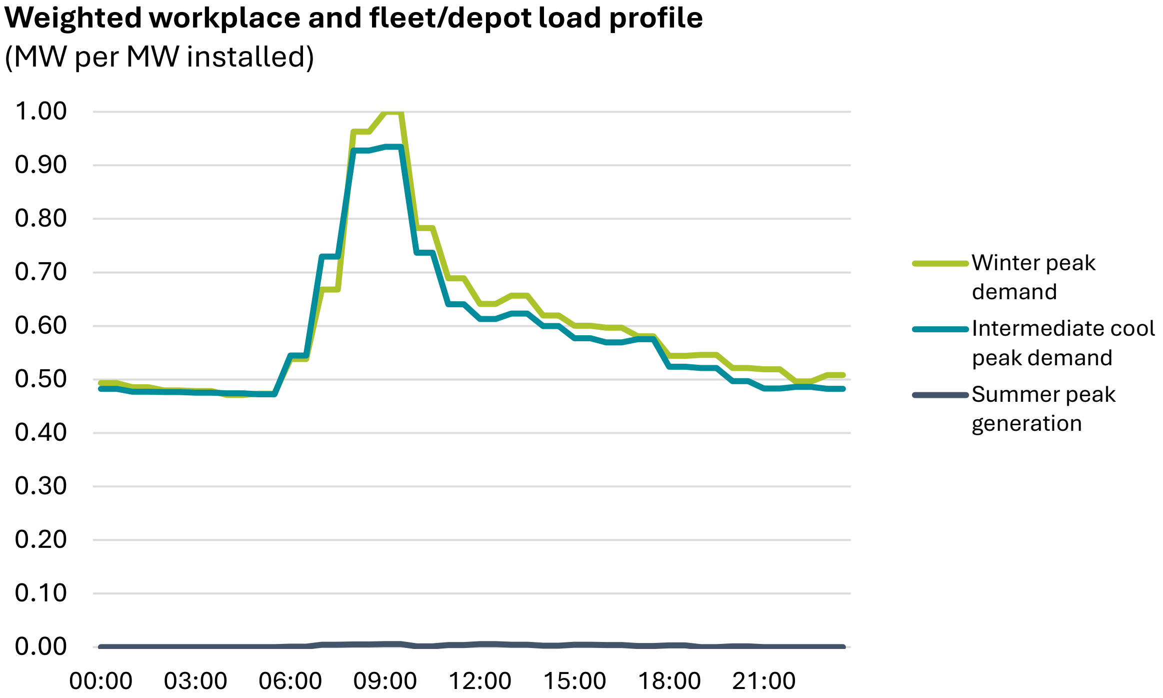

Figure 39: Weighted average load profile for workplaces, incl. fleet chargepoints, developed by Regen using inputs from NGED

Known limitations for workplace and fleet/depot chargepoints:

- The key limitation of the approach taken is that it is conservative and may overstate demand load. In reality, fleet/depot based chargepoints are very unlikely to operate at 100% capacity throughout peak demand days. As more data is gathered around workplace and fleet/depot behaviour, it is likely that a newer, less conservative assumption could be developed
- The Optimise Prime trial found that fleet/depot chargepoints can provide demand flexibility. This flexibility is not modelled in the weighted average load profile generated for this analysis.[62] The network model analysis, therefore, represents the upper range of network impact for fleet/depot chargepoints.

3.2.4. Public slow and fast chargepoints

Public slow and fast chargepoints include the sub-archetypes shown in Table 33, which were provided by NGED. To create a profile for public slow and fast chargepoints, the individual profiles of the three NGED chargepoint archetypes were weighted in proportion to the installed capacity (as projected in the scenario development analysis in Section 2.2.5).

[62] Final Learning Report, Optimise Prime, February 2023

Table 33: Public slow and fast chargepoint archetypes and projection of capacity split

FES building block	Regen transport model EV chargepoint archetype	Split of installed capacity (average from 2024 to 2050 from Regen projections)	2024 installed capacity (GW)	2050 installed capacity (GW)
Public slow and fast (up to 50kW)	Car parks	9%	0.11	0.89
	Destination	11%	0.17	0.96
	Domestic on-street	80%	0.68	8.86

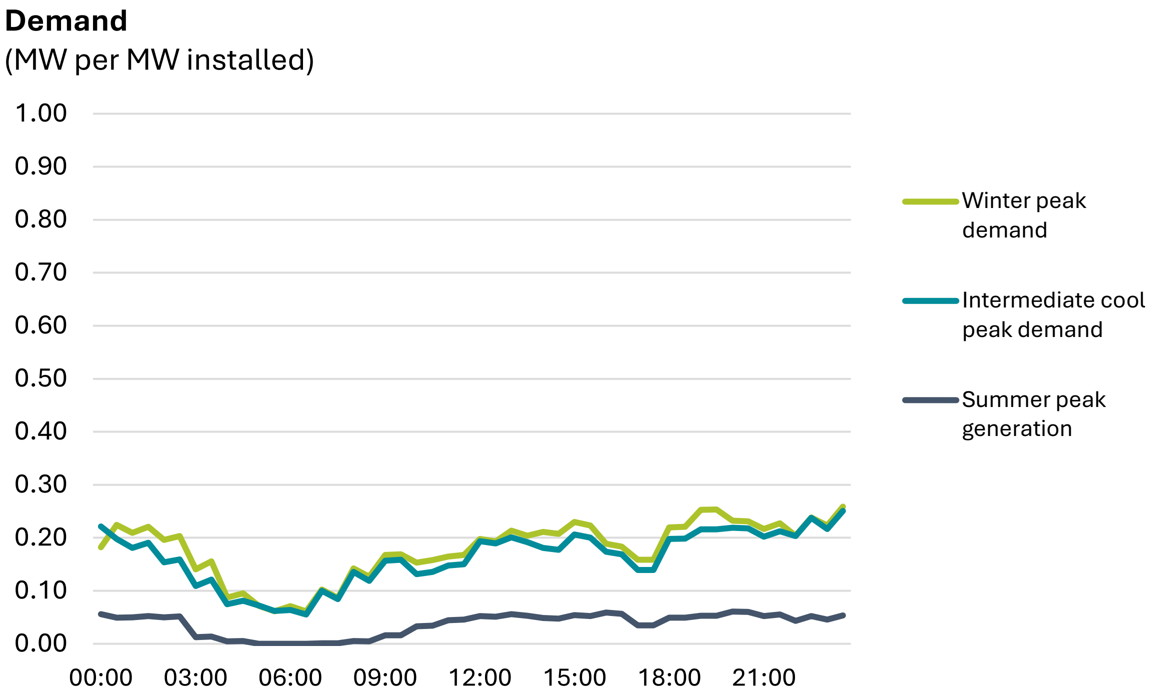

Figure 40: Weighted load profiles for public slow chargepoints. Includes car park, destination and domestic on-street chargepoints

Known limitations for public slow and fast chargepoints:

- The key limitation of developing a weighted profile is that the profile of on-street chargepoints differs significantly in shape and magnitude from car park and destination chargepoints. The output is a relatively flat profile, whereas the individual profiles show significant morning peaks in the case of car park/destination chargepoints and a smaller but noticeable overnight peak in the case of on-street chargepoints. Due to the weighting towards domestic on-street chargepoints, this could underestimate the daytime impact of car park/destination chargepoints and slightly underestimate the nighttime impact of on-street chargepoints. However, this chargepoint archetype (public slow and fast up to

50kW) makes up only c.6% of total installed chargepoint capacity in 2050, so the impact on the analysis is not significant

- There is assumed to be no flexibility in these chargepoint archetypes. This may be a realistic assumption for car park and destination chargepoints as drivers will be charging for shorter periods. For on-street chargepoints, where charging is more likely to take place over longer periods and in particular overnight, it is more likely that charging will be managed and could therefore be responsive to market price and other signals. To some extent, the weighted profile (which is flatter than the individual input profiles) can be considered as a proxy for a degree of flexibility.

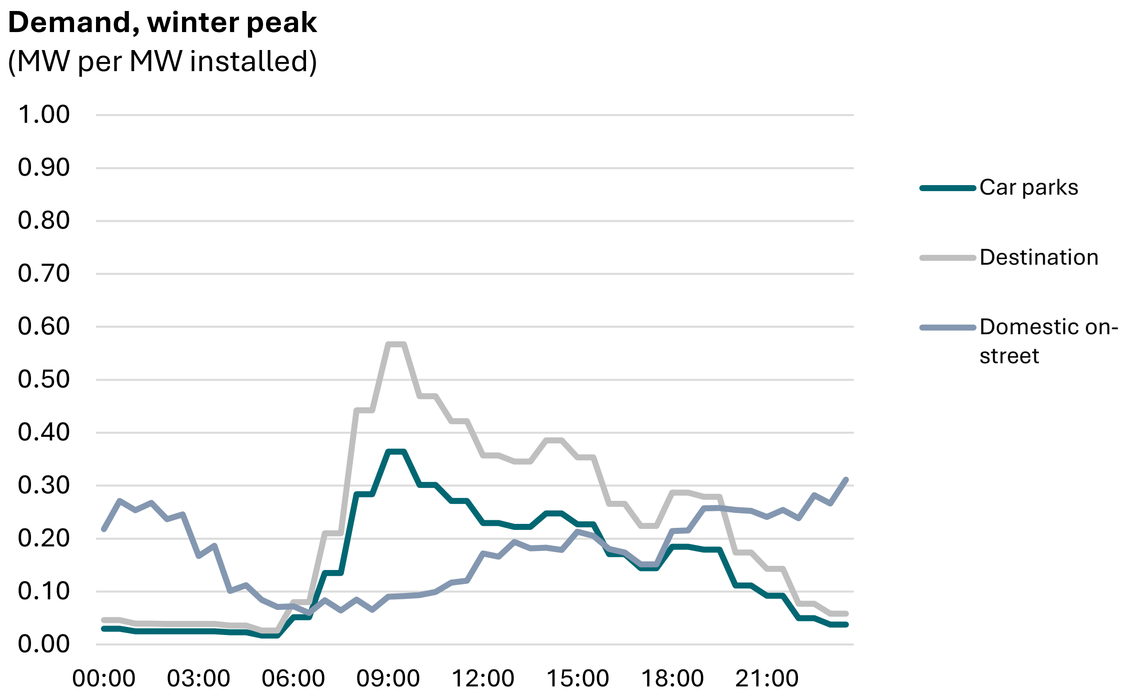

Figure 41: Individual load profiles for public slow chargepoints for winter peak demand day, sourced from NGED

3.2.5. Public rapid chargepoints

Public rapid chargepoints include the chargepoint archetypes and their projected capacity from the FES 2023 Consumer Transformation Scenario, which are shown in Table 34.

Table 34: Public rapid chargepoint archetypes and projection of capacity

FES building block	Regen transport model EV chargepoint archetype	Split of installed capacity (average from 2024 to 2050 from Regen projections)	2024 installed capacity (GW)	2050 installed capacity (GW)
Public rapid (over 50kW, including eHGV chargepoints)	En-route/local	70%	0.55	5.11
	En-route national network	14%	0.12	0.91
	En-route HGV	16%	0.02	2.29

The load profile for public rapid charge points is derived from a weighted average of the three en-route charge archetypes provided by NGED.

A point of note is that the NGED profile for en-route national and en-route eHGV chargepoints features a maximum import at 100% of capacity during peak demand days. This is conservative and, according to the NGED customer behaviour profiles and assumptions report, has been adopted because of a lack of available data on these chargepoint archetypes. NGED has indicated that they intend to update these profiles as more chargepoints of these archetypes are deployed and more data becomes available.

Profiles for each archetype, provided by NGED, are weighted in proportion to installed capacity (as projected in the scenario development analysis, shown in Table 34). The output weighted profiles (shown in Figure 42) have a similar shape to the input en-route local chargepoint profile, with higher overall demand and significantly higher night time demand.

Known limitations for public rapid chargepoints:

- Using a weighted profile removes the granularity of the individual profiles, potentially misrepresenting the constraints generated by each individual chargepoint archetype
- Modelling eHGV and en-route national chargepoints at maximum demand is conservative. In reality, there will be patterns in usage (though coincident peaks may occur at any time of day). The network impact of these chargepoints is, therefore, likely overestimated.
- The weighted profile overestimates the night time charging of en-route local demand, which can be very low.

Table 35: Maximum half-hourly demand on each representative day for load profiles provided by NGED

Max half-hourly demand (MW per MW installed)	En-route national network	En-route/local	En-route eHGV
Winter peak demand	1.00	0.65	1.00
Intermediate cool peak demand	1.00	0.54	1.00
Summer peak generation	0.00	0.10	0.00

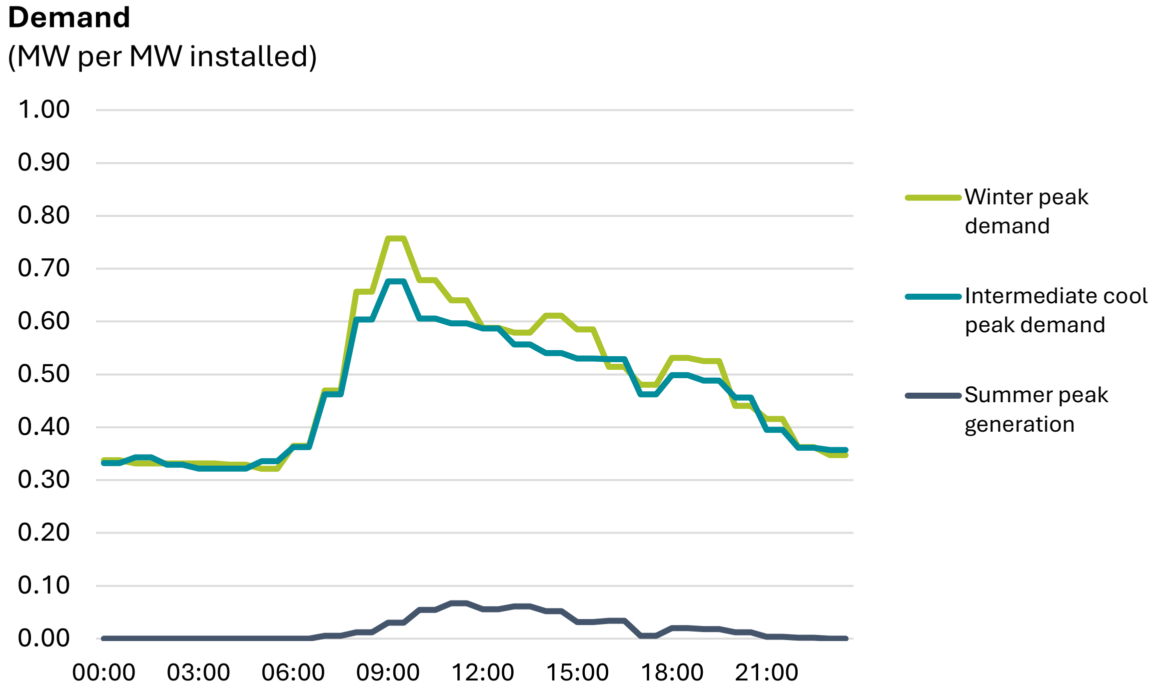

Figure 42: Weighted load profiles for public rapid chargepoints

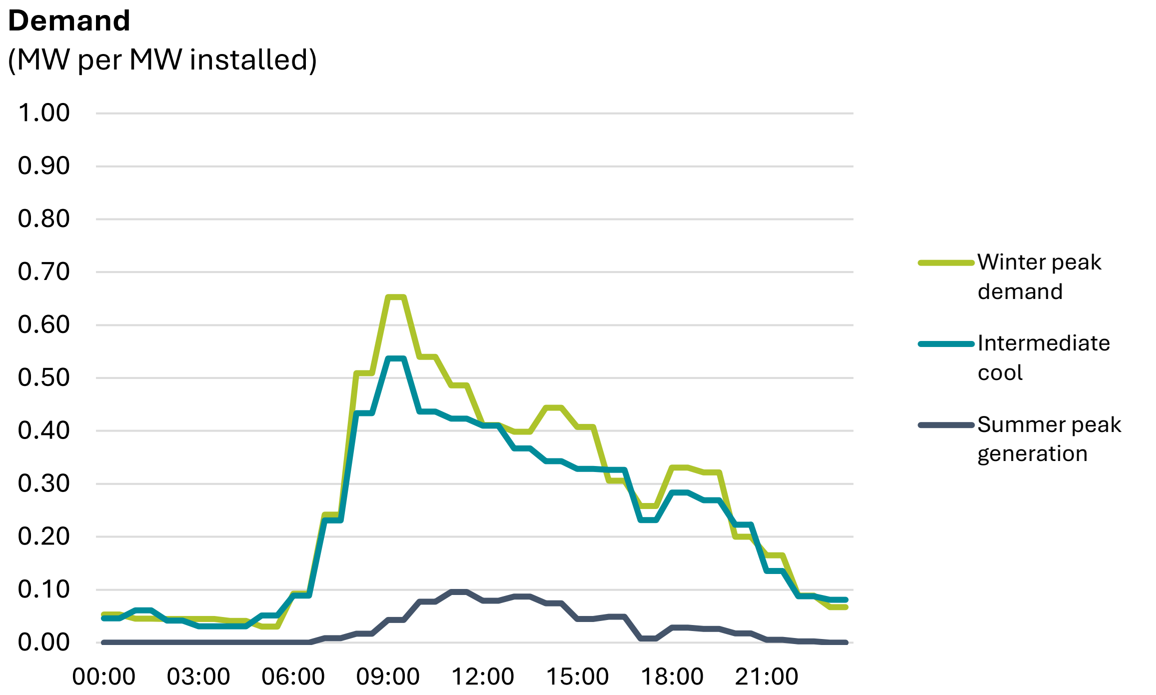

Figure 43: Unweighted load profiles for en-route local chargepoints

3.3. Heat

3.3.1. Heat summary

This section defines load profiles and flexibility behaviour for heat technologies for use in network capacity analysis conducted in WP2. Table 36 summarises the subtechnologies and the sensitivity cases included in the analysis. Load profiles are selected for each subtechnology. As described in Section 3.1.4, the flexibility sensitivities concern individual consumer behaviour in response to wholesale market signals provided through tariffs (implicit flexibility).

Table 36: Heat subtechnologies and sensitivities

Heat subtechnology	**Low flexibility sensitivity**	**High flexibility sensitivity**	**Winter stress test sensitivity**
Domestic heat pumps	All heat pumps are assumed to operate with unmanaged profiles	A proportion of heat pumps (changing over time) are assumed to operate with a managed profile	All heat pumps operate with a higher demand profile
Non-domestic heat pumps	All non-domestic heat pumps operate with the same profile in both low and high flexibility sensitivities		All non-domestic heat pumps operate with a higher demand profile
District heat networks	All district heat networks operate with the same profile in both the low and high flexibility sensitivities		District Heat connections operate with a higher demand profile
Direct electric heating	All direct electric heating systems operate with the same profile in both low and high flexibility sensitivities		Domestic direct electric heating systems operate with a higher demand profile. Non-domestic systems use the same profile due to a lack of available evidence

3.3.2. Domestic Heat pumps

Summary

A significant quantity of data was received from the six DNOs in relation to half-hourly heat pump load profiles in the RFI. All of the profiles are presented in the data workbook and a summary of the profiles received is provided in Table 37.The table records the coverage of profile data for:

- Air Source Heat Pumps (ASHP)
- Ground Source Heat Pumps (GSHP)
- Profiles for each heat pump type operating flexibly (an asterisk in Table 37 indicates that flexible profiles were also provided alongside unmanaged profiles – this is only the case for NGED).

Several DNOs did not differentiate between ASHP and GSHP profiles in the data provided to Regen. This is denoted in the table against GSHP line items with the note "(=ASHP)".

In this context, flexible profiles for heat pumps refer to those operating with thermal storage, which enables heat generation to be decoupled from demand. Generally, this refers to the use of an insulated buffer tank that stores heated water, the energy from which can then be dispatched via a heat exchanger to provide space heating, hot water, or both.

Table 37: Summary of half-hourly heat pump load profiles received from DNOs in RFI. The asterisk denotes that profiles were provided for unmanaged and flexible operation modes

DNO	Technology	Intermediate Cool peak demand	Summer peak generation	Winter peak demand
NPg	ASHP	✓		✓
NGED		✓*	✓*	✓*
UKPN		✓	✓	✓
ENWL				✓
SSEN		✓		✓
SPEN				✓
NPg	GSHP	✓ (= ASHP)		✓ (= ASHP)
NGED		✓*	✓*	✓*
UKPN		✓	✓	✓
ENWL				✓
SSEN		✓ (= ASHP)		✓ (= ASHP)
SPEN				✓ (= ASHP)

There is significant variation in approaches taken to modelling demand from heat pumps across the DNOs, representing the fact that heat pump demand is still emergent and there is limited data on usage in a range of settings in the UK. The underlying assumptions and their implications are explored further below in the “Load Profile Comparison” section.

Not all DNOs differentiate between ground-source and air-source, domestic and non-domestic systems, and some profiles used are significantly more conservative than others. Where possible, additional context has been sought from DNOs to enable a like-for-like comparison with the profiles of their counterparts without the need to introduce modelling assumptions that may be inconsistent with the DNO’s modelling approach.

The heat pump profiles provided by NGED provide the basis for the profiles used in this study for the following reasons:

- The profiles have full coverage of the required demand days for this study
- No additional assumptions regarding annual energy consumption are required as profiles provide information in terms of kW/heat pump rather than normalised against consumption
- The profiles build on sources used elsewhere by other DNOs, such as findings of the 2015 Consumer Led Network Revolution (CLNR) study conducted by Northern Powergrid and a consortium of others[63]
- The profiles contain provisions for the impact of flexible heat pump demand enabled by thermal storage, which is a key area of focus for this study and not provided elsewhere by the DNOs
- The profiles contain differentiated assumptions for air source and ground source units, which is not the case across all DNOs. Specifically, the profile shapes are the same but have been scaled to reflect a higher average coefficient of performance for GSHPs. This approach is consistent with the data provided by UKPN and ENWL and is discussed further in the “Load Profile Comparison” section.

NGED built upon the CLNR outputs in DFES 2023 by validating the profiles against a range of other studies and literature, detailed in their Consumer Behaviour report which accompanies the DFES.[64] This results in a scaled set of profiles for all representative demand days (including profiles for heat pumps with thermal storage acting flexibly) that capture demands for a severe cold spell, including additional demand for electrical backup heating. This, therefore, provides a conservative view of heat pump peak demands that go beyond the requirements for modelling an average cold spell.

To address this, the NGED profiles have been scaled down (using average peak demands for each representative demand day) to provide a final set of ASHP and GSHP profiles incorporating managed heat pump flexibility. Further detail is given in sections below. A summary of the domestic heat pump profiles selected for the analysis is given in Table 38.

[63] Consumer Led Network Revolution Insight Report: Domestic Heat Pumps, Durham Energy Instituite and Element Energy for Northern Powergrid, 2015 ,accessed via http://www.networkrevolution.co.uk/wp-content/uploads/2015/01/CLNR-L091-Insight-Report-Domestic-Heat-Pumps.pdf

[64] P74 Distribution Future Energy Scenarios 2023 – Customer behaviour profiles and assumptions report, National Grid Electricity Distribution, 2023

Table 38: Summary of load profiles used for domestic heat pumps (ASHP, GSHP, non-managed and with thermal storage)

Representative demand day	Profiles used (referenced by DNO)	Notes
Winter peak demand	Scaled NGED	NGED profiles scaled down by average peak demands (see “Selected load profiles” section below)
Intermediate cool peak demand	Scaled NGED	
Summer peak generation	NGED	Flat 0kW import – a conservative assumption
Winter stress event	NGED	Unmodified winter peak demand profile

Load Profile Comparison

Some modifications to the data received from the DNOs are necessary to enable a like-for-like comparison (i.e. in terms of kW per heat pump, for the defined demand days). These are summarised fully in Table 41. Consumption data is required to convert profiles normalised against annual energy usage (provided by ENWL, NPg and UKPN) into absolute demands. Where specific consumption data is not provided by DNOs, data from FES is used to calculate the average demands of non-domestic heat pump users.[65] As this analysis does not use profiles that change year-on-year, the average demand per non-domestic heat pump is calculated over the full time horizon (i.e. from present day to 2050) under the Consumer Transformation scenario. The normalised demand profiles from UKPN, ENWL and NPg are scaled accordingly, to give the profiles displayed in Figure 44. The average annual demands for UKPN, ENWL and NPg are summarised in Table 39. Consumption data from the other DNOs is not required because the profiles provided are not normalised against annual consumption.

Table 39: Average domestic heat pump annual energy demands used to scale normalised profiles

Relevant normalised profiles	Technology	Average annual energy consumption per domestic heat pump (kWh)	Source
UKPN	ASHP	3,440	UKPN data (total modelled heat pump consumption at licence area level, divided by counts)
	GSHP	2,380	
ENWL	ASHP	3,580	FES Table ED3, Consumer Transformation scenario
	GSHP	2,610	
NPg	ASHP	3,780	NPg data (total modelled heat pump consumption at licence area level, divided by counts)
	GSHP		

The resulting profiles for winter peak demand are compared in Figure 44.

[65] FES Data workbook V003, Table ED3, ESO 2023

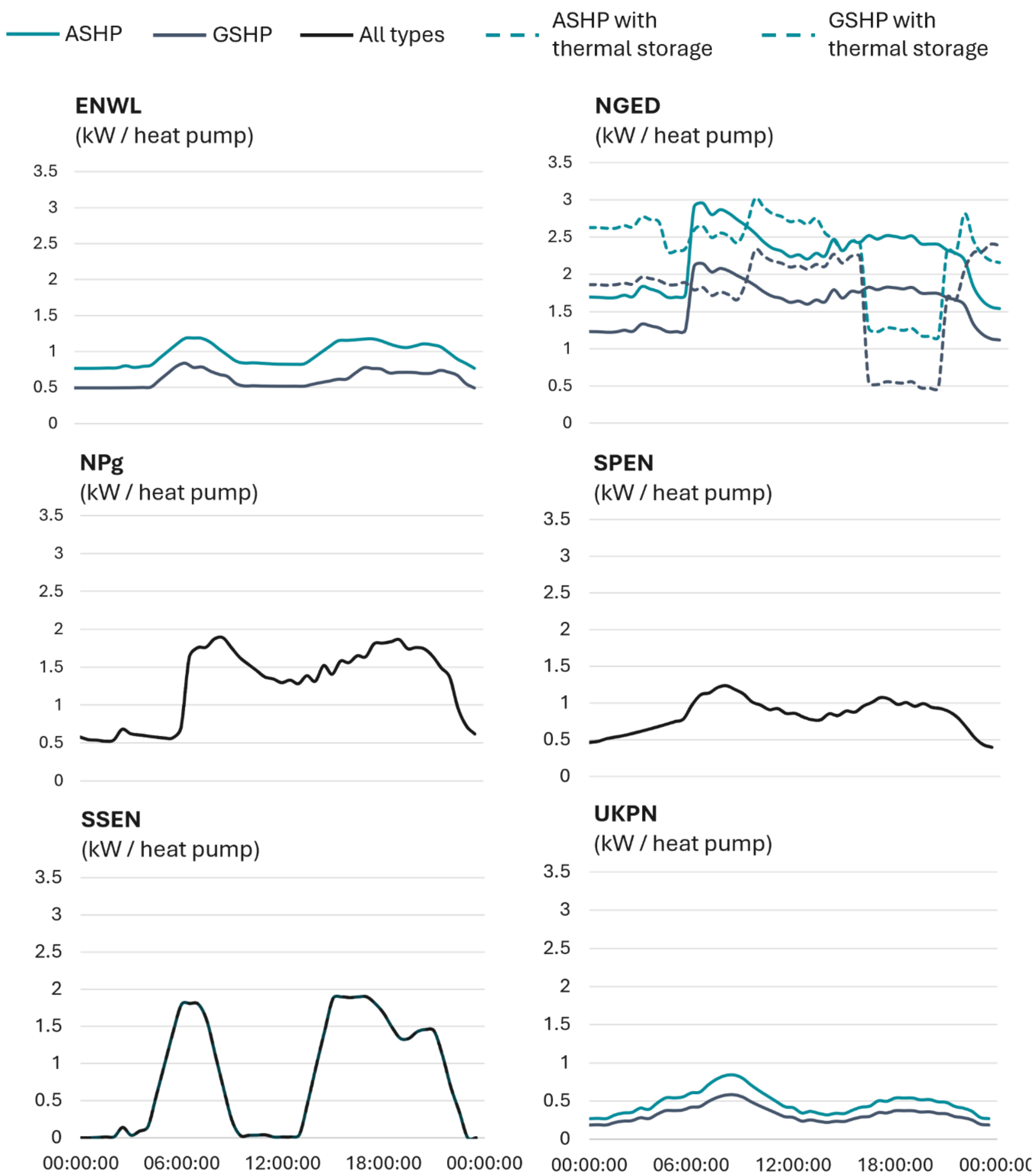

Figure 44: Winter peak demand profiles for ASHP and GSHP received in the RFI. [66,67,68,69,70] NPg, SPEN and SSEN do not differentiate between air-source and ground-source units, as shown in Table 37

In all cases where ASHP and GSHP are modelled separately, a scaling factor is applied by the DNOs to capture differing efficiencies (GSHP generally exhibit higher coefficients of performance). The implied scaling factors are given below in Table 40. The data show good agreement between the DNOs, with ASHP loads being 40-60% higher than GSHP. This suggests the average seasonal coefficient of performance (sCOP) of a GSHP is 40-60% higher than that of an ASHP.

Table 40: Summary of average scaling factors applied between ASHP and GSHP profiles

DNO	Average scaling factor [ASHP kW/GSHP kW]
NGED	1.4
UKPN	1.4
ENWL	1.6

Renewable Heat Incentive (RHI) data shows GSHP performance exceeds ASHP performance by up to 37%, varying based on installation age and time of year.[71] The RHI data shows older installations have an average sCOP of 2.5, while newer installations average 3.6. However, heat pumps eligible for the RHI have a minimum acceptable performance factor of 2.5, and data are based on installation certificates submitted in applications for the scheme.

Monitored performance data presented in the analysis of the DESNZ Electrification of Heat trial by Energy Systems Catapult show ASHP coefficients of performance in broad agreement with RHI data. On the coldest day, the trial sample achieved an sCOP of 2.44, and the overall median was around 2.90 (varies based on refrigerant).[72] GSHP sCOPs have not been reported on in the Electrification of Heat trial data due to a lack of coverage but applying the NGED assumption of a scaling factor of 1.4 suggests a GSHP sCOP of 4.06, which is comfortably within the range of GSHP sCOPs reported by the RHI data. As such, DNO assumptions are deemed reasonable but conservative.

[66] UKPN profile derived from: Neighbourhood Green Additional Heat Pump Demand Profiles WP6, ERM for UKPN, 2024

[67] ENWL and SSEN profiles derived from analysis of Managing the future network impact of electrification of heat, Delta EE for ENWL, 2016

[68] NGED profiles derived from Consumer Led Network Revolution TC3 Dataset and Heat pump insights report[63], modified in line with findings of several other studies outlined in NGED's Customer Behaviour report[64]

[69] NPg profile derived from Consumer Led Network Revolution TC3 Dataset and Heat pump insights report[63]

[70] SPEN profile derived from internal modelling of heat pump demands

[71] RHI monthly deployment data, Department for Energy Security and Net Zero, March 2024 (Annual edition)

[72] Interim Insights from Heat Pump Performance Data, Electrification of Heat Demonstration project, Energy Systems Catapult for Department of Energy Security and Net Zero, 2023

As noted above, some modifications have been applied to the source data profiles for domestic heat pumps to enable comparison on a kW per heat pump basis. These are summarised below in Table 41.

Table 41: Summary of modifications made to DNO profiles

DNO	Modification	Detail
NPg, UKPN, ENWL	Conversion from values normalised against annual consumption (i.e. kW/kWh_{annual}) to absolute demand per heat pump	Multiplying the normalised profile by an annual energy consumption gives a load profile in kW Data used is described in Table 39
NGED	Peak demand scaling factors	NGED apply scaling factors to their profiles each year in order to account for improving building stock efficiency and heat pump performance, as well as increasing ambient temperatures due to climate change (i.e. a reduction in heating demand requirement)[73] This analysis uses profiles which do not vary year-on-year. As such, an average scaling factor has been derived from NGED's data for each profile.[74] These are summarised below: • ASHP profiles: 88.8% • GSHP profiles: 90.8%
NPg	Mapping of monthly profiles to representative days in this study	NPg provided profiles on a monthly basis. The months were mapped to the seasonal periods (winter, intermediate cool etc.) in a manner consistent with the mapping in Section 3.1.1. Maximum values were then found for each half hour in each season to give an overall peak profile
SSEN	Mapping of seasonal profiles to representative days in this study	SSEN provided a seasonal profile for summer, winter and spring/autumn. These were mapped as follows: • Winter peak demand – winter profile

[73] Figure 65, Distribution Future Energy Scenarios 2023 - Customer behaviour profiles and assumptions report, National Grid Electricity Distribution 2023

[74] DFES Annual Scaling data, National Grid Electricity Distribution, 2023. Accessed via https://connecteddata.nationalgrid.co.uk/dataset/dfes

DNO	Modification	Detail
		• Intermediate cool peak demand – spring/autumn profile • Summer peak generation – heat pump demand assumed to be 0
UKPN	Mapping of seasonal profiles to representative days in this study	UKPN's profiles are provided for three seasons (winter, summer and "shoulder"). Max. and min. profiles have also been provided in each case. The UKPN season definitions broadly align with those being used in this study. Throughout the heat analysis, the mapping from UKPN seasonal max/min profiles to representative days is as follows: • Winter peak demand – UKPN winter maximum • Intermediate cool peak demand – UKPN winter maximum • Summer peak generation – UKPN summer minimum

Selected load profiles

As described above, NGED's winter peak profiles reflect demands for a severe cold spell. The profiles, therefore, exceed the requirements for modelling an average cold spell.

However, implicit flexibility and its impacts on peak demand is a key area of focus for this study and only NGED profiles (of the data received for this study from DNOs) provide a view of consumer-driven flexible heat pump usage (enabled via thermal storage). As such, the NGED profiles are scaled down to provide the final domestic heat pump profiles for this analysis.

This is achieved using the average peak demand across the DNO profiles for each representative demand day. Figure 45 compares the averages against the unmodified peak from the NGED profiles.

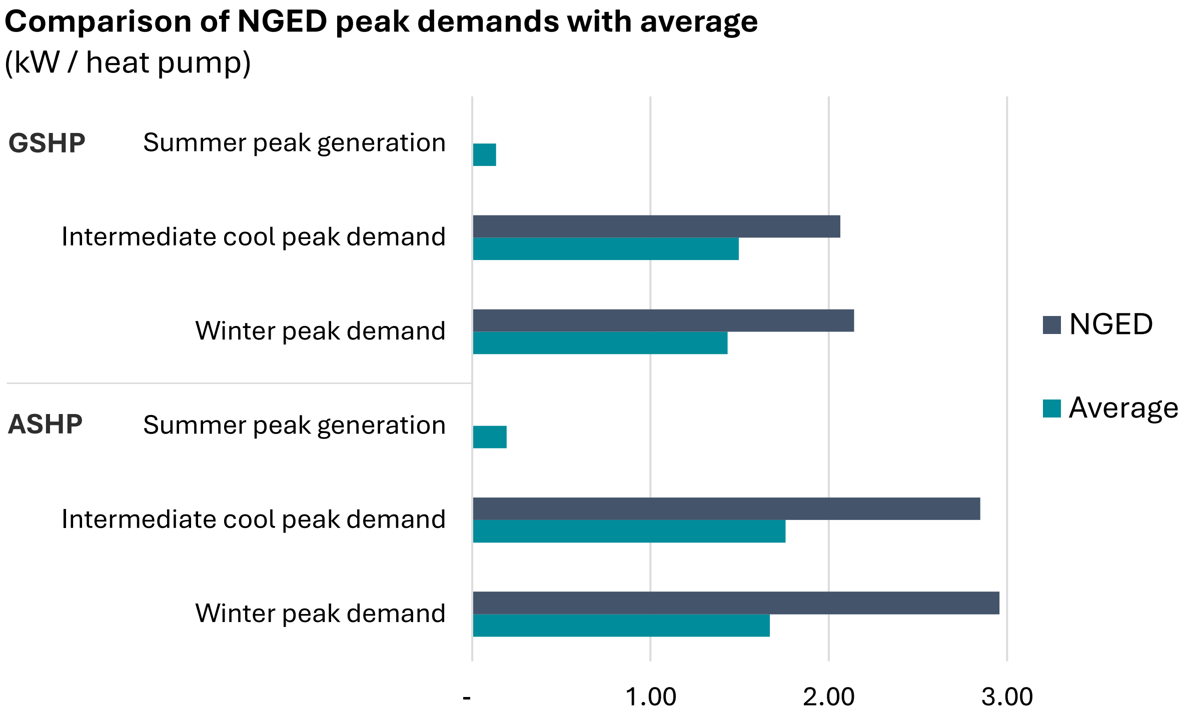

Figure 45: Comparison of NGED peak heat pump demands with averages

The NGED profiles are scaled down to bring the peak in alignment with the average values, retaining the shape from the CLNR study but reducing the peak impact of individual heat pump units. This provides a standard representative day, rather than a worst-case scenario. These are plotted below in Figure 46 for winter peak and the full set of scaled profiles is contained in the accompanying data workbook.

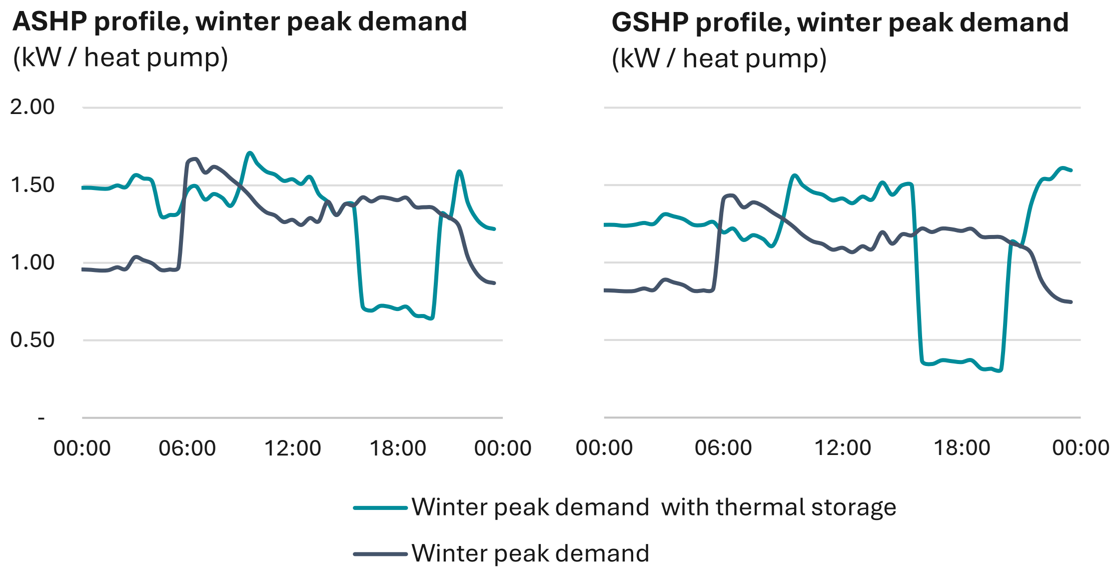

Figure 46: Scaled winter peak heat pump demand profiles, for ASHP and GSHP

Flexibility

Most DNOs did not provide profiles for flexible heat pump loads (see Table 37 above), indicating uncertainty in the effect and materiality of domestic heat pumps as a source for implicit demand-side flexibility. Demand reductions are generally applied in DNO modelling, which reduces peak demands over time to reflect improving efficiencies. However, heat demand shifting is currently only incorporated by NGED and this is enabled via the use of thermal storage.

In UKPN's recent Neighbourhood Green innovation study, which developed UKPN's heat pump profiles based on Electrification of Heat trial data,[75] there is discussion around the feasibility of heat pumps as a vector for demand management in domestic settings. The analysis found that the trial data suggests heat pump demand could be a suitable candidate for incentivised demand shifting due to high diversity. However, the trial did not explore how heat demand could be managed, or how this could be incentivised. As such, Neighbourhood Green did not present load profiles for heat pumps acting flexibly, meaning the UKPN heat pump profiles presented here do not contain flexibility assumptions.

Figure 47 shows heat pump profiles originally derived for the Transform model by GL Noble Denton.[76] The approach to flexibility is consistent with NGED's, with demand at network peak times being shifted to other parts of the day.

Similarly, Figure 48 shows heat pump demands from ESO's 2023 FES modelling, for Leading the Way in 2050[77]. These profiles show the variable operation of heat pumps on the peak day, with significant peak shifting during the morning and evening enabled by thermal storage. The data has been normalised against heat pump counts. Data is only presented in the FES for Leading the Way – as such it is unsuitable for use in this project, but indicates similarities in thermal storage behaviour to the profiles provided by NGED.

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[75] Electrification of Heat project – Heat Pump performance data, Energy Systems Catapult and Department for Energy Security and Net Zero, 2020-2023

[76] Figure 12.3, Assessing the Impact of Low Carbon Technologies on Great Britain's Power Distribution Networks, GL Noble Denton, EA Technology and others for Energy Networks Association Smart Grids Forum, 2012

[7777] Future Energy Scenarios 2023 workbook, data items FL.06 and FL.07, normalised with heat pump uptake data from table ED3.

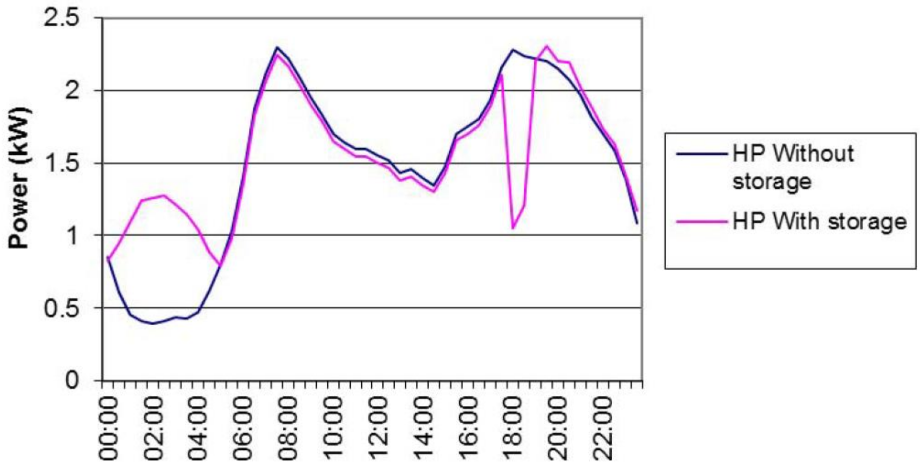
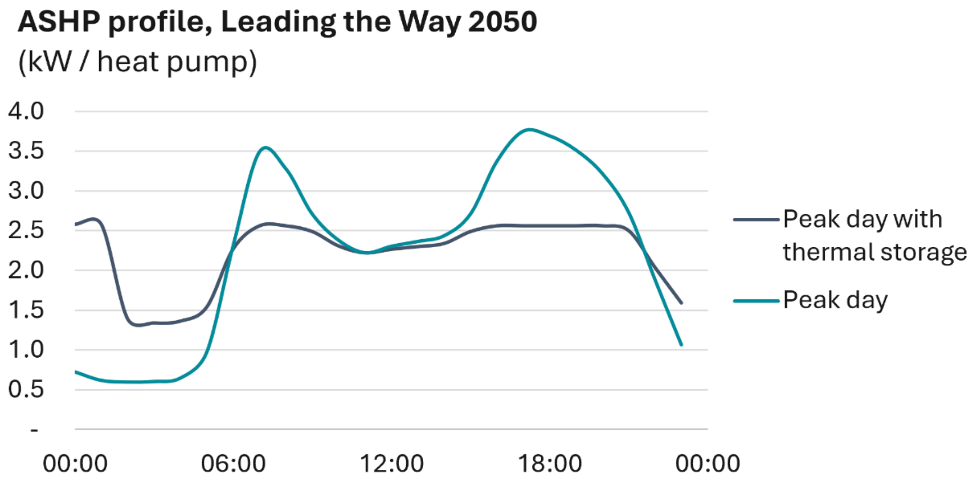


Figure 47: Heat pump profiles originally used in the Transform model[76]



Note: System level ASHP demand for Leading the Way in 2050 (FES 2023 data items FL.06 and FL.07) has been normalised against corresponding ASHP uptake (table ED3).

Figure 48: FES 2023 ASHP profile for Leading the Way, 2050

Given that profiles incorporating heat flexibility were only provided by NGED in the RFI, the approach adopted by NGED is adopted in WP2 of this study. As shown in Figure 47 and Figure 48, NGED's approach to flexibility is broadly consistent with that used in Transform previously (which was developed in collaboration with the Energy Networks Association), and the implied behaviour of heat pumps in FES. Varying levels of flexibility are captured by changing the number of heat pumps using thermal storage to provide flexibility between sensitivity cases.

The flexibility approach adopted in the NGED heat pump profiles with thermal storage is described in detail in their Consumer Behaviour Profiles and Assumptions report, and is summarised below:[78]

- In alignment with the approach described in Section 3.1.4 of this report, the flexible heat pump demand profiles are designed so that thermal energy is stored at times of low network demand – i.e. when prices are low – to alleviate peak demands
- The flexible profiles are based on the same underlying data as the standard ASHP and GSHP profiles but with reduced electrical demands in the morning and evening periods, which is typically when heat pump peaks are expected to occur in the domestic sector. This is seen consistently in the range of profiles provided by the DNOs, Figure 44
- The profiles were recently updated to reflect the impact of different price signals coming from a range of retail tariffs during the evening peak and other effects.

The market for heat pump tariffs is developing rapidly, though it remains in its infancy. Uptake rates are still relatively low compared to other technologies, like EVs. As the adoption of heat pumps increases, more data will become available and will help improve the accuracy of load profiles. A notable difference between heat pump and EV tariffs is the prevalence of multiple periods of discounted electricity prices seen in heat pump tariffs. Contrastingly, EV tariffs typically favour a single overnight discounted period. As the market for heat pumps matures and as smart technology is implemented, heat pump behaviour is expected to evolve in response to increasingly dynamic retail tariffs. However, the current early stage of market development means that significant uncertainty remains regarding how these factors will shape consumer behaviour.

High flexibility sensitivity case

The weighting between non-managed and flexible heat pump profiles is determined based on data from NGED's DFES analysis, which reports on the uptake levels of air source and ground source systems both with and without thermal storage. Heat pumps with thermal storage are not reported within FES building blocks, and wider evidence for the future uptake of flexible heat pump systems on a national level has not been found. As such, the proportion of non-managed heat pumps from NGED's DFES is used to further split out the heat pump uptake curves developed under work package 1.3. The split between standard ASHPs and those with thermal storage in NGED's Consumer Transformation is shown below in Figure 49. These proportions are to define the level of ASHP flexibility in the "high flexibility" sensitivity case. The equivalent data for GSHPs from NGED DFES is used for GSHPs.

Note that these assumptions are more conservative than implied in FES data – the profile shown in Figure 47 is derived from system level heat pump demand totals from FES 2023, which suggests an overall peak reduction of 13.9GW (or around 1kW per heat pump when considered

[78] P74 Distribution Future Energy Scenarios 2023 – Customer behaviour profiles and assumptions report, National Grid Electricity Distribution, 2023

across the entire stock of air source and ground source units). The profiles from NGED offer similar peak reduction (see Figure 46) for each heat pump with thermal storage – but as shown in Figure 49 below, not all heat pumps are assumed to provide flexibility in this manner.

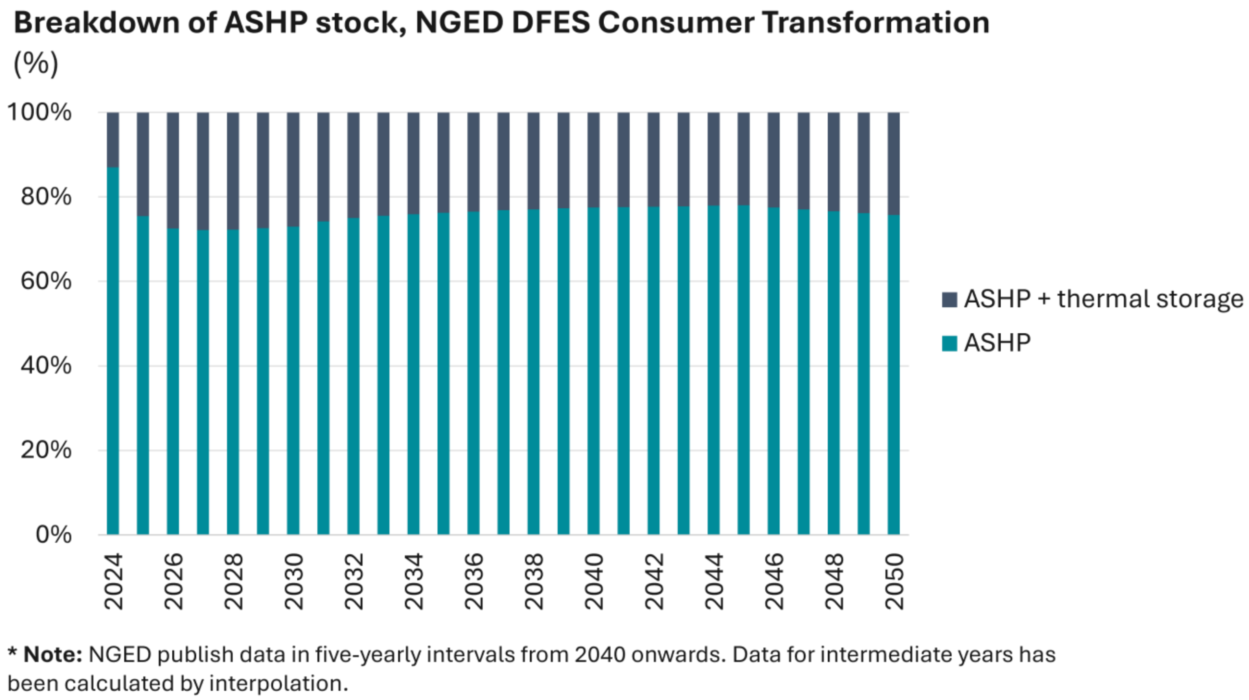


Figure 49: Breakdown of ASHP stock across NGED's region in NGED DFES Consumer Transformation[79]

Low Flexibility Case

In the low flexibility case, all heat pump demand is assumed to be non-managed. This approach aligns with that adopted by DNOs other than NGED, which do not assume heat flexibility in their profiles.

Winter stress test profiles

Model run 7 (see section 3.1.7) in this analysis tests high demands for a winter event which stresses the network by adopting higher load profiles for heating technologies based on the DNO data.

Ensuring system resilience by modelling extreme weather events, particularly cold spells, is a standard modelling practice across energy networks. The rationale is that on an extremely cold day, multiple confounding factors are likely to increase demand on the network. First, homes require more heat to maintain comfort for occupants. Second, lower outside temperatures

[79] DFES volume projections by local authority, National Grid Electricity Distribution, 2023

cause a drop in heat pump coefficient of performance (i.e., more electricity is required to provide the same heat output). In addition, lower diversity in network customer behaviour can be expected.

NPg and UKPN provided explicit modelling assumptions. NPg provided a specific profile, while UKPN provided a range of scale factors to apply to their domestic heat pump profile derived during the Neighbourhood Green innovation project.[63, 66]

As described in previous sections, NGED built upon CLNR profiles in DFES 2023 by validating them against a range of other studies and literature, detailed in their Consumer Behaviour report which accompanies the DFES.[80] The result of this process was the derivation of "edge case" load profiles, with peaks scaled to three standard deviations higher than the average to capture the maximum electrical demand from heat pumps in an winter stress test. The profiles also capture additional demand from direct electric backup heating operating in times of "extreme cold". This results in a very conservative peak load, which is also clear from comparing to other DNOs' winter peak day assumptions in Figure 44 above.

The profiles are plotted below in Figure 50. NGED's profile, being the most conservative, is used for the winter stress test sensitivity. This approach also retains the same profile shape as used in the standard heat pump profiles modelled for a winter day.

[80] P74 Distribution Future Energy Scenarios 2023 – Customer behaviour profiles and assumptions report, National Grid Electricity Distribution, 2023

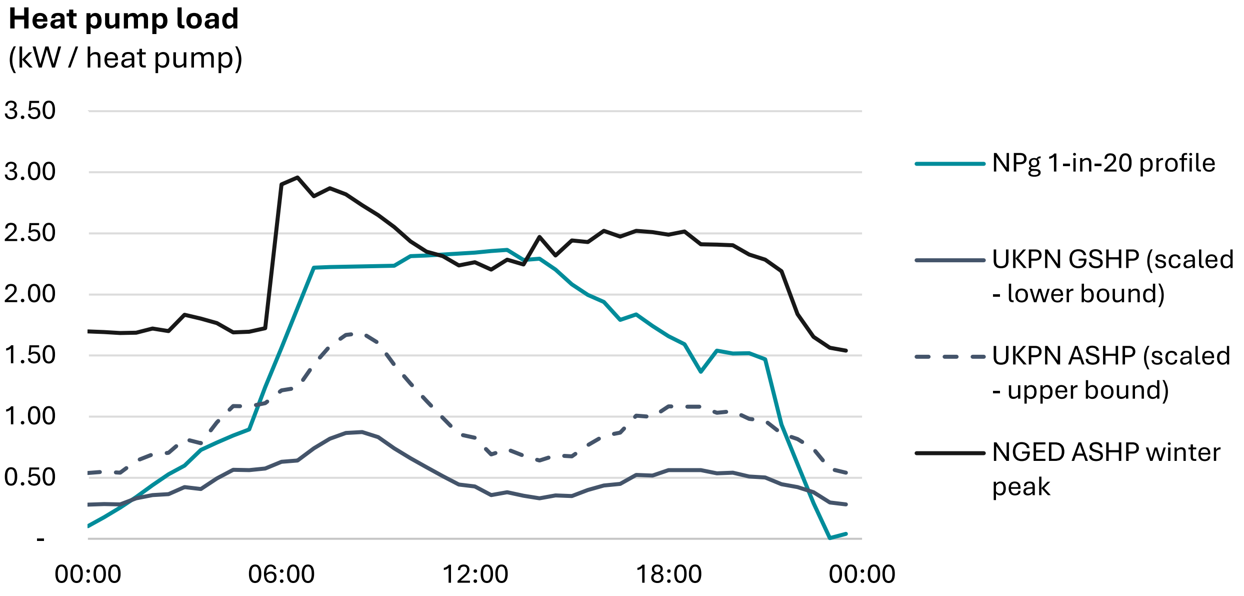


Figure 50: Comparison of load profiles provided by DNOs for cold weather.

Specific profiles and assumptions for extreme cold were not provided for other electrical heat technologies besides domestic heat pumps. In each case, the most conservative (highest peak) profiles have been adopted for the sensitivity case.

Limitations for domestic heat pumps

- **Heat demand peaks will not vary in the Transform model based on building type, as single load profiles are defined for all heat pumps in units of kW per heat pump.** Factors such as building size and efficiency will cause variation in heat pump demands, which is generally captured through DNOs scaling load profiles based on underlying building archetyping (i.e. using profiles normalised against annual heat pump energy consumption). This granularity is lost by using single average load profiles for all systems; at a network level, this may not have a significant impact but at individual substations and feeders, variation may be expected based on local building stock that will not be captured in Transform. This is a common limitation across the study.
- **Flexibility has only been captured for systems using thermal storage to respond to wholesale price signals.** The flexible heat pump profiles rigidly move demand from morning and evening peaks for a subset of users (i.e. those with thermal storage systems). UKPN's Neighbourhood Green report identifies that heat pumps may be a good candidate for demand shifting in general, given their findings of relatively flat diversified profiles, for example, in comparison with domestic underlying demand. However, sufficient evidence does not yet exist to confidently model this behaviour. Based on existing evidence, it is unclear how or if the resulting load behaviour would differ from that seen in the NGED profiles for heat pumps with thermal storage.
- **Heat pump usage is likely to be determined by a range of factors not captured in the load profiles used here, such as building stock efficiency.** The UKPN Neighbourhood Green report highlights the potential for heat pump profiles to be influenced by building efficiency, as more efficient buildings can retain heat for longer and shift demand more easily while maintaining comfort. However, data from the Electrification of Heat trial was insufficient to analyse the impact of factors such as EPC ratings on peak demands or flexibility potential. While no other data was available, future models may incorporate dynamic heat pump usage, adding location-specific granularity to both peak sizes and load profile shapes based on building characteristics.
- **Heat pumps acting flexibly are allocated proportionally across the building stock without consideration of additional factors.** In reality, the suitability of buildings for flexible heat pump operation may be highly variable. For example, Nesta and the Centre for Net Zero's Heatflex pilot project found that while generally heat flexibility was found to be achievable with limited impacts to residents, factors such as the fabric efficiency of a building, home layouts and interoperability issues with smart meters and other devices limited flexibility potential in some instances.[81]

[81] Automating heat pump flexibility – results from Heatflex pilot, Nesta and Centre for Net Zero, 2023

3.3.3. Non-domestic heat pumps

Summary

A range of non-domestic heat pump load profiles were provided by the DNOs in response to the RFI. These are summarised in Table 42. Note that the mapping between the data provided and the representative demand days used in this study is consistent with the processes outlined for heat pumps in Table 41.

Table 42: Summary of half-hourly non-domestic heat pump load profiles received from DNOs in RFI

DNO	Heat pump type	Intermediate cool peak demand	Summer peak generation	Winter peak demand
NPg	Non-domestic	✓		✓
NGED	Non-domestic	✓	✓	✓
UKPN	Non-domestic	✓	✓	✓
ENWL	Non-domestic			✓
SSEN	Non-domestic	SSEN does not currently model specific non-domestic heat pump profiles		
SPEN	Non-domestic	SPEN did not provide specific non-domestic heat pump profiles		

NPg's profiles are adopted for non-domestic heat pumps for the following reasons:

- Good coverage of representative demand days with no modification required
- Good agreement with profiles provided by other DNOs
- Peak load per heat pump sits in the middle of the range of profiles provided.

NGED's assumptions are most conservative, with a significantly higher peak demand per heat pump than other DNOs. NGED's winter profile is also flat throughout the day and night to capture uncertainty in non-domestic heat pump usage.[82] As such NGED's profile is used for the winter stress test sensitivity (run 7).

[82] P94, Distribution Future Energy Scenarios 2023 – Customer behaviour profiles and assumptions report, National Grid Electricity Distribution, 2023

NGED's profile for the summer peak generation day (flat, 0kW) is also used as this is consistent with the approach taken elsewhere in the analysis and provides a conservative worst-case scenario.

Load profile comparison for non-domestic heat pumps

As for domestic heat pumps, some modifications to the source data are made to enable a like-for-like comparison of profiles from each DNO. The changes described above in Table 41 also apply for non-domestic profiles.

The normalised demand profiles from UKPN and NPg are scaled according to the average demand figures given below in Table 43 to derive the profiles displayed in Figure 51. Though NPg's annual average consumption figures are significantly lower than FES's, this data is retained as it is derived directly from the outputs of NPg's DFES load modelling. Therefore, the resulting scaled profile best represents the DNOs' view of average I&C heat pump load profiles.

Table 43: Average non-domestic heat pump annual energy demands used to scale normalised profiles

Relevant normalised profiles	Average annual energy consumption per non-domestic heat pump (kWh)	Source
UKPN, ENWL	34,190	FES Consumer Transformation
NPg	19,840	NPg DFES results, provided by the DNO

Modifications are also made to NGED's profiles for several building archetypes, which are presented in terms of demand per m^2 of floorspace heated by a heat pump. The archetypes used by NGED are based on building use cases, such as shops, restaurants, warehouses, and hotels. This approach is also seen in other sources, including the ESO's Non-domestic Consumer Building Blocks.[83] The Transform model's internal logic also splits I&C customers into similar categories based on Valuation Office Agency data. However, the Transform inputs are aggregated across all I&C users.[84]

The NGED profiles are converted into a weighted average kW per connection assumption through the following process:

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[83] Consumer Building Blocks, ESO, March 2024 (Data download)

[84] P188, Assessing the Impact of Low Carbon Technologies on Great Britain's Power Distribution Networks, GL Noble Denton, EA Technology and others for Energy Networks Association Smart Grids Forum, 2012

1. Using NGED DFES projections for heat pump heated floorspace, an aggregate (licence area level) peak demand is calculated for each building type for every year until 2050 (for the Consumer Transformation scenario)
2. The peak demands of the building types are summed to give a total non-domestic heat pump peak demand for each representative day, every year to 2050
3. NGED DFES does not report on the number of non-domestic heat pumps. Instead, the FES data is summed to give non-domestic heat pump counts for NGED's licence areas under Consumer Transformation each year to 2050
4. Dividing the aggregate demand by the FES heat pump counts gives an average non-domestic heat pump demand for each year
5. Given that this analysis uses one profile per technology for the whole time horizon, the mean value of the trend to 2050 is taken for each of the representative demand days. The resultant demands are given in full in the data workbook and the winter peak demand day is plotted in Figure 51.

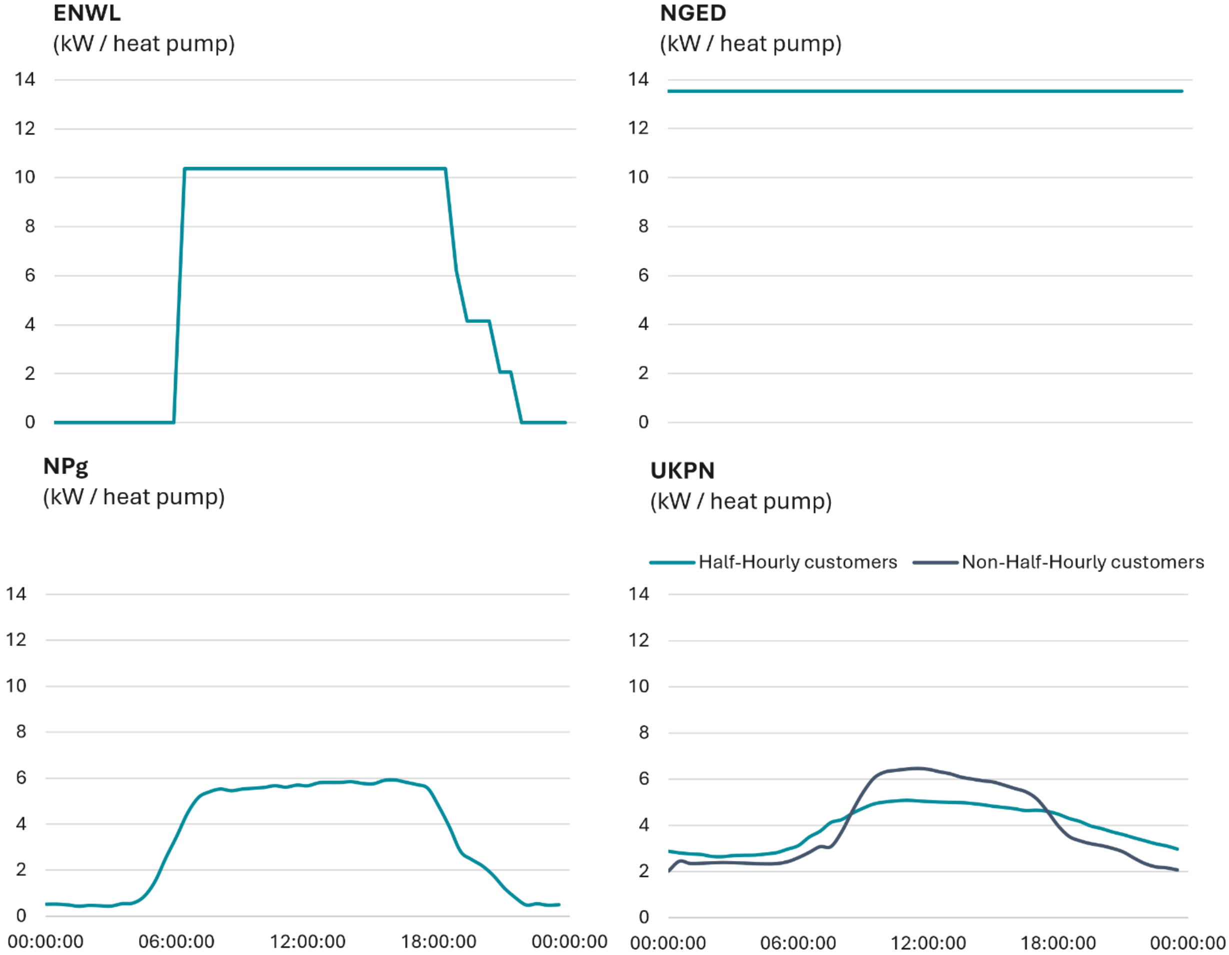


Figure 51: Winter peak demand load profiles for non-domestic heat pumps received in the RFI

The profiles displayed in Figure 51 come from a range of sources, summarised in Table 44. This also shows key assumptions and the implications of their use in this analysis.

Table 44: Description of load profiles provided by DNOs through the RFI, including key sources, assumptions and implications for this analysis

DNO	Non-domestic profile source	Key assumptions/notes
UKPN	Energy Demand Research project (2011)[85] and analysis	Source data is normalised against annual consumption, as described above

[85] Energy Demand Research Project Final Analysis, Ofgem, 2011

DNO	Non-domestic profile source	Key assumptions/notes
	of UKPN monitoring data	The profile aligns broadly with those provided by ENWL and NPg, with heat pump demand coinciding with non-domestic building occupation patterns Profiles vary by half-hourly and non-half-hourly customer groups, but not building types
NGED	NGED modelling (2023) and Building Services Research and Information Association (BSRIA) "rules of thumb" (2010)[86]	Profiles are expressed in terms of demand per m^2 of heated floor space, which is assumed to be constant for a given building type. In reality, energy requirements per unit area of heated floor space are expected to vary on a building-by-building level This analysis uses a weighted average profile derived from the proportion of heated floor space belonging to each non-domestic building archetype (further detail below) Profiles are assumed to be flat, with NGED citing insufficient evidence to accurately model intra-day load variations. The result is the most efficient possible distribution of load required to deliver the energy demand to non-domestic buildings. NGED have indicated an intention to research the heating profile in greater depth to determine whether heat pump usage patterns will be run for efficiency or to align with building occupancy It is nonetheless worth noting that the resultant average kW per connection derived from NGED's data is significantly higher than peaks seen in other DNO load profiles
NPg	Profile developed by Element Energy for use in NPg load modelling	Source data is normalised against annual consumption, as described above. The resulting profile sits in the mid-range of others provided Specific assumptions are not provided. The profile qualitatively aligns with those provided by ENWL and

[86] P94, Distribution Future Energy Scenarios 2023 – Customer behaviour profiles and assumptions, National Grid Electricity Distribution 2023

DNO	Non-domestic profile source	Key assumptions/notes
		UKPN, with heating demand appearing to broadly mirror non-domestic building occupancy
ENWL	Internal modelling	Source data is normalised against annual consumption, as described above Specific assumptions are not provided. The profile qualitatively aligns with those provided by NPg and UKPN, with heating demand appearing to broadly mirror non-domestic building occupancy.

Selected load profiles

The profile selection for non-domestic heat pumps is summarised in Table 45.

Table 45: Profile selection for non-domestic heat pumps

Representative demand day	Source of the profile used in the analysis	Notes
Winter peak demand	NPg	Normalised profiles (kW/kWh_{annual}) scaled using NPg DFES average energy consumption outputs
Intermediate cool peak demand	NPg	
Intermediate warm peak demand	NPg	
Summer peak demand	NPg	
Summer peak generation	NGED	Flat 0 kW import – a conservative assumption
Winter stress test	NGED	Flat profile with the highest peak seen in the evidence received

Winter stress event profile

As for other heating technologies, excluding domestic heat pumps, no specific assumptions regarding cold spells are provided for non-domestic heat pumps. As described elsewhere, the approach is, therefore, to adopt the most conservative profile received, which in this case is the NGED load profile, shown in Figure 51This has a significantly higher peak demand than other profiles received and uses a flat profile throughout the day to incorporate uncertainty around the load behaviour of non-domestic heat pumps. In their consumer behaviour report, NGED discusses varying approaches to heat pump operation leading to different load profiles (e.g., maximising efficiency vs. mirroring building occupancy).[82] As heat pumps are an emergent demand in the non-domestic sector, NGED uses a flat profile to capture this. Owing to the approach's conservatism, it is only adopted in the winter stress test sensitivity, where heat demands are expected to be higher.

Known limitations for non-domestic heat pump profiles

- **Using average load profiles removes the granularity of building archetype-specific assumptions (used by several DNOs)** from the analysis. with all non-domestic heat pumps exhibiting the same load behaviour on a given representative day. The aggregate network level impact of this simplification is likely to be minor, but variability in heat pump usage may have significant localised effects in some parts of the LV network, that is not captured by average profiles. This limitation is common across technologies in this analysis, as load profiles for a given technology do not vary by user or building types.
- **Emerging non-domestic heat pump usage patterns, noted by NGED, are not captured in the analysis.** NGED notes uncertainty around emerging non-domestic heat pump usage patterns, with load diversity in this sector being particularly important due to the wide range of end users (e.g., restaurants, warehouses, schools, etc.).[86] This uncertainty is not captured in this analysis, except for in the winter stress test sensitivity where NGED's profile is used as a conservative assumption.

3.3.4. District heat networks

Summary

None of the DNOs profiles contain specific data on intraday demand variability for heat networks. The approaches taken to modelling heat networks differ and are summarised in Table 46A challenge to modelling district heat networks is that designs vary significantly, and their demand profiles will be specific to the technology used and whether there are sources of waste heat.[87] The role of electricity within the heat network will also vary. Network operators will, therefore, tend to model these on a case-by-case basis. However, some network operators adopt general modelling approaches for projected heat network developments, which are summarised in Table 46.

The profiles selected as inputs for WP2 assume that the load profile shapes for heat networks align with those of heat pumps, which is consistent with the approaches of UKPN and NPg. No heat network specific profiles were provided by DNOs. This indicates uncertainty in the future of electric heat network operation and is a key area for future research. NGED's Consumer Behaviour report discusses this uncertainty, noting that their modelling conservatively assumes a flat profile due to a lack of evidence and the likelihood that running patterns will vary significantly from site to site based on connected loads and design characteristics.[87] Despite this, the profiles compatible with the Transform model (UKPN and NPg) do not provide a large enough range in outlook to provide significant insight in a sensitivity analysis (both are of a similar magnitude and are scaled versions of heat pump profiles).

Table 46: Summary of approach to heat network load modelling by each DNO

DNO	Approach to heat network modelling
UKPN	Geospatial heat demand analysis is used to model future heat network uptake for DFES. Uptakes combined with building demand assumptions are used to scale normalised load profiles. Heat network profile are assumed to match heat pump profiles (domestic and I&C treated separately)
NPg	Additional heat demand for heat networks is added to heat pump demand as a sensitivity at the network level. Heat network profile is assumed to match heat pump profiles (domestic and I&C treated separately)
NGED	Geospatial analysis and stakeholder engagement are used to identify future heat network locations and energy centres sized to

[87] p75, Distribution Future Energy Scenarios 2023 – Customer behaviour profiles and assumptions report, National Grid Electricity Distribution , 2023

DNO	Approach to heat network modelling
	meet local demands. Profiles are flat throughout the year and in terms of MW per unit of installed heat pump capacity
SSEN, SPEN, ENWL	No evidence is provided for the general modelling approach (district heat sites may still be included in network modelling on a case-by-case basis)

Load profile comparison for district heat networks

Figure 52 shows load profiles for district heat network customers on the winter peak demand day for NGED, NPg and UKPN.

Note that the NGED profile is based on the utilisation of installed heat pump capacity rather than scaled to a "per-customer" basis and is in terms of the number of customers connected to heat networks. NGED's approach (described above in Table 46) s not adopted in this analysis. This is because additional analysis of heat network capacity at a national level would be required. However, the NGED summer peak generation profile assumes no demand. This is conservative (heat networks are likely to still draw some electrical demand throughout the year, given the diversity of customers and requirements for domestic hot water etc.) but is adopted for this study as it aligns with the approach taken to summer peak generation elsewhere.

As for heat pump profiles, the UKPN and NPg profiles were modified to derive kW per connection data for heat networks. Heat network specific consumption data was not provided by the DNOs, so the following approaches were taken:

- **UKPN – domestic:** UKPN provided average heat pump consumption data for ASHP and GSHP. Multiple technologies are not modelled for district heat, and electricity use will vary based on system design. As such, the average consumption for domestic heat network users is calculated from FES. This falls within the range of ASHP and GSHP average consumptions from UKPN
- **UKPN – non-domestic:** UKPN did not provide data on average non-domestic heat pump or heat network consumptions. As for the domestic connections, the average consumption of non-domestic heat network users is calculated from FES. This is consistent with the approach for UKPN non-domestic heat pump profiles, which uses the FES average consumption for non-domestic heat pump users. The FES average consumption for non-domestic heat network users is slightly lower than that for users of individual heat pumps.
- **NPg – domestic:** NPg data for average heat pump consumption is used directly as NPg does not split by ASHP and GSHP units and models district heat connections as additional heat pumps. As such, the study's approach is consistent with theirs
- **NPg – non-domestic:** For domestic heat network connections, NPg average heat pump consumption data is used.

The scaled normalised profiles are displayed in Figure 52. The average annual demands are summarised in Table 47.

Table 47: Average heat network connection energy demands, derived from FES

DNO	Heat network customer type	Average annual electrical demand for heat (kWh)	Source
UKPN	Domestic	2,560	FES Table ED3, average heat network user demands, Consumer Transformation
UKPN	Non-domestic	30,100	
NPg	Domestic	3,780	NPg DFES results for average heat pump demand, provided by the DNO
NPg	Non-domestic	19,840	

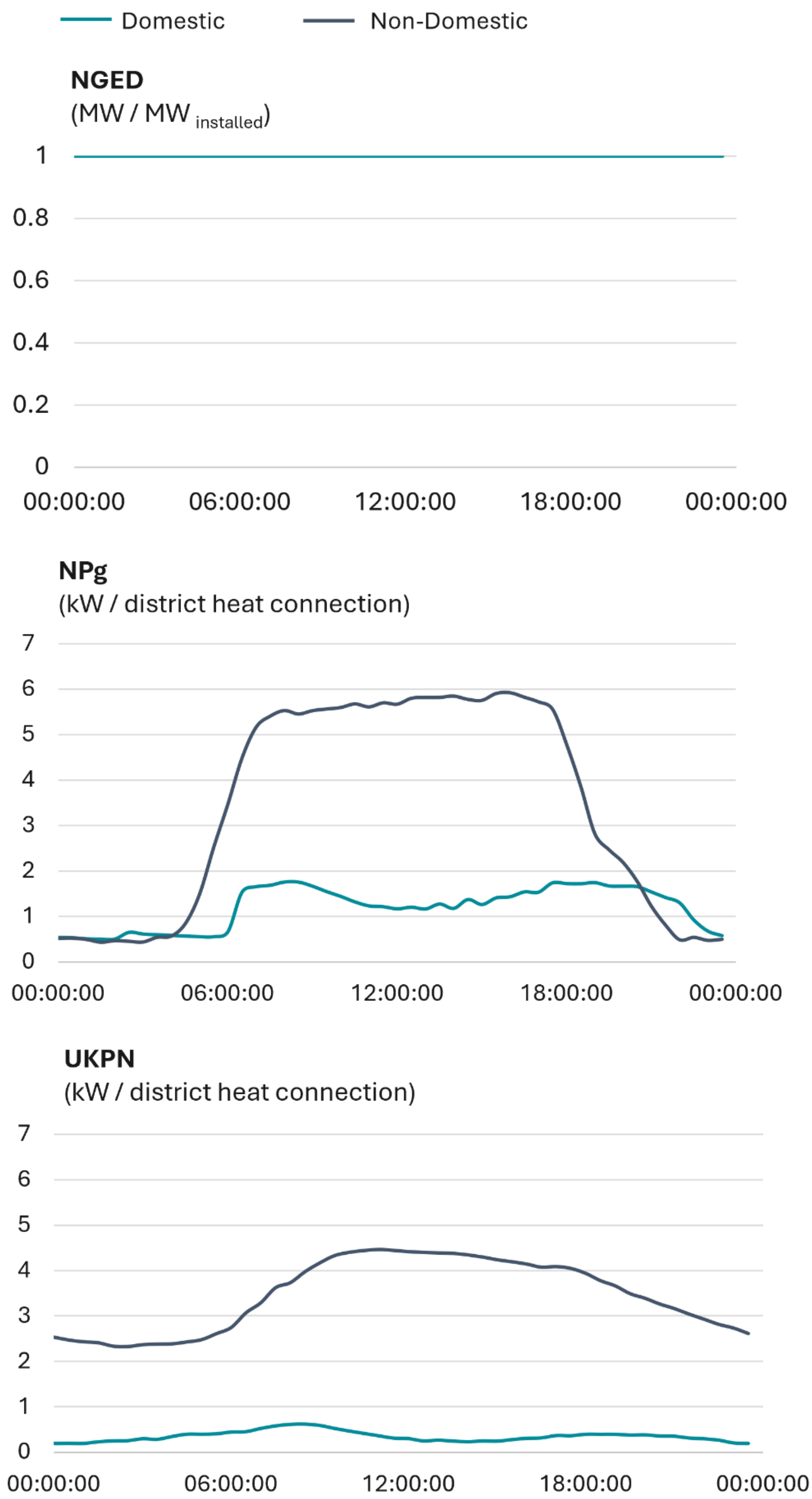


Figure 52: Winter peak demand profiles for district heat networks received in the RFI

Selected load profiles

The profiles for heat networks for each representative demand day are summarised below in Table 48.

Table 48: Profiles selected for district heat customers

Representative Demand Day	Heat network customer type	Source of profile used in the analysis	Notes
Winter peak demand	Domestic	UKPN	Scaled heat pump profiles, as per UKPN advice
	Non-domestic	UKPN	
Intermediate cool peak demand	Domestic	UKPN	
	Non-domestic	UKPN	
Summer peak generation	Domestic	NGED	Flat 0 kW import – a conservative assumption
	Non-domestic	NGED	
Winter stress test	Domestic	NPg	Most conservative profiles. Scaled heat pump profile, as per NPg advice
	Non-domestic	NPg	

Known limitations for district heat profiles

- **Variability in heat network operation is not captured by average load profiles**. Heat network designs and behaviour will be highly variable based on the specifics of a given project, such as its connected energy loads, the fuel mix adopted and the technology mix used to deliver heat.
- **The profiles DNO profiles used mimic heat pump profiles.** There is likely to be significant diversity in heat network operation cycles dependent on design, demands etc. The lack of any heat network specific load profiles across all six DNOs indicates current uncertainty in the future of electric heat network operation, presenting a key area for future research
- **No evidence was received in relation to implicit flexibility in heat networks, and therefore it is not captured in the analysis in WP2.** Heat networks may be able to act to provide significant system flexibility – again, this is highly dependent on the design of a given system. DNOs are likely to work directly with district heat providers to procure flexibility (explicit flex, not included in load profiles – see Section 3.1.4). However, heat networks may also adjust demand based on wholesale price signals (implicit flexibility), but this is not reflected in the load profiles used for this analysis.

3.3.5. Direct electric heating

Summary

Direct electric heating consists of two separate heating modes; electric resistive heating and night storage heating. Load profile data received from DNOs is summarised below in Table 49.

Domestic and non-domestic sectors are modelled separately. The two direct electric heating technologies (electric resistive and night storage heating) have been grouped to give the final load profiles for use in WP2 shown in Figure 56 and Figure 57. The subsections below provide more information on the approach.

The load profiles used for each representative day are:

- **Winter peak demand and intermediate cool peak demand:** domestic and non-domestic profiles provided by UKPN
- **Summer peak generation:** NGED profile used (flat 0kW import), in alignment with approach for other heat subtechnologies.
- **Winter stress test:** NGED domestic profiles have been used as they are the most conservative. UKPN profiles are retained for non-domestic direct electric heating as no alternatives were received from DNOs. As such non-domestic direct electric heating load profiles do not vary as a sensitivity in this analysis.

Table 49: Summary of profile data received from DNOs for direct electric heating types in the RFI

Technology	DNO	Intermediate cool peak demand	Summer peak generation	Winter peak demand
Electric resistive heating	NPg	Modelled within underlying demand		
	NGED	✓ *(domestic and non-dom.)*	✓ *(domestic and non-dom.)*	✓ *(domestic and non-dom.)*
	UKPN	✓	✓	✓
	ENWL			
	SSEN	✓		✓
	SPEN			
Night storage heating	NPg	Modelled within underlying demand		
	NGED	✓ *(domestic and non-dom.)*	✓ *(domestic and non-dom.)*	✓ *(domestic and non-dom.)*
	UKPN	✓	✓	✓
	ENWL			
	SSEN			
	SPEN			

Load profile data processing

The modifications to the source data for other heat subtechnologies are also made for direct electric where necessary (see Table 41). NGED profiles for non-domestic heat are presented in demand per square meter of heated floor space. This requires additional data to convert the profiles to units of kW per connection, which is not available (i.e. floorspace per connection).

Instead, for non-domestic direct electric heat the approach uses national average consumption data for direct electric heating technologies from the FES to scale the normalised profiles provided by UKPN. For domestic direct electric heating, UKPN provided their own average energy consumption data, which is used. The consumption data is summarised below in Table 50.

Table 50: Annual consumptions used to scale UKPN direct electric heating profiles

Technology	Average Annual Demand (kWh)	Source
Domestic electric resistive heating	5,510	UKPN data (total modelled direct electric heating demand consumption at licence area level, divided by counts)
Domestic night storage heating	6,550	
Non-domestic electric resistive heating	31,610	FES Table ED3, Consumer Transformation Scenario
Non-domestic night storage heating	69,240	FES Table ED3, Consumer Transformation Scenario

Electric resistive heating profiles comparison

Figure 53 shows the resistive heating profiles for the winter peak day received from the DNOs. Though the UKPN profiles have been used to formulate the weighted average profiles for use in WP2, it is worth noting that, as for other heating technologies, NGED's assumptions for domestic heating units are significantly more conservative with much higher peak demands, due to the winter scaling process applied by NGED to their loads. As for domestic heat pumps, NGED’s winter scaled profiles are used in the winter stress test sensitivity (model run 7).

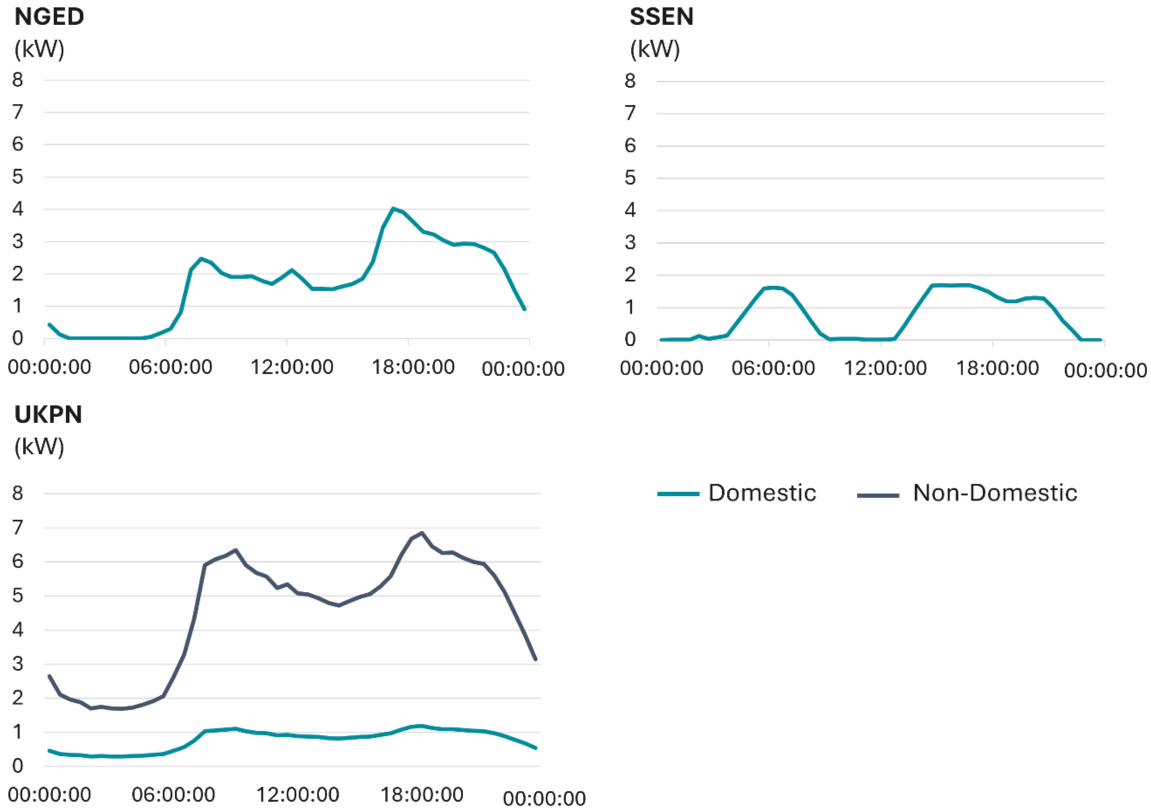


Figure 53: Comparison of winter peak demand electric resistive heating profiles from DNOs in the RFI

Night storage heating profiles comparison

Figure 54 This shows the night storage heating profiles for the winter peak day from the DNOs. As for electric resistive heating, NGED's assumptions are far more conservative, especially for the winter peak. NGED's domestic profile is used to create the overall direct electric heating profile for the stress-test case analysis.

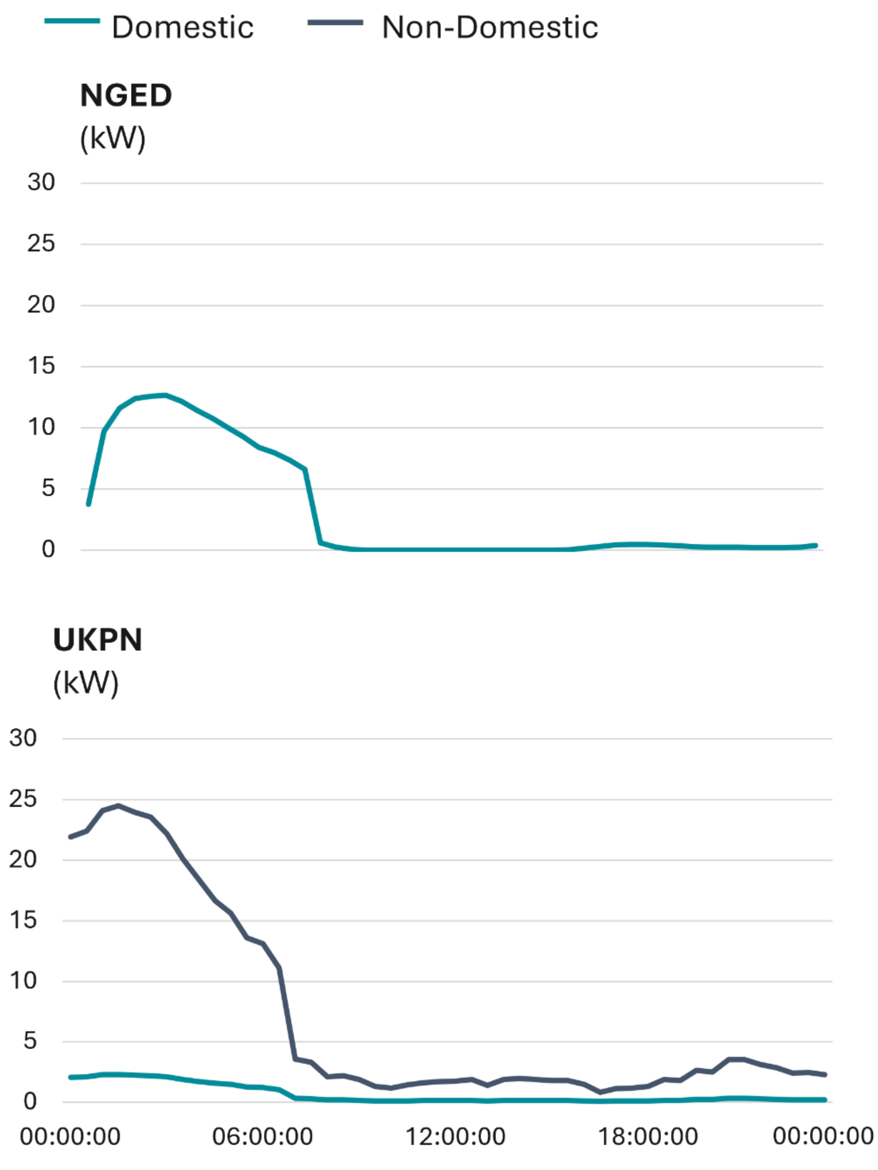


Figure 54: Comparison of winter peak demand domestic night storage heating profiles from DNOs in the RFI

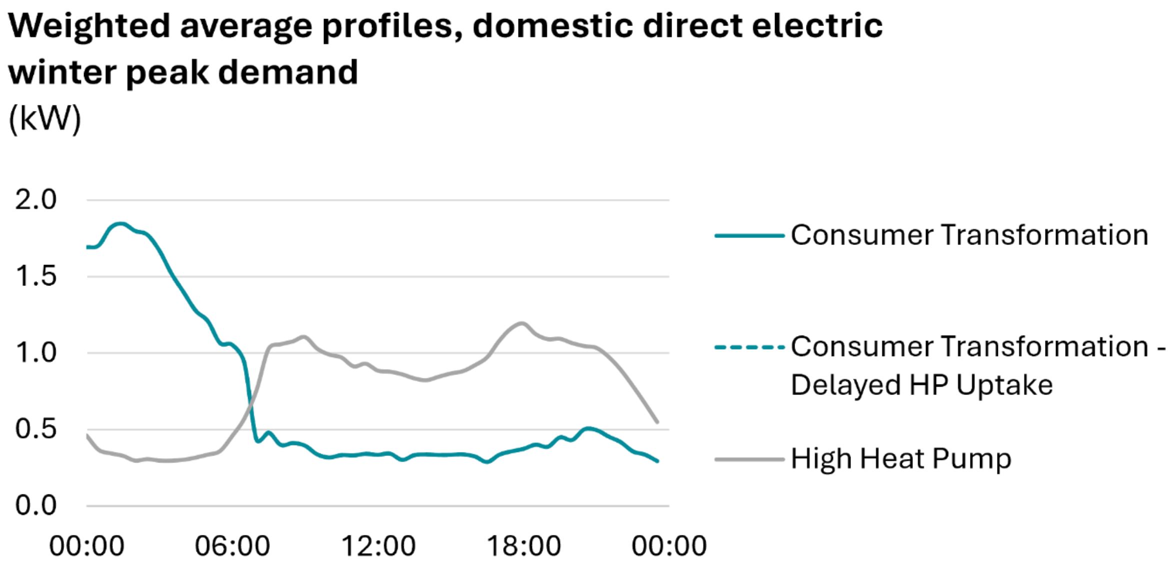
Final load profiles used for direct electric heating

The effects of electric resistive and night storage are combined to produce weighted average direct electric heating profiles for domestic and non-domestic customers.

The resulting weighted average profiles (derived from the UKPN profiles as described above) are shown below in Figure 56 and Figure 57. The weighted average is calculated based on the average proportion (from 2024-2050) of electric resistive and night storage heaters in the domestic and non-domestic sectors, which is shown in Figure 55.

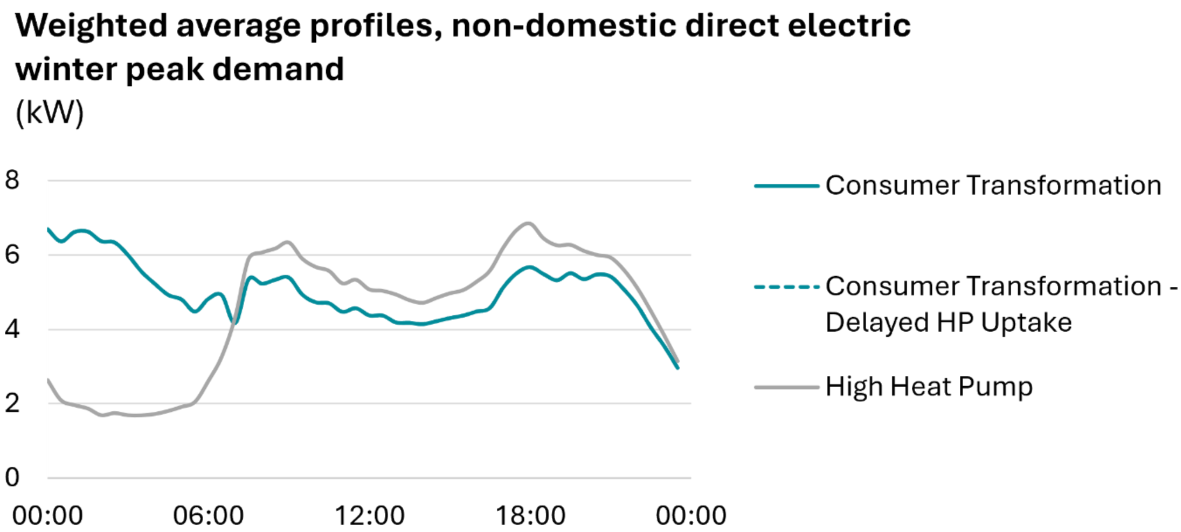
Figure 55: Direct electric heating stock breakdown, Consumer Transformation scenario. Top: domestic; Bottom: non-domestic

As the relative proportion of electric resistive heaters and electric night storage heaters varies between heat uptake scenarios, the load profiles used also vary.



Note: Consumer Transformation and Consumer Transformation – Delayed HP Uptake profiles are equal as the breakdown of direct electric heating types does not vary.

Figure 56: Weighted average winter peak profile for domestic direct electric heat, based on UKPN profiles and technology uptake data from Section 2



Note: Consumer Transformation and Consumer Transformation – Delayed HP Uptake profiles are equal as the breakdown of direct electric heating types does not vary.

Figure 57: Weighted average winter peak profile for non-domestic direct electric heat, based on UKPN profiles and technology uptake data from Section 2.

Profiles for winter stress test (run 7)

For the winter stress test sensitivity (run 7), the most conservative combination of load profiles for direct electric heat is used. These are summarised in Table 51. Refer to Figure 53 and Figure 54 for a comparison of the source profiles against other data received. Only UKPN provided non-domestic profiles, so these remain unchanged from the winter peak profiles.

Table 51: Direct electric heat profiles used for stress test sensitivity analysis

Technology	Sector	Profile used for stress test sensitivity
Night storage	Domestic	NGED
Electric resistive		NGED
Night storage	Non-domestic	UKPN
Electric resistive		UKPN

The resulting profiles for domestic and non-domestic after the weighted averaging are plotted below in Figure 58 and Figure 59, respectively.

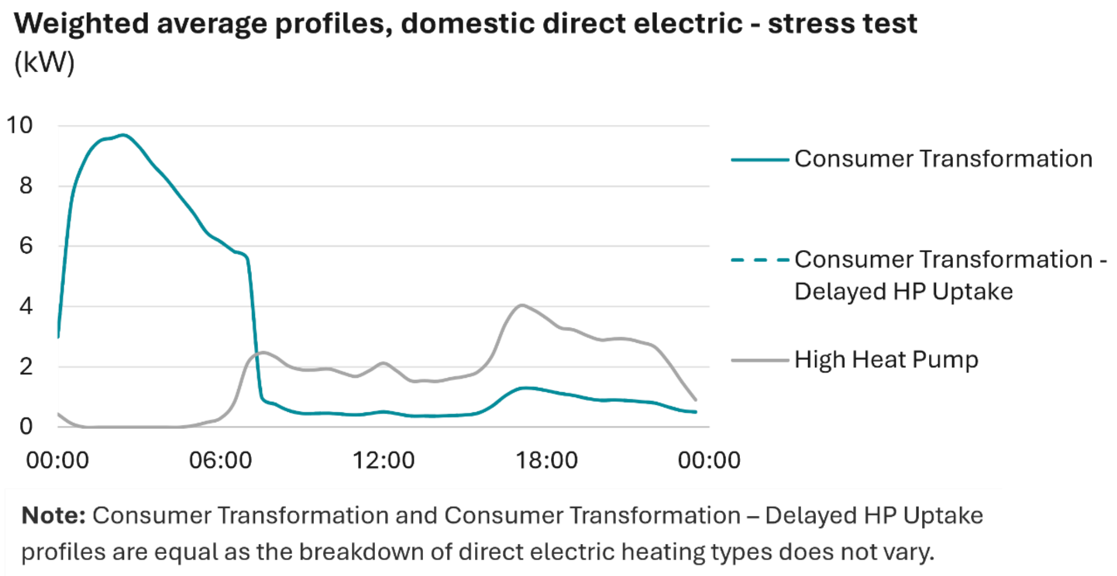


Figure 58: Domestic direct electric heat profile for stress test sensitivity

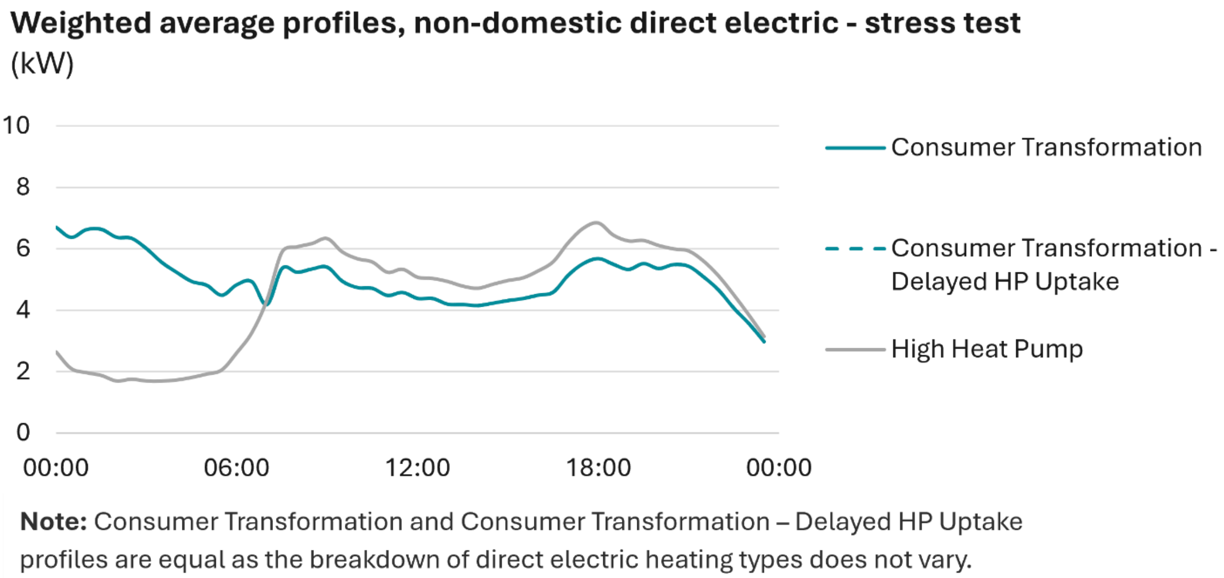


Figure 59: Non-domestic direct electric heat profile for stress test sensitivity

Limitations related to direct electric heating approach:

- **The direct electric heating profiles received from DNOs have a low peak demand.** Comparison of the profiles with those provided for heat pumps implies that direct electric heating units deliver less heat. This is a reasonable assumption for today, where direct electric heating systems are typically adopted in smaller residences often inhabited by people on lower incomes, and electricity is several times more expensive than gas per unit. As the energy transition progresses, a wider range of customers may adopt direct electric heaters. In addition, if policy measures are introduced to address the gap between electricity and gas unit rates (the so-called "spark gap"), improved affordability may lead to increased direct electric demand.
- **Demand shifting enabled by night storage heating may reduce in the future.** For decades, Economy 7 tariffs have provided domestic energy users with cheap overnight electricity prices. This makes storage heaters an economical option for many homes. FES uptakes project significant future adoption of night storage heaters, and this combined with present-day profiles (which are likely influenced by Economy 7 tariff price signals) gives a significant level of implicit flexibility. Market arrangements in the future may change, which could remove the incentive to store heat overnight – this would likely increase loads outside of overnight periods.
- **Aggregating technologies removes the high peak seen from storage heaters**. Uptake is relatively low and the weighted average profile captures the overall network level effect of storage heaters. However, in reality, constraints may arise on specific feeders with a high concentration of storage heaters, giving a significant overnight peak. The opposite is also true, where modelled overnight demands may be higher due to the inclusion of storage heaters. However, storage heaters are not included in the NIA2 High Heat Pump uptake scenario developed in section 2.3, testing the impact of this effect.
- **Profiles do not vary for non-domestic direct electric heat between the standard cases and the winter stress event sensitivity.** For other heat subtechnologies, this study adopts the most conservative available profile for the sensitivity case – however, a non-domestic profile was only provided by one DNO (UKPN) so there is no variation for the winter stress test (run 7).

3.4. Industrial and commercial

3.4.1. Industrial and commercial underlying demand

Summary

In this analysis, underlying demand refers to electricity demand for standard appliances, lighting, computing, etc, in industrial and commercial settings. Demand growth in this sector is driven by increases in building stock – data for this is presented in section 2.4.1. Underlying demand does not cover demand due to emergent low-carbon technologies, such as commercial heat pumps or commercial vehicle charging – this is captured elsewhere with technology sector-specific assumptions. Industrial process electrification is also not included in the scope of this study.

A single profile is used for I&C underlying demand, which is a weighted average of sectoral load profiles presented in ESO's Consumer Building Blocks innovation project, shown in Figure 60.[88] Hot water and heating components of the load profile are excluded, as these demands are captured within the heat section. The same load profile is adopted for all representative days as data was inconclusive on the seasonal variation of I&C load – some sectors peak in summer, while others peak in winter.

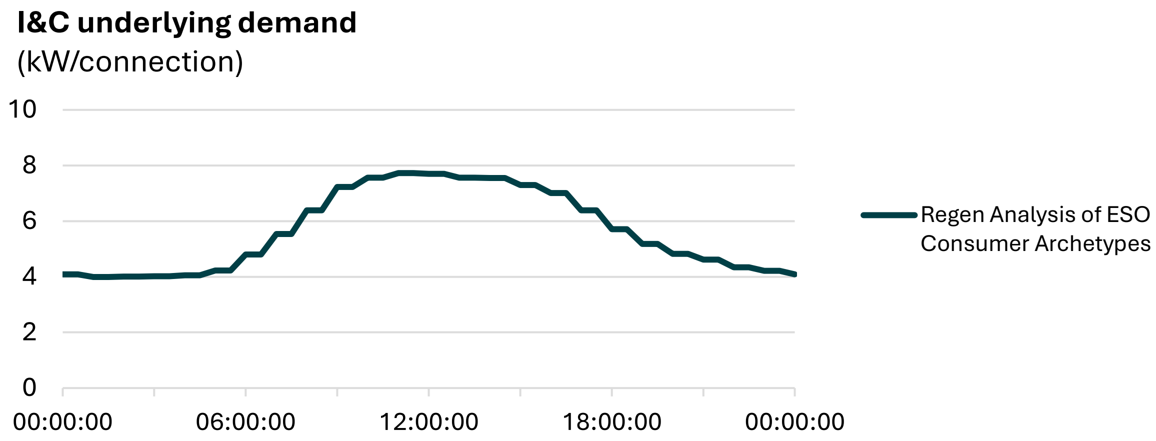


Figure 60: Load profile for I&C underlying demand.

Approach

Real underlying I&C demand varies significantly by sector and site. The DNOs' approaches to addressing this vary, but several use half-hourly monitored demand data collected at the

[88] Consumer Building Blocks, ESO, March 2024 (Data download)

substation level to calibrate I&C demand projections with significant locational granularity.[89] Such an approach is not compatible with EA Technology's Transform model, which is parametric and therefore non-locationally specific. Consequently, a streamlined approach to modelling I&C energy use is required, while significant uncertainty in modelled loads must be noted.

The ESO recently published the 'Consumer Building Blocks' innovation project for domestic and non-domestic customer segments (note this is a separate set of outputs to the building blocks data in FES which describes regional technology uptake).[88] These are intended for use across the sector to analyse domestic and non-domestic loads, and were integrated into some FES 2023 outputs. As such, their use in this project is consistent with the adoption of data from FES 2023 to inform technology uptake forecasts.

The Consumer Building Blocks dataset includes sectoral load profiles derived from a 2012 Ofgem Study.[90] These profiles characterise normalised load use by month for a range of non-domestic customer types, which have been mapped to the archetypes used in the ESO Consumer Building Blocks. Note that the data excludes heavy industrial sites. It is assumed that the largest industrial loads will connect above EHV level, which is not within the scope of EA Technology's Transform model. Industrial process electrification is also not captured in this analysis, as described in section 2.1.2.

The Ofgem load profiles data is used to provide a weighted average load profile based on the 2022 sectoral split of annual energy consumption in the Consumer Building Blocks study.

The Ofgem load profiles contain information for splitting out energy usage by sub-loads on a monthly basis. This is used to remove any electricity demand for heat and hot water from the I&C profiles, which are captured in other demand segments in this analysis (e.g. direct electric heating and heat pumps). An example of this breakdown is given below for offices in Figure 61.

[89] NPg DFES and Load Modelling, Methodology and Assumptions, Northern Powergrid, March 2024

[90] I&C Sectoral Load profiles, Element Energy for Ofgem, 2012

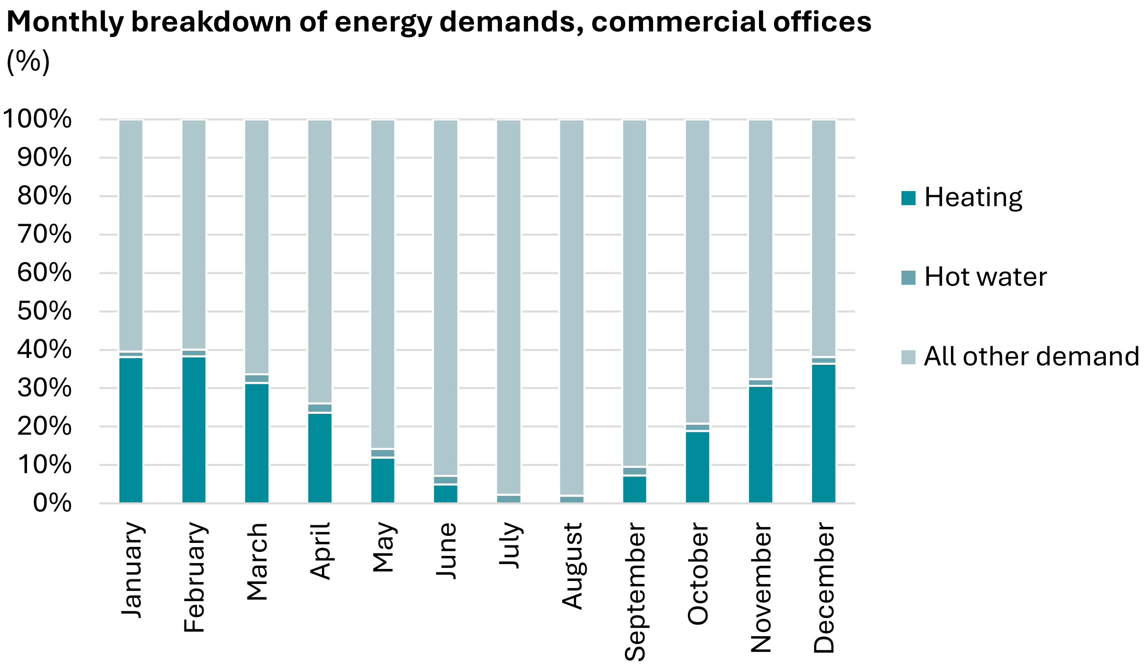


Figure 61: Annual variation in the breakdown of electricity demand in offices[90]

The weighted average profile with heat and hot water components removed is shown above in Figure 60.

The Consumer Building Blocks profile dataset indicates that peak demand for I&C occurs in summer for several (but not all) I&C user types. The maximum monthly load profile is therefore used for all representative demand days for conservatism.

Comparison with other sources

Given the diversity of I&C demands in the real world, single profiles for the whole sector are sparse. However, EA Technology' s default profile for the Transform model is a useful comparison. This is derived using a similar methodology to the Regen analysis of the ESO Consumer building blocks, but using different source data (I&C buildings split by Valuation Office Agency category, and summed weighted by annual consumption).[91]

Figure 63 shows a comparison of the default Transform load profile and the weighted average load profile from ESO's Consumer Building Blocks. The Consumer Building Blocks data is used

[91] P188-189, Assessing the Impact of Low Carbon Technologies on Great Britain's

Power Distribution Networks, EA Technology Ltd, 2012, accessed via https://www.ofgem.gov.uk/sites/default/files/docs/2012/08/ws3-ph2-report.pdf as the baseline, given the highest certainty around the data's origin and the method used to arrive at the load profile.

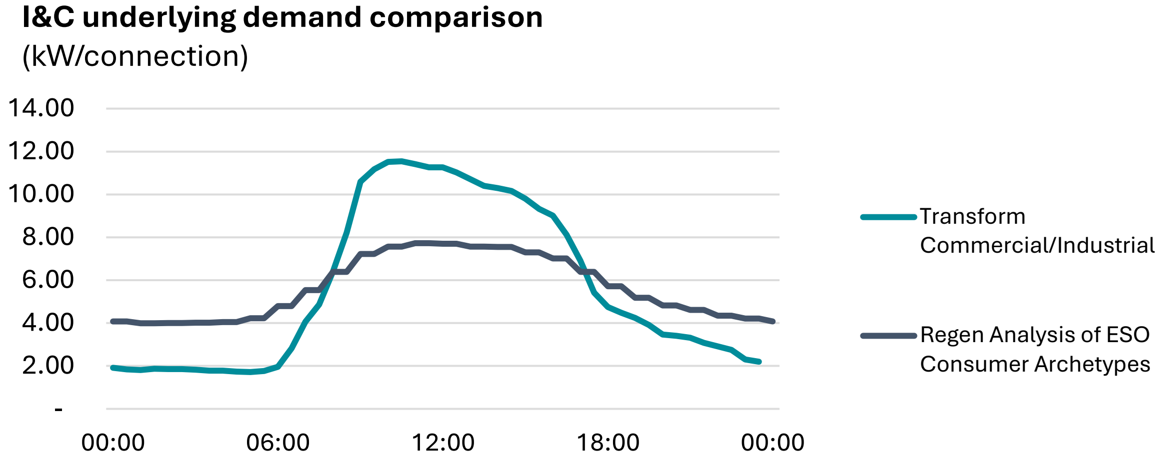


Figure 62: Comparison of default Transform profile and weighted average profile from ESO Consumer Building Blocks

At the time of the development of the Transform model, the original profiles EA Technology Ltd (and their project partners, GL Noble Denton) created for I&C demand modelling in Transform are detailed in their report “Assessing the Impact of Low Carbon Technologies on Great Britain’s Power Distribution Networks”, and were validated against relevant Elexon profiles. This is shown in Figure 63. The current default profile used in Transform has a higher peak demand per connection than the profile shown in the original report (Figure 63). EA Technology Ltd has validated the higher peak by comparing to monitored data of industrial/commercial sites, which have shown typical peak demands of 10-20 kW.

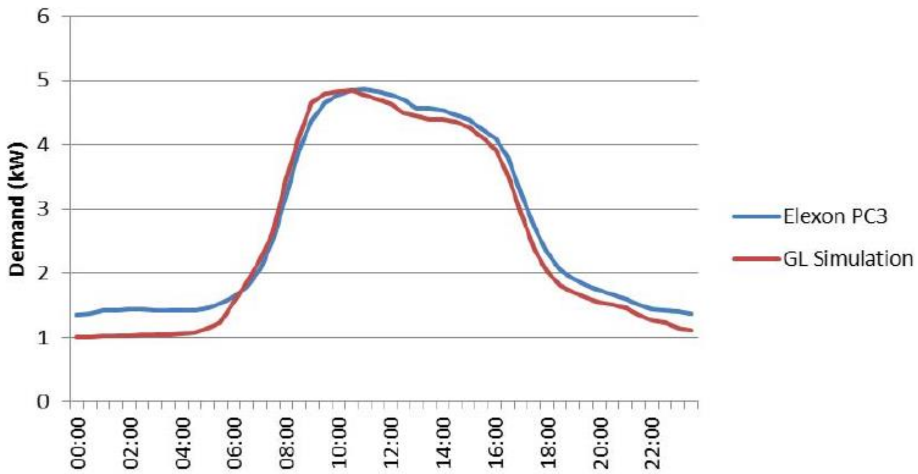


Figure 63: Comparison of GL Noble Denton simulated load profile for I&C baseload (generated for the development of the Transform model) with Elexon profile class 3.

Calibration of I&C loads

Due to low I&C building counts in FES 2023 Consumer Transformation, the implied peak load per I&C customer is very high – 29.8kW (this is calculated by dividing I&C peak demand components by the total non-domestic building stock in FES).[92,93] This is much higher than the peak demands in the load profiles described above.

The FES I&C building stock is used in this study (see section 2.4.1) to retain consistency with other sectors (especially heat, where technology counts reconcile to building stock totals). When combined with the load profiles above, this results in very low I&C demands in aggregate. Therefore, I&C peak loads in this analysis are calibrated upwards so that 2024 peak demand per I&C customer is aligned with the values in FES. The same calibration factor is used for each year and model run. The effect of this is to increase peak I&C loads from ~8kW to ~30kW per connection.

Flexibility potential sensitivity

An additional model run tests the impact of I&C flexibility. I&C customers offer significant potential for demand side response, as shown by the reduction in system peak due to "Triad avoidance" by large commercial and industrial demands. Transmission network charges are determined based on a user's contribution to the net system peak during the three half hours of highest demand in a financial year – known as Triads. Significant value is available to large customers by predicting when Triads will occur, and reducing demands accordingly. Large I&C

[92] Industrial and commercial demand subcomponents, Table ED1, Future Energy Scenarios 2023

[93] Number of I&C customers (Dem_BB002a), Table BB1, Future Energy Scenarios 2023

users adopt various techniques to reduce their demand, including straightforward demand turn-downs and ramping up behind-the-meter generation. Triad data for the last decade shows a reduction in system peak of around 13%.[94]

FES peak demand components show that I&C demands account for approximately 60% of system peak in 2024.[92] To achieve 13% demand reduction through I&C demand response the I&C load profile is reduced by 22% (13.2%/60.8%.= 21.7%).

This assumes that gross demand has not moved significantly since 2013, but Triad avoidance accounts for the reductions seen in the data on net system demand. This is simplistic as not all of this can be attributed to Triad avoidance in reality (increases in embedded generation, deindustrialisation, energy efficiency and other factors are also at play). However, the sensitivity is used as an illustration of the potential value of I&C demand response.

Limitations of I&C underlying demand profiles

- **There is significant uncertainty in modelling the scale of I&C underlying demand**, despite broad agreement across sources when it comes to the qualitative shape of I&C load profiles. This is evidenced by the variation in load profiles seen, and the implied peak per customer from FES. The impact of profile choice in this sector may significantly impact results because of the number of I&C connections and scale of variation between profiles. The uncertainty is also present in the scale of FES non-domestic building stock (see section 2.4), resulting in the calibration of I&C loads in the Transform model.
- **Aggregate I&C load profiles overlook the substantial variation in real I&C loads.** In reality, the diversity of the I&C sector means that actual load profiles at individual substations and feeders are likely to vary significantly. DNOs capture this by using substation specific monitoring data to derive bespoke load profiles for I&C demand.[89] Given Transform adopts a parametric (i.e. non-locationally specific) modelling approach, aggregation to average load profiles is required. This mirrors the limitations described in other sections relating to the use of average profiles overlooking the granularity of individual demands and potentially misrepresenting the constraints generated.
- **The same profile is being used for all representative demand days**. Data sources suggest some seasonal variation but this appears to be sector specific, while the overall demand of I&C customers is uncertain. More granular modelling of the I&C sector would be required to address this limitation as the complexities and diversity of I&C load cannot be fully reflected when modelling the sector as a whole.

[94] Regen Analysis of Triad data, 2014-2023, National Energy System Operator (formerly National Grid ESO)

3.4.2. Electrolysis

With limited electrolysis deployment to date, the operation of future electrolyser capacity is highly uncertain. Whilst patterns of behaviour may emerge, for example, ramping down during high price periods, until those patterns are shown to exist it is reasonable to assume that electrolysers could use the extremes of their capacity at any period during the year. ENW and NGED assume maximum import during peak demand days.

There will be diversity in electrolyser load profiles at system level but at the distribution network level diversity will be lower. Where single projects connect to each network asset there will be no diversity.

For this reason, this analysis uses worst-case assumptions around operation:

- During peak demand days, electrolysers are assumed to import at maximum capacity
- During peak generation days, import is assumed to be zero.

Table 52: Load profiles used for electrolysis

Representative day	**Load for all half-hourly periods** (MW/MW installed)
Winter peak demand	1.0
Intermediate cool peak demand	1.0
Summer peak generation	0.0

Known limitations

In reality, electrolysers may operate in ways that are more supportive to the electricity network. As electricity is the core input cost, some operators will operate their plants in response to changes in electricity prices. Therefore, the analysis tests the upper bound of network impact that could be expected.

3.4.3. Data centres

UKPN provided load profiles for data centres in terms of MW per annual energy consumption, the only DNO to do so. These are plotted in Figure 64 in terms of MW per MW installed capacity, assuming an annual capacity factor of 35% (provided by UKPN). The profiles come from a recent internal UKPN study of approximately 20 data centres' energy demand data.

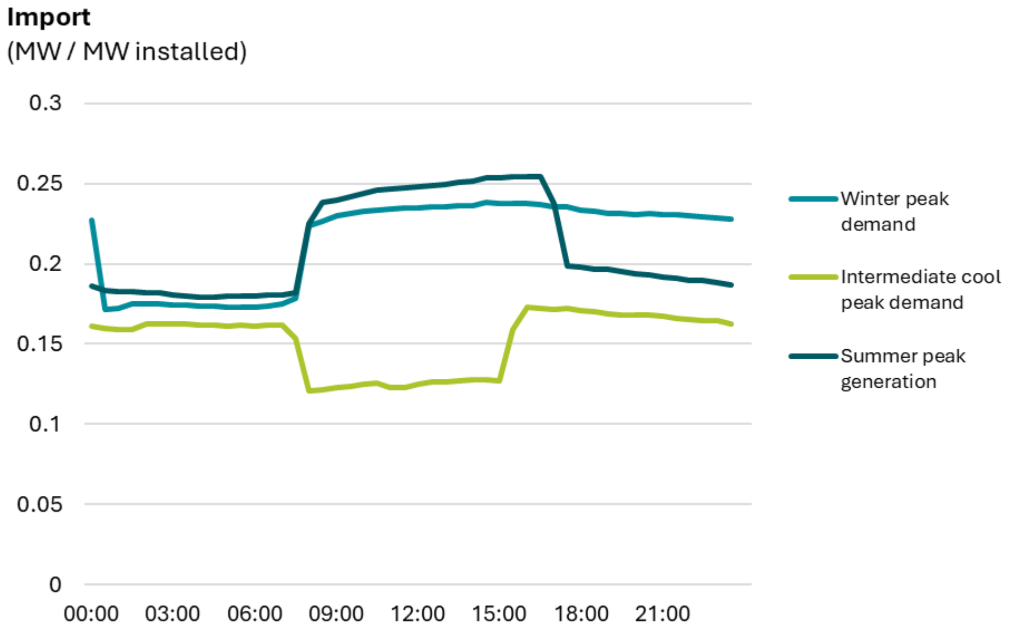


Figure 64: UKPN Data Centre load profiles for representative days

The load profiles provided by UKPN are not used in the analysis because the load profiles are very low relative to the peak import capacity available. More conservative assumptions around operation are used to test the network's capacity to meet more demanding conditions:

- During peak demand days, data centres are assumed to import at maximum capacity
- During peak generation days, import is assumed to be 0.18 MW – the minimum of UKPN's summer peak generation day.

The assumptions for each representative day are summarised in Table 53.

Table 53: Data centre load assumptions used in analysis

Representative day	**Load for all half-hourly periods** (MW/MW installed)
Winter peak demand	1.0
Intermediate cool peak demand	1.0

Summer peak generation	0.18

Limitations

It is possible that data centres will operate with greater flexibility than assumed in this analysis. Therefore, the analysis will test the upper bound of network impact that could be expected.

3.5. Generation technologies

As with demand technologies, three profiles are selected for each generation technology:

- **Winter peak demand**, with minimum coincident generation – an assessment of the network's capability to meet peak winter demand conditions when demand is high and generation is low
- **Intermediate cool peak demand,** with minimum coincident generation – an assessment of the network's capability to meet demand conditions outside of winter and summer
- **Summer peak generation**, with minimum coincident demand – an assessment of the network's capability to handle generation output.

As the main focus of this analysis is on emergent forms of demand and to minimise the burden of wide-ranging data collection on the DNOs, profiles for wind and solar technologies are only sourced from NGED.

3.5.1. Solar generation

Generation profiles for solar have been sourced from NGED's Customer Behaviour Report.[95]

NGED developed half-hourly generation profiles for each of the representative days used for network analysis by analysing generation data from solar sites on its network. NGED's analysis did not include sites under 1MW to remove the contributions of self-consumption, as these sites are more likely to be associated with onsite demand. These effects are captured in demand profiles for other technologies.

Regen calculated the mean average for the four NGED licence areas. Note that the output was not correlated with latitude (a proxy for solar irradiance), suggesting other factors at play, such as installation age, orientation, configuration and regional climate. The profiles for each representative day are presented below.

[95] Customer behaviour profiles and assumptions report, National Grid, 2023

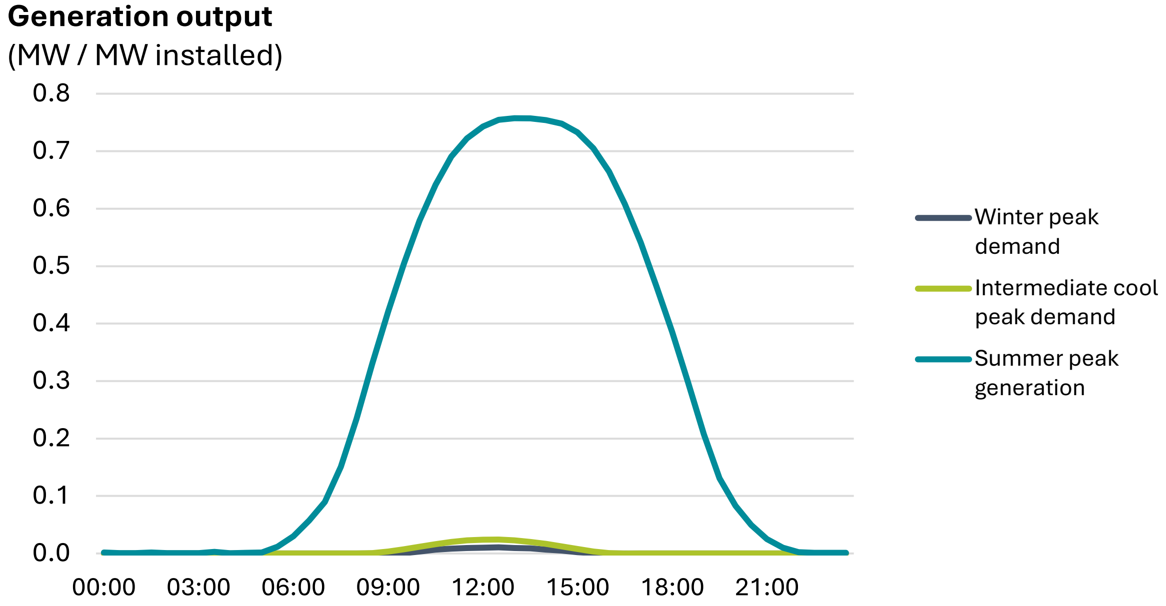


Figure 65: Solar generation output profiles for the three representative days. Source: Regen analysis of NGED load profiles

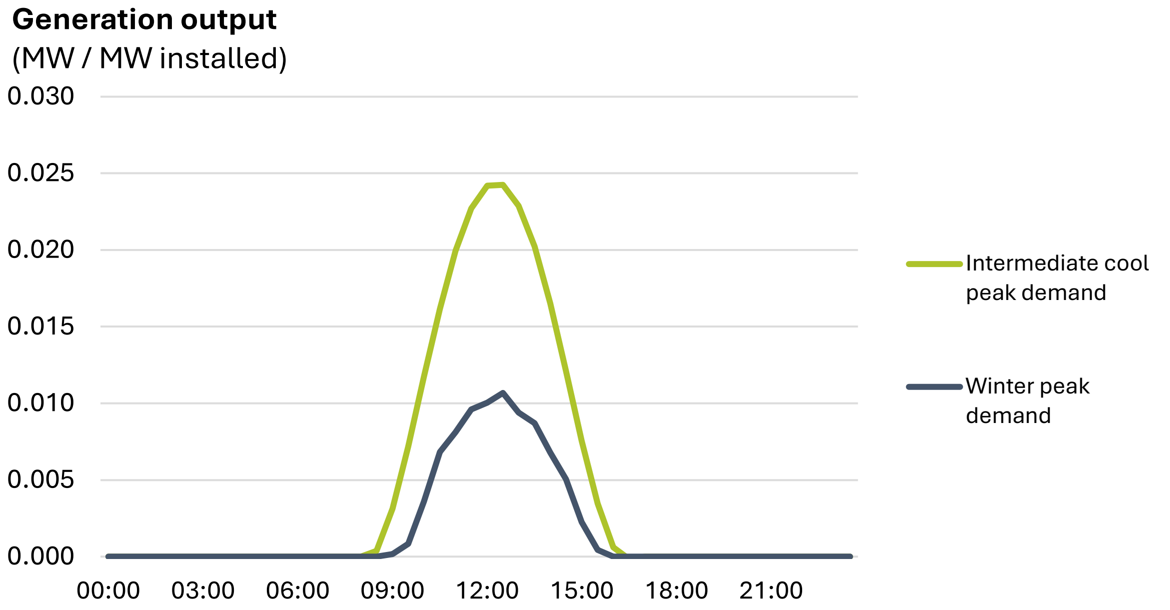


Figure 66: Solar generation output profiles for representative days (summer peak generation day removed). Source: Regen analysis of NGED load profiles

Known limitations – solar generation:

Profiles are assumed not to change over time. There are several ways in which profiles might change:

- As panel costs have fallen relative to the balance of the plant (and other non-panel costs such as grid and land), the ratio of panel capacity to installation capacity has grown (i.e. installations have more panel capacity than the system is capable of exporting). This leads to flatter output profiles
- Lower panel costs also allow alternative orientations to become viable. For example, vertical east-west facing installations. Orientation can also be influenced by price signals that encourage generation outside of peak generation periods (historically orientations have been selected to maximise yield over the year)
- Panel efficiencies are improving over time, leading to higher output profiles[96]

Categorisation by type of installation:

- Due to the exclusion of sites under 1MW, categorisation by installation type (ground-mount, commercial rooftop, domestic rooftop) was not possible. Ground-mounted sites are more likely to experience lower levels of shading and to have optimised orientations leading to higher outputs

Latitude and longitude:

- Whilst NGED's licence areas receive greater solar irradiance than the GB average due to lower latitudes, it was deemed a reasonable proxy as, generally, south GB has seen and continues to see more solar installation (due to higher yields)
- The impact of longitude (differences in output in mornings and afternoons) is not visible between NGED licence areas so no adjustment has been made for NGED's more westerly longitudes.

3.5.2. Wind

Load profiles for wind are sourced from NGED. NGED developed these profiles using analysis of wind output from sites connected in its four licence areas – East and West Midlands, South Wales and the South West – and categorised sites into two – those greater than 1MW and those under 1MW in capacity. Profiles for sites over 1MW are used in this study as smaller LV-connected sites make up less than 1% of installed capacity. More detail is given in section 2.5.

Regen calculated the mean average for the four NGED licence areas for each representative day and for each half-hourly period. For peak summer generation, there is very little change in output throughout the day (range of 0.71 and 0.77 MW/MW installed).

For peak demand days, output is almost zero with significant amounts of noise (max output is less than 0.01% of installed capacity for peak winter, i.e. 100kW of output per GW of installed capacity). Output is assumed to be zero for the duration of these peak days to simulate peak demand with minimum coincident generation, which would be associated with still conditions.

[96] Cell efficiency, National Renewable Energy Laboratory, 2023

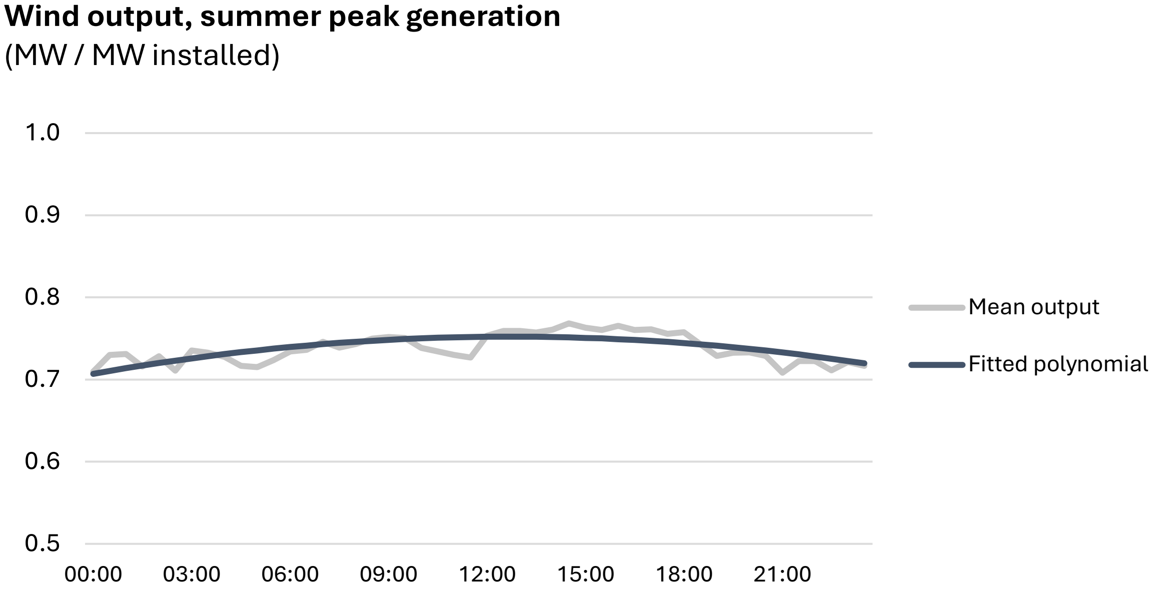


Figure 67: Generation profile for wind. Note that the axis starts at 0.5

Known limitations – wind generation:

- **Locations:** There is a significant range in the output of wind generation in the data of the four NGED licence areas during peak summer days. There could be regional variation in wind output but to develop a profile that could be applied nationally an average profile is used[97]
- **Plant size:** The analysis uses an average output for all wind generation capacity. This masks variations in output due to factors such as turbine height and rotor diameter.

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[97] Wind speed map of UK, Met Office

3.5.3. Dispatchable

While an analysis of historic thermal generation does exist, generation behaviour has evolved in response to traditional domestic and commercial demand, with dispatchable plants mainly fuelled with fossil fuels. Future behaviour is likely to change. Therefore, all dispatchable generation is assumed to export at full capacity for all periods of peak demand days. During peak generation days thermal generation is assumed to have zero output. This follows the assumption that dispatchable generation tracks demand.

Table 54: Output profiles for dispatchable generation

Representative day	**Generation output for all half-hourly periods** (MW/MW installed)
Winter peak demand	1.0
Intermediate cool peak demand	1.0
Summer peak generation	0.00

Known limitations – dispatchable generation:

- **Flat profile:** In reality, dispatchable plants will respond to demand profiles and are unlikely to exhibit a flat export profile
- **Maximum export:** Not all DNOs assume that dispatchable generation exports at maximum capacity. At a fleet level, this behaviour would be highly unlikely. However, at a network asset level it is likely that dispatchable plant would export at peak capacity.

3.5.4. Grid-scale storage

Electricity storage and battery storage, in particular, are highly flexible. Individual sites can import or export at between 0% and 100% of rated capacity at any time during the day to provide the services they have been contracted to provide.

The initial business model for battery storage was based primarily on providing frequency response services – very rapid but short-duration battery charge and discharge in response to fluctuation in electricity frequency around the 50 Hz target.[98] As grid frequency is subject to many factors and rapid change, it was not possible to discern any predictable battery profile. Therefore, network operators generally assumed a worst-case scenario that batteries would charge during peak demand periods and discharge during peak generation.

As frequency response markets have become saturated, there has been a clear trend towards market orientated business models level, with more and more storage assets now generating revenue from wholesale price arbitrage (buying when prices are low and selling when high).

The Balancing Mechanism (BM) and Balancing Reserve (BR) are also becoming increasingly important revenue streams for storage operators. [98] In addition to these recent changes in revenue streams, past trends of daily and seasonal operations may not be a good indicator of future behaviour due to the introduction of longer-duration assets, the electrification of heat and transport, and changing wholesale market dynamics.

DNOs have started to change their profile analysis to take into consideration the change in battery behaviour and to provide evidence that will enable them to move away from a worst-case profile. Battery storage business models are evolving rapidly and so DNO load profiles will continue to be updated by DNOs.

[98] UKPN Battery Storage Impact Assessment, Regen, 2024

Comparison of load profiles provided by DNOs

The load profiles received from DNOs for grid scale storage behaviour are shown below in Figure 68.

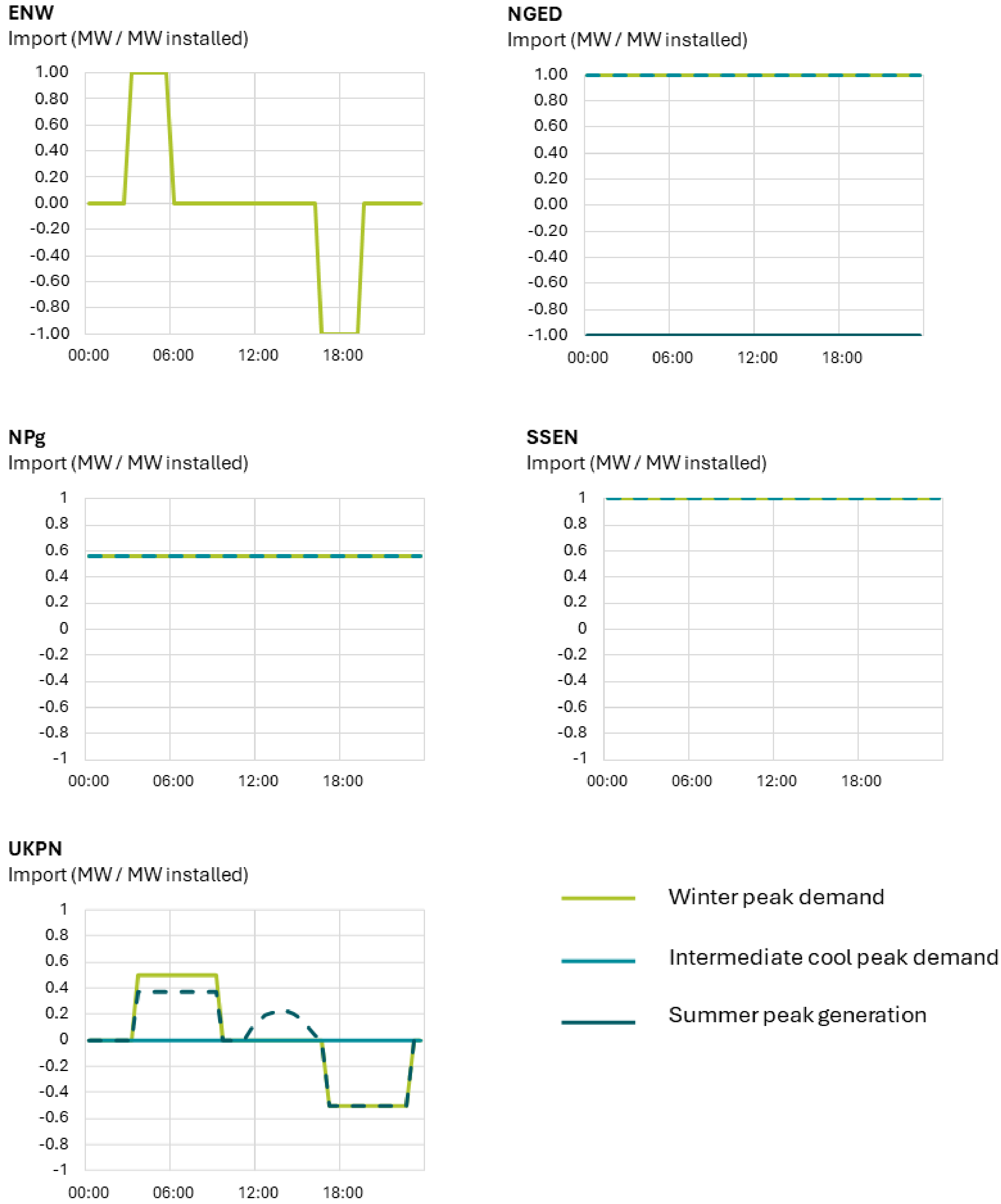

Figure 68: DNO load profile comparison for grid-scale storage.

Adapted profiles for network modelling - low flexibility sensitivity case

Profiles for storage are adapted to reflect the degree of uncertainty about future storage behaviour but also recognise the growing evidence that storage assets will increasingly operate in ways that reflect market price movements.

For the low flexibility sensitivity case, storage is assumed to have a neutral impact on the distribution network during all three representative days, shown below in Figure 69. This will establish the levels of network capacity needed to meet peak demand and peak generation when storage systems are not supporting the system with import or export. Whilst this is a highly unlikely situation, it is a plausible occurrence and it does not assume the very worst-case scenario that storage would, in fact, operate in ways that would be detrimental to supply/demand balancing.

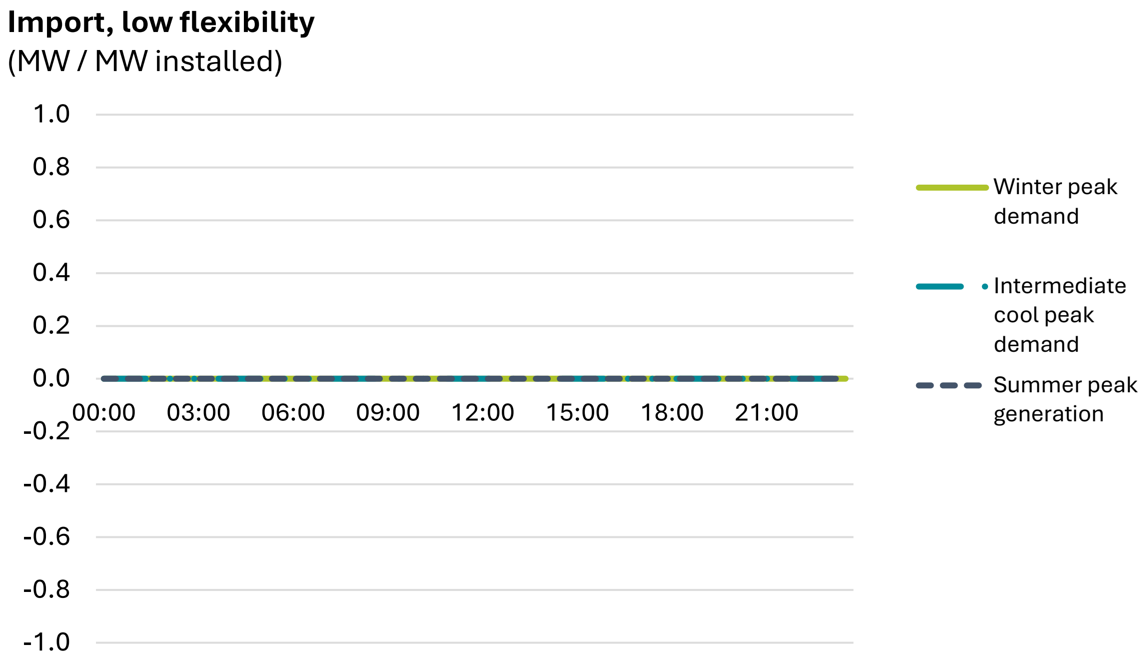

Figure 69: Load profiles for grid-scale storage, low flexibility sensitivity

High flexibility sensitivity case

For the high flexibility sensitivity case, storage is assumed to support system balancing with some degree of export during winter peak demand and import during peak generation, although not at 100% of capacity. During intermediate peak demand, it is assumed to have a neutral impact (no import or export). The profiles are plotted below in Figure 70.

This will establish the needs of the distribution network when storage is supporting the system as expected. Storage systems are not modelled to export or import at full capacity to account for the diversity in individual systems' behaviour.

The quantum of import/export is sourced from load profiles provided by UKPN, which are based on storage behaviour analysis carried out by Regen.

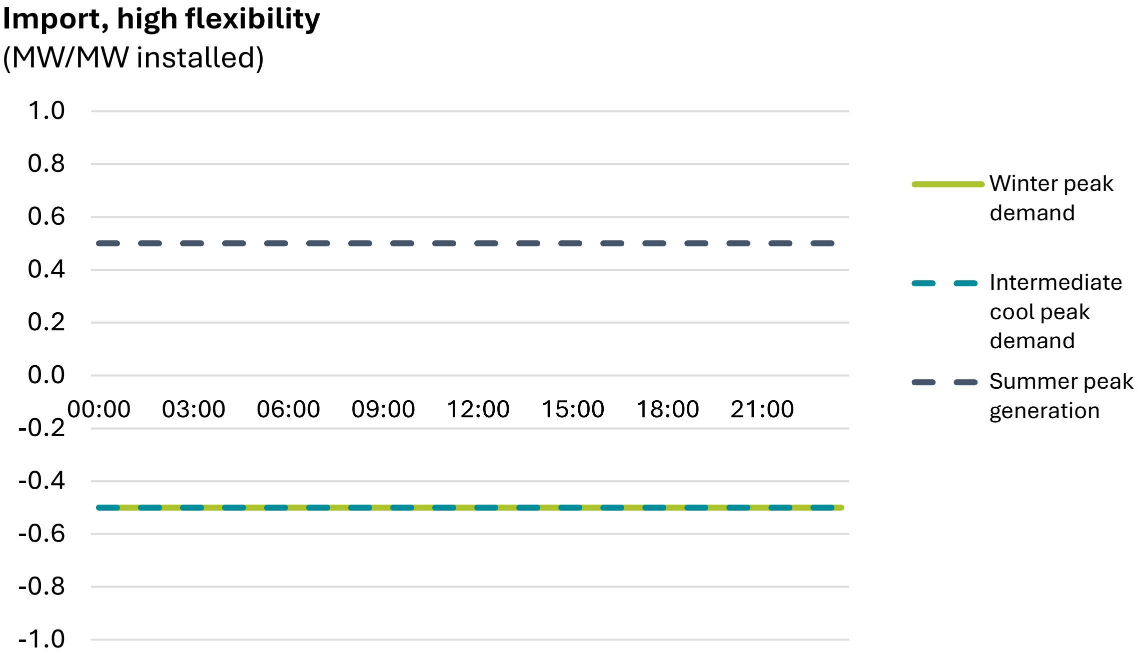

Figure 70: Grid-scale storage load profiles selected for the high flexibility sensitivity with export/import at 50% of capacity on peak demand/generation days

Limitations

- **The adapted profiles greatly simplify very complex and evolving operating models for storage assets.** They represent a compromise between assuming a worst-case scenario whereby batteries are detrimental to load balancing and the best-case scenario where batteries always operate to support load balancing. In reality, at any given moment, different storage assets may be pursuing different revenue streams and providing a range of network services
- **Variable daily profile.** The proposed load profiles exhibit no change throughout the day. A more nuanced approach would assume that storage responds to changes in demand with changes to profiles through the 2024 to 2050 model period. The impact of this assumption will be most notable during the high flexibility, peak summer generation case where it is possible that a flat profile will cause demand constraints in the evening peak. During the winter peak, it may underestimate overnight demand constraints
- **Subtechnology scope.** The proposed load profiles are generated using only an analysis of battery storage. Whilst this form of storage dominates the storage technology mix currently and likely into the future, the FES Consumer Transformation scenario does project a small and growing share (over 5% in 2050) of other storage technologies including pumped storage, liquid air and compressed air storage. Liquid air and

compressed air storage are likely to have similar operational profiles to batteries due to their frequent cycle/short duration operation. Pumped hydro can operate over 4hrs to multi-day cycles, with lower network impact (i.e. they are less likely to need to behave in ways that are unhelpful to the network). Assuming battery-like behaviour is therefore conservative.

3.5.5. Small-scale storage

Load profile comparison

Small-scale storage (domestic and commercial battery storage systems under 1 MW in capacity) are typically installed alongside rooftop solar systems to maximise consumption of self-generated electricity and to enable opportunities for price arbitrage with either dynamic or time-of-use tariffs. The load profiles provided by DNOs, plotted in Figure 71, reflect this, with export during evening peaks following charging during the morning.

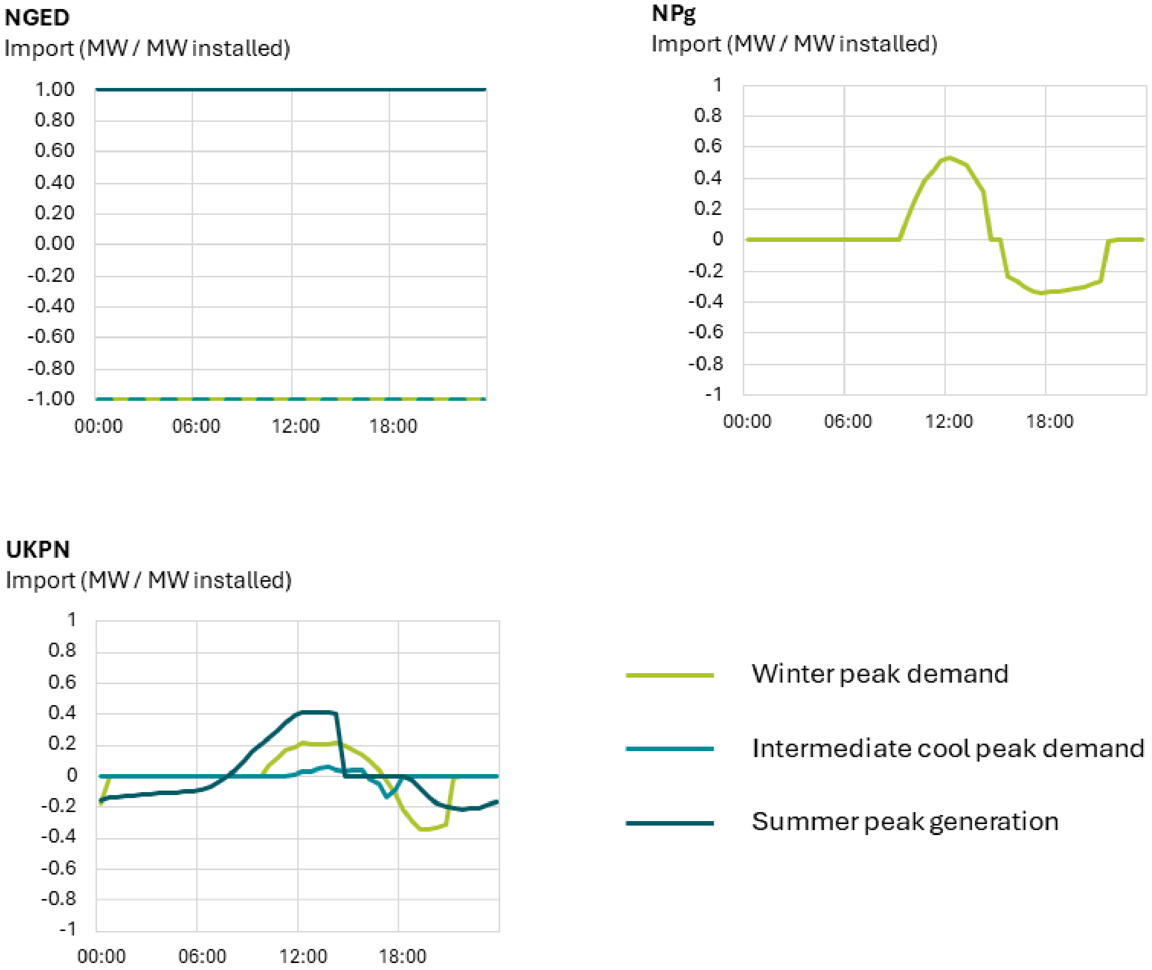

Figure 71: Comparison of small-scale storage load profiles provided by DNOs. Note: NGED profiles assume "flexed" behaviour, NPg profiles assume pairing with solar PV, UKPN profile shown for summer peak generation was provided as 'summer max'

Selected load profiles for small-scale storage

As with grid-scale storage, two adapted sets of load profiles are selected for low and high flexibility sensitivities.

The low flexibility sensitivity represents a system where storage has a neutral impact. Import and export are set to zero, testing the distribution network's capacity with no support from battery storage. This is a conservative case.

The high flexibility sensitivity assumes that small-scale storage will have a positive impact on the system (a more likely test case) using import and export profiles sourced from UKPN. Note that profiles are theoretical 'use cases' and have not been produced using analysis of actual customer behaviour. This is appropriate, as historic behaviour may not be a good indicator of future behaviour. Even in the high flexibility scenario, there is a significant diversity of behaviour; peak export during winter is only 35% of installed capacity. This approach for small-scale storage diverges from that taken for grid-scale storage where there is greater uncertainty and less diversity of storage behaviour.

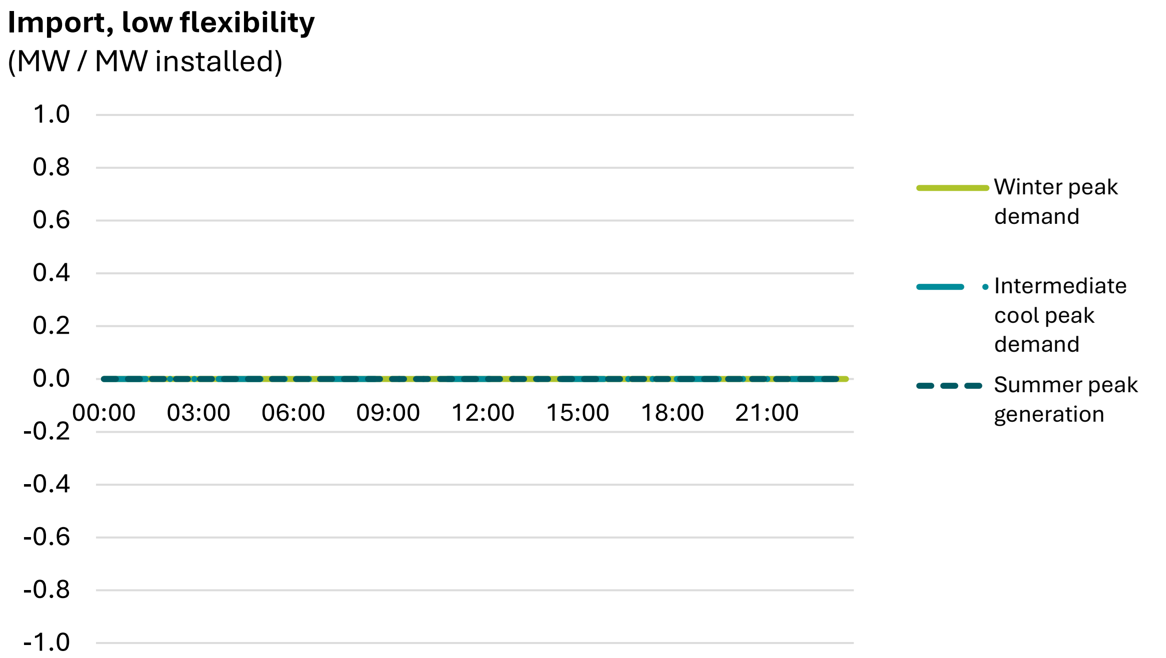

Figure 72: Small-scale storage profiles selected for the low flexibility sensitivity

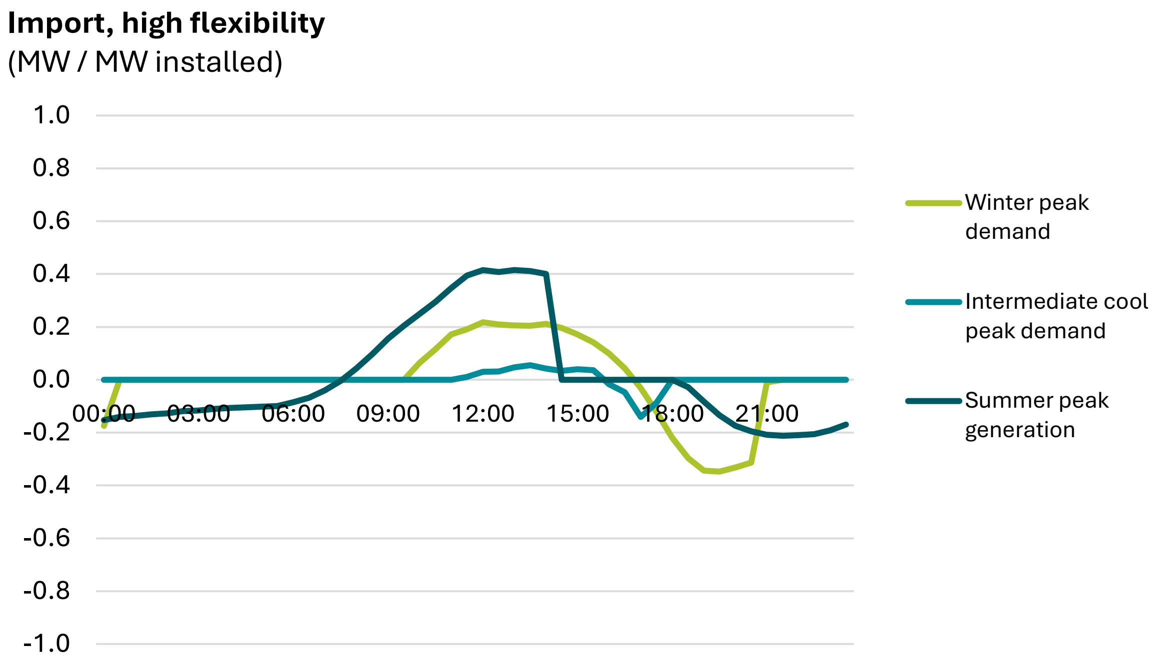

Figure 73: Load profiles selected for the high flexibility sensitivity showing some degree of support for load balancing

Limitations

- **Future operational behaviour:** the future of small-scale storage behaviour is highly uncertain. Whilst storage will likely respond to either dynamic pricing or time-of-use prices, the patterns of these price signals will likely change substantially over the next 25 years. A particular simplification of the profiles used is that they demonstrate just one charging cycle per day. It is possible that price signals will encourage two cycles, discharges during both morning and evening peak demand periods
- **Summer peak generation:** the profile for summer peak generation is provided by UKPN as a summer peak demand profile. In the absence of other evidence, this profile best reflects the conditions of high levels of solar-driven generation during summer months
- **Impact of assumptions:** capacity of small-scale storage is currently very low (the FES 2023 Consumer Transformation projects just 130 MW of capacity by end of 2024, 0.28% of all distribution-connected storage and generation capacity) and so the near-term impact of assumptions related to small-scale are not anticipated to significantly impact the analysis. In the long-term, small-scale storage capacity will become significant (growing to 7 GW by 2050, or 36% of all storage) and so the daily profile and quantum of load profiles will have a more significant impact on network constraint analysis.

3.6. Domestic underlying demand

Domestic underlying demand refers to the typical sources of demand in a domestic property from appliances and lighting, but not including heat or new sources of demand, such as EV charging.

Domestic appliance profiles are already set in the Transform modelling package used in WP2 for national network capacity analysis and have not been developed in WP1.[99]

The domestic appliance profiles include demand from:

- Lighting
- Wet appliances (washing machine, dishwasher, tumble drier)
- Cold appliances (fridge, freezer)
- Cooking (oven, hob, microwave, kettle)
- Consumer electronics.

Section 12.1.3 of the original documentation for the Smart Grids Forum project, during which Transform was developed, outlines the derivation of underlying demand load profiles.[100] Note that this documentation does not include the methodology used to derive load profiles for each building archetype.

The main limitation of using these load profiles as data inputs is that they are based on data that is more than 10 years old, during which period technological and societal changes, as well as the time of use tariffs, may have led to changes in electricity demand. These profiles are likely conservative, as improvements in appliance efficiency may have led to a reduction in demand. More recent consumer archetypes and demand profiles have been developed,[101] but adapting these for use in the Transform model would require significant work and is outside the scope of this study. The profiles for all domestic building archetypes are plotted below in Figure 74. Figure 75 compares the range of loads across archetypes in the minimum and maximum half hourly periods.

[99] EA Technology's proprietary network modelling tool developed with the DNOs in 2012

[100] Section 12.1.3, Assessing the Impact of Low Carbon Technologies on Great Britain's Power Distribution Networks, Energy Networks Association on behalf of Smart Grids Forum, 2012

[101] For example CSE Consumer Archetypes for Ofgem

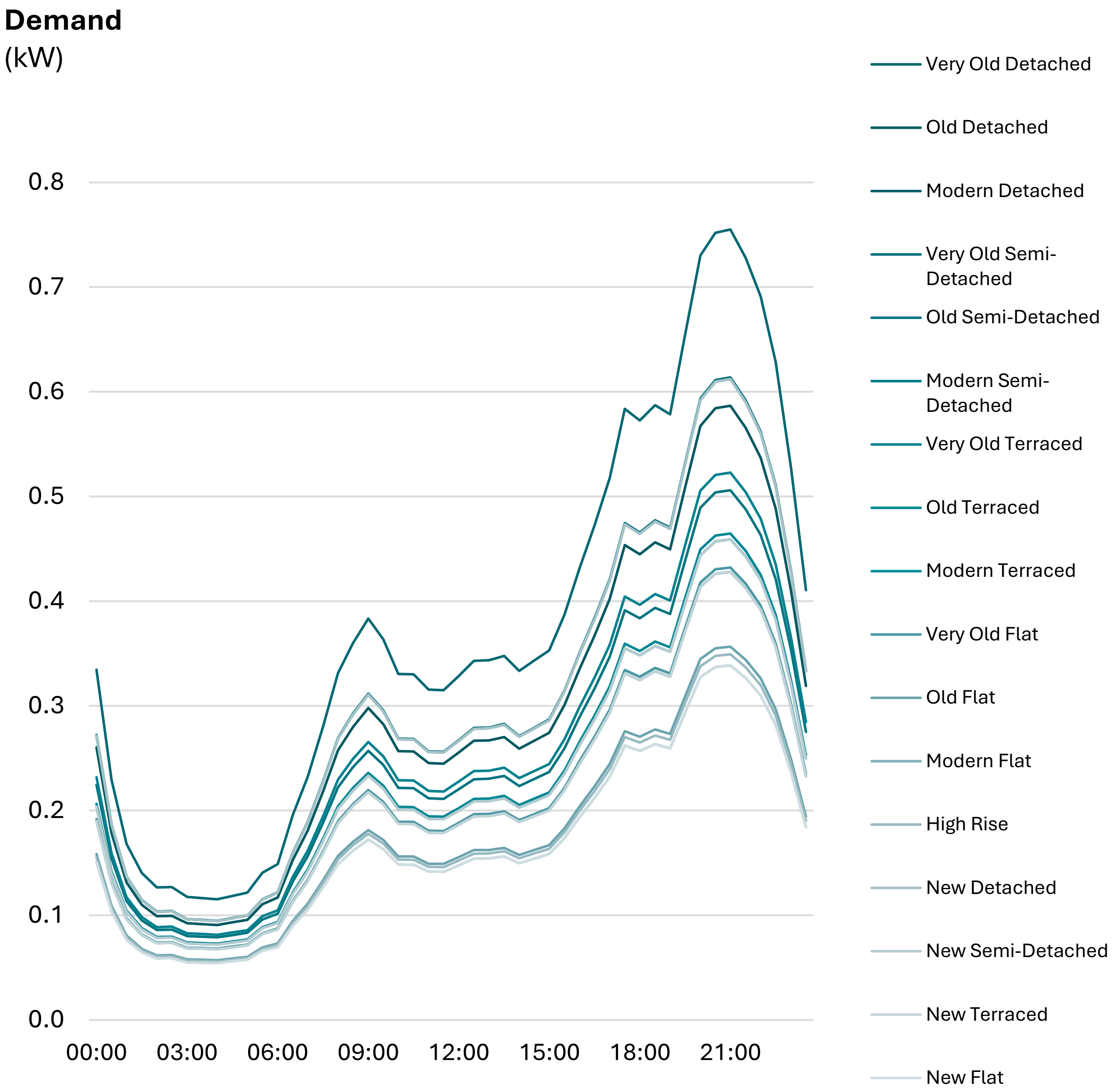

Figure 74: Load profiles for different domestic property archetypes, provided by EA Technology Ltd

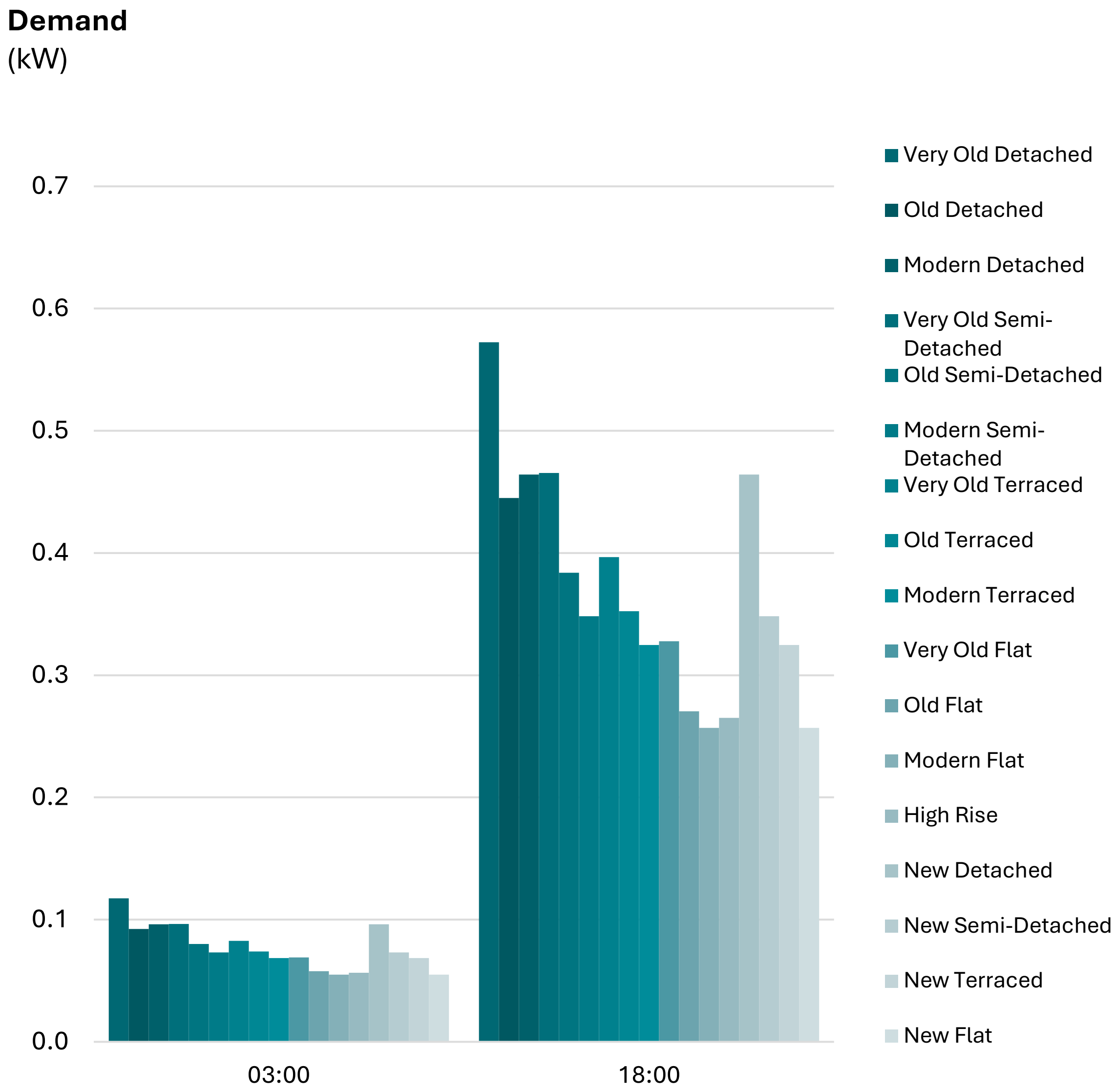

Figure 75: Loads for minimum and maximum half-hourly periods for domestic property archetypes

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November 2024