



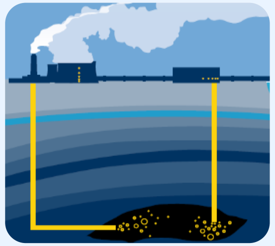



Low Carbon Heat Study – Phase 2

The Kensa Group

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elementenergy
an ERM Group company

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This study aims to assess the benefits that flexibility in domestic heating can bring to the GB electricity system in 2050, and compares the impact of varying the proportions of ASHPs & GSHPs in the housing stock

Kensa have commissioned a study by Element Energy to undertake modelling of the GB electricity system, to estimate the financial and system benefits that heat flexibility can bring, and to assess the impact on the electricity system of varying the proportion of ASHPs and GSHPs in the GB domestic housing stock. This study is the second Phase of work of the Low Carbon Heat Study. In Phase 1, Element Energy compared performance and lifetime costs of ASHPs & GSHPs. Phase 2 considers 6 distinct scenarios of a 2050 GB electricity system. These scenarios vary the proportions of ASHPs and GSHPs in GB homes, and also the use of other flexible technologies such as EV charging and heat batteries. The results will be used by Kensa to inform future decisions and provide an evidence base when interacting with other organisations.

- **Specific aims** of the project are to:
  1. *Quantify the potential to shift electrified heating demand in GB domestic buildings away from hours of peak electricity demand through pre-heating and use of heat batteries*
  2. *Understand how the potential to shift demand varies throughout the year using real weather data*
  3. *Analyse how flexibility of heating demand across the entire GB housing stock could interact with other flexible demand (e.g. EV charging)*
  4. *Quantify the reduction in peak electricity demand and the reduction in curtailment of renewable energy generation that can result from heat flexibility alongside other flexible technologies*
  5. *Assess the benefit to the GB electricity system that result from varying the proportion of Air Source Heat Pumps (ASHP) and Ground Source Heat Pumps (GSHPs) in the GB housing stock, using the detailed modelling of heat pump performance from Phase 1 results*

- The performance data of ASHPs and GSHPs comes from the detailed modelling undertaken by Element Energy in Phase 1 of this Low Carbon Heat Study, with hourly weather data from the Met Office was then used to generate hourly COPs.
- The cost and performance data for the electricity system comes from a range of public data sources in the UK, including National Grid and the electricity distribution network operators.

This study modelled the impacts of varying ASHP & GSHP deployment rates on the electricity system by modelling flexibility of domestic heating alongside other flexible electricity demand types

Rationale for this study

- Heat pumps are being targeted as a key technology to decarbonise the UK's buildings. The UK Government is aiming for over 600,000 heat pumps to be installed per year from 2028, according to the 10 Point Plan for a Green Industrial Revolution.
- According to National Grid's 2022 Future Energy Scenarios, over 40% of homes could have a heat pump installed by 2035, with between 41% and 72% of homes having heat pumps by 2050.
- Although heat pumps are likely to be a key heating technology in domestic and non-domestic buildings in the UK, there is uncertainty over the role that GSHPs can play in the final technology mix by 2050.
  - National Grid's 2022 Future Energy Scenarios estimate between 1 million and 9 million GSHPs could be installed in British domestic buildings by 2050.
- Phase 1 of the Low Carbon Heat Study (undertaken by Element Energy) investigated the cost and performance of ASHPs and GSHPs in individual homes in Great Britain, and found that consumers can achieve lifetime cost benefits from GSHPs compared to ASHPs.
- However, this study was limited to benefits that individual consumers would receive, and did not consider the system impacts of an ambitious deployment of GSHPs in the UK housing stock.
- Kensa has therefore commissioned Element Energy to study the impact on the electricity network that can arise from flexible heating and high deployment of GSHPs in domestic buildings in Great Britain, with the hope of providing an evidence base for policy makers.

Summary of method used in this study

- In this study, Element Energy's Integrated System Dispatch Model (ISDM) has been used to optimise electricity demand profiles for electric vehicle charging, electric heating through heat pumps and other flexible demand types.
- 6 scenarios have been considered, representing variations in the deployment rate of flexible technologies such as ASHPs, GSHPs, smart charging, and heat batteries.
- These 6 scenarios represent different potential net-zero end-states in 2050.
- The ISDM takes electricity demand profiles and uses linear optimisation to shift electricity demand to reduce the peak electricity demand on the grid or to coincide with period of higher renewable energy generation.
- The analysis presented in this study considers 6 distinct domestic building archetypes of varying size, typology and energy efficiency level, providing different levels of potential for heat flexibility. These archetypes are used to assess the potential for heat flexibility across the entire British domestic housing stock.
- The 6 scenarios in this study are compared in terms of annualised cost, accounting for cost savings through reducing peak electricity demand and reducing the need for dispatchable power generation in the British energy system.

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Phase 1 of the Low Carbon Heat Study incorporated various sensitivities to take into account weather patterns, house types, householder behaviour, fuel cost variations and technology options

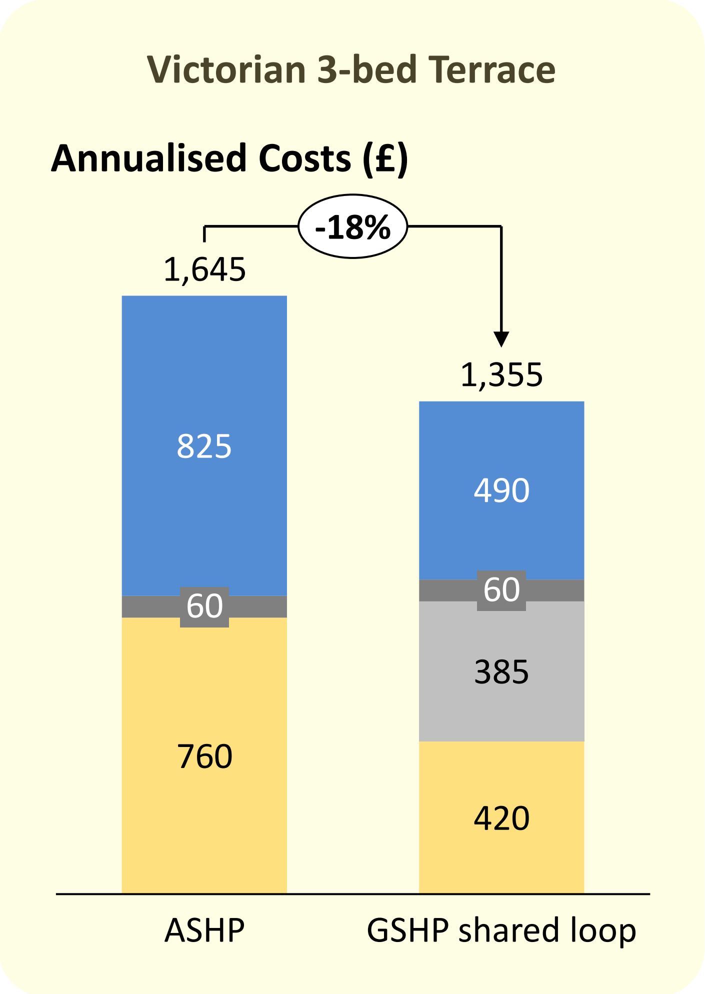
Project Scope

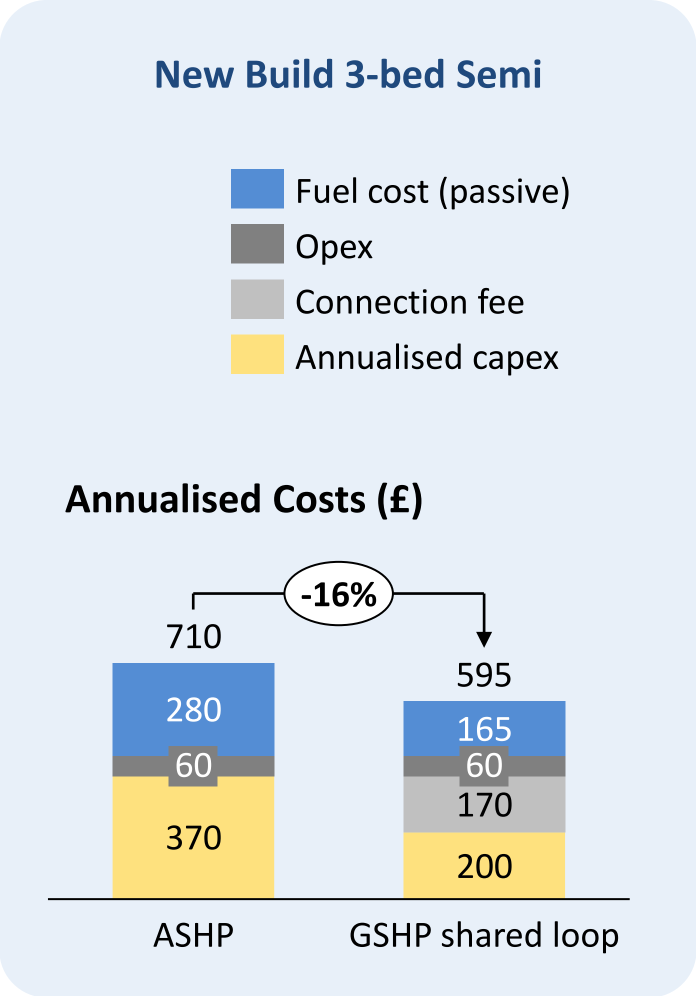
Technology	• Two technologies are compared: a single ASHP system and a GSHP with a shared ground loop.
Location	• Leeds was identified as representative of the UK average for temperature and humidity (also used in SAP). The nearest location that had suitable weather data (complete hourly data) was the nearby town Bingley.
Weather Years	• Based on average winter temperatures over the last 40 years, 2015 was identified as an average year. 2010 was identified as a 1-in-20 cold year and was used to model the impact of a cold winter.
Building Types	• A 3-bed Victorian terrace property was chosen to represent the average UK building, used to determine expected heat demand and heat loss rates. A new-build semi was also studied.
Heat Demand Profiles	• Demand profiles were modelled based on literature., which used smart meter data to model daily heat demand profiles whose shape and peak height depend on daily external temperatures.
Householder Types	• Two householder types were studied, with variations in tolerance to temperature fluctuations allowing preheating using the thermal mass of the home: ‘comfort’ tolerating ±0.5°C and ‘economy’ tolerating +2°C, -1°C.
Heat Battery	• A heat battery was also incorporated in some scenarios to study the impact of increased flexibility on household fuel bills.
Electricity Cost Projections	• Three electricity cost projection scenarios were studied, varying costs and the level to which they incentivise moving demand away from peak times.

Phase 1 investigated the costs and performance of GSHPs and ASHPs in two building archetypes

Phase 1 of the Low Carbon Heat Study found that shared-loop GSHPs have lower annualised costs due to longer lifetimes

- The **annualised costs for GSHP shared loop systems are up to £290 per year (18%) lower than for ASHP** systems for the retrofitted property. The new build offers annualised savings of £115 per year (16%).
- Annual fuel costs are around are around 40% lower for the GSHP shared loop system than an ASHP system in a typical year, increasing to 45% in a 1-in-20 cold year.
- The **combined annual fuel costs and connection fee** (based on 2020 capex) **for GSHP shared loop systems are generally around £50 more than ASHP** systems
- When instead **using the 2030 capex costs to calculate the connection fee**, **most scenarios** have **lower combined annual fuel costs and connection fee for the GSHP shared loop systems than ASHP systems.**
- **Thermal mass flexibility** offers similar percentage reductions in fuel costs across the technologies studied, which translates to **greater fuel cost savings for the ASHP systems due to the higher initial costs**.
  - Cost reductions for the retrofit of £100-£150 are achievable in the GSHP shared loop system with thermal mass flexibility alone, reduced to £20-£50 for the new build.
- A **heat battery offers an alternative to thermal mass flexibility** to access low-cost hours of electricity.
- Please see Phase 1 Study for further details including details of a GSHP shared loop.





The shared ground loop model separates the cost of groundworks from GSHP installation costs to reduce upfront costs to customers and take advantage of economies of scale

GSHP Shared Loop Model

- The shared ground loop model seeks to address the high installation costs associated with GSHP systems compared to ASHP systems by **removing the cost of the groundworks from the upfront cost to the consumer and with multiple householders sharing a single ground loop**.

- The **groundworks are installed and managed by a separate entity from the householder** and the **householder pays a connection fee** to use the infrastructure, akin to the standing change included in gas and electricity bills. This model removes the issue of higher initial investment for householders for GSHP systems.

- This model can be made commercially viable through economies of scale: designing and installing large-scale ground infrastructure to serve many properties simultaneously.

- **Phase 1 of the Low Carbon Heat Study separates the costs to consumers from the cost of the groundworks** to study how the upfront and ongoing costs could be adapted to make high efficiency GSHP systems accessible to consumers. The considered costs to consumers are:
  - Upfront costs excluding groundworks;
  - Fuel bills;
  - Maintenance costs;
  - and a connection fee.

- This consumer offering must be balanced with a **commercial offering that enables and encourages investment** in shared ground loop infrastructure. The commercial analysis considers:
  - Upfront cost of groundworks
  - Internal rate of return and investment lifetime.

This present study applies the Phase 1 results to the Great British national housing stock to quantify how varying the share of ASHPs & GSHPs impacts the national electricity system

Phase 1 studies two building archetypes whereas this study produced 6 archetypes representing the entire GB housing stock

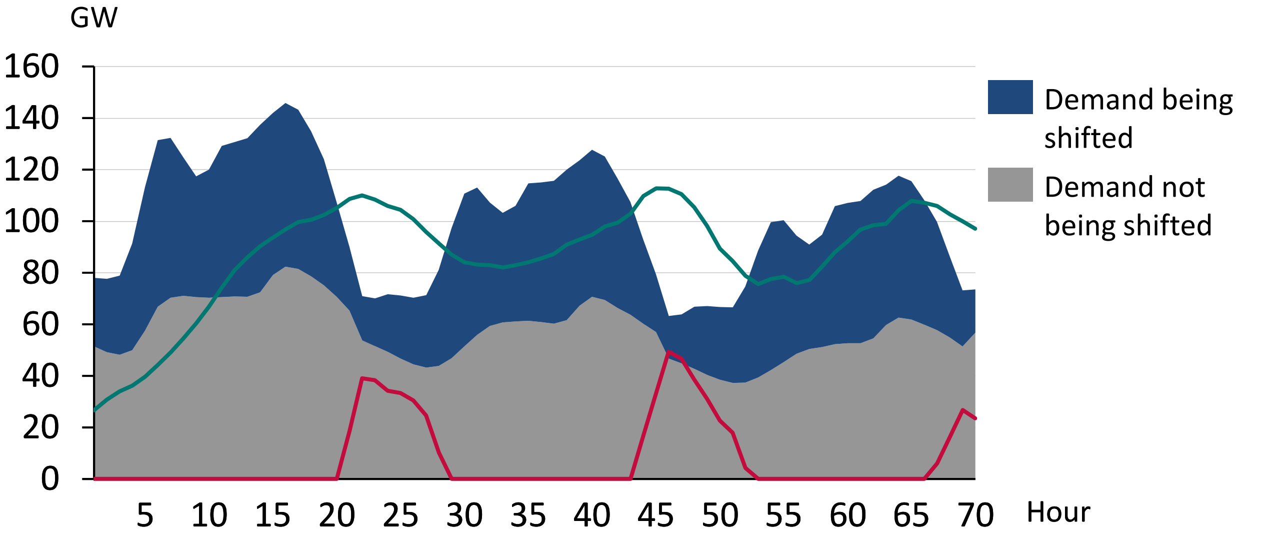
- Phase 1 of this study considered only two building archetypes: a 3-bed Victorian terraced house and a 3-bed, new-build semi-detached. The annual heat demand and hours of flexibility were adapted for each of these properties based on assumed characteristics such as property type, heat loss rates and thermal mass.
- In Phase 2 the entire British housing stock was analysed, where the heating demand and hours of flexibility of 6 archetypes were modelled to represent the potential for electricity demand shifting in the British domestic building stock.
- By analysing the electricity demand flexibility of the entire British housing stock, the benefits of heat flexibility can be determined, in terms of reducing the curtailment of renewable electricity and analysis of any cost benefits from flexibility.
- Different heating system compositions throughout the British domestic housing stock have been analysed through 6 different scenarios in this study, to identify if any significant benefits can be achieved through varying deployment levels of ASHPs or GSHPs, or through additional flexible technologies such as heat batteries.

Benefits from flexibility of electricity demand include lower costs and lower emissions

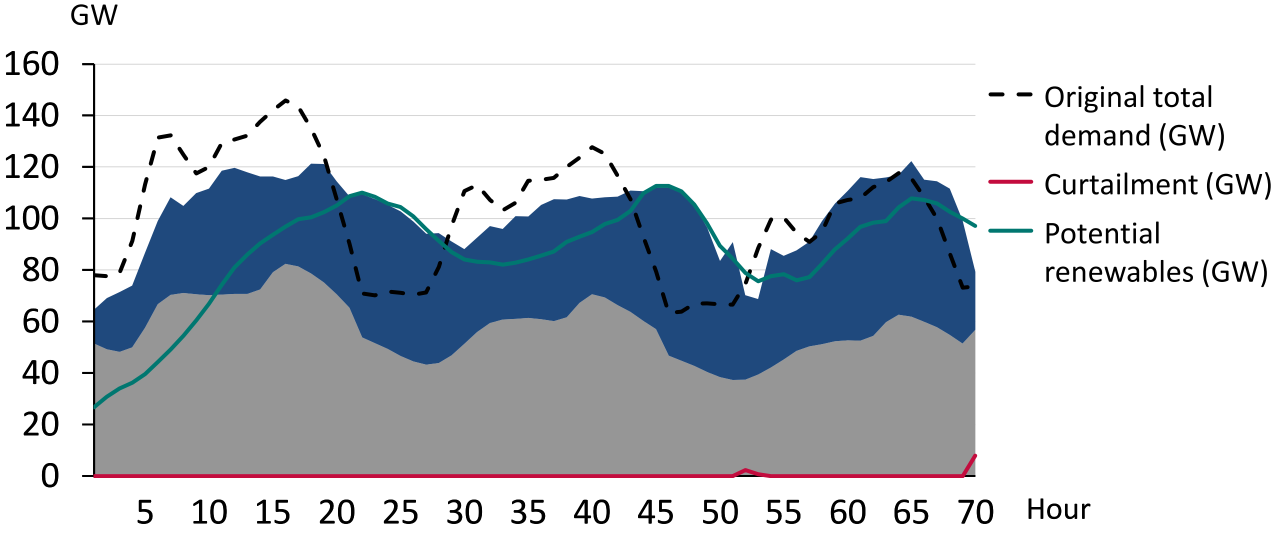
Flexibility of electricity demand, also known as load shifting or demand-side response (DSR), can provide a number of benefits, including:

1. **A reduced peak annual electricity** demand, avoiding additional transmission and distribution system upgrade costs.
2. **Accelerating the decarbonisation of the electricity system** through reduced curtailment of renewable energy.
3. **Increased utilisation of renewable energy**, leading to lower energy costs for both energy consumers and developers of renewable energy generation plants,
4. **Increased resilience in the electricity system** as assets can reduce or shift their electricity demand to support the system, which could occur at short notice or even automatically.
5. **Reduced need for dispatchable generation**, which reduces system and consumer electricity costs both from a reduced capacity and reduced utilisation of dispatchable generation plants with relatively high fuel costs.

Demand before load shifting



Demand after load shifting



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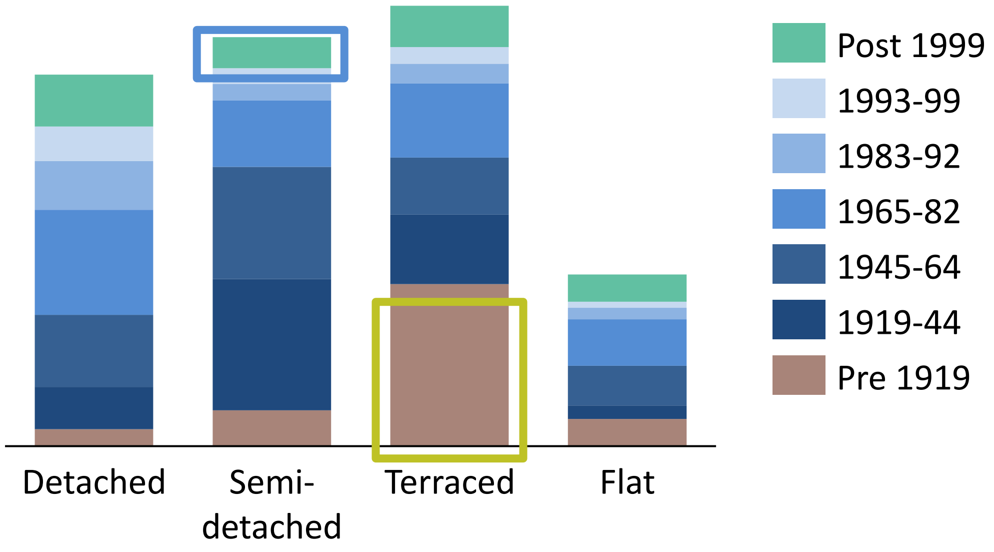
This study produced 6 domestic building archetypes to represent the entire domestic building stock, expanding on the archetyping work in Phase 1

6 building archetypes were analysed to represent the Great British housing stock, with varying flexibility for each archetype

- 2 building archetypes were used in Phase 1 (a three-bed Victorian terrace, and a three-bed new build semi-detached home)
- 6 new archetypes were produced to represent the full range of heating demand and heat flexibility in British domestic buildings, using the ~ 9000 archetypes produced for the CCC's 6th Carbon Budget as a starting point
- These ~ 9000 archetypes were aggregated into 6 representative archetype groups that cover the range of flexibility and heating demand in the British housing stock
- 6.3 million new build homes were also included in this stock analysis, using CCC 6th Carbon Budget projections for domestic new builds

- For each archetype, the thermal mass and heat loss rate was estimated:
  - Archetype description data (from EPC, EHS data) & geometric assumptions were used to estimate thermal mass
  - Heat loss rate estimations were made using archetype description data
  - A calculation of the changes to heat loss rate & total heating demand was made following energy efficiency deployment, based on the CCC 6th Carbon Budget analysis, which updated the heat loss rate & total thermal demand of each archetype accordingly
  - The hours of flexibility for each archetype can then be calculated at a range of indicative temperatures
- More detail on these calculations are given in the Appendix

Breakdown of GB domestic property types, with the two highlighted portions representing the Phase 1 archetypes



The CCC's Sixth Carbon Budget archetypes provide full coverage of existing domestic buildings in GB, and were used in the archetyping process with Sixth Carbon Budget energy efficiency assumptions

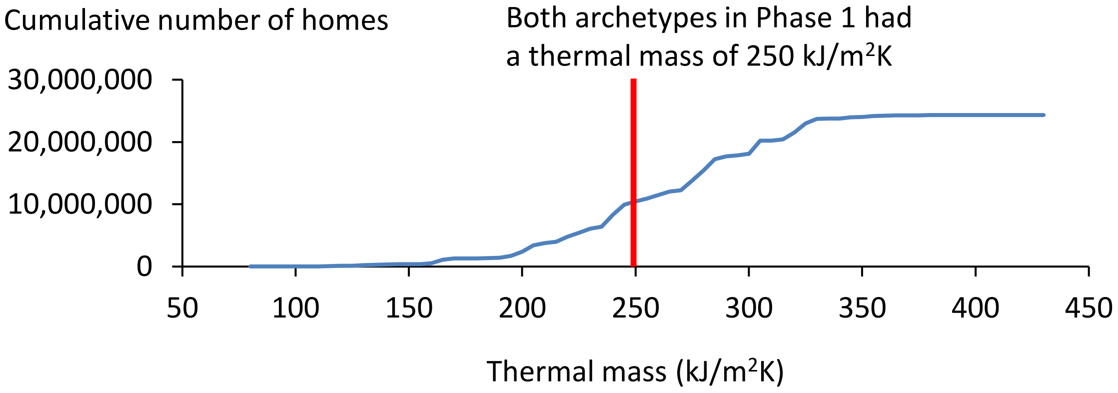
The building archetype data used for this study come from detailed analysis by Element Energy for the CCC

- The initial set of archetypes used in this study were first produced for Element Energy's work for the Committee on Climate Change (now the Climate Change Committee) on the 'Development of trajectories for residential heat decarbonisation to inform the Sixth Carbon Budget': LINK
- These provide a summary of the existing Great British domestic building stock, and allocate each domestic property in Great Britain into an archetype using the following characteristics:
  - Wall type: with 7 categories, subdivided by construction (external stone, internal stone, cavity) insulation level, (insulated, uninsulated) and ease of treatment
  - Loft type: No loft and 7 loft categories, subdivided by thickness subdivided by thickness (0-100, 100-200, 200+ mm) and ease of treatment
  - Floor type: None and 4 floor categories, subdivided by type (solid, suspended) and insulation level (insulated, uninsulated)
  - Glazing type: single glazed or double glazed (pre- or post-2002)
  - Property type: Detached house, semi-detached house, terraced house, or flat
  - Existing heating system: gas boiler, oil boiler, or electric heating system
  - Size: small/medium/large based on floor area
- Each archetype represents a unique combination of these characteristics, with British buildings allocated to one of these archetypes based on available housing data. Data from EPCs, English Housing Survey, Welsh Housing Condition Survey, Scottish Housing Condition Survey and the Northern Ireland Housing survey were used to allocate buildings into these archetypes.
- For more information on this process, please see pages 55-59 of the 'Development of trajectories for residential heat decarbonisation to inform the Sixth Carbon Budget' report (LINK) or accompanying assumptions workbook.
- To account for energy efficiency improvements between now and 2050, the energy efficiency deployment assumptions in each domestic archetype was taken from the CCC's Sixth Carbon Budget 'Tailwinds' scenario, which covers assumptions on behavioural change and fabric energy efficiency improvements.
- This scenario was chosen as it most closely aligns with the National Grid FES Consumer Transformation scenario, in terms of behaviour change and deployment of GSHPs.
- The energy efficiency improvements are determined by consumer uptake modelling alongside heating system replacements, supported by expected government policy. This energy efficiency deployment results in a reduction of 22% domestic heating demand by 2050.
- For more information behind the archetyping process and energy efficiency assumptions, see the detailed reporting and assumptions at this link: LINK

The thermal mass and heat loss rate was calculated for the 9000 initial archetypes, which represent the entire British domestic building stock

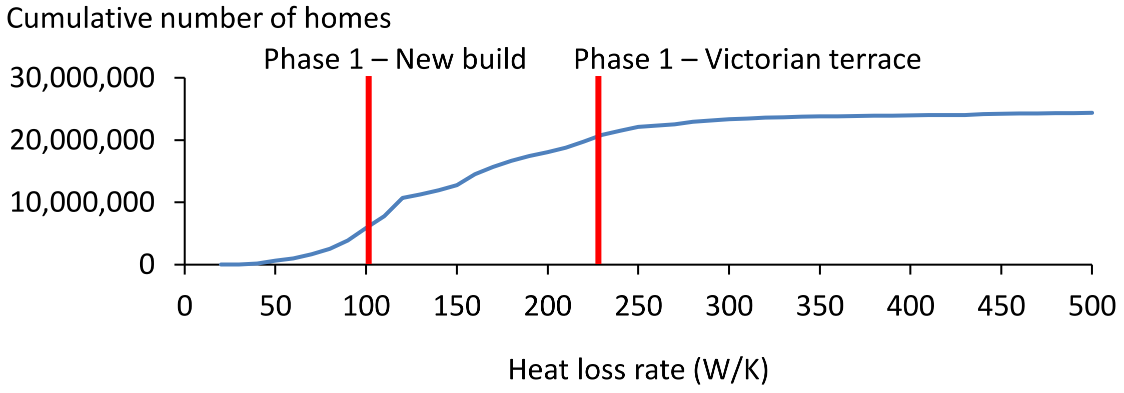
Calculation of archetype thermal mass

- To estimate the thermal mass of each building, assumptions were made about the materials that make up the building fabric in each archetype.
- The labels to describe the building archetype fabric types in the CCC's Sixth Carbon Budget residential archetypes were mapped to fabric types in Table 1e in the domestic SAP methodology (see here in the Appendix).
- Each fabric type has a heat capacity in units of kJ/m^{2}K, which are multiplied by estimated surface areas for each external fabric type in each archetype which results in a fabric's thermal mass.
- A full description of the assumed SAP fabric materials for each building archetype fabric, and their assumed heat capacity and areas, is given here in the Appendix.
- The total building thermal mass is the sum of the thermal mass of each fabric type in the building.
- A distribution of the domestic building stock's thermal mass is given below:



Calculation of archetype heat loss rate

- Each archetype's heat loss rate was calculated using the following two methods:
  1. First principles, using U-values for each archetype fabric type, and standard assumptions around ventilation losses etc;
  2. Archetype heating demand data & heating degree day analysis.
- Results from both methods agreed typically within 5-15%, both for individual archetypes and across the whole British domestic housing stock; the heating degree day analysis was used in the final modelling.
- This method assumes that each archetype heat loss rate varies linearly with its annual heating demand. The heat loss rate is estimated by dividing the annual heating demand by the heating degree hours (~ 46,700 heating degree hours in a year) in the winter heating period.
- Following the application of energy efficiency (in line with the CCC's 6th Carbon Budget Tailwinds scenario), the heat loss rate was updated for each archetype using this method.
- A distribution of the domestic building stock's heat loss rate is given below:



The thermal mass and heat loss rate of buildings is used to estimate the hours of flexibility a domestic building can provide

The number of hours of flexibility that can be provided by flexible heating varies with a number of factors, given below

- Using a building's thermal mass and heat loss rate, a building's thermal hours of flexibility is calculated as follows:

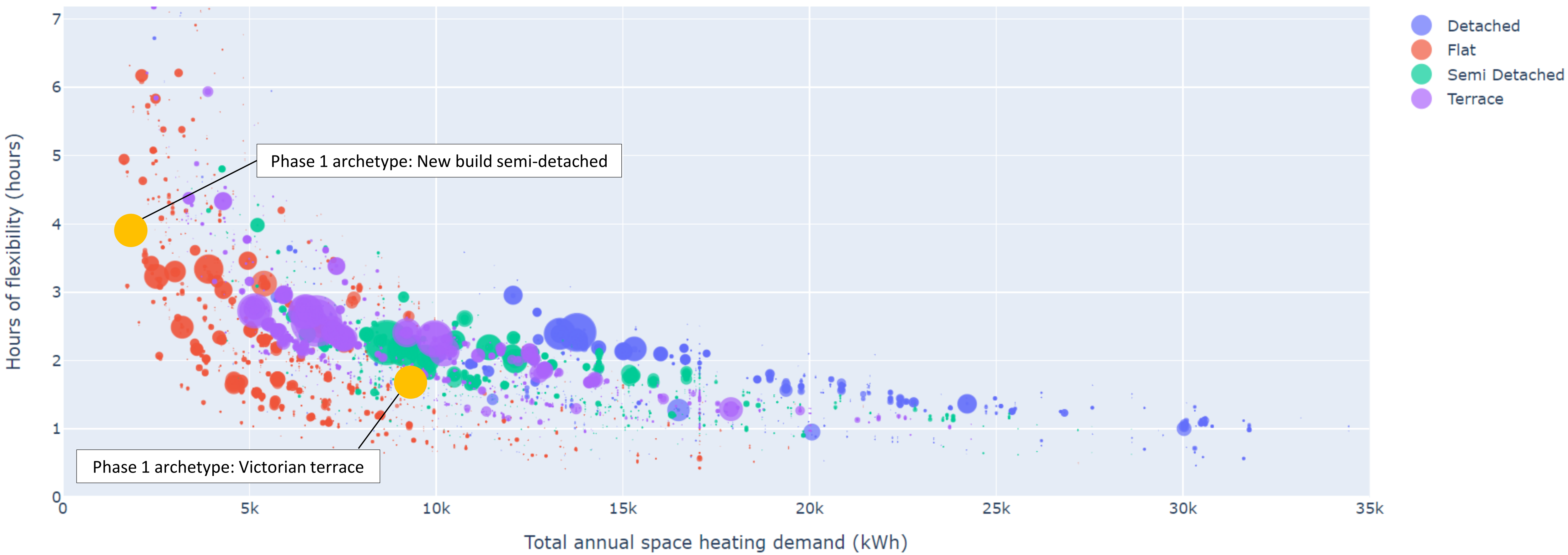
$$hours\ of\ flexibility\ (h) = \frac{building\ thermal\ mass\ (kWh\ K^{-1})\ \times\ allowed\ temperature\ change\ (K)}{building\ heat\ loss\ rate\ (kW K^{-1})\ \times\ (T_{inside}\ (K)\ -\ T_{outside}\ (K))}$$

- The allowed temperature change refers to how much temperature change is allowed within the building while demand is being shifted, above or below a typical operating temperature of 21°C.
- For example, an allowed temperature change of ±0.5°C represents allowing the internal temperature to increase to 21.5°C or decrease to 20.5°C, to shift heating demand away from the electricity peak by pre-heating a building or delaying heating and allowing the building to cool.
- Increasing the allowed temperature change allows for heating demand to be shifted for more hours, as more pre-heating can occur or the building is allowed to cool further beyond the typical operating temperature of 21°C.
- This study assumes a weighted average of the following allowed temperature changes: 20% of all building occupiers with ±0.5°C allowed temperature change; 50% of all building occupiers with +1.5°C/-0.5°C allowed temperature change; and 30% of all building occupiers with +2°C/-1°C allowed temperature change.
- This distribution of allowed temperature change aims to reflect the variety in the allowed change in comfort for different types of occupiers, and reflects the high level of consumer engagement and behavioural change that is central to National Grid's FES Consumer Transformation scenario.
- T_{inside} represents the typical internal temperature of 21°C, while $T_{outside}$ represents the external temperature, which was varied hourly in the modelling using real-world hourly weather data from England for two years; more detail is provided here in the Appendix.
- The following two slides show the distribution of hours of flexibility and space heating demand for all British domestic buildings, for an allowed temperature change of ±0.5°C and with an outside temperature of 5.8°C (which represents the average heating temperature of the typical heating season in Great Britain).
  - The graphs show the archetypes coloured by property type, before (first graph) and after energy efficiency (second graph).
  - In the model runs, the hours of flexibility will vary hourly, based on real-world hourly weather data.

1. The outside temperature (5.8 °C) was calculated as a heating degree day-weighted average of outside temperature in the UK between 2000-2020, from November to March

Plotting the hours of flexibility against total annual heating demand for all British domestic buildings shows the variation in flexibility potential in the British housing stock

Total annual space heating demand against hours of flexibility, for 1°C ΔT on a typical heating season day (5.8°C)

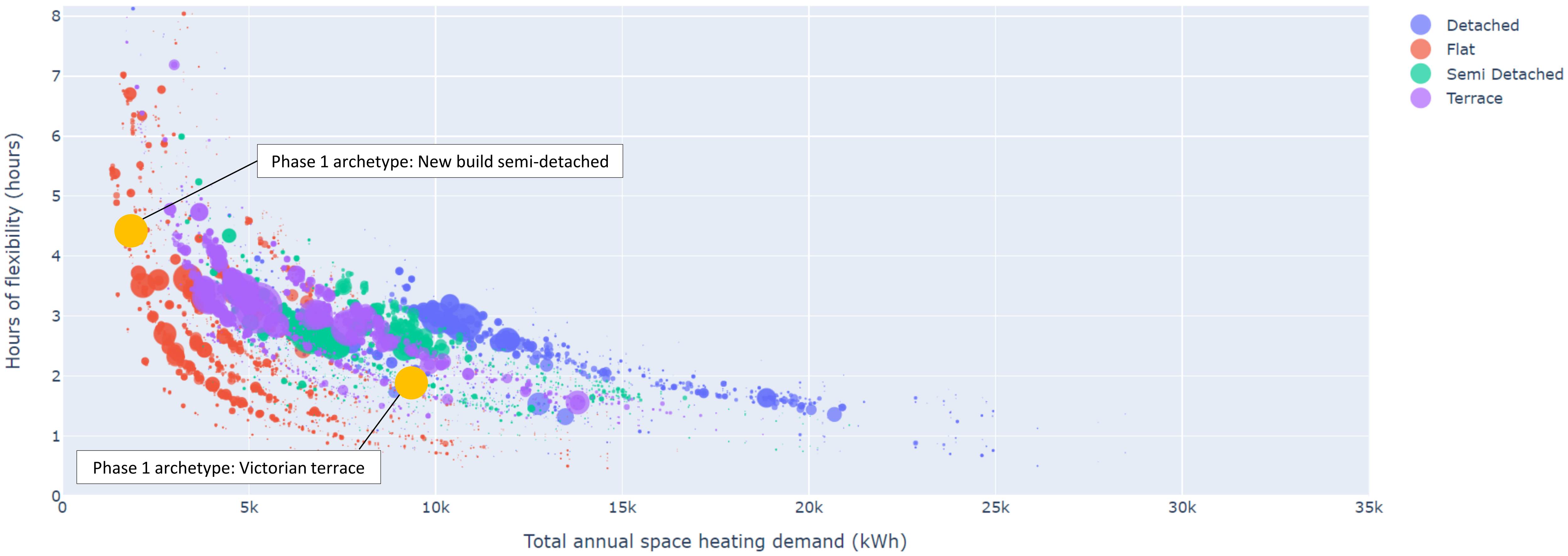


Note that the size of the bubble represents the number of buildings in each archetype.

After significant energy efficiency deployment in most archetypes this distribution changes, but there are clear differences between different archetypes potential to provide flexible heating

After energy efficiency

Total annual space heating demand against hours of flexibility, for 1°C ΔT on a typical heating season day (5.8°C)



Note that the size of the bubble represents the number of buildings in each archetype.

The amount of flexibility that an archetype can provide varies based on the outside temperature, and allowed temperature change inside the building

Outside temperature and allowed temperature change are key flexibility drivers

- The table on the right shows the proportion of the building stock with more than 4 hours of flexibility under varying conditions of outside temperature and allowed temperature change.
- Only 6% of buildings are 'flexible' on a typical day with ΔT = 1°C.
- More than ⅔ of buildings are 'flexible' with ΔT = 3°C, even on a 1-in-20 year peak day.

Temperature inputs used

- Heating season average day temperature = 5.8°C.
- Typical peak day = -4°C (Hybrid Heat Pumps, Element Energy for BEIS, 2017).
- 1-in-20 peak day = -9°C (Challenges for the decarbonisation of heat: local gas demand vs electricity supply, Winter 2017/2018, Grant Wilson et al., 2018).

Aggregating the British housing stock

- Modelling the flexibility of each archetype individually would provide the most accuracy, but would be time-intensive in the modelling.
- The archetypes need to be grouped into a manageable number of new archetypes to reduce the model run-time, although these new archetypes need to remain representative of the British housing stock.
- <u>The following slide shows the used grouping of archetypes for the modelling in this study.</u>

Outside T	Allowed ΔT	Percentage of buildings with ≥ 4 hours of flexibility
5.8	1	6.0%
-4	1	0.8%
-9	1	0.2%
5.8	1.5	66.6%
-4	1.5	3.1%
-9	1.5	1.7%
5.8	2	89.2%
-4	2	29.9%
-9	2	6.2%
5.8	2.5	95.6%
-4	2.5	68.4%
-9	2.5	34.3%
5.8	3	98.7%
-4	3	86.3%
-9	3	68.4%

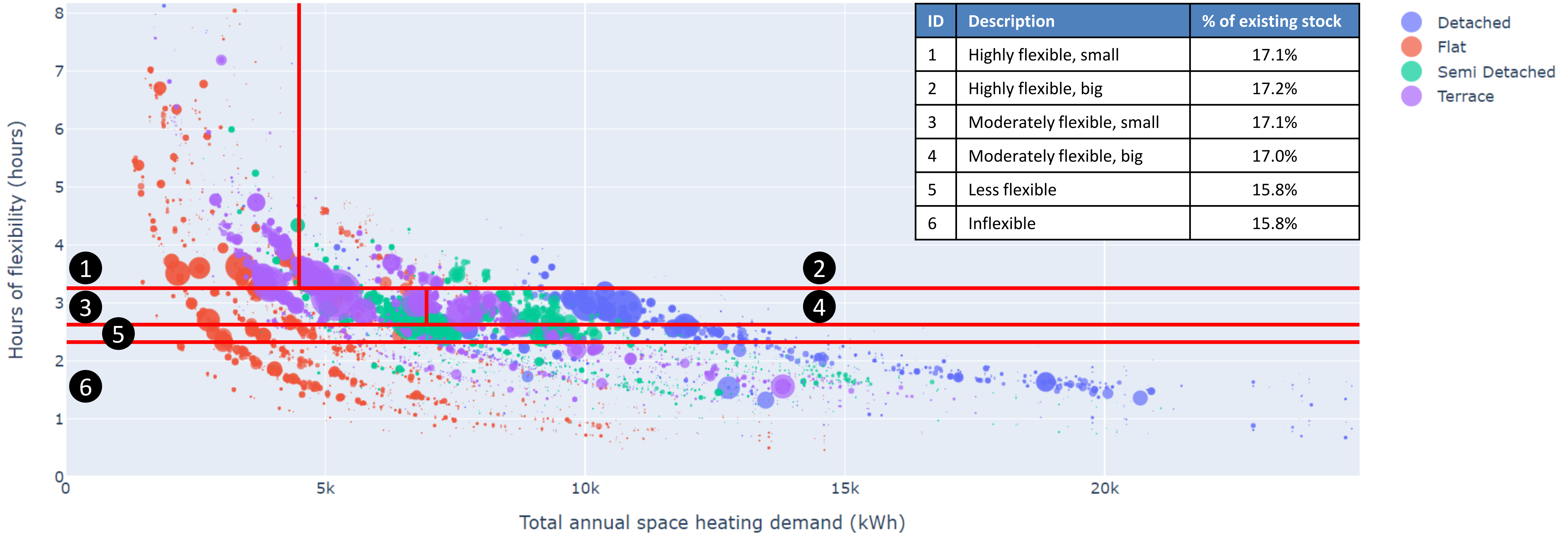
Temperature variations for householder types in Phase 1

Comfort
±0.5°C

Economy
+2°C/-1 °C

The ~ 9000 initial archetypes were aggregated into 6 new archetypes to split the stock into roughly even segments while also grouping key space heating and heat flexibility characteristics

Total annual space heating demand against hours of flexibility, for 1°C ΔT on a typical heating season day (5.8°C)



ID	Description	% of existing stock
1	Highly flexible, small	17.1%
2	Highly flexible, big	17.2%
3	Moderately flexible, small	17.1%
4	Moderately flexible, big	17.0%
5	Less flexible	15.8%
6	Inflexible	15.8%

Please note that the x-axis limits have been adjusted following energy efficiency improvements to archetypes

The 9000+ granular archetypes were aggregated into 6 new archetypes, using the thresholds outlined below

Justification for the thresholds used to aggregate the archetypes

- The archetypes have been split into 6 groups to model the smart heating of buildings with similar heating demand and potential flexibility of heat demand.
- This aggregation is necessary to provide a manageable number of archetypes using our integrated modelling.
- The flexibility of all aggregated archetypes will be modelled separately in the ISDM.
- The thresholds used to group the archetypes have been applied in the following order:
    1. The ‘highly flexible’ archetypes (eventually groups 1 & 2) were identified as archetypes with more than 4 hours of flexibility on a 1-in-20 year peak coldest day (-9°C), with 2.5°C allowed temperature change.
        a. This is equivalent to archetypes having more than 3.16 hours of flexibility on a typical winter day (5.83°C) with 1°C allowed temperature change.
    2. These highly flexible archetypes have been split into two groups with ~ equal total stock, with ‘highly flexible, small’ archetypes (ID 1) having less than 4,520 kWh/year space heating demand (after energy efficiency), and ‘highly flexible, big’ (ID 2) having more than 4,520 kWh/year space heating demand.
        1. 4,520 kWh/year space heating demand was used as this evenly splits the stock between archetypes 1 & 2.
    3. The ‘Less flexible’ and ‘Inflexible’ archetypes (groups 5 & 6) were identified as archetypes with less than 4 hours of flexibility on a typical year coldest day (-4°C), with 2.5°C allowed temperature change.
        a. This is equivalent to archetypes having more than 2.64 hours of flexibility on a typical coldest winter day (5.83°C) with 1°C allowed temperature change.
    4. The ‘Inflexible’ archetypes (group 6) were those with less than 2.33 hours of flexibility on a typical winter day 5.83°C) with 1°C allowed temperature change. This value was chosen to split the buildings in groups 5 & 6 into groups of equal stock.
    5. The rest of the archetypes were considered as ‘moderately flexible’, and were split into groups 3 & 4 based on whether they had more or less annual space heating demand than 7,000 kWh/year. This value was chosen to split the ‘moderately flexible’ archetypes into two groups with ~ equal stock.

The 6 new archetypes are representative of the British existing housing stock after expected energy efficiency improvements, and new builds have been included to reflect additional homes by 2050

The archetypes were grouped based on the segmentation shown in the previous slide

- Changing the allowed ΔT or outside temperature modifies the hours of flexibility for each archetype, but scales all archetypes in the same way
- The thresholds (red lines) between archetypes segments on the previous graph have been to designed to:
  - Split the stock based into archetype groups of similar heating demand and flexibility
  - Keep similar proportions of stock in each of the four ‘flexible’ archetype groupings (IDs 1 to 4 below)
- In the scenario modelling, each grouped archetype’s flexibility will be modelled in each hour
- Below is a summary of these six archetypes, showing some key archetype characteristics.

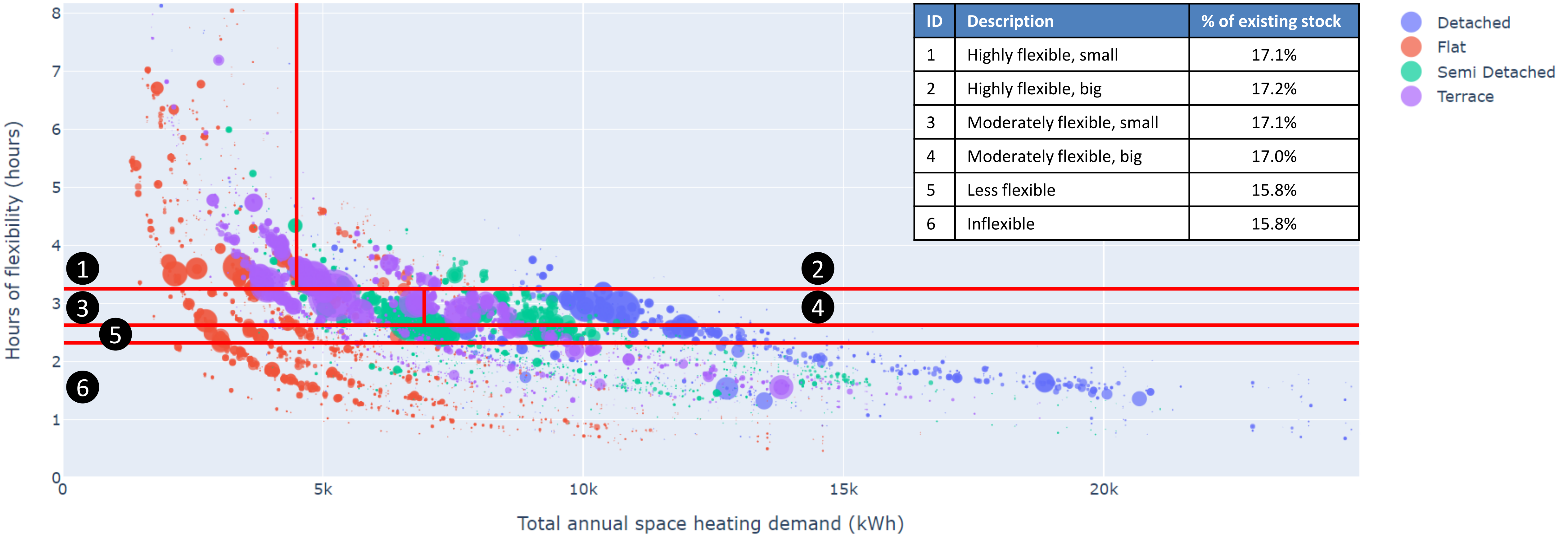
ID	Description	Representative building type	Existing stock	Average SH demand (kWh)	Average hours of flexibility with 1°C allowed variation (hours)
1	Highly flexible, small	Flat	4,157,818	3,430	4.01
2	Highly flexible, large	Terrace	4,202,531	5,491	3.44
3	Moderately flexible, small	Terrace	4,171,623	5,535	2.92
4	Moderately flexible, large	Detached	4,133,525	9,170	2.88
5	Less flexible	Semi Detached	3,842,934	8,029	2.51
6	Inflexible	Detached	3,855,132	9,621	1.79

- An additional 6.3 million homes were included within Archetype 1, to reflect new homes to be built by 2050 that are projected to install heat pumps, using the CCC’s 6th Carbon Budget assumptions, with the archetype’s characteristics updated to reflect these additional buildings.

The effects of the archetype aggregation can be seen on the next slide, with the 6 new archetypes presented on the same set of axes

After energy efficiency

Total annual space heating demand against hours of flexibility, before archetype aggregation

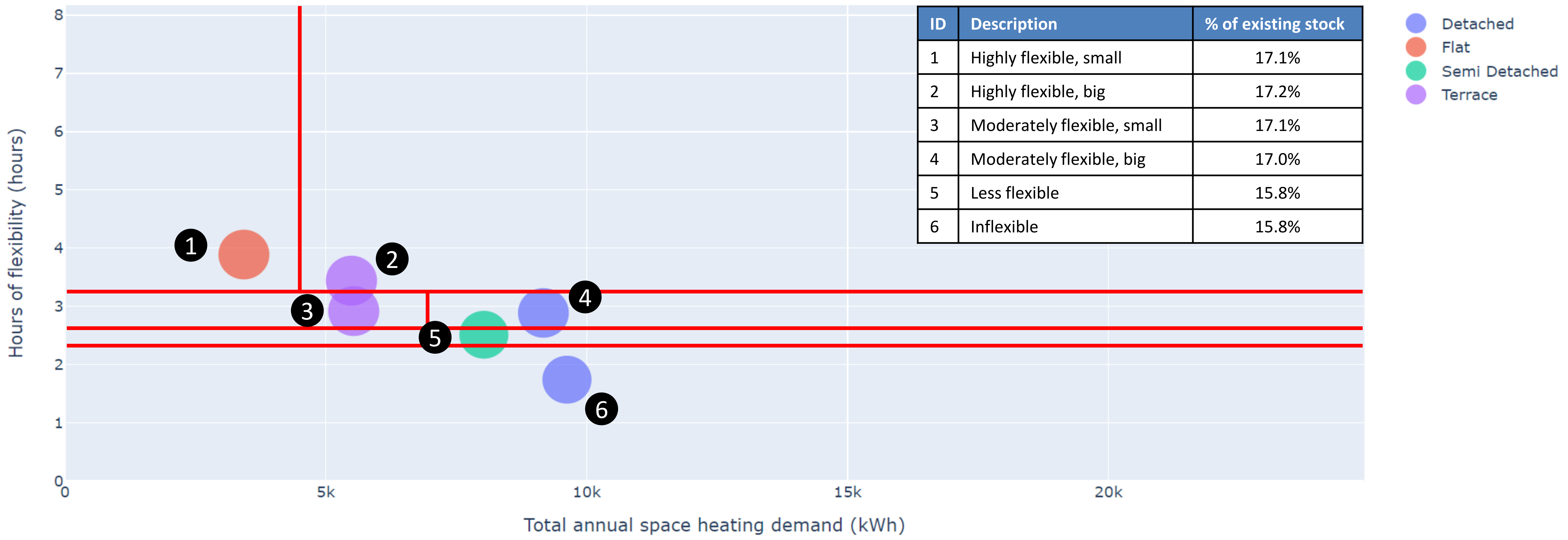


ID	Description	% of existing stock
1	Highly flexible, small	17.1%
2	Highly flexible, big	17.2%
3	Moderately flexible, small	17.1%
4	Moderately flexible, big	17.0%
5	Less flexible	15.8%
6	Inflexible	15.8%

Please note that the x-axis limits have been adjusted following energy efficiency improvements to archetypes

The aggregation into the 6 new archetypes retains representation of differences in heat demand and flexibility within British housing stock while providing reasonably short model run times

Total annual space heating demand against hours of flexibility, after archetype aggregation



ID	Description	% of existing stock
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Please note that the x-axis limits have been adjusted following energy efficiency improvements to archetypes. The colour of each bubble on this graph is only indicative, as all grouped archetypes contain a range of buildings types.

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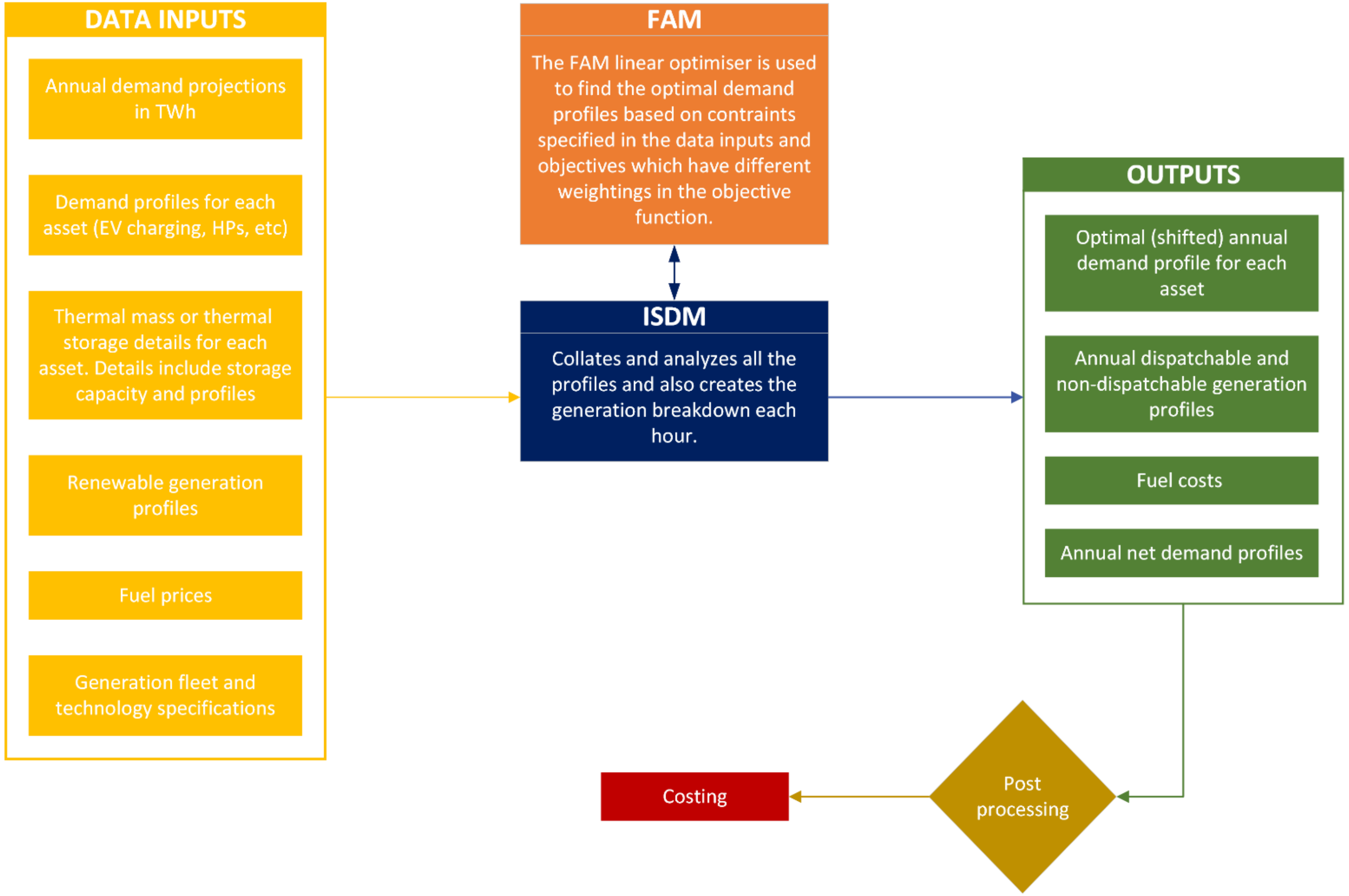
This study uses Element Energy's Integrated System Dispatch Model (ISDM) to model the British electricity system in 2050, and simulates hourly flexibility of electricity demand

The diagram below shows the inputs, processes and outputs for Element Energy's Integrated System Dispatch Model

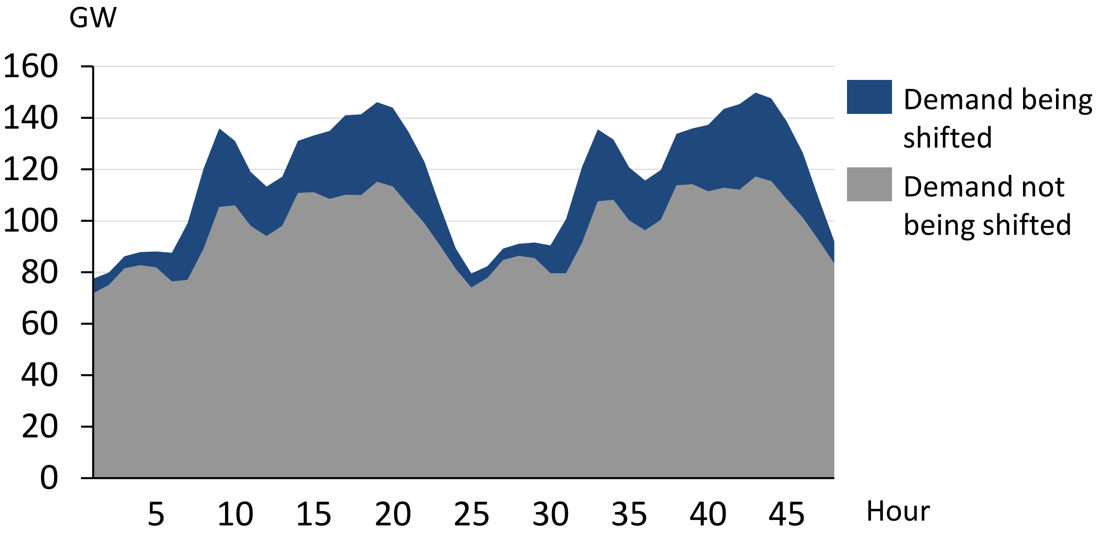
- The Integrated System Dispatch Model (ISDM) is an internally developed tool that has two core outputs:
  - **optimised electricity demand profiles**
  - **dispatchable and non-dispatchable electricity generation profiles**
- The demand profile optimisation is achieved using a linear optimiser, adapted from another internal model called the Flexible Asset Model (FAM), used in Phase 1.
- The information from the optimised profiles is used alongside other inputs to create the electricity generation annual profile, distinguishing between sources of generation based on the generation costs (prioritising low cost generation i.e. renewables).
- The outputs from the ISDM go through post-processing to obtain the costing analysis that is shown, explained in [this section of this report](#).



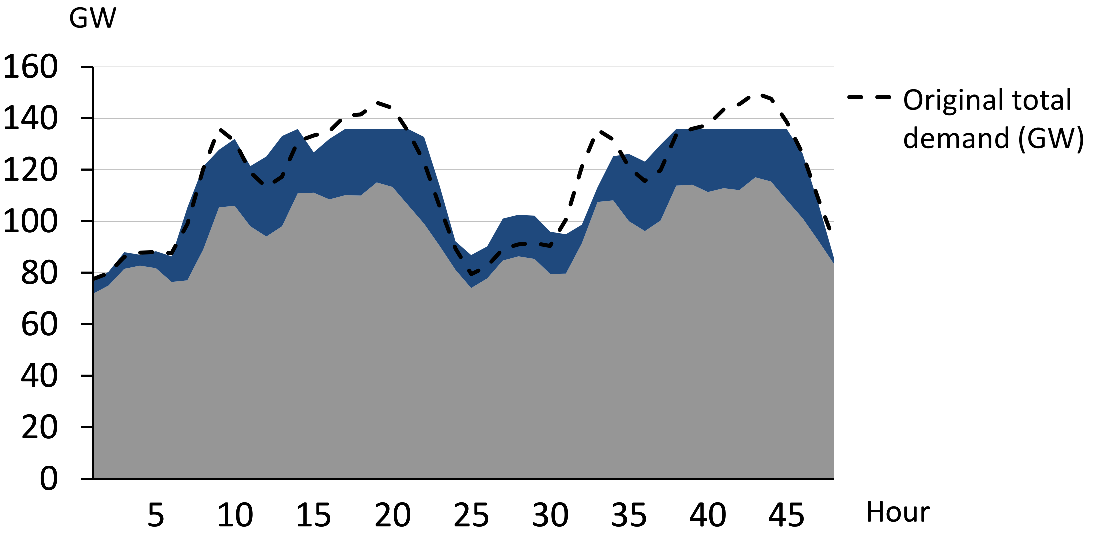
Explaining how the ISDM shifts demand: peak reduction

- The two graphs to the right show how the demand shifting works in practice when **aiming to only reduce peak demand**.
- Each graph contains two electricity demand profiles; one profile that is not being shifted in grey, and a navy profile that is being shifted.
  - The top graph shows the initial demand profiles before any demand shifting has occurred;
  - The bottom graph shows the new profiles after the ISDM has shifted the blue profile to reduce the peak demand.
- The electricity demand is shifted from hours with a high total demand to hours with a lower total demand, flattening the overall demand profile.
- The demand is not 100% flat after shifting for two reasons:
  1. Not all demand can be shifted in the flexible blue profile can be shifted. For example, when considering heating a home, although some of the peak heating demand in a day can be shifted to earlier in the day, some heating demand is still required at the peak.
  2. The demand can only be shifted a certain number of hours from the hour in which it occurs initially.
- The proportion of demand that can be shifted for each demand type considered, and the number of hours that the demand can be shifted by, depends on the demand type, and in some cases on the time of day or year.
  - For example, EV charging is more flexible than baseline industrial electricity demand.
  - In colder hours buildings lose heat more quickly, and so less heat can be shifted from these hours.

Demand before load shifting



Demand after load shifting

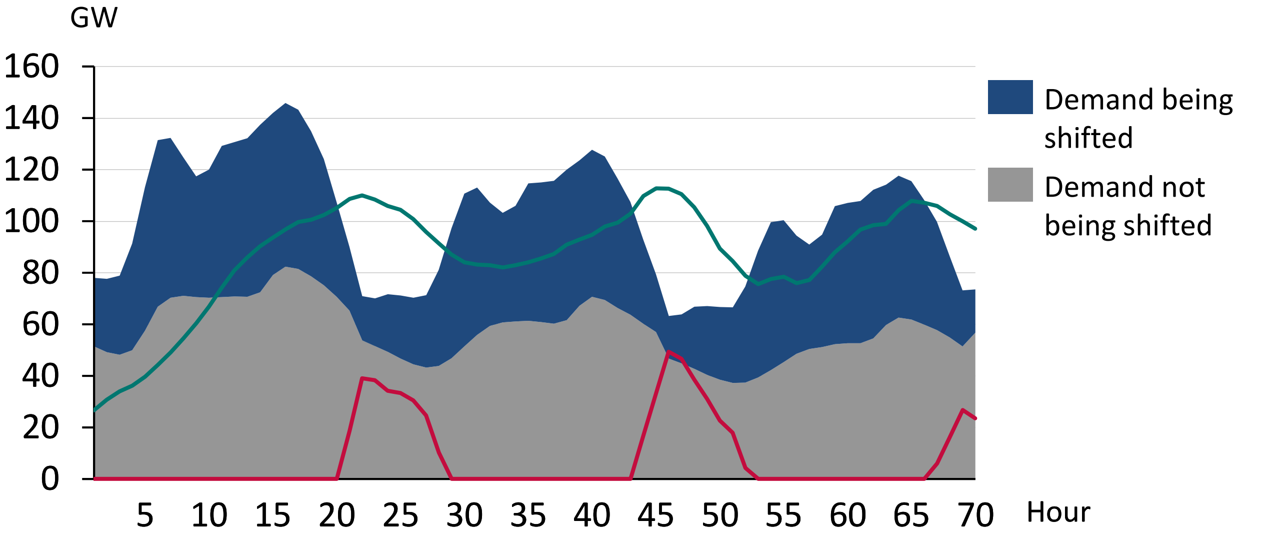


Explaining how the ISDM shifts demand: increasing consumption of renewables

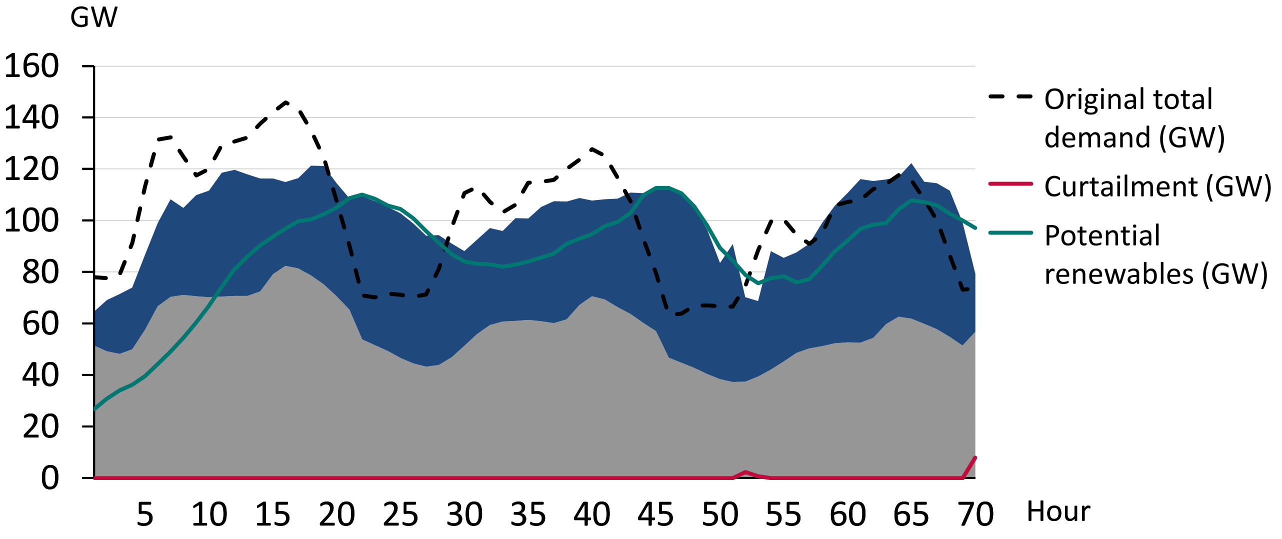
- The two graphs to the right show how the demand shifting works in practice **when aiming to reduce both peak demand and use renewable energy.**
- Each graph again contains two electricity demand profiles; one profile that is not being shifted in grey, and a navy profile that is being shifted.
- The top graph is again showing the demand before and shifting, while the bottom graph shows the profiles after shifting.
- The renewables availability (green) and curtailment (red) are now shown, both before and after load shifting.
- In this example the ISDM is aiming to reduce peak demand and decrease the use of curtailment simultaneously. This results in:
  - A reduction in the peak by over 20 GW in this 70 hour period.
  - Shifting of the peak demand hours to coincide with peak renewable generation hours (e.g. hour 47) to minimise curtailment.
  - The overall demand profile tracking the renewable generation profile after load shifting (e.g. hours 20-30) to reduce curtailment by over 550 GWh in this 70 hour period.
  - Where demand exceeds renewables, the difference between the two is minimised to reduce dispatchable capacity.

In practice, the ISDM shifts individual electricity profiles (e.g. ASHPs, GSHPs, EVs) sequentially, with each profile being shifted while all other profiles are kept constant.

Demand before load shifting



Demand after load shifting

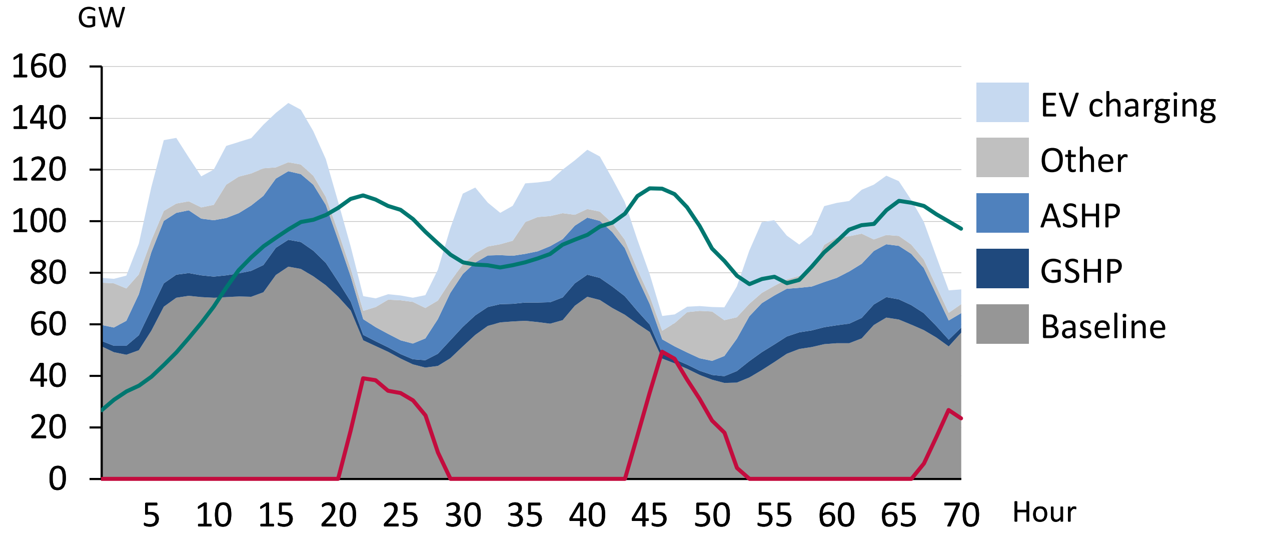


Note that interconnectors are also included in the ISDM electricity generation and transmission modelling, so that curtailment occurs only when renewable generation exceeds the sum of the demand profile and the interconnector export capacity.

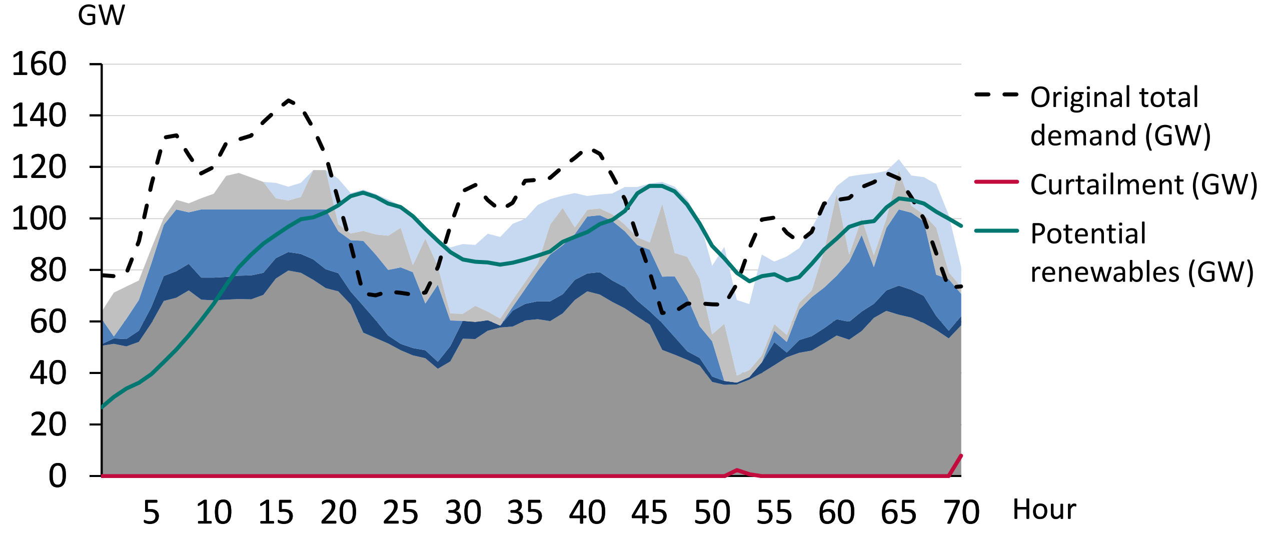
Explaining how the ISDM shifts demand: multiple profiles optimisation

- The two graphs to the right again show how the demand shifting works in practice when aiming to reduce both peak demand and use renewable energy.
- These graphs are the same as on the previous page, but here show the component profiles of the flexible demand.
- The flexible profiles shown are GSHPs, ASHPs, Other (other heating options including direct electrified heating and electrified heat supply for district heating), and EV charging, as well as a small amount of flexibility within the baseline profile (dark grey).
- The shifting in the heat pump profiles (ASHP and GSHP) aims to reduce the overall peak electricity demand and reduce curtailment of renewables;
  - This reduction in peak demand is visible is the flat profile shown between hours 5-20 in the bottom graph, when considering just the baseline, ASHP and GSHP profiles.
- The Other and EV profiles also try to reduce the peak while maximising use of renewables after the ASHP and GSHP profiles have been shifted.
- This sequential shifting of the different flexible electricity profiles happens in this way for each hour in the year.
- 6 scenarios have been produced for this study, which each use the ISDM to evaluate the effects of electricity load shifting under different conditions, including varying levels of ASHP and GSHP deployment, different weather and temperature profiles, use of heat batteries, and where flexibility in EV charging is unavailable.

Demand before load shifting



Demand after load shifting



The model uses linear optimisation to determine how each flexible demand profile should be shifted to provide the most benefit to Great Britain's low carbon electricity network in 2050

Below is a summary of linear optimisation, used by the model to shift electricity demand in this study

- Linear optimisation is an analytical method that is used to optimise (e.g. maximize or minimize) a certain function (the objective function) subject to constraints.
- The objective function (shown on the right) for the linear optimisation is given in terms of the generation profile $g_{t,i}$. The model shifts the flexible electricity demand profiles sequentially to minimise the objective function.
- The terms on the right of the equals sign of the objective function represent objectives that need to be reduced:
  - $A\left[\max \sum_i g_{t,i}\right]$ term denotes the peak utilised generation (or peak demand).
  - $\sum_{t,i}\left(g_{t,i}B_{t,i}\right)$ term denotes the cost of electricity.
- The two key objectives that the objective function is seeking to reduce are therefore the **annual peak** and the **cost of electricity generated**.
- The annual peak occurs in the hour of peak electricity demand throughout the entire year. Minimising this peak leads to a reduction in electricity network upgrade costs required to support additional electricity demands on the grid.
- The cost of the electricity generated for each hour relates to curtailment and dispatchable generation, as reducing curtailment and the use of dispatchable generation leads to a reduction in the cost of electricity term $B_{t,i}$.
- These two objectives can be prioritized by the relative size of the weighting factor A to the costing factor $B_{t,i}$. In this study the **peak reduction is given priority** by sizing A to be ~1000x higher than the annual sum of the costing factors $B_{t,i}$.
- The linear optimiser is also given a number of constraints within which the solution can be found by modelling the physical system. E.g. for a heat pump with thermal storage cylinder, the electricity demand profile of the heat pump can be altered to minimise the objective function, but the hot water must be available when required and the hot water cylinder must not exceed it's capacity.
- There are also constraints on the generators e.g. the energy available from renewable generators in each hour must not be exceeded.

$$D(g_{t,i}) = A\left[\max \sum_i g_{t,i}\right] + \sum_{t,i}\left(g_{t,i}B_{t,i}\right)$$

Objective function minimised by the linear optimiser

$D(g_{t,i})$ – the objective function.

$g_{t,i}$ – Utilised electricity generation.

i – Generation assets. Can be renewables, or dispatchable.

t – Time period. The time period is hourly since we are dealing with hourly annual profiles.

A – Weighting factor for the peak reduction.

$B_{t,i}$ – Costing factor which for renewable generation assets is between 0-1 and the inverse of the renewable availability at that hour, whereas for dispatchable generation assets it is the fuel cost.

Each flexible demand profile is optimised sequentially, on top of any inflexible profiles and any profiles that have already been optimised

Below is a summary of linear optimisation, used by the model to shift electricity demand in this study

- Each demand profile is fed into the linear optimiser as a constraint in a sequential order and the demand profile for each asset is found accordingly.
- The order in which profiles are fed into the linear optimiser is as follows:
  1. Flexible portion of baseline demand (including electricity demand in industry, appliance consumption in buildings, electrolysis for hydrogen production, and commercial heating);
  2. Heat pumps (ASHPs and GSHPs), with each archetype's demand profile fed into the linear optimiser sequentially, starting from the least flexible (archetype 6) and ending with the most flexible (archetype 1);
  3. Other electrified heating options (direct electric heating, and electrified district heating);
  4. Electric vehicle charging demand.
- When each demand profile is fed into the linear optimiser, it is optimised on top of an inflexible background demand consisting on any inflexible demand profiles and profiles that have been fed into the linear optimiser earlier in the process.
  – For example, the heat pump profiles will only see the baseline demand (after it's portion is optimised), whereas the electric vehicle charging demand will be optimised on top of the optimised profiles of the baseline demand, heat pumps, and other electrified heating options.

- There is further potential for flexibility in the Baseline demand profile, which includes significant increased demand in electricity from wider electrification of industrial energy demand and of heating in non-domestic building.
  – This study is however exploring the benefits of flexibility of domestic heating demand following electrification via deployment of GSHPs vs. ASHPs, and so only a small proportion of flexibility of non-domestic heating and of industrial electricity demand is considered.

$$D(g_{t,i}) = A\left[\max \sum_{i} g_{t,i}\right] + \sum_{t,i}(g_{t,i}B_{t,i})$$

Objective function minimised by the linear optimiser

$D(g_{t,i})$ – the objective function.

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i – Generation assets. Can be renewables, or dispatchable.

t – Time period. The time period is hourly since we are dealing with hourly annual profiles.

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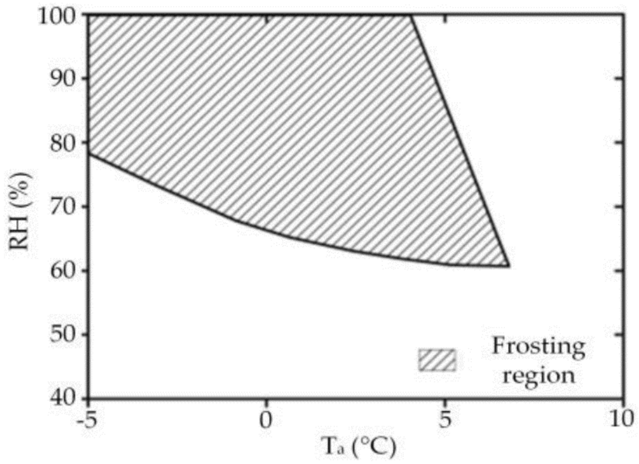
Reports from published literature indicate that the hourly decrease in COP for ASHPs when in the defrost zone is in excess of 0.4

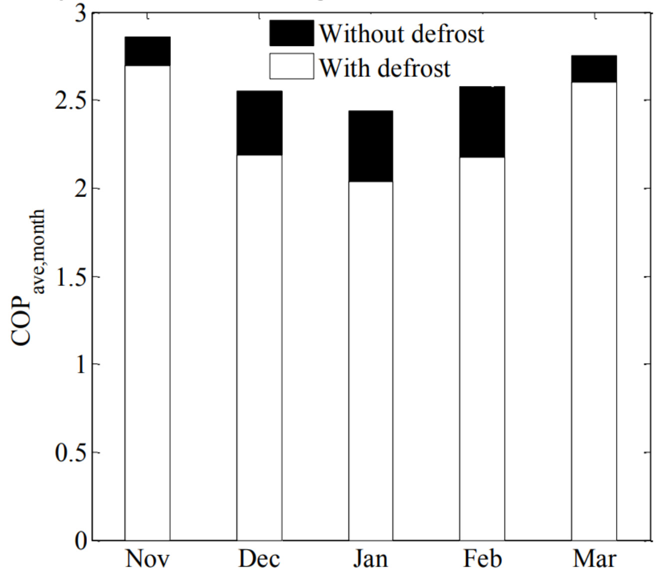
ASHP Performance Modelling

- In certain weather conditions, frost forms on the external elements of an ASHP and the unit must perform a defrost cycle. This cycle involves heating the external elements to remove the frost. Most ASHPs use a reverse cycle defrost mode, which runs the heat pump in reverse, pulling heat from the building and returning it to the external elements.
- **Defrosting is required in conditions of low temperature and high humidity**, as shown in the upper figure on the right[1]
  - Such **conditions are typical of a UK winter**
- The COP of the ASHP is reduced in three ways during the defrost cycle:
  - The heat pump is using electricity to power the cycle
  - The heat pump is not heating the building during the defrost cycle
  - Heat is being drawn from the building to heat external elements.
- The reduction in COP as a result of defrosting is not well quantified in literature.
  - Some manufacturers quote some of their reported COPs values as explicitly including the impact of defrost cycles but the difference between values that do and do not include defrosting are not shown and **it is not clear if SCOPs are quoted with any defrosting impact included**.
  - A Vocale 2014 study,[2] based on first principles calculations using weather data from a number of Italian cities found **monthly COP penalties of up 0.4** when including the impact of defrost cycles. Some results from the Vocale 2014 study are shown in the lower figure on the right.

Frost region [1]



Impact of defrosting from Vocale 2014[2]



1. Adachi et. al. "On the refrigeration cycle property of heat pump air conditioners operating with frost formation." *Refrigeration* **1975**
2. Vocale et. al. “Influence of Outdoor Air Conditions on the Air Source Heat Pumps Performance” *Energy Procedia* **2014**

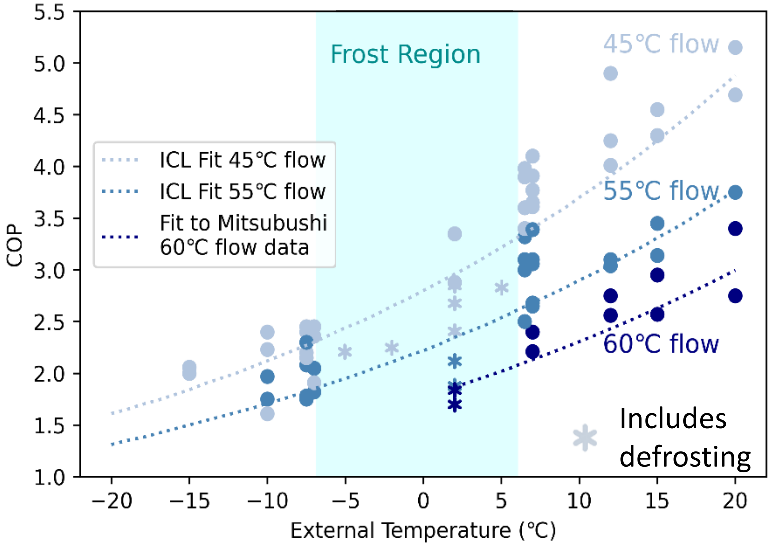
The average value for the defrost penalty, based on the Mitsubishi and NIBE datasets, is 0.46 – consistent with the values reported in literature

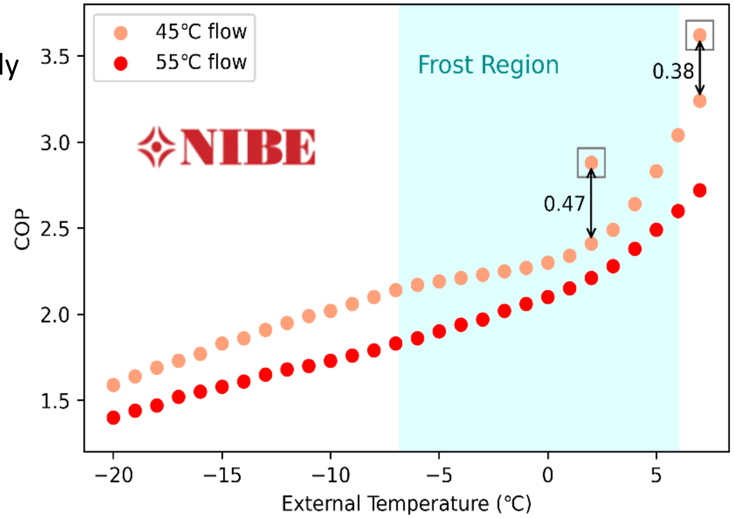
Quantifying the Impact of Defrost Cycles

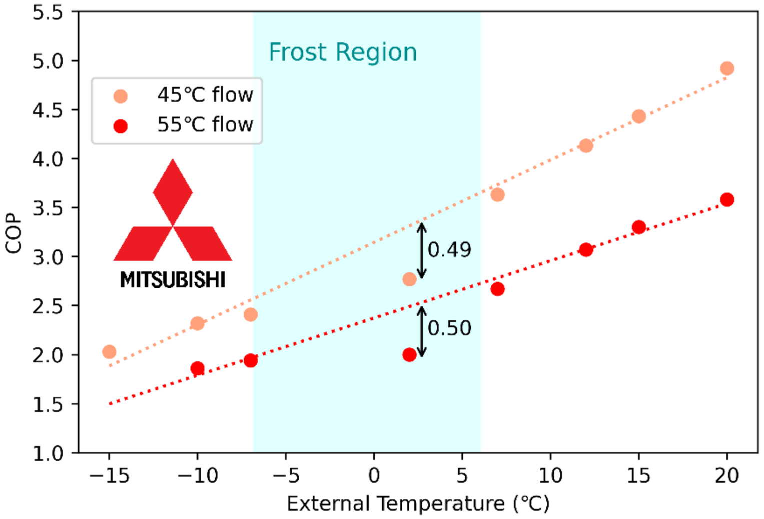
- The Vocale 2014 study found that the **highest monthly COP penalty** for defrosting was around **0.4**
  - If all hours in that month were in the frost region, this would suggest a defrost penalty of 0.4. We assume not all hours are within the frost region, therefore the hourly defrost penalty must be >0.4.
- The defrost penalty used in our modelling is based on an average of the defrost values calculated from the NIBE and Mitsubishi datasets, shown in the table below. More detail on this process is provided the Phase 1 report appendix, but a brief over view is given below.
  - NIBE provided two COP values at 2°C and 7°C, one set as part of a series explicitly including the impact of defrost cycles; the difference between theses values was taken as the defrost penalty
  - Mitsubishi provided a set of COP values, one of which explicitly included the impact of defrost cycles; a linear function was drawn between the values that did not include defrosting and the deviation of the value that includes frosting taken as the defrost penalty

NIBE		Mitsubishi		Average
2°C	7°C	45°C flow	55°C flow	
0.47	0.38	0.49	0.50	**0.46**

- For the ASHP COP calculations, the 0.46 defrost penalty was used when the hourly weather datapoint was within the frost region.





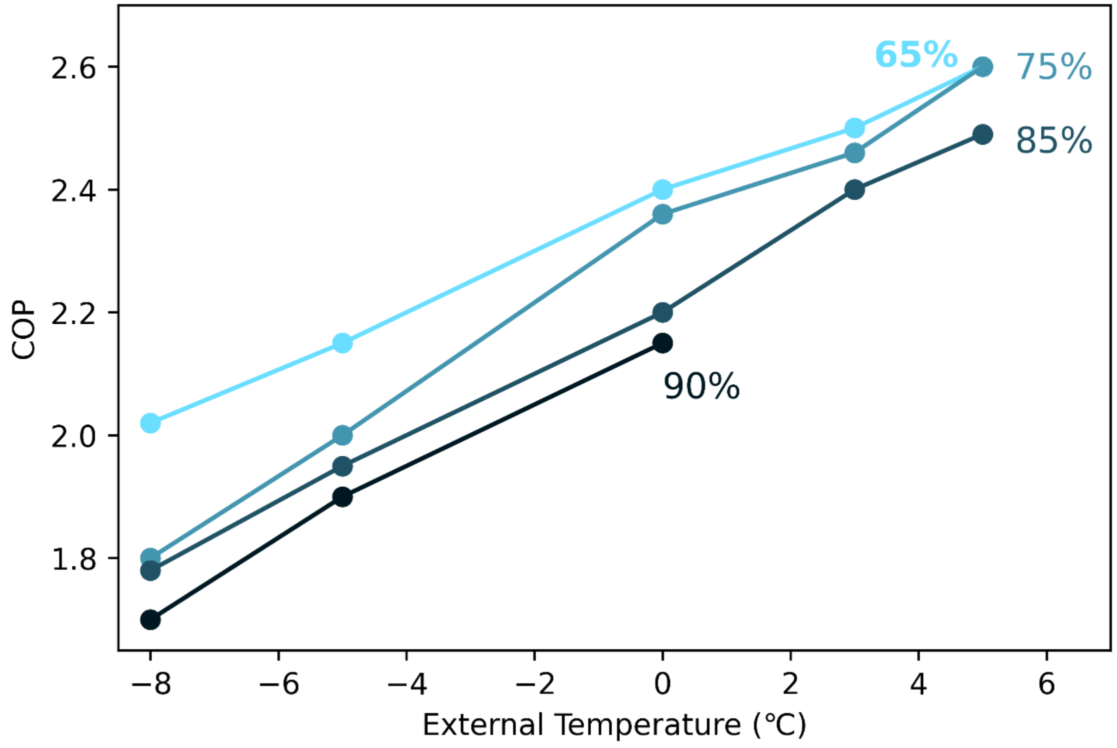


The data reported by manufacturers is measured under standard test conditions of 85% humidity, therefore an additional correction factor has been applied where humidity deviates from 85%

Additional Impact of Humidity

- ASHPs COPs are measured under standard test conditions with a humidity of 85%
- The data from the Zhang 2014 study (shown right) shows the **negative impact of humidity on COP in weather conditions that would require defrosting**
  - These values are not as high as the defrost penalty but can provide a small, humidity dependant adjustment to ensure the COP values account for the local climate as far as possible.
- Based on the Bingley 2015 data, nearly 70% of hours in the heating season have humidity higher than 85%, rising to over 80% of the hours in the coldest months.
- While this humidity correction may even out across the year, humidity drops during the day so can affect the optimisation of flexibility.
- As the data presented here is associated with the impact of humidity on defrosting, the **additional humidity correction was only applied in hours within the frost region.**

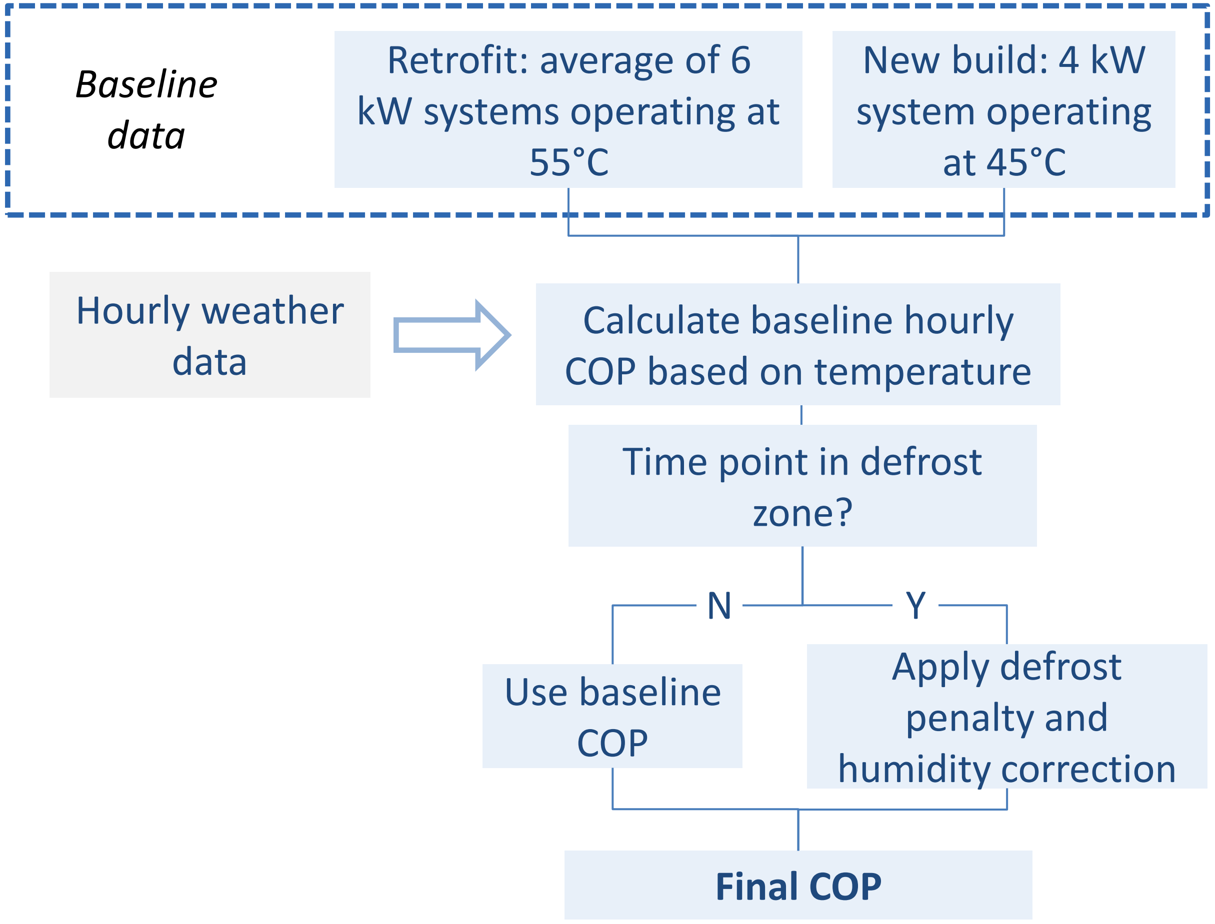
COP vs external temperature for various humidity values



Hourly COP values have been calculated using manufacturer data as a baseline, then applying a defrost penalty and humidity correction when a timepoint is in the frost region

Apply Hourly Temperature and Humidity Dependent COPs

- For each hourly weather point:
  - The baseline COP is calculated using Mitsubishi data[1]
    - Victorian Terrace: Average of data from two 6 kW models operating at 55°C flow
    - New build: 4 kW model operating at 45°C
  - If the timepoint is in the frost zone
    - A set **defrost penalty of 0.46** is applied
    - A **positive or negative humidity correction** factor is applied based on whether the humidity is lower or higher than 85% respectively
  - If the timepoint is not in the frost region, no penalties or corrections are applied.
- The **COP is then applied to the heat demand for each half-hourly time point**.
- Archetype 1 (see this slide) used the COP profile for the new build operating temperature (45°C); all other archetypes used the Retrofit operating temperature (55°C).



1. The Mitsubishi dataset was the most complete of the ASHP manufacturers investigated over the temperature ranges relevant to this study. Additionally, the data was well aligned with other sources indicating that these values were reasonable to use for a typical ASHP installation.

The two years chosen show distinctly different distributions of hours within the frost region over the heating season

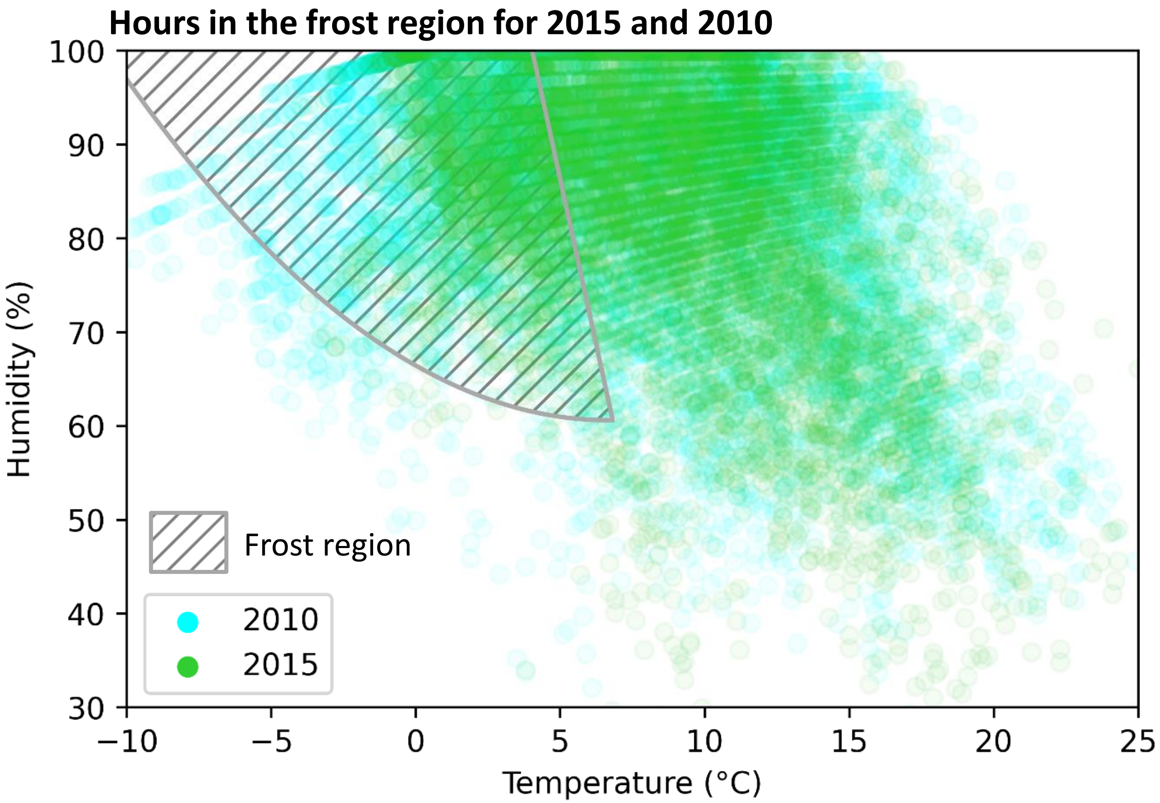
Hours in the Frost Region

- The impact of defrost cycles was naturally expected to vary between weather years.
- Two weather years were compared to understand the difference between ASHP and GSHP performance in an average year (2015) and in a 1-in-20 cold year (2010).

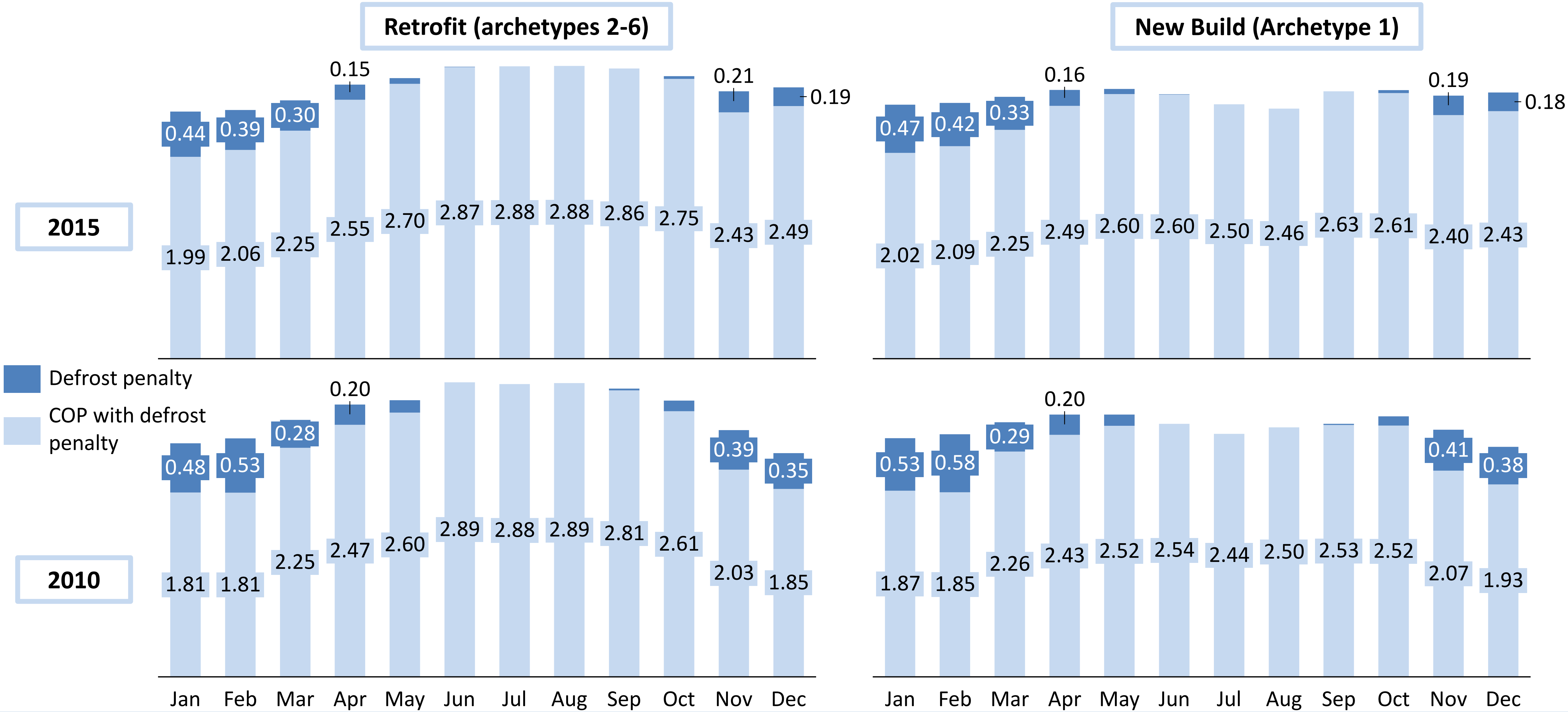
Impact on Heat Pump Performance

- As ASHP system performance is directly related to external temperature, it was expected that ASHP systems would fare worse in cold weather conditions than in an average year.
- The figure rights shows a plot of shows **air temperature against humidity for each hour of the year** in 2010 (blue) and 2015 (green).
  - In 2010, 35% of hours were in the frost region, compared to 25% in 2015, increasing the impact of defrost cycles on ASHP performance.

Year	2010	2015
Annual hours in frost region	35%	25%
Heating season hours in frost region	61%	42%



Defrost penalties reduce the monthly ASHP COPs by close to 0.5 in the coldest months of the average year (2015), going above 0.5 in some months in the 1-in-20 cold year (2010)



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GSHP COPs were calculated using the temperature outputs from the GLD modelling and the temperature dependant COPs published by Kensa for their Evo 7 heat pump

Ground Loop Design Modelling

Overview

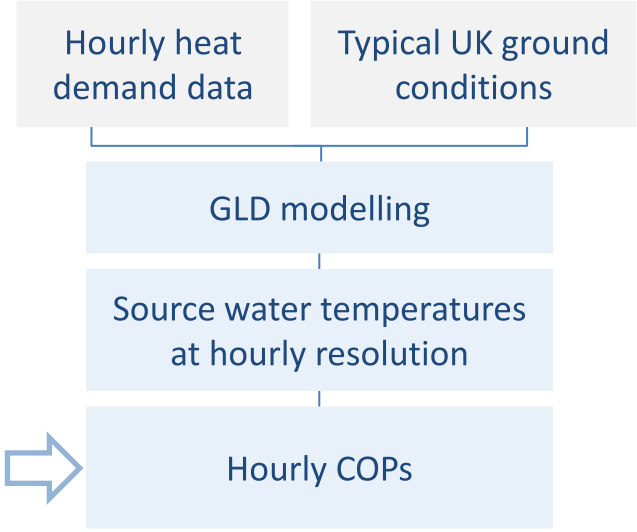
- GSHP performance modelling was based on operational performance as calculated in Ground Loop Design (GLD) software carried out by Genius Energy Labs.
- The GLD modelling was run at hourly resolution runs over the system lifetime based on the hourly heat demand profiles discussed on slide 26.
- The GLD software tracks the source temperature in detail over the heating season, accounting for the heat extracted from the source over time as well as the ground and weather conditions.

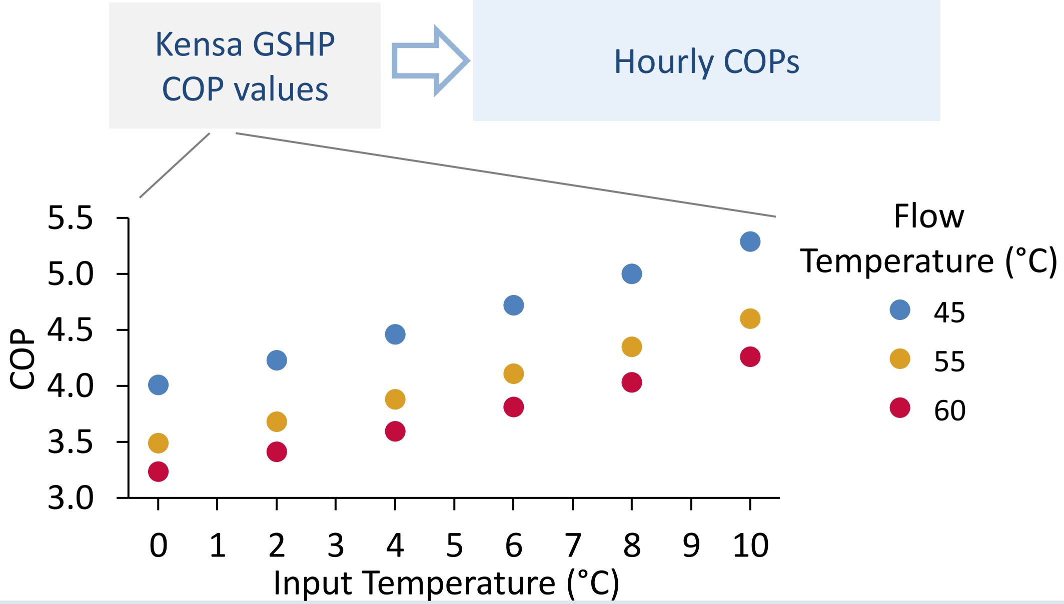
Ground Array Model

- The following details were assumed in the GLD GSHP shared loop model
  - 1 borehole per dwelling
  - Borehole depth
    - Retrofit: 216 m
    - New build: 74 m
  - For ground conditions, the most frequently encountered values for the UK were used:
    - conductivity 2.1W/mK, diffusivity 0.1m^2/day, undisturbed ground temperature 11.0^{o}C

Heat Pump Systems

- COP values for the GSHP systems were based on published Kensa data for the **Evo 7 heat pump**, the model Kensa would expect to install in a retrofit property like the Victorian terrace house
- Kensa is currently developing a version of its Shoebox model, designed specifically with new-build properties in mind, that will use the same compressor system as the Evo 7 and is therefore expected to have similar COPs
  - Therefore, the **same COP relationships were used for both the retrofit and the new build**



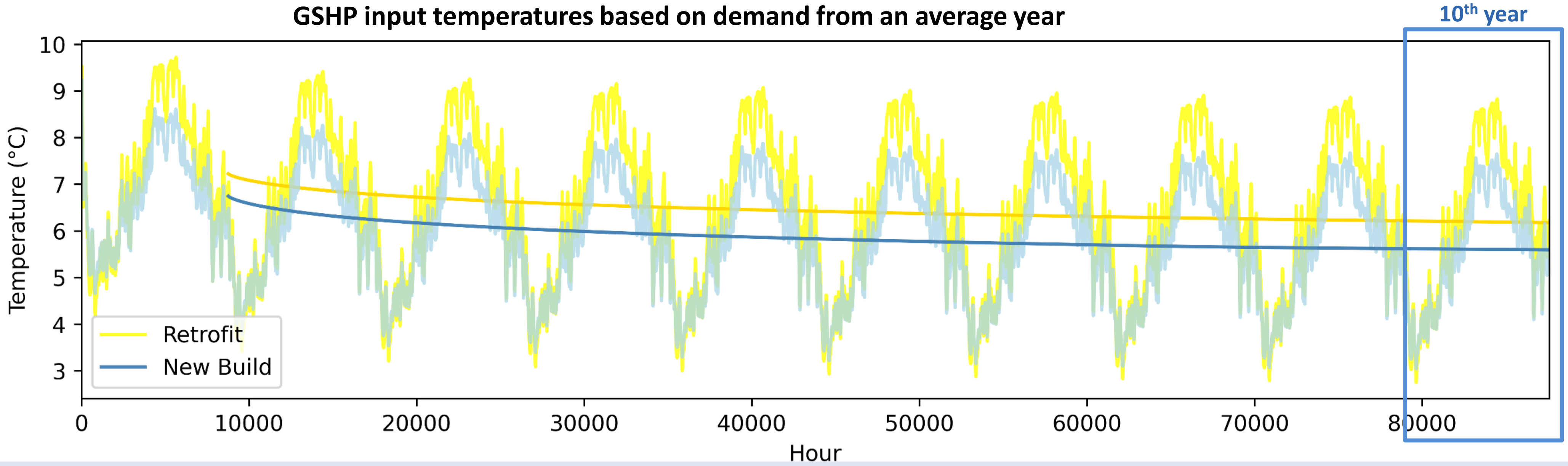


By the 8th year of operation, the ground temperatures around the borehole have stabilised; temperature data from the 10th year of operation was therefore used to model GSHP COPs

GSHP Performance Modelling

- The figure below shows the modelled **variation in the daily average temperature** from the first 10 years of operation, plus the yearly average values (flatter lines).
- As can be seen from the yearly average values, the ground temperature slowly drops over the first few years of operation, stabilising by the 8th year
  - The **10th year of operation was therefore chosen to use as the input temperatures to generate the hourly GSHP COPs**.
- For the 1-in-20 cold year, the ground temperatures were started from the end of the 9th year for consistent comparison with the 2015 average year values.
  - The impact of the cold year is primarily the increase in heat demand from the properties reducing the ground temperature more over the winter, as opposed the impact of lower than average air temperatures.
- Within any given year, the ground temperature drops over the winter months as a significant amount of heat is extracted during the heating season and recovers over the summer months when less heat is extracted

GSHP input temperatures based on demand from an average year



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The ISDM outputs were used to calculate the cost of the electricity system

The electricity system costs were split into three components; generation, network and heating system costs

- The ISDM produces outputs describing the amount of electricity generation in each hour by each generation technology type in the generation fleet, as well as how the electricity demand in each flexible profile type is shifted in each hour.
- These profiles were used to calculate the annualised cost of the future electricity system in 2050 in each of the 6 modelled scenarios, allowing for comparison between scenarios.

Annualised costs for the following components have been included in the analysis, with further cost data and a description of the method provided in the following slides.

- Generation costs:
  - CAPEX: for all generation technologies modelled (wind, solar, hydro, nuclear, and dispatchable generation)[1]
  - OPEX: for all generation technologies modelled[1]
  - Fuel costs: for generation technologies with an input fuel (nuclear, some dispatchable generation e.g. hydrogen, biomass)[1]

  The installed capacities for renewable generation technologies was taken from the National Grid's 2022 Future Energy Scenarios, Consumer Transformation. The amount of dispatchable generation was calculated by the ISDM, based on the peak total dispatchable generation throughout the year.
- Network costs:
  - Transmission network: CAPEX and OPEX for the transmission and distribution networks[1], sized to reflect the increased demand on the network in 2050 from wider electrification.
  - Network reinforcement for additional peak network demand on top of 2022 peak demand[2].
- Heating system costs:
  - The CAPEX AND OPEX for both ASHPs and GSHPs have been included alongside the electricity system costs. This is to evaluate how additional costs or savings from increased deployment of flexible technologies compares with the cost of these flexible technologies.
  - CAPEX for heat batteries were also included to compare the additional costs from heat battery deployment against the cost savings from the additional flexibility provided by the heat batteries.

  Costs for other flexible assets (e.g. EVs) were not included, as these are assumed to be constant in all scenarios.

1. Future Energy Scenarios 2020 Costing Workbook, National Grid (2020)
2. Common Distribution Charging Methodology, all UK electricity network operators (2020)

Corresponding cost inputs for each electricity generation technology modelled in the ISDM were used to calculate the annual cost of electricity generation in the scenarios

The cost inputs and methodology used are given in the table and text below

- The generation technology CAPEX and OPEX values were multiplied by the installed capacities for each technology in 2050.
  - The hydrogen gas turbine generation capacity is calculated dynamically in the model based on the balancing of supply and demand after load-shifting in each flexible profile.
  - For all other generation technologies the installed capacity is fixed, as given in the table below, and matches the installed generation capacity in National Grid's FES Consumer Transformation scenario.

Technology	Installed capacity (GW)	Non-annualised capacity CAPEX (£/MW)	Capacity OPEX (£/MW)	Fuel costs (£/MWh)	CAPEX, OPEX & fuel cost source	Lifetime (years)	Lifetime source	Annualised capacity CAPEX (£/MW/year)*	Combustion efficiency (%)	Efficiency source
H2 gas turbine	Calculated dynamically	539,113	22,950	27	AS.1 (Power Gen) tab of FES20 Costing Workbook, 2050 cost column.	25	LINK	38,251	59.8%	LINK
Nuclear	15.3	4,020,773	80,750	-	AS.1 (Power Gen) tab of FES20 Costing Workbook, 2050 cost column. Fuel costs not present (assumed negligible)	60	LINK	212,410		
Interconnector	22.0	381,905	3,400	-	AS.1 (Power Gen) tab of FES20 Costing Workbook, 2050 cost column	40	LINK	22,257		
Biomass	0.29	1,581,000	54,060	29	AS.1 (Power Gen) tab of FES20 Costing Workbook, 2050 cost column	25	LINK	112,176	38%	LINK Page 18
Wind	111.2 (Offshore) & 47.2 (Onshore)	917,250	76,681	-	AS.1 (Power Gen) tab of FES20 Costing Workbook, 2050 cost column. Weighted average (from installed capacity in FES) of onshore & offshore wind.	25	LINK	65,081		
Solar	79.3	318,750	7,123	-	AS.1 (Power Gen) tab of FES20 Costing Workbook, 2050 cost column.	25	LINK	22,616		
Hydro	2.5	1,147,500	15,300	-	AS.1 (Power Gen) tab of FES20 Costing Workbook, 2050 cost column.	50	LINK	62,856		

* Not inclusive of generation fuel costs or OPEX costs, which are included separately.

Cost assumptions: electricity transmission and distribution networks

The network cost inputs and methodology used are given in the table and text below

- Unit costs for the CAPEX and OPEX of the electricity network (including both distribution and transmission) in 2050 were taken from National Grid's Future Energy Scenarios 2020 costing workbook; no more recent cost workbook has been published by National Grid.
  - These costs were multiplied by the peak network demand in 2050, as calculated by the ISDM after demand-side flexibility.
- Network upgrade costs were also included, to account for upgrading the electricity network that will be needed to provide significantly higher electricity demands than are experienced today following wider electrification of heating and transport by 2050.
  - The cost of network upgrades was taken from the networks' Common Distribution Charging Methodology cost workbooks, as explained in the table below.
  - The current peak demand compared with is 58.8 GW, Taken from cell R147, ED1 Tab in FES 2022 data workbook, 2021 value for 'GBFES Peak Customer Demand: Total Consumption plus Losses'.
  - This value is subtracted from the ISDM's calculated demand and multiplied by the per-unit-cost value for the network upgrade cost from the table below.
- The cost values used are given in the table below.

Cost item	Unit	Value	Source
Transmission OPEX per GW peak on the electricity system	£m / GW peak demand	17.64	Unit Cost for OPEX Electricity Transmission networks, taken from AS.8 (Network Cost) tab of FES20 Costing Workbook.
Distribution OPEX per GW peak on the electricity system	£m / GW peak demand	86	Unit Cost for OPEX Electricity Distribution networks, taken from AS.8 (Network Cost) tab of FES20 Costing Workbook.
Transmission system annual CAPEX	£ / MW peak demand	166,753	Average of Overhead electricity transmission costs, from Unit Cost for CAPEX Electricity Transmission networks, AS.8 (Network Cost) tab of FES20 Costing Workbook.
Distribution network replacement CAPEX	£m / GW peak demand	103.5	Average of Unit Cost for CAPEX Electricity Distribution networks, taken from AS.8 (Network Cost) tab of FES20 Costing Workbook.
Total network upgrade cost per year	£ / kW / year difference between 2050 peak demand and 2021 peak demand	142.9	Upgrade cost data collected from network Common Distribution Charging Methodology cost workbooks from 2020, demand-weighted by demand in each network Local Distribution Zone, and summed over the entire network (low voltage to extra-high voltage).

GSHP costs are based on previous Kensa deployments while ASHP costs are based on a mixture of Kensa and Delta-EE costs; orange boxes indicate cost values updated for Phase 2

Below outlines the costs used in Phase 1 of the reporting, which were updated to reflect the additional archetypes in Phase 2

- For GSHP, costs are shown both for an installation on an individual house basis (house-by-house) and the costs per house for the shared loop model (street-by-street). Following the high-level comparison in this section, only the costs for the shared loop model are taken forward in the analysis and the cost of the groundworks is covered by a connection fee.
- The total GSHP street-by-street costs (i.e. including groundworks costs) are around 60% higher than ASHP but 45% lower than GSHP costs when installing on a house-by-house basis.
  - The benefits from economies of scale is most significant in the reducing the cost of ground works, with savings of around £5,700 per property vs individual installations for the retrofit on groundworks alone.
- Cost used for a heat battery was taken as £500 (shown right), provided by Kensa.
- Street-by-street represents Kensa's shared loop system, where multiple homes (20 in retrofits, 50 in new builds) share the same ground loop.

A description of how the costs in orange cells are scaled is on the next page

Additional Costs (per property)	
Heat battery	£500 uplift

Cost Element	ASHP			GSHP House-by-House			GSHP Street-by-Street		
	Cost (£)		Source	Cost (£)		Source	Cost (£)		Source
	Retrofit	New build		Retrofit	New build		Retrofit	New build	
Technology (heat pump unit)	£3,570	£3,040	*Delta-EE*	£4,800	£4,000	*Kensa*	£4,320	£3,600	*Kensa*
Hot water tank	£1,080	£1,080	*Delta-EE*						
Labour	£1,800	£1,400	*Delta-EE*	£2,340	£1,390	*Kensa*	£1,520	£1,140	*Kensa*
Heat distribution system	£4,975	-	*Kensa*	£4,975	-	*Kensa*	£4,365	-	*Kensa*
Groundworks	-	-		£12,870	£6,600	*Kensa*	£7,175	£3,000	*Kensa*
Design/PM Costs	*Included in tech. costs*		*Delta-EE*	£1,460	£1,170	*Kensa*	£735	£615	*Kensa*
Total	**£11,425**	**£5,520**		**£26,445**	**£13,160**		**£18,115**	**£8,355**	

1. Delta-EE study for BEIS "Cost of installing heating measures in domestic properties" https://www.gov.uk/government/publications/cost-of-installing-heating-measures-in-domestic-properties

Phase 1 costs assumptions were used as a basis for the heating technology costs in this study, with some costs updated to better represent the range in sizes between new archetypes

Costs for the heat pump unit and the heat battery were adjusted to reflect the different heating demands of archetypes

- The costs for heat pump components used the Phase 1 costs for 2030, which were assumed to not change by 2050.
- Some costs were taken as the same in all of the 6 archetypes, covering the following heat pump components:
  - Labour, Fittings (elbows, pump valves), Controls, Buffer tank & cylinder, Heat distribution system, Design/project management, ASHP & GSHP OPEX, Heat battery OPEX, GSHP groundworks.
- 3% of GSHPs in all scenarios were assumed to be house-by-house; the remaining 97% were assumed to be street-by-street GSHPs. Note this only affects the GSHP cost calculations, and not the modelling of demand shifting or of the network costing.

The other cost items were scaled to account for different heating demands in each archetype, in the following ways.

- **Heat pump unit CAPEX**:
  - The marginal (£259 / kW) and fixed (£1852) costs from Phase 1 were used to calculate the total cost based on the required size of each archetype's heat pump. Sources are given below.
    - FIXED COSTS: Phase 1 costs, Delta-EE for BEIS "The Cost of Installing Heating Measures in Domestic Properties"
    - MARGINAL COSTS: Assumptions log: Development of trajectories for residential heat decarbonisation to inform the Sixth Carbon Budget (Element Energy). 'Technology base costs' tab, row 47, 2050 costs. LINK
- **Heat battery**:
  - The heat battery size in Phase 1 was 6 kWh, and this size was scaled with the total annual space heating and hot water demand of each archetype so that the heat battery could provide the same proportion of heating demand in each archetype.
  - The cost of the heat battery in each archetype was assumed to scale linearly with size (i.e. a 12 kWh heat battery would be twice as expensive as a 6 kWh heat battery).
  - The cost of installing a 6 kWh heat battery was assumed to be a £500 uplift, as in Phase 1.
  - 50% of buildings were assumed to have a heat battery in the 'Heat batteries' scenarios; in all other scenarios no heat batteries were included or costed in the modelling.

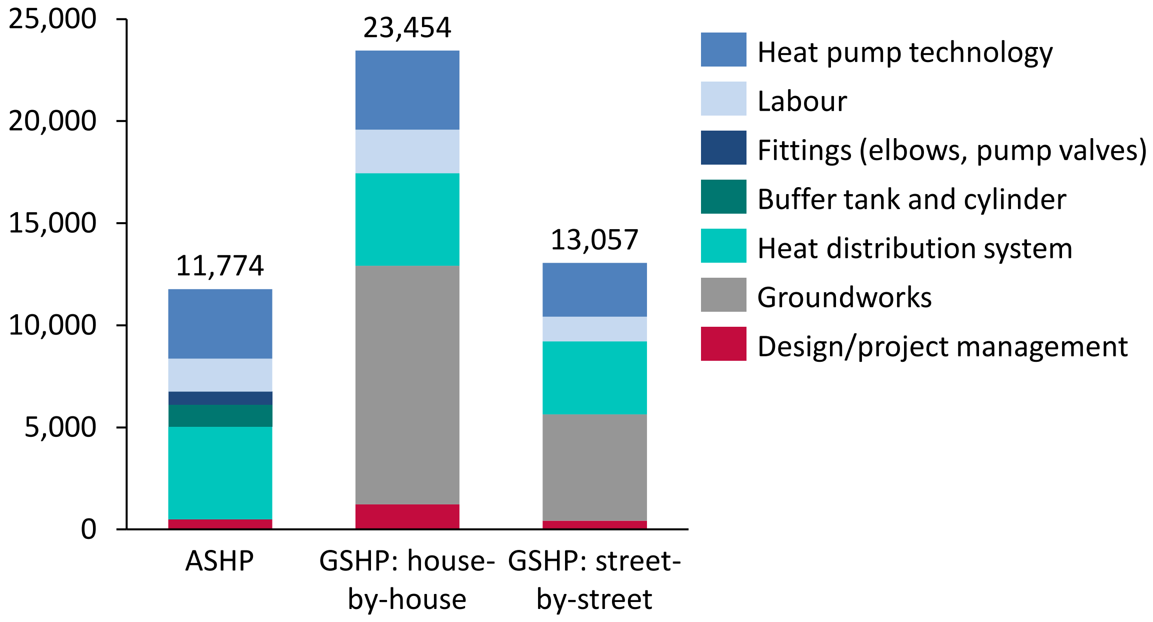
Lifetimes of 12 years for ASHP components and 20 years for GSHP components were used in this study

The lifetime assumptions for each cost component are given in the table below

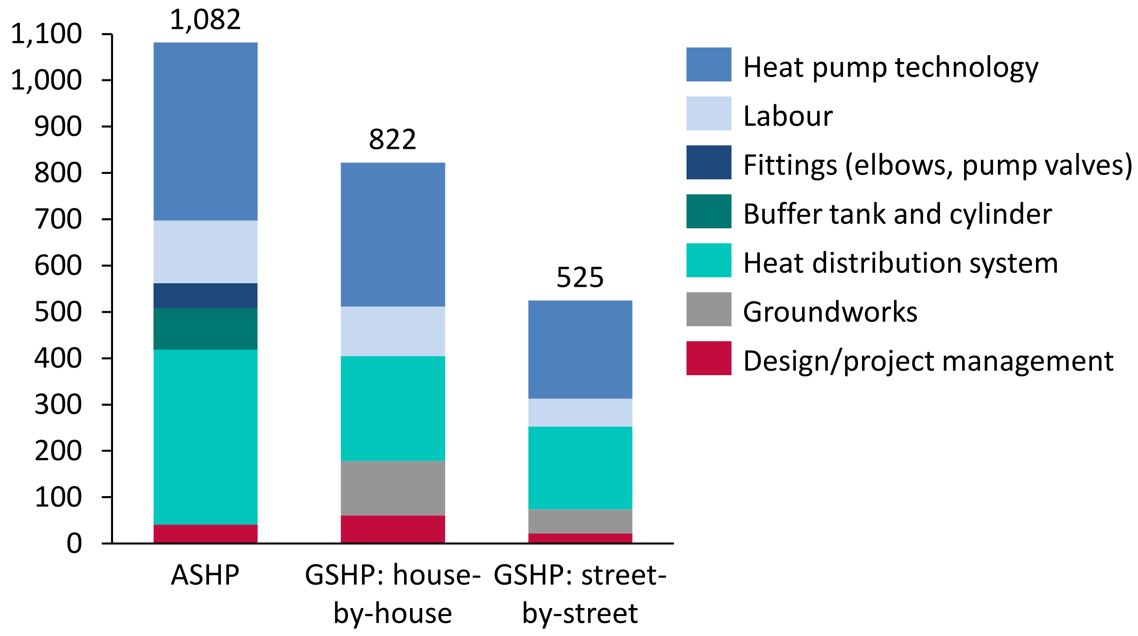
Technology	Component	Lifetime (years)	Source
ASHP	Heat pump technology	12	LINK
ASHP	Labour	12	
ASHP	Fittings (elbows, pump valves)	12	
ASHP	Controls	12	
ASHP	Buffer tank and cylinder	12	
ASHP	Heat distribution system	12	
ASHP	Design/project management	12	
All systems	Heat battery	20	LINK
GSHP - HbH	Heat pump technology	20	LINK
GSHP - HbH	Labour	20	
GSHP - HbH	Fittings (elbows, pump valves)	20	
GSHP - HbH	Controls	20	
GSHP - HbH	Buffer tank and cylinder	20	
GSHP - HbH	Heat distribution system	20	
GSHP - HbH	Groundworks	100	
GSHP - HbH	Design/project management	20	
GSHP - SbS	Heat pump technology	20	
GSHP - SbS	Labour	20	
GSHP - SbS	Fittings (elbows, pump valves)	20	
GSHP - SbS	Controls	20	
GSHP - SbS	Buffer tank and cylinder	20	
GSHP - SbS	Heat distribution system	20	
GSHP - SbS	Groundworks	100	
GSHP - SbS	Design/project management	20	

ASHP systems have the lowest non-annualised upfront costs, but both GSHP configurations have lower annualised upfront costs

Non-annualised CAPEX per heat pump in Archetype 4



Annualised CAPEX per heat pump in Archetype 4



- The large upfront cost of groundworks in both GSHP configurations leads to higher upfront costs than in the ASHP.
- The groundwork costs for the GSHP street-by-street configuration is assumed to be distributed over a shared loop for 20 homes (when being retrofitted) or 50 homes (for new builds), leading to lower groundwork costs per connection than in the house-by-house configuration.

- The upfront costs were annualised over the lifetime of each cost component (given here) to calculate the annualised cost of each system, using a discount rate of 5%.
- Both GSHP configurations have lower annualised costs due to the longer assumed lifetimes, especially for the groundworks with a lifetime of 100 years.

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ASHP efficiency (from Phase 1 study)

GSHP Shared Loop efficiency (from Phase 1 study)

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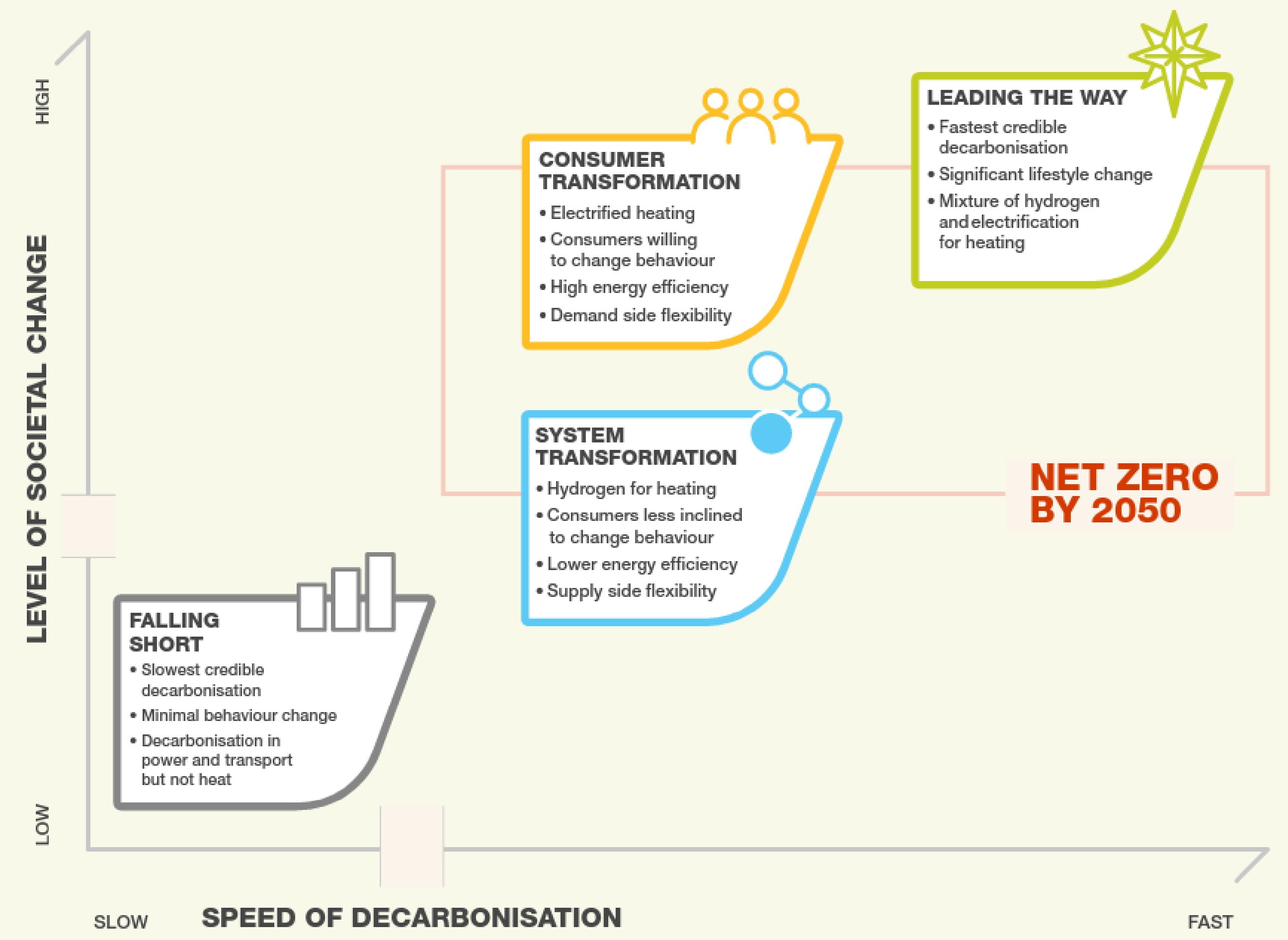
Appendix

The 6 scenarios in this study align to the Consumer Transformation scenario in National Grid's 2022 Future Energy Scenarios, which represents high demand side flexibility and major electrification

The ISDM models an electricity system based on the 2050 electricity system in the Consumer Transformation scenario

- Element Energy's Integration System Dispatch Model (ISDM) has been used in this study to model the electricity system in Britain in 2050.
- Installed capacities for electricity generation from renewables (wind, solar, hydro), nuclear, and biomass plants were aligned to the Consumer Transformation scenario.
- Capacities for dispatchable generation (e.g. from low-carbon hydrogen gas turbines) are dynamically calculated in the ISDM, to evaluate the impact of varying flexibility on the requirement for dispatchable generation.
- Total electricity demand was aligned between the ISDM modelling and the Consumer Transformation scenario for the following demand types: electric vehicle charging, industrial electricity demand, building appliance demand in domestic and non-domestic properties, non-domestic electric heating demand, and domestic direct electric heating.
- Electricity demand from domestic heat pumps was not taken from the Consumer transformation scenario, although the total demand is within 10% in this study and in the Consumer Transformation scenario.
  - The 6 scenarios modelled in this study vary the proportions of GSHPs and ASHPs in this study, which will impact the heat pump electricity demand due to differences in COPs between ASHPs an GSHPs.
  - The total number of heat pumps in existing domestic buildings (23,300,000; 72% of British homes in 2050) was kept constant, but the proportions that are ASHPs and GSHPs are varied between scenarios.
  - This study therefore models the electricity demand for ASHPs and GSHPs in each archetype, for both heating and hot water.



Source for figure on right: Page 7 – Future Energy Scenarios, National Grid (July 2022): LINK

Hourly weather data, renewable generation load factors and demand profiles were used in the ISDM

The ISDM used several hourly profiles as inputs throughout the entire year to accurately model electricity load shifting

- One weather year was used in the modelling, for 2015; representative of a typical weather year.
  - The hourly temperature and humidity profiles for both years were taken from Met Office data for Leeds, assumed to be a representative location within Britain.
  - These temperature and humidity profiles were used to calculate the hourly efficiency of ASHPs, and the hourly value for hours of flexibility, for each archetype.
  - More details are given here.
- Hourly renewable load factor profiles were taken from renewables.ninja, which provides hourly renewable generation profiles using a method set out in the following academic papers:
  - Pfenninger, Stefan and Staffell, Iain (2016). Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data. Energy 114, pp. 1251-1265. doi: 10.1016/j.energy.2016.08.060
  - Staffell, Iain and Pfenninger, Stefan (2016). Using Bias-Corrected Reanalysis to Simulate Current and Future Wind Power Output. Energy 114, pp. 1224-1239. doi: 10.1016/j.energy.2016.08.068
- The hourly demand profiles for the 'EV charging' profiles, and the quantification of the flexibility that electric vehicle charging can provide, is taken from a 2019 Element Energy study for Transport & Environment, Iberdrola, Renault and ENEL. The method to derive the charging profile is given on slide 10 of this technical appendix.
- The hourly demand profiles for the 'Baseline' portion of electricity demand was taken from the ENTSO-E (European Network of Transmission System Operators for Electricity) data transparency platform, using the 2040 demand profile data for the UK. This data was processed to remove the effect of electricity demand from heat pumps and EV charging.
- The hourly demand profiles for the heat pumps were developed during Phase 1 of this study based using profiles modelled by Watson et al., published in 2019[1]. , with more detail given in the Phase 1 report or here in the Appendix in this report.
- The hourly electricity demand profile for district heating is assumed constant throughout the heating season.
- The hourly demand profile for electric heating was developed for the ACCESS Project, linked here.

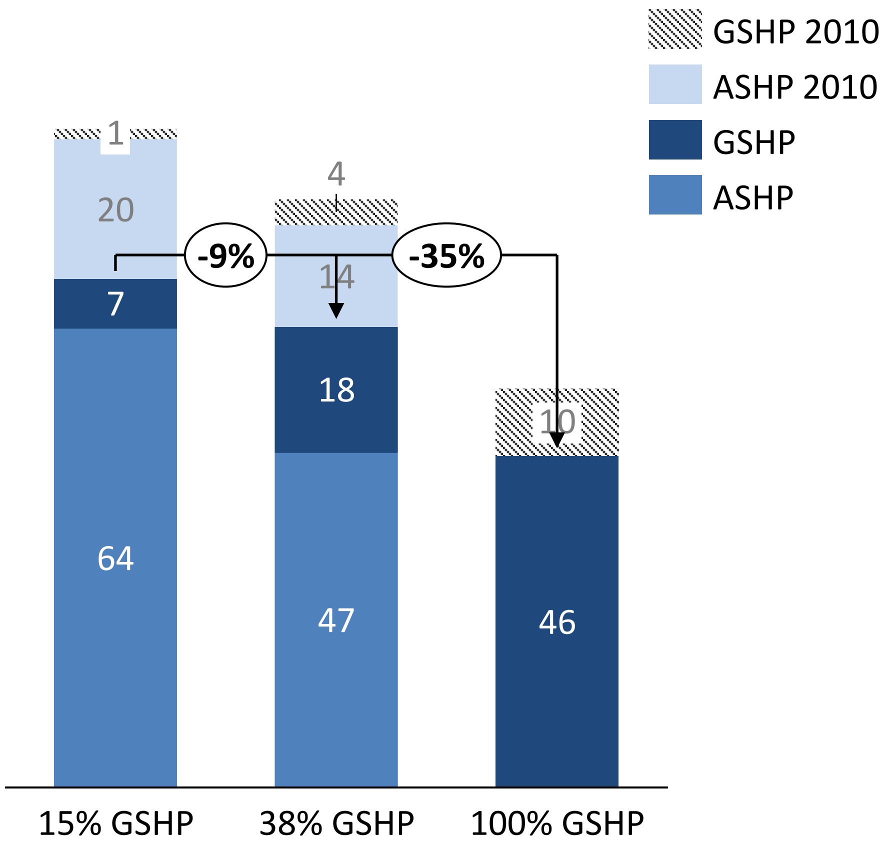
1. Watson et. al. "Decarbonising domestic heating: What is the peak GB demand?" https://www.sciencedirect.com/science/article/pii/S0301421518307249 **2019**

Varying the proportion of GSHPs and ASHPs that represent the total domestic heat pump stock can reduce the annual electricity demand for heat pumps by up to 35% in a typical weather year

GSHPs use less electricity than ASHPs to provide the same amount of heat due to higher efficiencies

- The figure right shows how the **total annual domestic electricity demand for heat pumps** varies when GSHPs represent different proportions of the total domestic heat pump stock.
- This study varies the proportion of GSHPs in the total domestic heat pump stock across the scenarios:
  - The 15% GSHP scenario reflects today's proportion of approximately 15% GSHPs, and 85% ASHPs (according to domestic RHI installations, as of September 2022).
  - The 38% GSHP scenario assumes that 38% of domestic heat pumps will be GSHPs, with the remaining 62% ASHPs, in line with the Consumer Transformation scenario (LINK).
  - The 100% GSHP scenario assumes a hypothetical 100% deployment of GSHPs in all domestic properties with heat pumps; although this is not a realistic deployment scenario, it explores the impact that high GSHP deployment has on the electricity system.
  - All scenarios assume the same heat pump proportions in each archetype e.g. in the 38% GSHP scenario, 38% of heat pumps in each archetype are GSHPs.
- In terms of total demand, moving from 15% networked GSHPs to 38% results in annual electricity savings of 9%, around 6.7 TWh.
- This savings increases to 9 TWh in the 1-in-20 cold year.
- For the **peak electricity demand**, the **percentage reduction will be larger** due to the larger than average difference between the ASHP and networked GSHP COPs on a peak winter evening.
- Increasing the proportion of GSHPs also reduces the amount of electricity demand that can be flexibly shifted as GSHPs use less electricity to supply the same amount of heat.

Domestic electricity demand for heat (TWh)



The 6 modelled scenarios represent a range of sensitivities on proportions of ASHPs and GSHPs, increased heating demand due to colder weather, and varying levels of flexibility in heat and EV charging

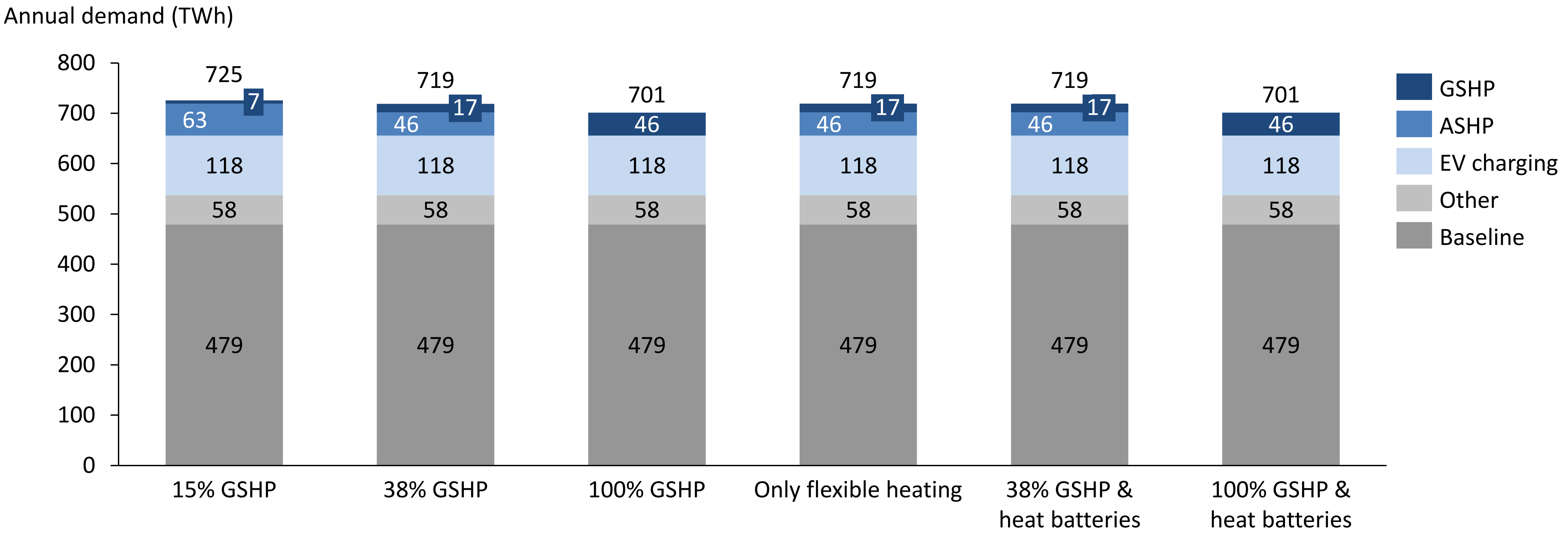
This study focuses on measuring the impact of varying the amount of electricity that can be moved through flexibly

- The first three scenarios (15% GSHP, 38% GSHP, 100% GSHP) vary the proportion of heat pumps that are ASHPs or GSHPs, out of the total 23.3 million heat pumps installed in domestic buildings in 2050 in the Consumer Transformation scenario.
- As explained on the previous slide, varying the proportions of heat pumps varies the total initial electricity demand for domestic heating and total electricity that can be shifted, as GSHPs have lower electricity demands due to their higher COPs (see here) than ASHPs.
- The 'Only Flexible heating' heating scenario assumes that ASHPs and GSHPs can provide flexibility to the system by shifting heating demand as in the 38% GSHP scenario, but assumes that other electricity demands (e.g. baseline, EV charging, district heating) are inflexible, and so domestic heat pumps are the only source of demand-side flexibility.
- The Only flexible heating scenario assumes the same heat pump deployment proportions of GSHPs and ASHPs as the 38% GSHP scenario.
- The Heat batteries scenarios assumes that 50% of each archetype installs a heat battery capable of storing heat for ~ 1 hour of peak demand (for more details, see here), in properties both with ASHPs or GSHPs, which provide flexibility by shifting heating demand further than is possible by heat pumps without heat batteries.
  - These have been costed as heat batteries in this study, but the modelling is technology-agnostic and so is equivalent to modelling of electrochemical batteries storing electricity to power heat pumps at a later time.

Scenario name	Heat pump proportions	Weather year	Flexibility of non-heat sectors	Rollout of heat battery across non-flexible stock	Systems impact assessed by
15% GSHP	15% GSHP	Average	Flexible	0	GSHP rollout rate
38% GSHP	38% GSHP				
100% GSHP	100% GSHP				
Only flexible heating	38% GSHP	Average	Non-flexible	0	Only flexible heating
38% GSHP & heat batteries	38% GSHP	Average	Flexible	50%	Extra heat flexibility
100% GSHP & heat batteries	100% GSHP	Average	Flexible	50%	GSHP rollout rate, extra heat flexibility

The total electricity demand varies between the scenarios, although heat pumps only account for ~ 10% of total electricity demand in all scenarios

Total annual electricity consumption (TWh) after demand side response



- The total electricity demand, and share of electricity demand for domestic heating, is lowest when deployment of GSHPs is highest (in the 100% GSHP scenarios) due to higher COPs.
- These 6 scenarios use weather data from a typical year to determine the hourly COP of heat pumps and the hourly heating demand.

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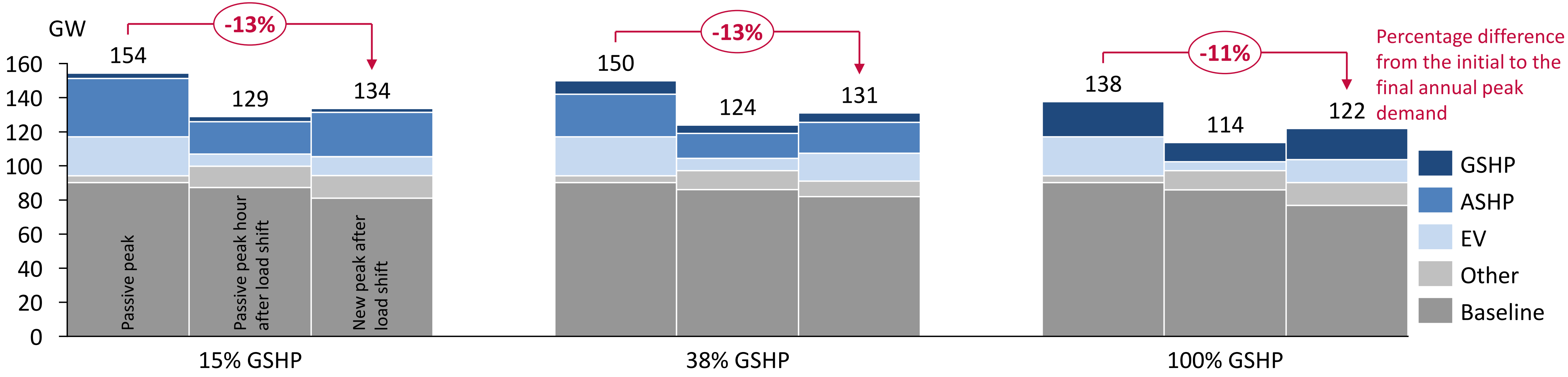
Maximum GSHP deployment leads to a 16 GW peak demand reduction before load shifting compared with the 15% GSHP scenario, with a further 16 GW peak reduction achieved after load shifting

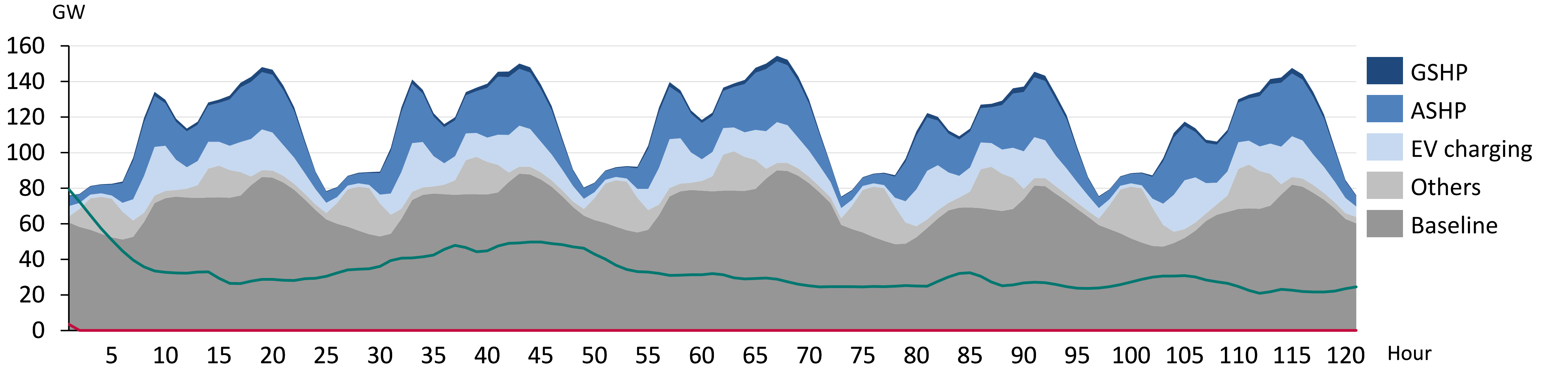
Peak hourly demand (GW): before any load shifting (left), in the initial peak hour after load shifting (middle), and in the whole year after load shifting (right)



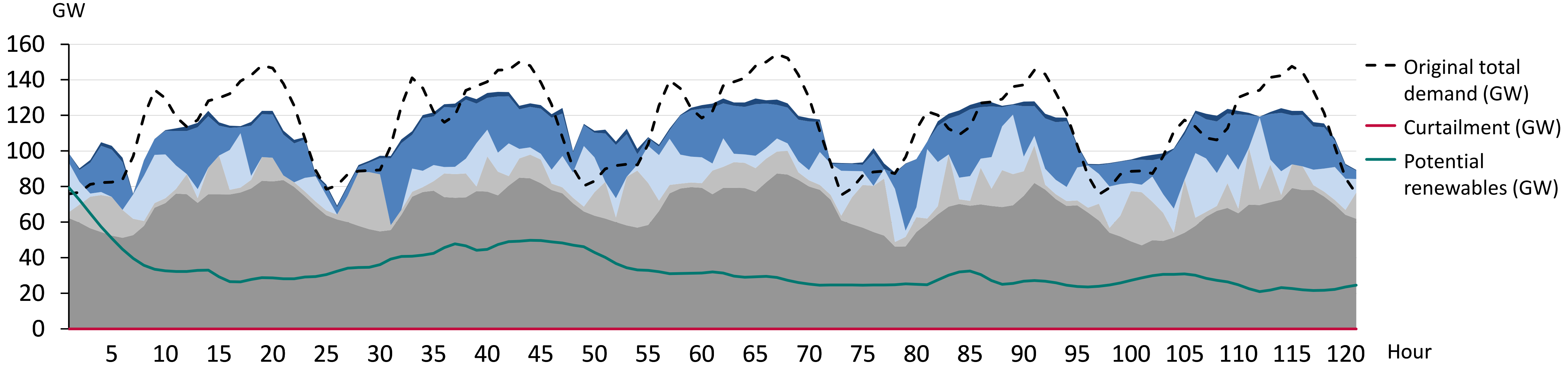
- The 100% GSHP scenario (where all heat pumps are GSHPs) shows a 16 GW peak demand reduction (from 154 GW to 138 GW) compared with the 15% GSHP scenario (where GSHPs are 15% of all heat pumps) before any load shifting, and a further 16 GW peak demand reduction (to 122 GW) after load shifting.
- The peak demand of 122 GW in the 100% GSHP scenario after load shifting is 12 GW lower than in the 15% GSHP scenario after load shifting (a 9% reduction).
- Even with the heat flexibility modelled in this study, the final peak hourly demands occur on cold days in winter months where shifted heating demand aligns with peak demand in other sectors, in all scenarios.
- The demand profiles for 5 days around the peak demand day pre and post load shifting are presented in the next three slides, for each of the scenarios.
- In all cases, pre-heating in homes and charging EVs flexibly allows reducing the peak demand by approximately 20 GW.
- ‘Passive Peak’ refers to the peak annual demand without any load shifting. ‘Passive peak hour after load shift’ represents the demand in the same hour as ‘Passive Peak’ but once load shifting has taken place. ‘New peak after load shift’ refers to the new peak annual demand after load shifting, and is now in a different hour to the original ‘passive peak’.

15% GSHP scenario: Demand profiles in week of initial peak demand

Demand before load shifting



Demand after load shifting

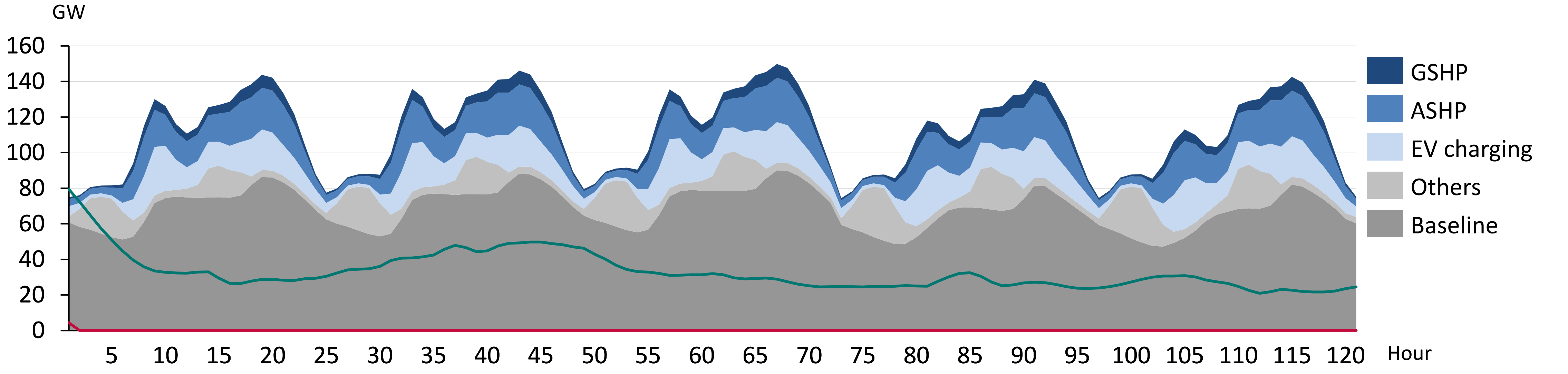


The graph starts from midnight on January 16th (hour 384 of the year). The peak demand occurs in hour 67 of this graph (hour 451 of the year); 6-7pm on January 18th.

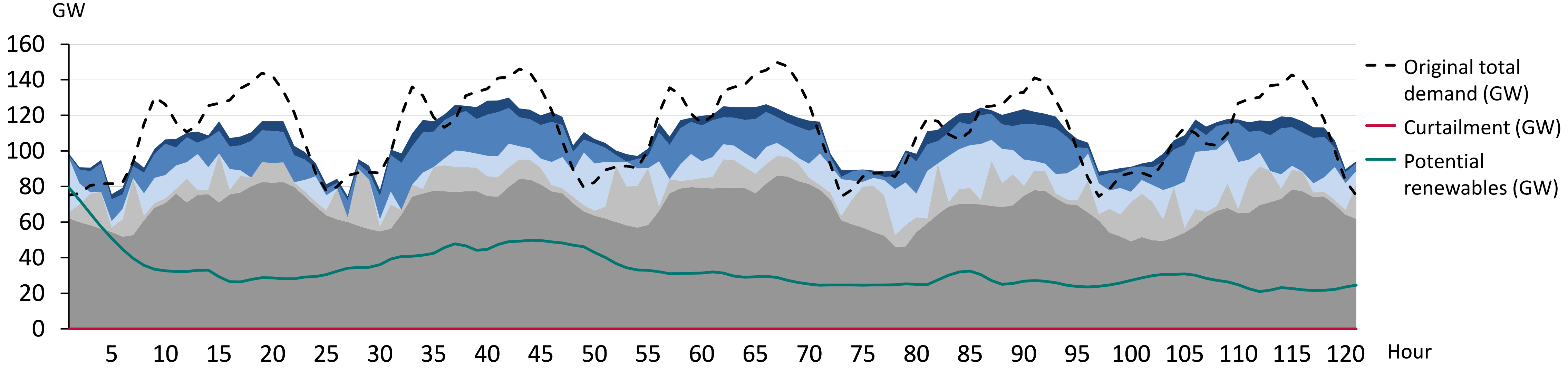
elementenergy an ERM Group company

38% GSHP scenario: Demand profiles in week of initial peak demand

Demand before load shifting



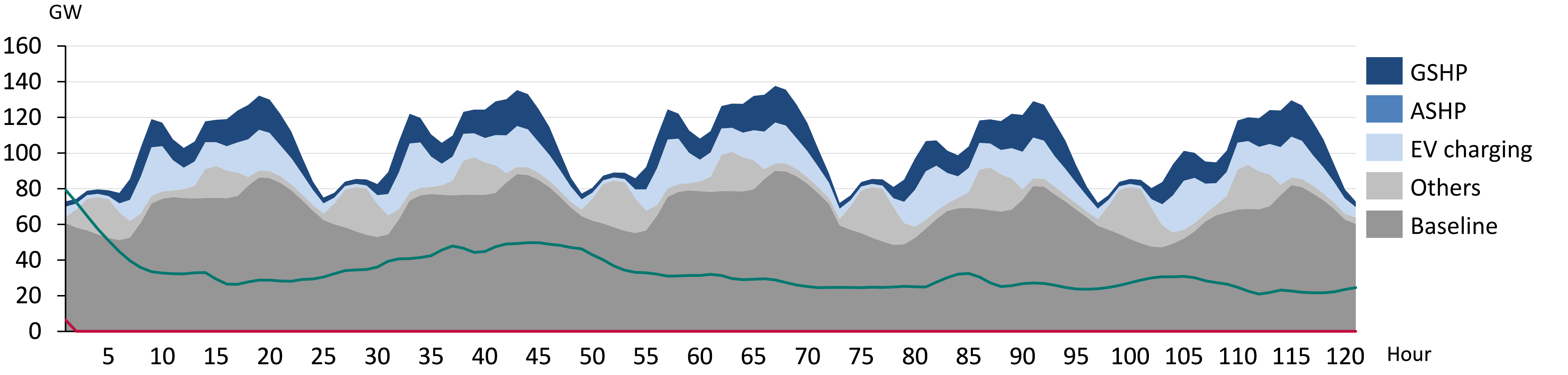
Demand after load shifting



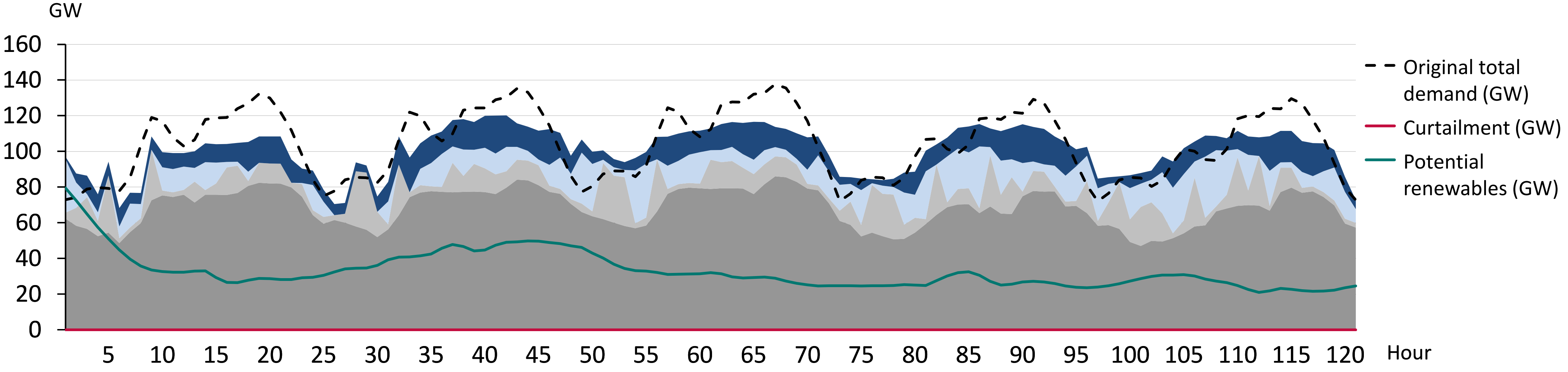
The graph starts from midnight on January 16th (hour 384 of the year). The peak demand occurs in hour 67 of this graph (hour 451 of the year); 6-7pm on January 18th.

100% GSHP scenario: Demand profiles in week of initial peak demand

Demand before load shifting



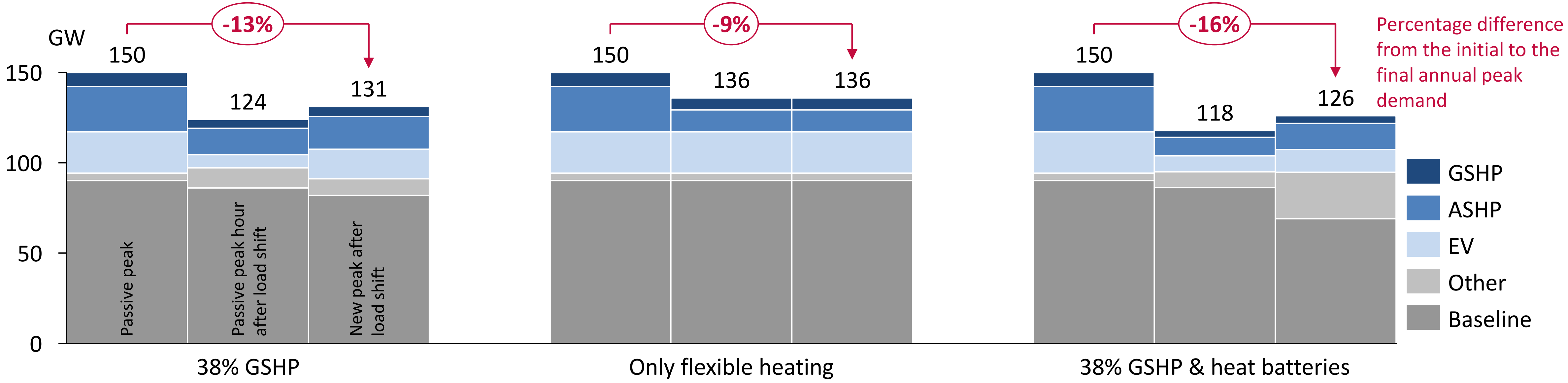
Demand after load shifting



The graph starts from midnight on January 16th (hour 384 of the year). The peak demand occurs in hour 67 of this graph (hour 451 of the year); 6-7pm on January 18th.

Deployment of heat batteries alongside 38% GSHPs leads to an additional 5 GW peak reduction, while flexible heating with no flexibility of EV charging results in 14 GW reduction in peak demand

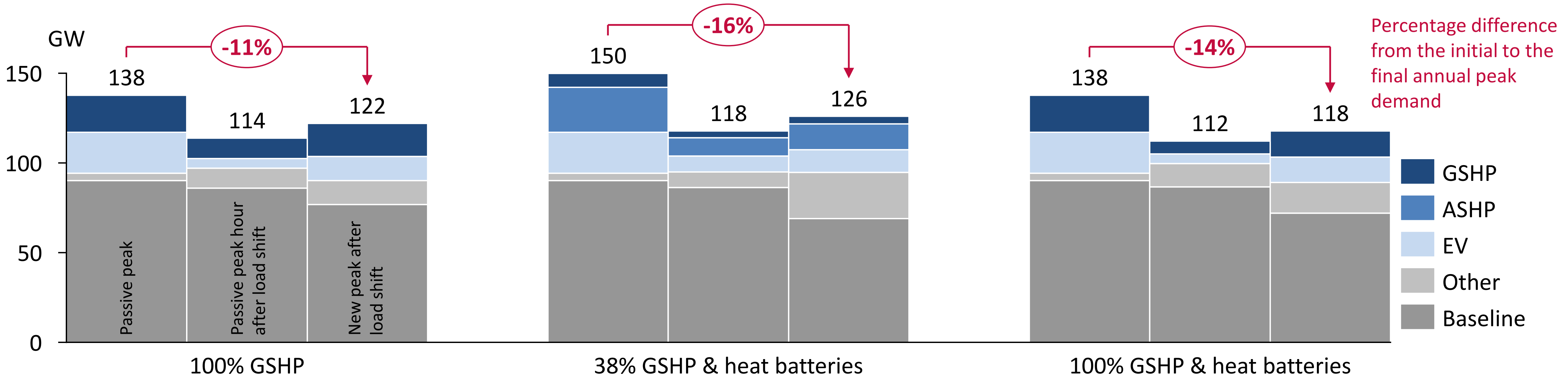
Peak hourly demand (GW): before any load shifting (left), in the initial peak hour after load shifting (middle), and in the whole year after load shifting (right)



- Heat flexibility alone (reflected in the 'Only flexible heating' scenario) leads to a 9% reduction in peak demand. When both heating and EVs are flexible, load shifting reduces the peak annual electricity demand by 11-16% across the various scenarios.
- Including heat batteries reduces the system peak demand by an additional 5 GW compared to the 38% GSHP scenario (126 GW vs 131 GW) in which there is no deployment of heat batteries.
- In some cases (e.g. the new peak hour after load shift in the '38% GSHP & heat batteries' scenario) the electricity consumption for certain demand types can increase (with demand shifted into this hour) to minimise the curtailment of renewable energy; this happens with the 'Other' demand type in this case.
- In the 'Only flexible heating' scenario the peak hour after load shifting is the same hour as the initial peak electricity demand before any load shifting. This hour is the initial peak hour as it has a high heating demand that coincides with a high electricity demand for EV charging and for other 'baseline' uses. The demand in this hour after load shifting is the highest of any hour in the year, as heating demand is still significant alongside the unshifted electricity demand for other demand types.

Deployment of heat batteries alongside 100% share of GSHPs leads to the lowest final peak electricity demand of 118 GW, with a 14% peak demand reduction possible with demand side response

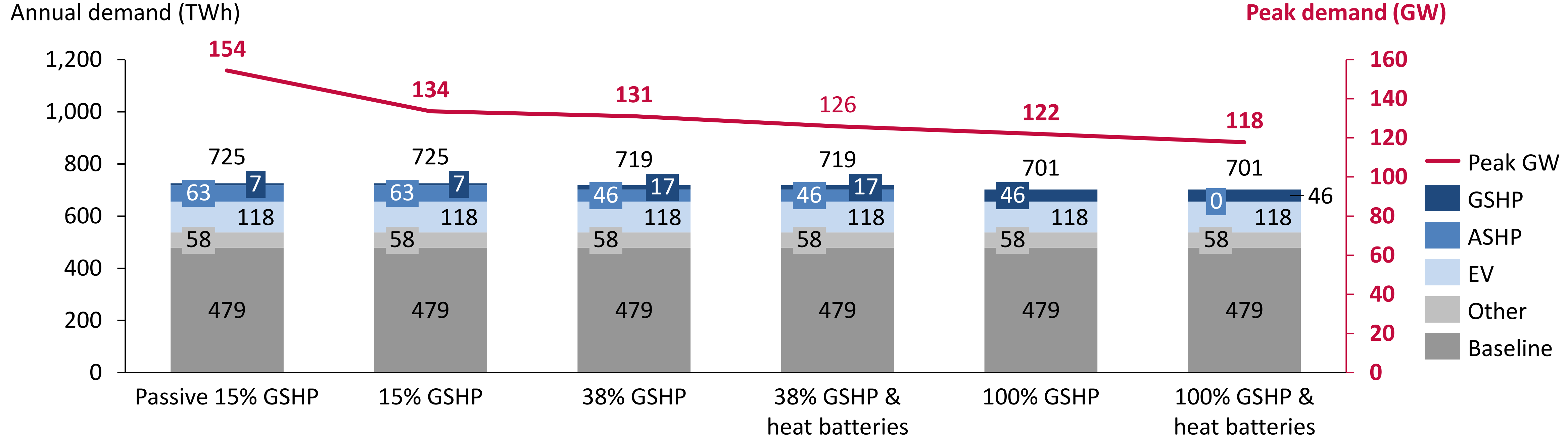
Peak hourly demand (GW): before any load shifting (left), in the initial peak hour after load shifting (middle), and in the whole year after load shifting (right)



- 100% GSHP deployment and no heat batteries (the '100% GSHP' scenario) leads to a lower final electricity peak than 38% GSHPs alongside heat batteries in 50% of homes (the '38% GSHP & heat batteries' scenario), due to the higher efficiencies of GSHPs compared to ASHPs.
- The lowest final peak electricity demand across all scenarios was in the 100% GSHP & heat batteries scenario (with heat batteries installed in 50% of homes with a heat pump). The peak demand in this scenario was 20 GW lower after demand-side flexibility.
- The 100% GSHP & heat batteries scenario has a final electricity demand after load shifting that is 36 GW lower than the 154 GW initial peak demand (before load shifting) in the 15% GSHP scenario, which has no heat batteries. This is a 23% reduction in the peak compared to the 154 GW initial demand.

Increasing the share of GSHPs from 15% to 100% leads to a 2.5% reduction in annual electricity consumption but a 9% reduction in peak demand

Total annual electricity consumption (TWh) after demand side response

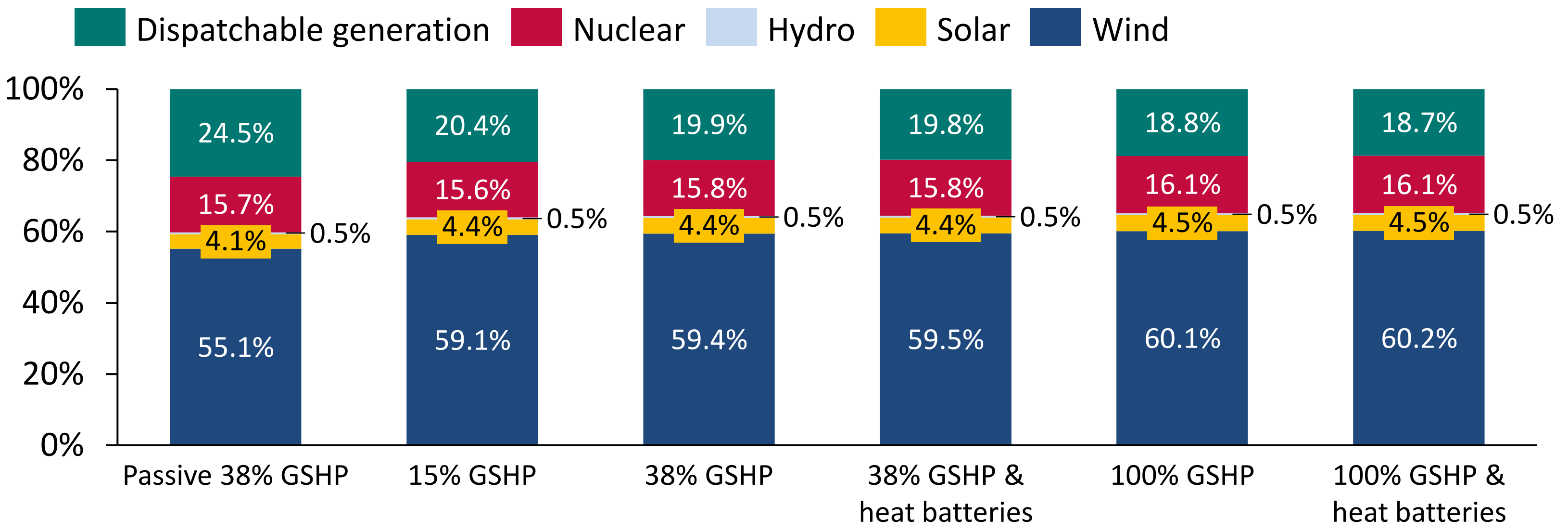


- Total electricity demand, and share of electricity demand for domestic heating, is lowest when deployment of GSHPs is highest (in the 100% GSHP scenario) due to higher modelled COPs, as ASHPs suffer an efficiency penalty in hours in the defrost zone.
- Heat demand is highly seasonal and peaky by nature, and in any future scenario with high proportions of electrification of heat will lead to increased peak electricity demand on cold days when heating demand is high and buildings lose heat more quickly.
- Enabling heating demand load shifting helps shift large portions of electricity on peak cold days and reduces the peak capacity required for electricity generation or distribution by 19 GW (13% of passive peak) in the 38% GSHP scenario with both heat flexibility and EV charging flexibility.
- Increasing the proportion of GSHPs from 15% to 100% reduces the annual total electricity demand by only 3.3%, but this leads to a 12 GW peak demand reduction when load shifting is used, as heating demand is especially concentrated on cold days.

Flexibility reduces curtailment by over 50% in all scenarios with flexible heating and EV charging, and increasing the proportion of GSHPs to 100% leads to an 11 TWh reduction in dispatchable generation

- The renewable generation capacity was kept the same in all scenarios, with only the dispatchable generation capacity adjusted dynamically in the ISDM.
- Flexibility increases the proportion of total electricity supply that is met by renewables by at least 4.6% of total demand share between the Passive 38% GSHP and 38% GSHP scenarios. This leads to a reduction in the dispatchable generation by up to 25% compared to the passive scenario.
- Increasing the deployment of GSHPs to 100% of domestic heat pumps in the 100% GSHP scenario leads to a further 1.1% increase in final consumption of renewable energy. This is because this leads to a lower initial demand due to higher efficiency of GSHPs, leading to less requirement for dispatchable generation in hours of low renewable potential.
- Additionally, curtailment is reduced by over 50% in all scenarios where both heat and EV charging are flexible.
- Flexibility of heat alone leads to a reduction in curtailment by 34%.

Breakdown of final generation mix by technology, after load shifting



Annual generation (TWh) by technology type (data from the graph above)

Generation type	Passive 38% GSHP	15% GSHP	38% GSHP	38% GSHP & heat batteries	100% GSHP	100% GSHP & heat batteries
Dispatchable generation	188	157	152	151	141	140
Nuclear	120	120	120	120	120	120
Hydro	4	4	4	4	4	4
Solar	31	34	34	34	34	34
Wind	423	454	454	454	450	450

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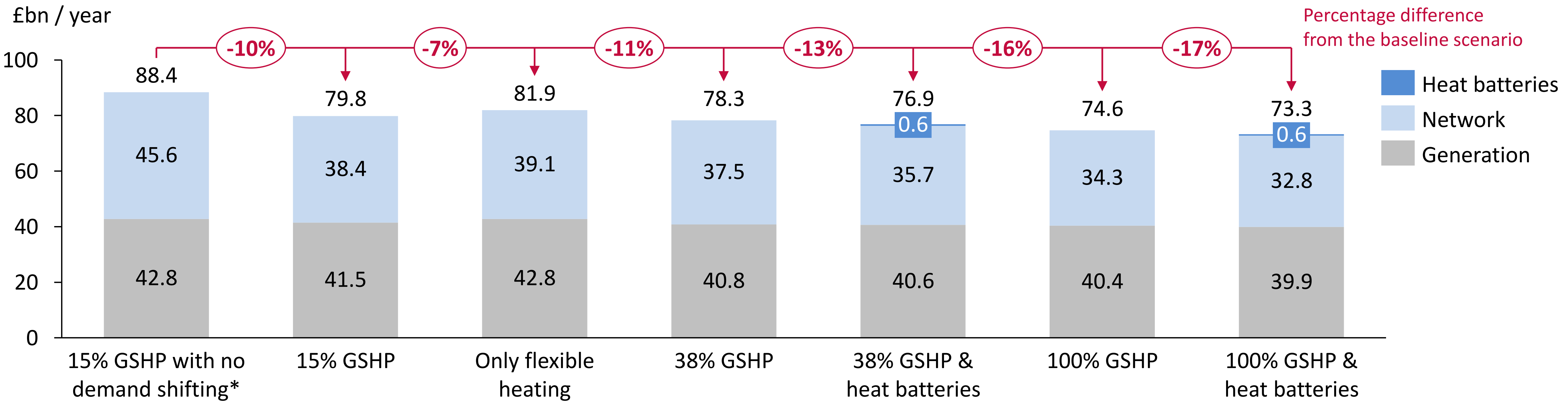
Lower electricity demand in scenarios with higher GSHP proportions leads to cost savings of £1.5-£5.2 billion per year for generation and network costs in the electricity system

Total scenario annualised cost (£ billion per year) for the electricity system, covering network and generation costs

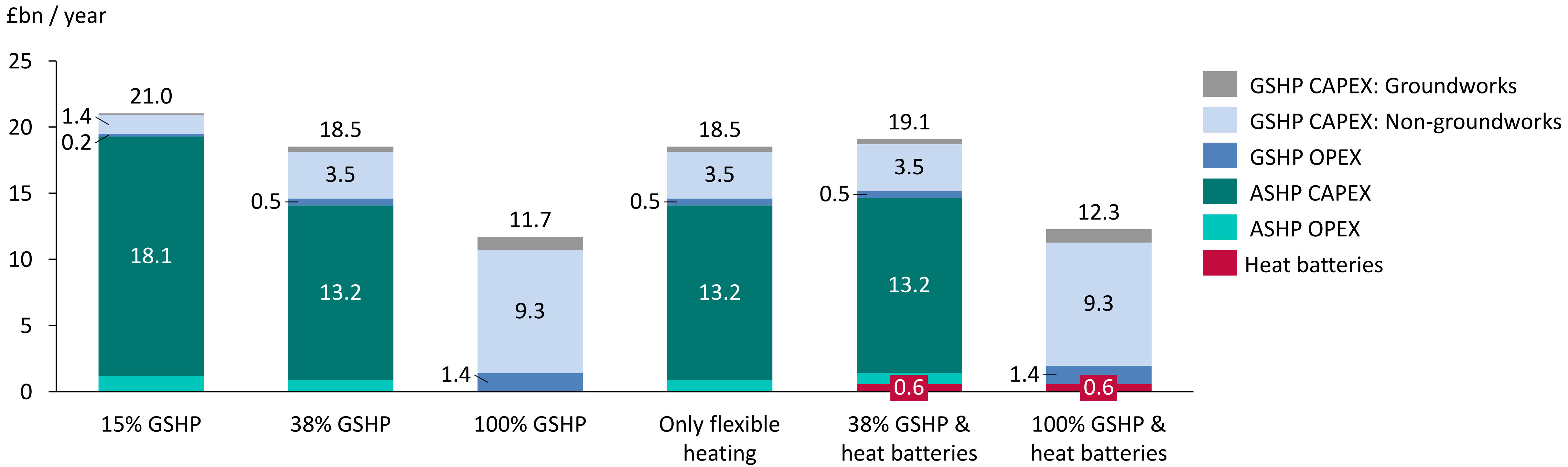


- The network costs include maintenance and upgrade costs for both transmission and distribution networks; generation costs include CAPEX, OPEX and fuel generation costs for all generation technologies.
- Flexibility of heating provides electricity system cost savings of at least £6.5 billion per year in all scenarios when compared to the 15% GSHP with no demand shifting case.
- Increasing the proportion of GSHPs from 15% to 38% leads to annual cost savings of £1.5 billion per year. Increasing the GSHP proportion to 100% leads to further cost savings of £3.3 billion per year.
- Heat flexibility alone ('Only flexible heating' scenario) provides annual savings of 6% for the electricity system versus the Passive 38% GSHP scenario, with savings of up to 16% achievable in the 100% GSHP & heat batteries scenario with flexibility in domestic heating, EV charging and other electricity demand.

* The network cost is calculated using the 15% GSHP scenario demand profile with no load shifting used. The generation costs use the Only flexible heating scenario costs, although this is an optimistic assumption as flexible heating will reduce the peak generation capacity.

The annualised costs of all heating systems are £2.5-£9.3 billion per year lower in scenarios with higher GSHP deployment due to longer assumed lifetimes

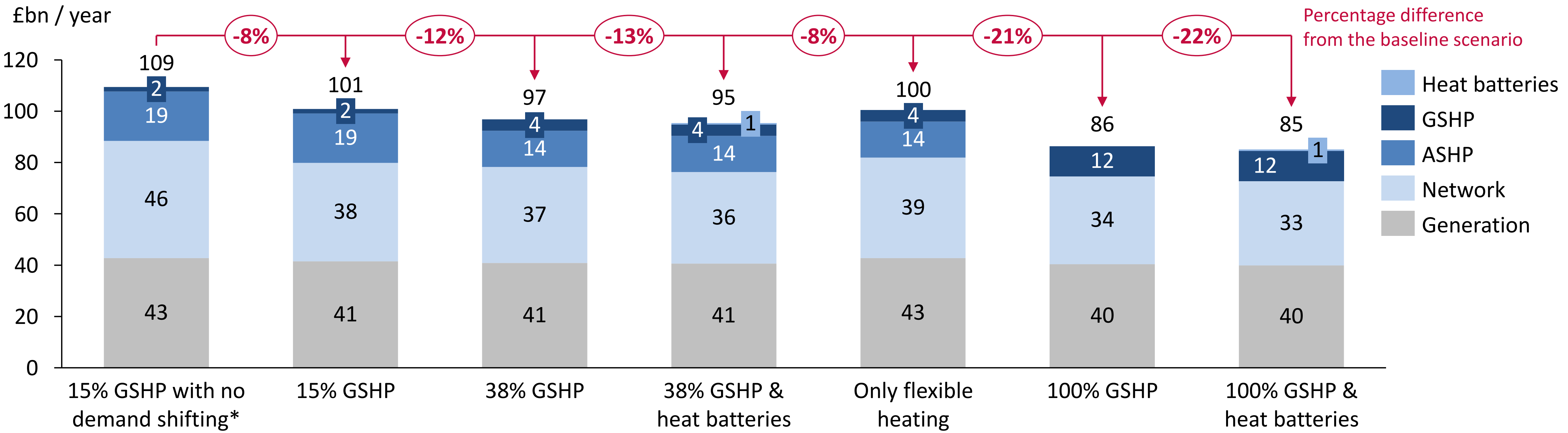
Total scenario annualised heating system costs (£ billion per year)



- Longer assumed lifetimes for GSHPs offsets their higher upfront costs, and so scenarios with the highest deployment of GSHPs have lower annualised heating system costs.
- Here, 97% of all GSHP installations are assumed to use Kensa's shared-loop costs ('street-by-street GSHPs'); the remaining 3% are assumed to be house-by-house GSHPs.
- Higher efficiencies for GSHPs will also lead to lower fuel bills for consumers; however these are not considered here as electricity costs are considered in the previous slide instead.
- Include heat batteries in 50% of homes leads to a £0.6 billion / year increase in total heating system costs in any scenario without heat batteries. The costs above do not however account for any system cost savings from the deployment of heat batteries, or from consumer fuel cost savings by avoiding heating during peak demand hours.

When considering costs for both the electricity system and for heating systems, 100% GSHP deployment leads to £15 billion / year savings when compared to 15% GSHP deployment

Total scenario annualised cost (£bn / year), for electricity system, GSHPs and ASHPs



- Cost savings from the lower annualised heating system costs of GSHPs leads to an 18% reduction in annualised total system costs in the 100% GSHP scenario.
- Flexibility of heat alone (in the 'Only flexible heating' scenario) reduced the network and overall electricity system costs by £5bn/year.
- The inclusion of heat batteries in 50% of homes (in both the heat batteries scenarios) reduced the generation and network costs compared to the same scenario without heat batteries by more than the additional costs for the heat batteries.
- This 50% deployment of heat batteries is in each archetype and therefore reflects a non-targeted high rollout of heat batteries in the British housing stock, instead of a more optimised deployment of heat batteries in homes which would benefit most from the additional flexibility (e.g. homes with large heating demands, or with high heat loss rates).

* The network cost is calculated using the 15% GSHP scenario demand profile with no load shifting used. The generation costs use the Only flexible heating scenario costs, although this is an optimistic assumption as flexible heating will reduce the peak dispatchable generation capacity.

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Key findings from Phase 2 of the Low Carbon Heat Study

Building stock flexibility

1. With an internal allowed temperature change of 3°C and after energy efficiency improvements, over 66% of the British housing stock can shift their heating demand by over 4 hours on a peak cold day in a 1-in-20 cold year.
2. With an internal allowed temperature change of 2°C and after energy efficiency improvements, 30% of British homes can shift their heating demand by over 4 hours on a peak cold day in a typical year.

Flexibility impact on power network

1. Hypothetical 100% deployment of GSHPs leads to a peak electricity demand reduction of 17 GW (11%) before load shifting and 12 GW (9%) after load shifting compared to the 15% GSHP scenario, caused by higher GSHP COPs.
2. Flexibility of heat and EVs leads to over 50% reduction in curtailment in all scenarios, and reduce the use of dispatchable generation by 17-25% in a typical weather year.
3. Heat flexibility alone can reduce network peak demand by 14GW (9%) when compared to the baseline demand.
4. A large rollout of heat batteries reduces the system peak demand by an additional 5 GW (3%) in the 38% GSHP scenario, and by an additional 4 GW (3%) in the 100% GSHP scenario.
5. The peak electricity demand in the system is driven by peak heating demand and occurs on the coldest days, both before and after heat flexibility is applied.

Cost impact of flexibility

1. The 38% GSHP scenario (38% GSHPs) has annual electricity system (generation + network) cost savings of £1.5 billion per year, or 2% of the annual electricity system cost, compared to the 15% GSHP scenario.
2. Hypothetical 100% deployment of GSHPs leads to an additional 10% savings in total system costs (generation + network + heating system) compared to the 38% GSHP scenario, caused by:
   a) 4% lower electricity system costs (generation + network) in the 100% GSHP scenario (equivalent to £3.7 billion per year), driven by lower peak demands caused by higher COPs.
   b) 37% lower annualised costs for GSHPs vs. ASHPs, due to higher asset lifetimes.
3. Costs savings from heat battery flexibility outweigh additional cost of heat battery deployment, even when rolled out across 50% of the stock.

Government policy can reduce impacts of electrification on the electricity system by ensuring flexibility can be performed at scale and GSHPs installations are maximised where suitable

- Generation, transmission and distribution of electricity in 2050 is 10% cheaper with flexibility of both heating and EV charging, or 6% cheaper when only heat pumps are providing flexibility. This can provide cost savings of £4.9-8.5 billion per year.

- These benefits can only be achieved if the following requirements, modelled in this study, are met:
  1. Domestic energy efficiency improvements ramp up to the levels required in the National Grid's FES Consumer Transformation scenario. This increases the number of hours that heating demand can be shifted by, and it reduces the total heating demand throughout the year.
  2. High deployments of heat pumps by 2050, which will require ramping up of supply chains immediately to ensure no gas boilers are installed beyond 2035.
  3. All heat pumps and electric vehicles installed beyond 2030 have flexible capabilities.
  4. Significant buy-in from the majority of homeowners into flexible use of heat pumps and electric vehicles. To reach this goal, flexibility of heating and electric vehicle charging is expected to be financially incentivised, for example through dynamic electricity pricing to encourage consumers to shift electricity demand to times of lower demand or higher renewable generation.

- Additional benefits can be achieved by maximising the rollout of GSHPs where these are most suitable:
  1. GSHPs are better suited when they can be installed as "street-by-street", where a single ground loop would provide heat to all houses on a street or block of flats. This reduces the upfront cost to consumer as it allows the expensive groundwork to be socialised across all GSHP users and enable the development of innovative business models.
  2. GSHPs have a higher CAPEX than ASHPs. There is therefore a need to better incentivise consumers to take up GSHPs despite this higher CAPEX cost, in order to maximise system benefit as well as lower the annualised consumer cost. Ultimately this higher CAPEX costs could be met through a utility model as detailed in Slide 8.

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Initial week demand profiles

Final week demand profiles

To model real-world system performance, hourly weather data was utilised: Leeds was chosen as an average UK location, 2015 was chosen as an average weather year and 2010 as a 1-in-20 cold year

For this study, weather data was used to model the performance of each of the heat pump systems in real-life weather conditions.

The modelling placed a number of requirements on the data that could be used:

- Weather data at hourly resolution was required
  - The Met Office provides data at various resolutions but few datasets are complete, this restricted the years and locations that could be chosen.
- The required metrics were air temperature and humidity, as these were needed to calculate the COP of the ASHP each hour.

Location

The decision on which location to use was based on two primary factors:

- Location representative of an average UK climate
- Location has complete weather data available for the chosen years.

Leeds was found to be close to the UK averages for temperature and humidity. Leeds is also used in the SAP framework to represent a UK average.

Weather data is not available for Leeds itself, the closest location with full hourly data is Bingley, a village to the north west of Leeds:

- **Weather data from the nearby town of Bingley** has been used to predict hourly heat demand and heat pump performance.

Year

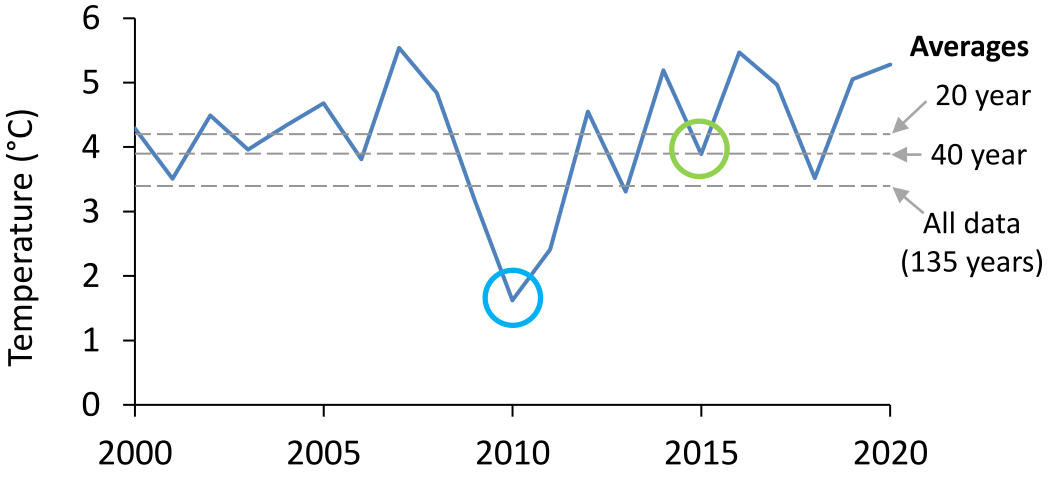
It was decided to study **two weather years, an average weather year and a year 1-in-20 extreme cold winter**.

The availability of complete hourly datasets meant that years would have to be chosen from no earlier than 2010.

Average winter temperatures were plotted for each year

- While 2013 and 2018 had average winter temperatures close to the UK average over the last 100 years, **2015 had an average closer to that of the last 40 years** and is therefore more likely to be representative of the coming 40 years
- **2010 represents a 1-in-20 year extreme cold** winter for the UK

Average UK Winter Temperature



Archetype geometry assumptions

Below are the geometry assumptions used to estimate the thermal mass in each archetype, before aggregation

- The CCC 6th Carbon Budget archetypes were used as the initial basis for the archetypes.
- The floor area (m^2) was taken from the CCC archetype data.
- Assumed number of storeys: Flats assumed 1, others (Det., Semi-D, Ter.) assumed 2.
- Ground floor area (m^2) = floor area / number of storeys.
- Roof area (m^2) = ground floor area (m^2).
- All buildings assumed to be rectangular boxes: using archetype ground floor areas & aspect ratios to determine width & depth, with form factors for semi-detached houses and flats taken from table 2.5a of the UK 2nd Cost Optimal Report.
  - Terraced house assumed to have the same aspect ratio as a semi-detached house.
  - Detached houses assumed to be two semi-detached homes side-by-side in shape.
- Area of internal party walls:
  - Detached: no party walls
  - Semi-detached: depth * number of storeys * storey height (one side consisting of party walls)
  - Terraced: 2 * depth * number of storeys * storey height (two sides consisting of party walls)
  - Flats: (width + depth) * storey height (assuming that flats have two exposed walls & two party walls)
- All buildings assumed to have one party floor (flats assumed to have either party of ground floor, not both)
- Number of rooms per floor, EHS data, 4.8 average for all property types (Det., Semi-D, Ter., Flats)
- Area of internal partitions = (number of rooms)/2 * building depth * storey height & number of storeys
- Exposed wall area = total available wall (4 (walls) * depth * storey height * number of storeys) – Area of internal party walls (calculated above) – window area (calculated for NG project)

Estimating heat capacity: mapping of archetype parameters to SAP fabric descriptions

Archetype parameter	Parameter description	Mapped description from SAP	Heat capacity (kJ/m^{2}K)
Wall	Cavity insulated	Average of (Cavity wall; dense plaster, lightweight aggregate block, filled cavity, any outside structure) & (Cavity wall; plasterboard on dabs or battens, lightweight aggregate block, filled cavity, any outside structure)	125
Wall	Cavity uninsulated (inc. EHTT, HTT, ETT)	As above	123
Wall	Solid uninsulated	Weighted average based on EPC data from England. If EPC field: 'WALLS_DESCRIPTION' timber or stone mentioned, mapped to 'Solid wall: plasterboard on dabs or battens, 200 mm dense block, insulated externally'. If brick mentioned, mapped to 'Solid wall: plasterboard on dabs or battens, 210 mm brick, insulated externally'.	112
Wall	Solid insulated (internal)	Simple average of two internal solid wall insulated heat capacity values (9 and 17)	13
Wall	Solid insulated (external)	As in 'Wall', 'Solid uninsulated'	142
Roof	All roof types (no difference in heat capacity in SAP)	All roof types the same in SAP	9
Floor	Solid insulated	Slab on ground, screed over insulation	110
Floor	Solid uninsulated	Suspended concrete floor, carpeted	75
Floor	Suspended insulated	Suspended timber, insulation between joists	20
Floor	Suspended uninsulated	Suspended concrete floor, carpeted	75
Floor	None	Assumed to have no thermal mass. Flats are still getting the value from party floors, if they have 'None' floor.	0
Party walls	No data on this: Sam, please feel free to suggest alternatives	Single plasterboard on both sides, dense cellular blocks, cavity (E-WM-5)	70
Party floors	No data on this: Sam, please feel free to suggest alternatives	Assumed to be a simple average of all values in the 'Party floors' section, ignoring the 'concrete floor slab' value as assumed to be uncommon	52
Internal walls	All archetypes	Dense block, plasterboard on dabs	75
Glazing	All window types	N/A (assumed no thermal mass)	0

Table 1e, SAP 2012

	Construction	Heat capacity (kJ/m2K)	Heat capacity from above (kJ/m2K)	Heat capacity from below (kJ/m2K)
Ground floors	Suspended timber, insulation between joists	20		
	Slab on ground, screed over insulation	110		
	Suspended concrete floor, carpeted	75		
Exposed floors	Timber exposed floor, insulation between joists	20		
External walls - masonry, solid, external insulation	Solid wall: dense plaster, 200 mm dense block, insulated externally	190		
	Solid wall: plasterboard on dabs or battens, 200 mm dense block, insulated externally	150		
	Solid wall: dense plaster, 210 mm brick, insulated externally	135		
	Solid wall: plasterboard on dabs or battens, 210 mm brick, insulated externally	110		
External walls - masonry, solid, internal insulation	Solid wall: dense plaster, insulation, any outside structure	17		
	Solid wall: plasterboard on dabs or battens, insulation, any outside structure	9		
External walls - cavity masonry walls, full or partial cavity fill	Cavity wall: dense plaster, dense block, filled cavity, any outside structure	190		
	Cavity wall; dense plaster, lightweight aggregate block, filled cavity, any outside structure	140		
	Cavity wall: dense plaster, AAC block, filled cavity, any outside structure	70		
	Cavity wall: plasterboard on dabs or battens, dense block, filled cavity, any outside structure	150		
	Cavity wall; plasterboard on dabs or battens, lightweight aggregate block, filled cavity, any outside structure	110		
	Cavity wall: plasterboard on dabs or battens, AAC block, filled cavity, any outside structure	60		
External walls – timber or steel frame	Timber framed wall (one layer of plasterboard)	9		
	Timber framed wall (two layers of plasterboard)	18		
	Steel frame wall (warm frame or hybrid construction)	14		
Roofs	Plasterboard, insulated at ceiling level	9		
	Plasterboard, insulated slope	9		
	Plasterboard, insulated flat roof	9		
Party walls	Dense plaster both sides, dense blocks, cavity or cavity fill (E-WM-1)	180		
	Dense plaster both sides. lightweight aggregate blocks, cavity or cavity fill (E-WM-2)	140		
	Single plasterboard on dabs on both sides, dense blocks, cavity or cavity fill (E-WM-3)	70		
	Single plasterboard on dabs both sides, lightweight aggregate blocks, cavity or cavity fill (E-WM-4)	110		
	Single plasterboard on both sides, dense cellular blocks, cavity (E-WM-5)	70		
	Plasterboard on dabs mounted on cement render on both sides, AAC blocks, cavity (E-WM-6 or E-WM-7)	45		
	Double plasterboard on both sides, twin timber frame with or without sheathing board (E-WT-1 or E-WT-2)	20		
	Steel frame (E-WS-1 to E-WS-3)	20		
Party floors	Precast concrete planks floor, screed, carpeted (E-FC-1)		40	30
	Concrete floor slab, carpeted (E-FC-2)		80	100
	Precast concrete plank floor (screed laid on insulation) ,carpeted (E-FC-3)		40	30
	Precast concrete plank floor (screed laid on rubber),carpeted (E-FC-4)		70	30
	In-situ concrete slab supported by profiled metal deck, carpeted (E-FS-1)		64	90
	Timber I-joists, carpeted (E-FT-1)		30	20
Internal partitions	Plasterboard on timber frame	9		
	Dense block, dense plaster	100		
	Dense block, plasterboard on dabs	75		
Floor/ceiling/ between floors in a house	Carpeted chipboard floor, plasterboard ceiling		18	9

Hourly gas demand profiles for space heating, hot water and cooking were generated based on the daily external air temperature using a methodology published in 2019 by Watson et. al.

Heat Demand Profiles

- The daily heat demand profiles were generated using profiles modelled by Watson et. al., published in 2019.[1] These profiles were based on smart meter data from gas heated homes.
- The Watson et. al. paper provides functions for calculating the gas demand for space heating and for hot water (separated) based on the external air temperature.
- A series of daily demand profiles were provided, the shape of which is also dependent on the external temperature, with colder days having higher, flatter demand profiles
  - This effect can be seen in the figure on the right which has higher daytime demand for the coldest winter day (blue) compared to an average winter day (green)
  - The demand profile methodology is illustrated on the next slide.
- Daily demand profiles for each property were generated by spreading the daily demand across the appropriate daily profile.

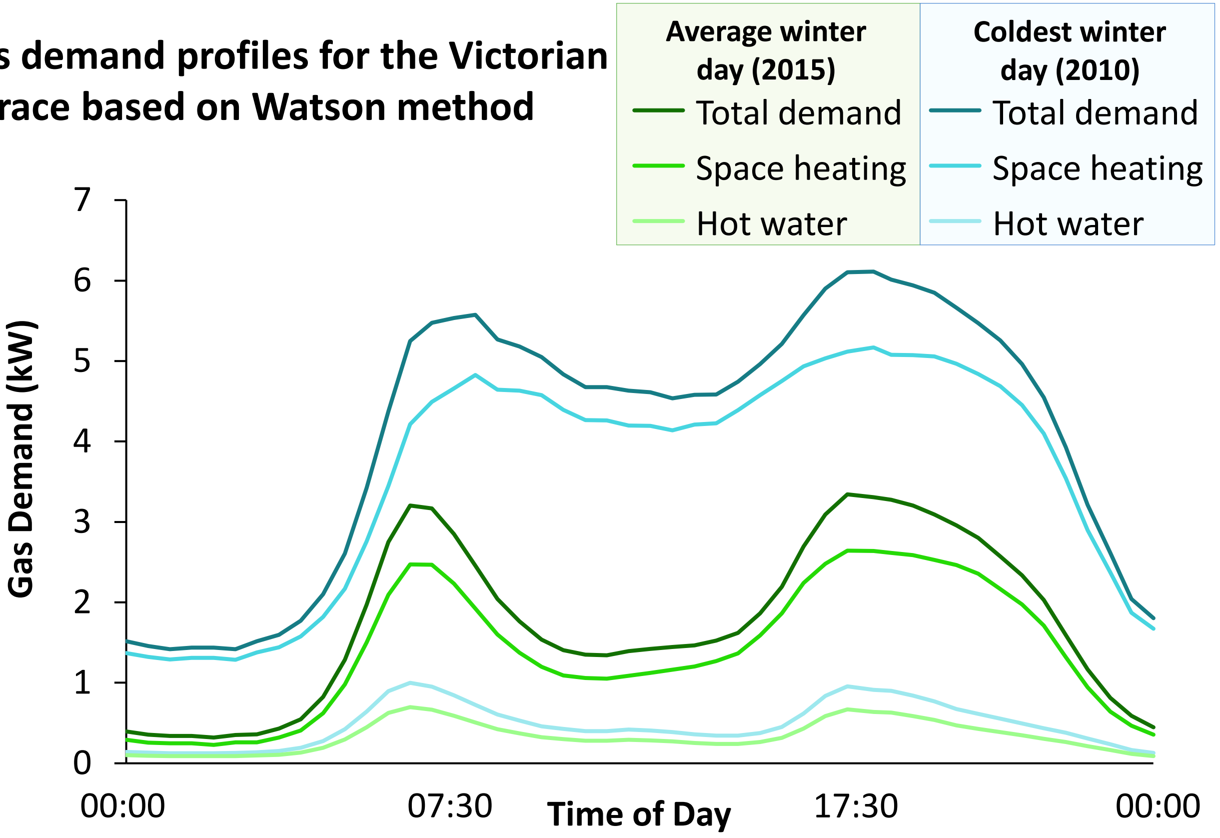
Victorian Terrace

- The Watson method was used to calculate the daily gas demands for space heating and hot water for the Victorian Terrace property in each of the weather years studies.
  - In 2015, the overall gas demand was 15.7 MWh per year, higher than the NEED mean values but within the range for the building type.
  - In 2010, the overall demand increased to 18.3 MWh/year, due to a large increase in demand for space heating and a small increase in hot water demand

New-Build Semi-Detached

- The space heating values calculated using the Watson method were calibrated down for the new build (hot water was assumed to remain the same) to 6.5 MWh per year, in line with the NEED UK lower quartile values for Post-2002, 3-bed, semi-detached homes.

Gas demand profiles for the Victorian terrace based on Watson method

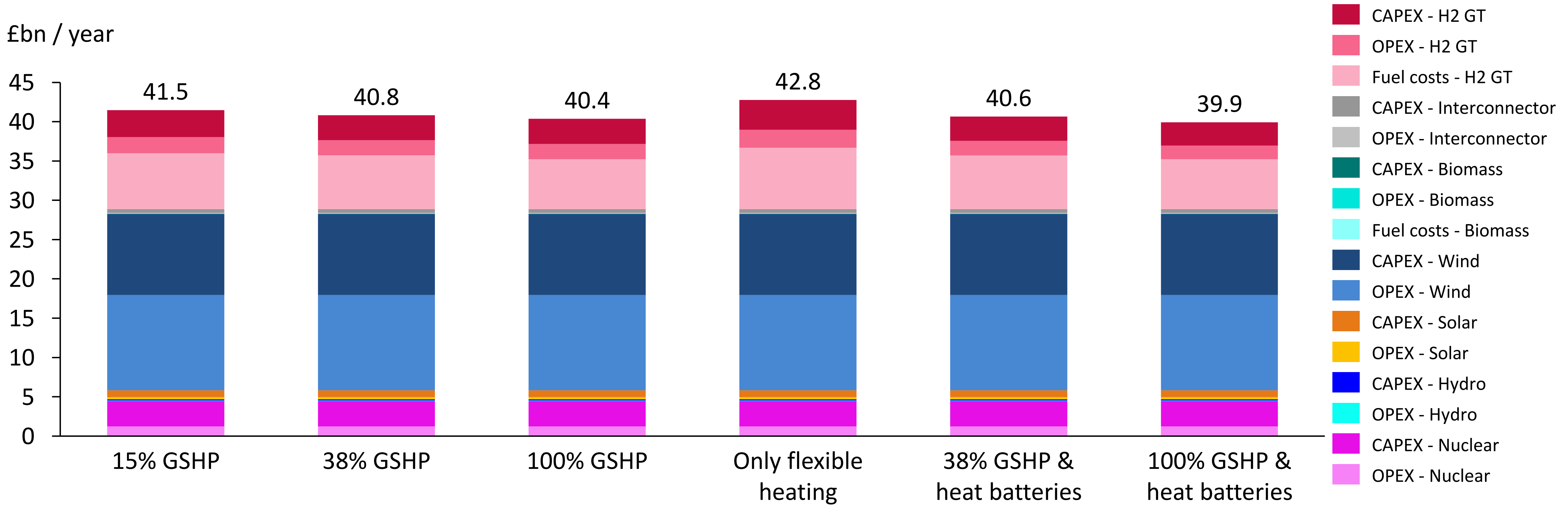


Gas Demand (MWh/year)	Victorian Terrace		New-Build Semi-Detached	
	2015	2010	2015	2010
Space Heating	11.7	14.1	2.5	3.0
Hot water	3.7	3.8	3.7	3.8
Cooking	0.3			

1. Watson et. al. "Decarbonising domestic heating: What is the peak GB demand?" https://www.sciencedirect.com/science/article/pii/S0301421518307249 **2019**

Scenario comparison: Generation cost components

Total scenario annualised generation cost (£ billion per year)



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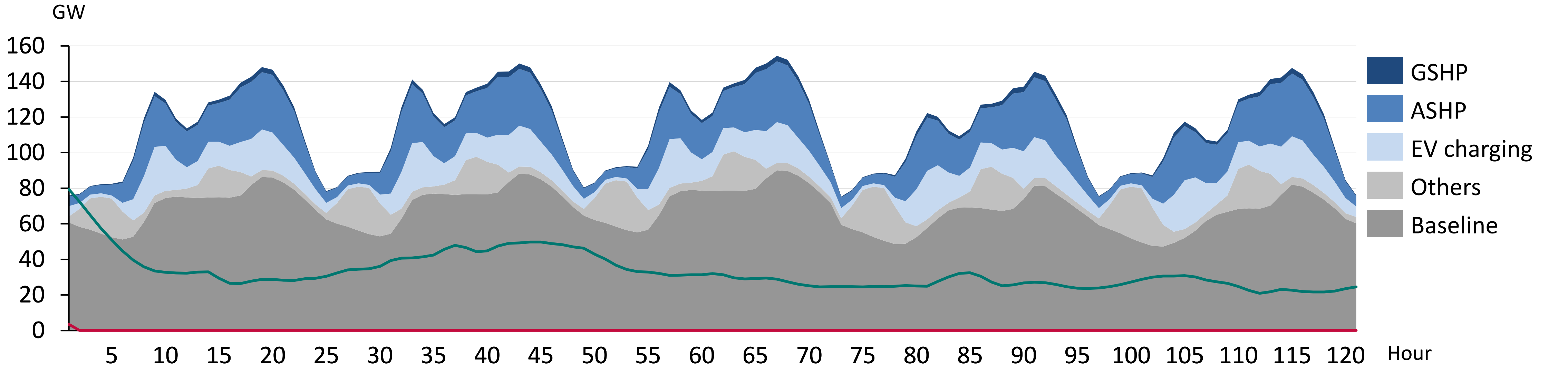
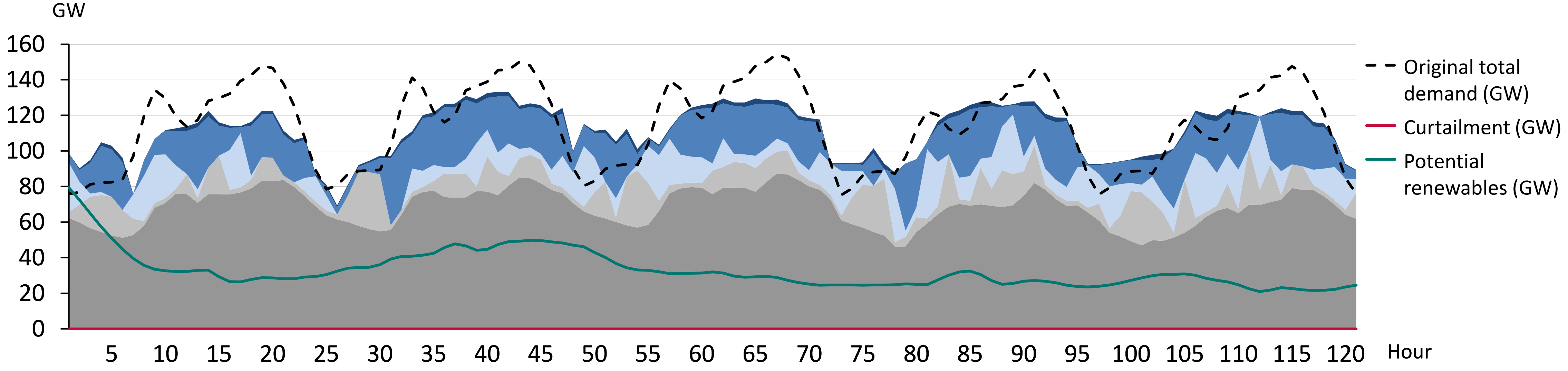
15% GSHP scenario: Demand profiles in week of initial peak demand

Demand before load shifting



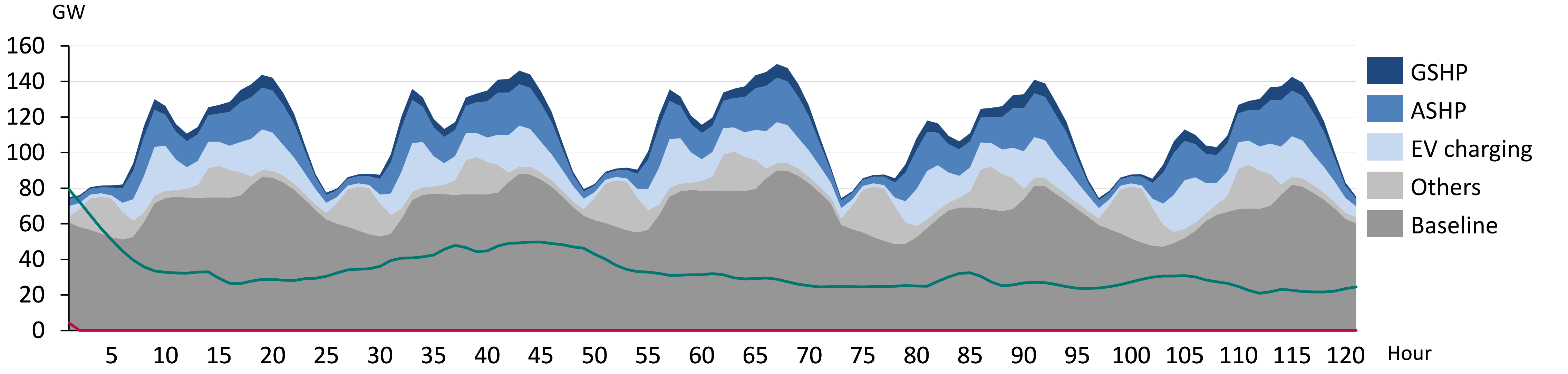
Demand after load shifting



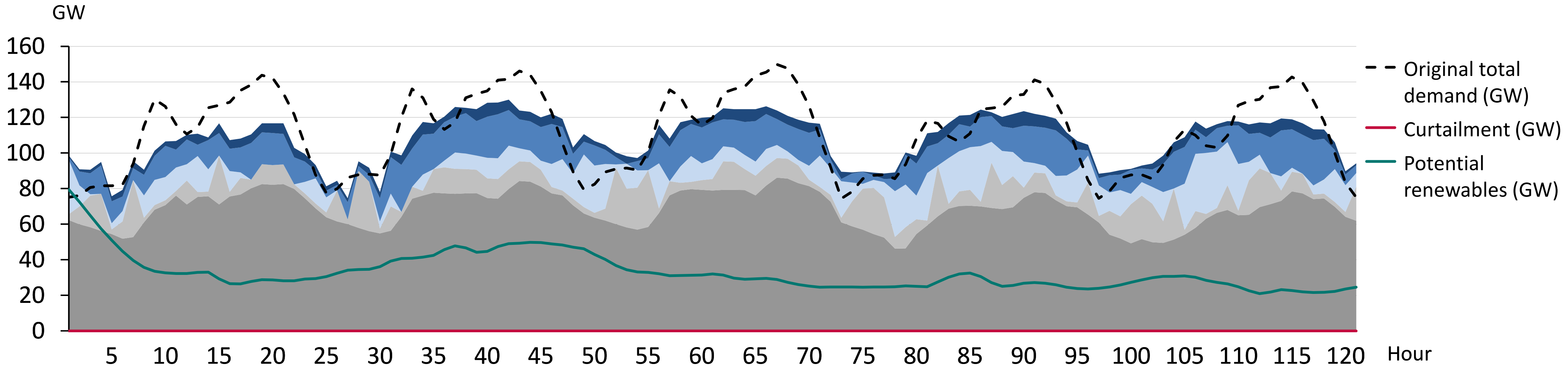
The graph starts from midnight on January 16th (hour 384 of the year). The peak demand occurs in hour 67 of this graph (hour 451 of the year); 6-7pm on January 18th.

38% GSHP scenario: Demand profiles in week of initial peak demand

Demand before load shifting



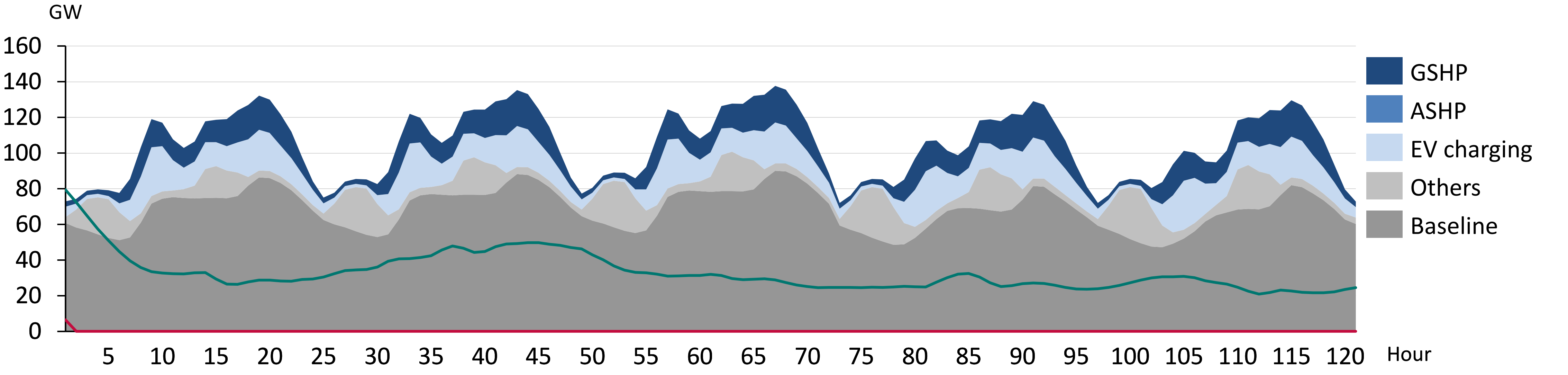
Demand after load shifting



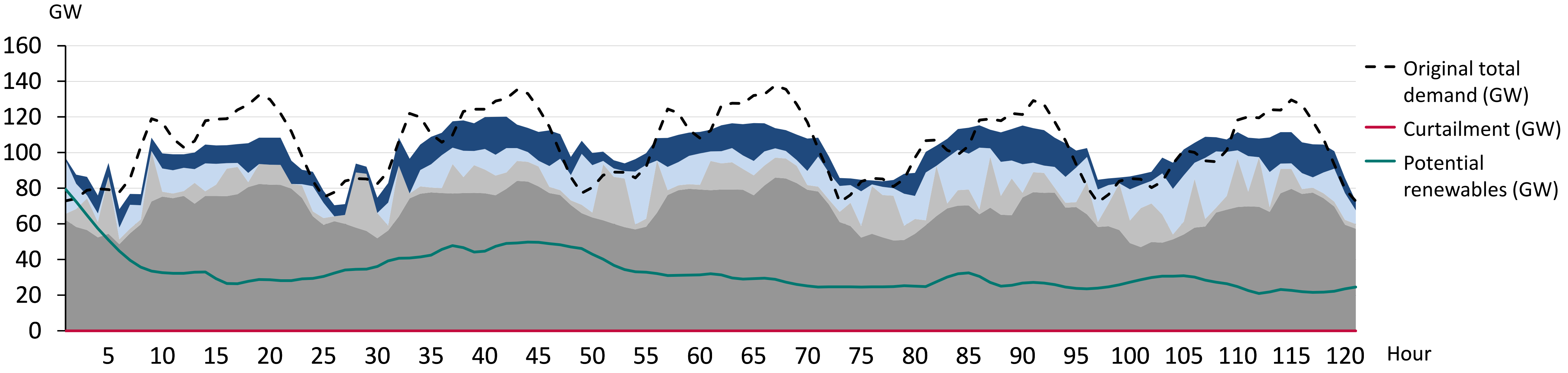
The graph starts from midnight on January 16th (hour 384 of the year). The peak demand occurs in hour 67 of this graph (hour 451 of the year); 6-7pm on January 18th.

100% GSHP scenario: Demand profiles in week of initial peak demand

Demand before load shifting



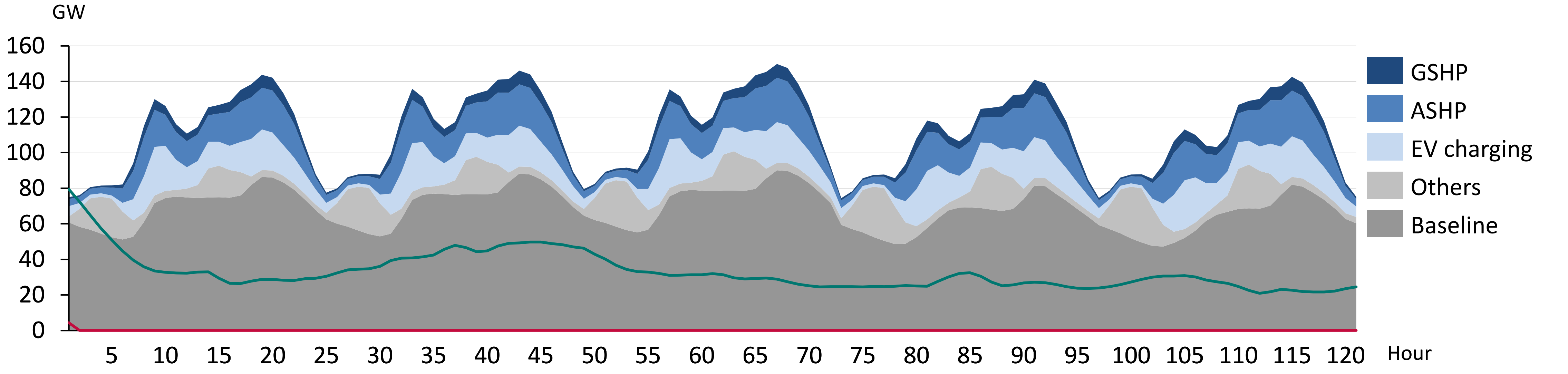
Demand after load shifting



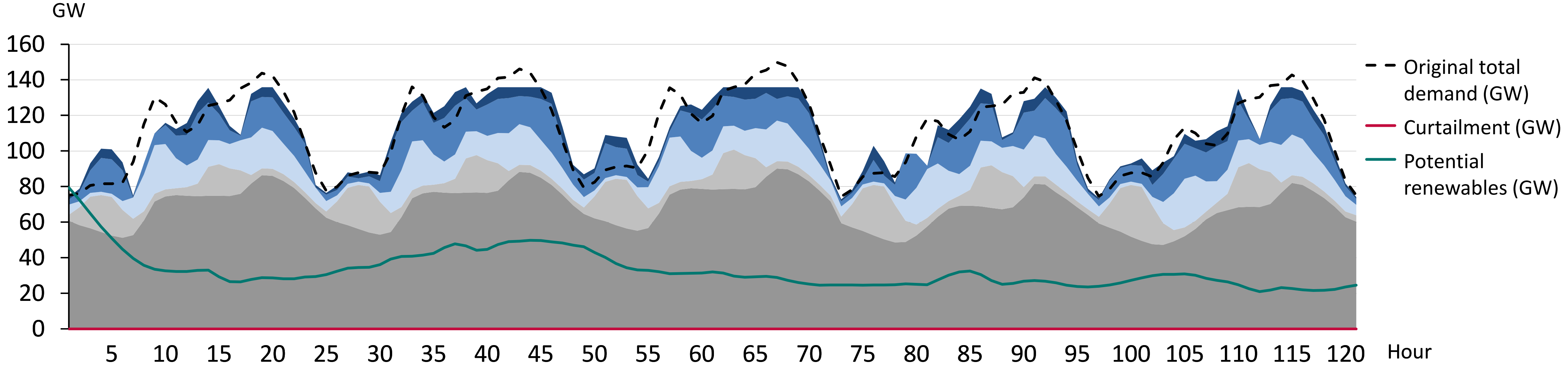
The graph starts from midnight on January 16th (hour 384 of the year). The peak demand occurs in hour 67 of this graph (hour 451 of the year); 6-7pm on January 18th.

Only flexible heating scenario: Demand profiles in week of initial peak demand

Demand before load shifting



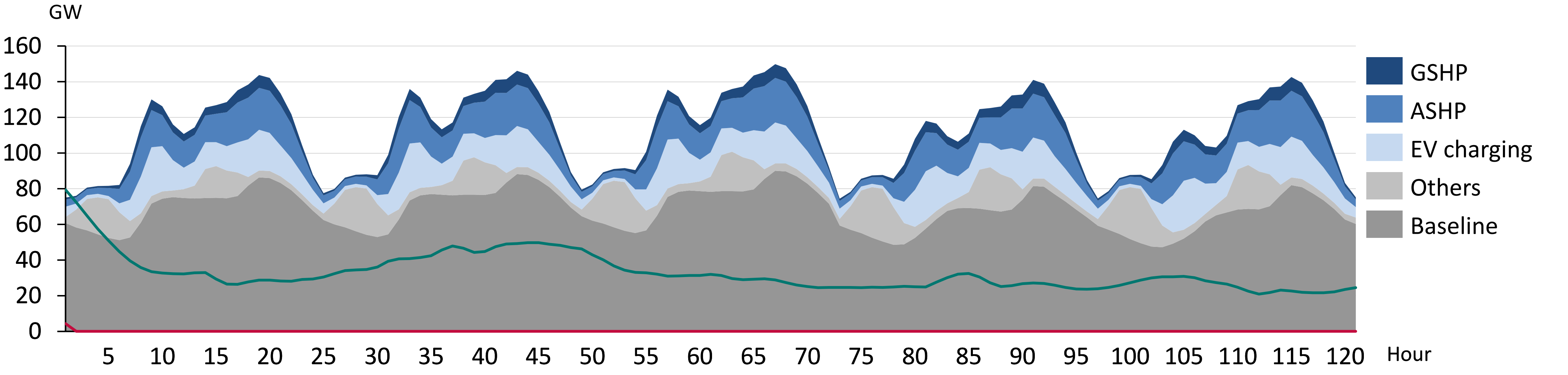
Demand after load shifting



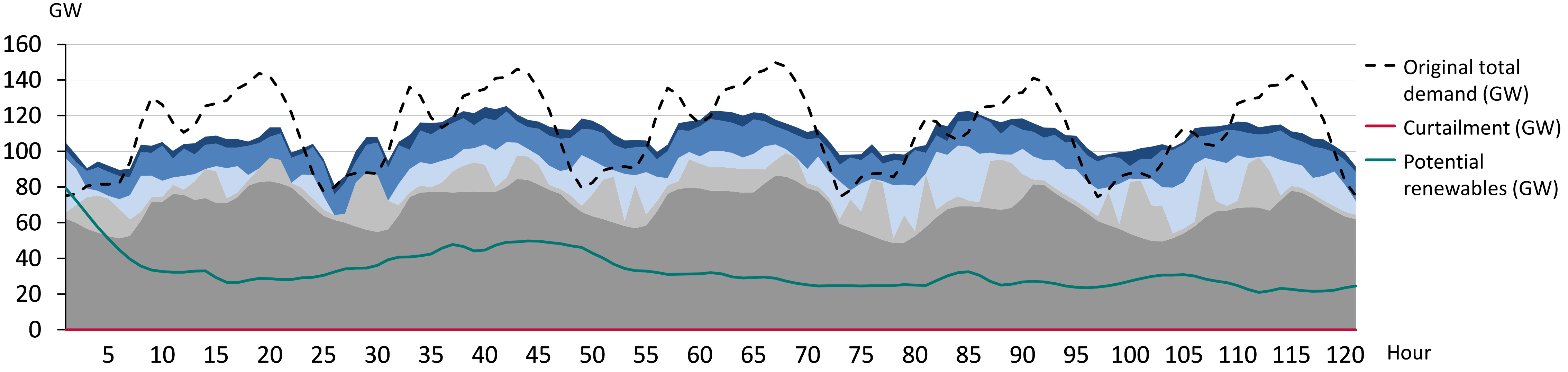
The graph starts from midnight on January 16th (hour 384 of the year). The peak demand occurs in hour 67 of this graph (hour 451 of the year); 6-7pm on January 18th.

38% GSHP & heat batteries scenario (in 50% of homes): Demand profiles in week of initial peak demand

Demand before load shifting



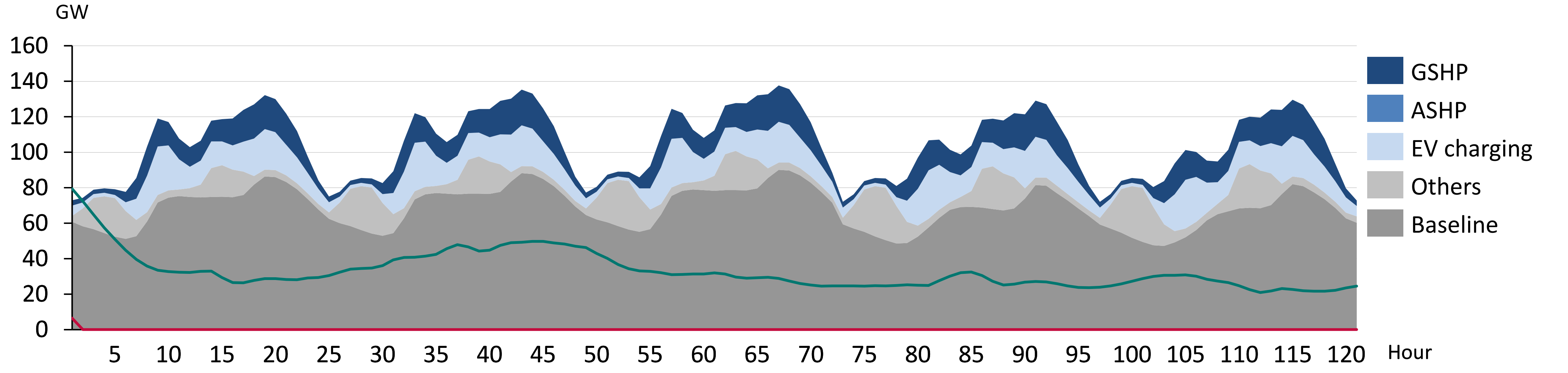
Demand after load shifting



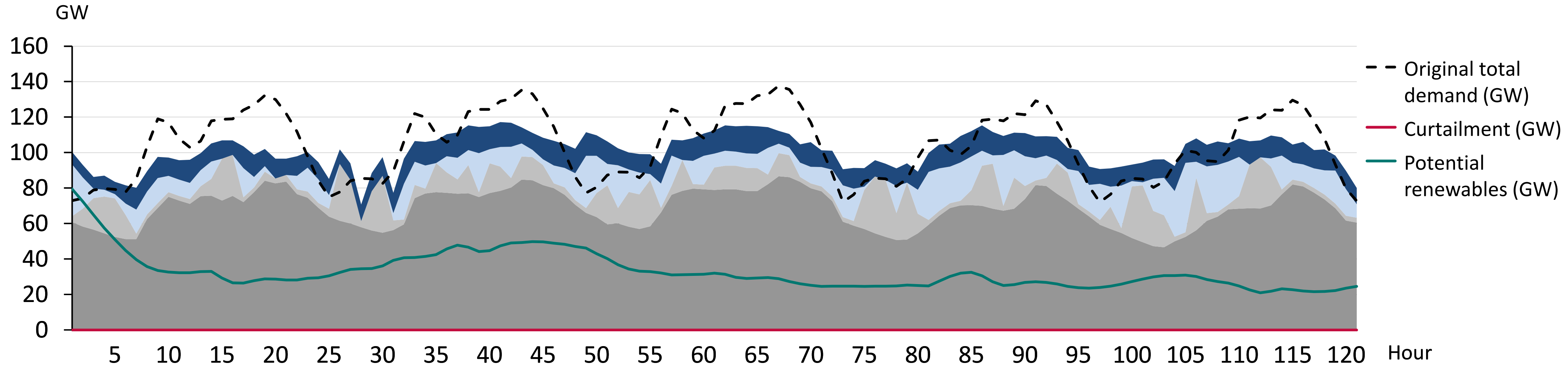
The graph starts from midnight on January 16th (hour 384 of the year). The peak demand occurs in hour 67 of this graph (hour 451 of the year); 6-7pm on January 18th.

100% GSHP & heat batteries scenario (in 50% of homes): Demand profiles in week of initial peak demand

Demand before load shifting



Demand after load shifting



The graph starts from midnight on January 16th (hour 384 of the year). The peak demand occurs in hour 40 of this graph (hour 424 of the year); 3-4pm on January 17th.

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Key findings and recommendations
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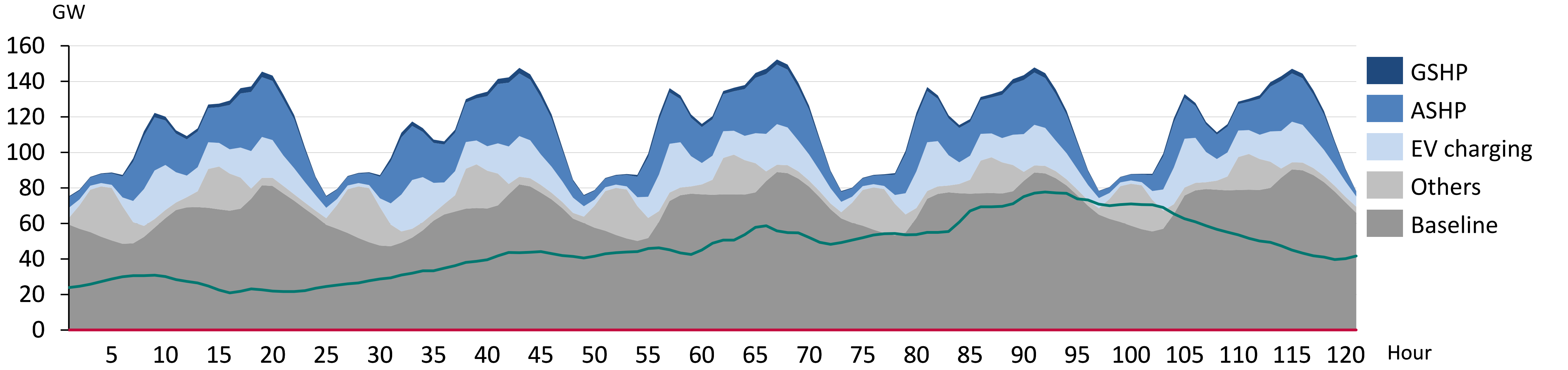
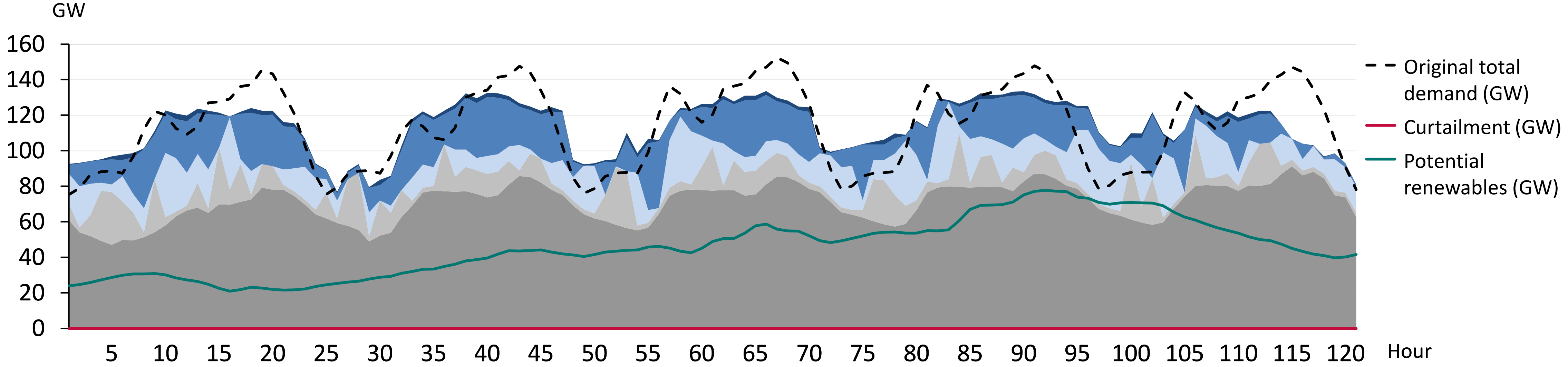
Initial week demand profiles
Final week demand profiles

15% GSHP scenario: Demand profiles in week of final peak demand

Demand before load shifting



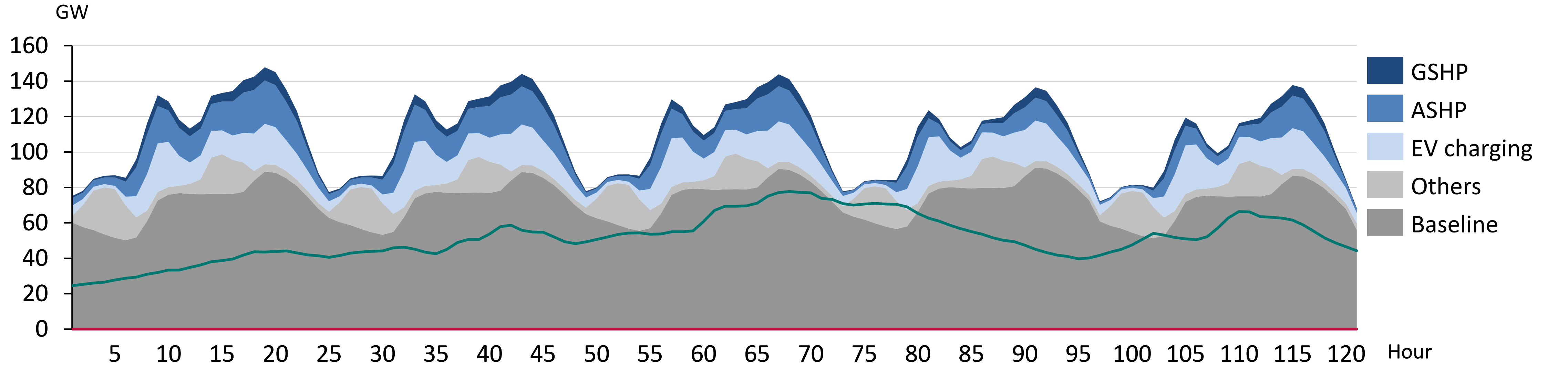
Demand after load shifting



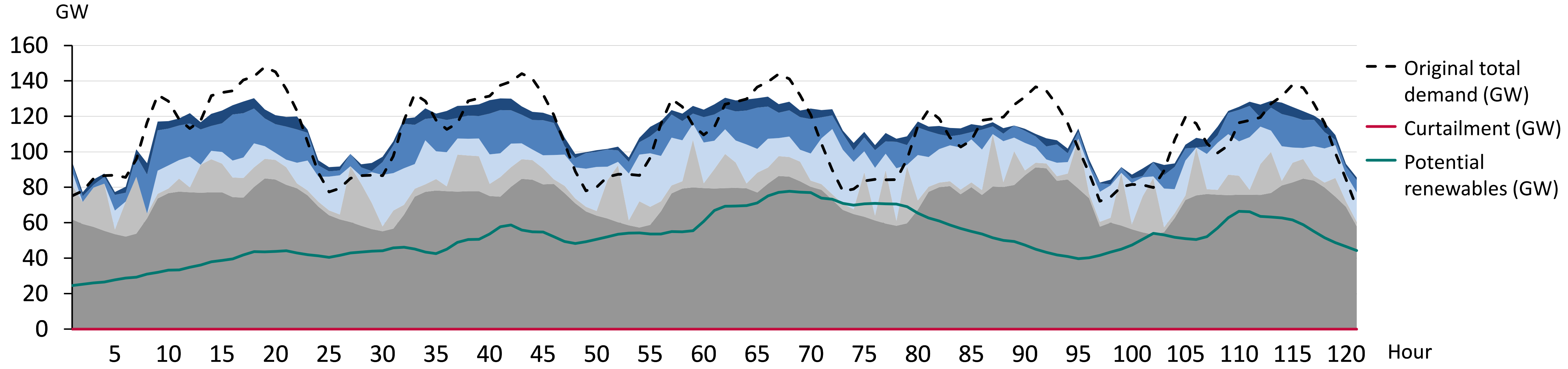
The graph starts from midnight on January 20th (hour 480 of the year). The peak demand occurs in hour 66 of this graph (hour 545 of the year); 5-6pm on January 23rd .

38% GSHP scenario: Demand profiles in week of final peak demand

Demand before load shifting



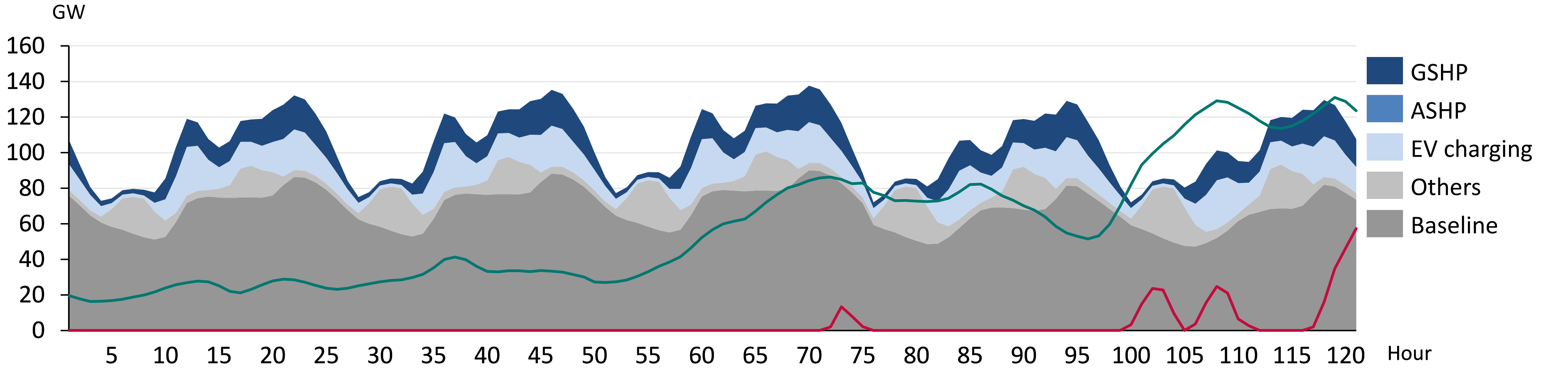
Demand after load shifting



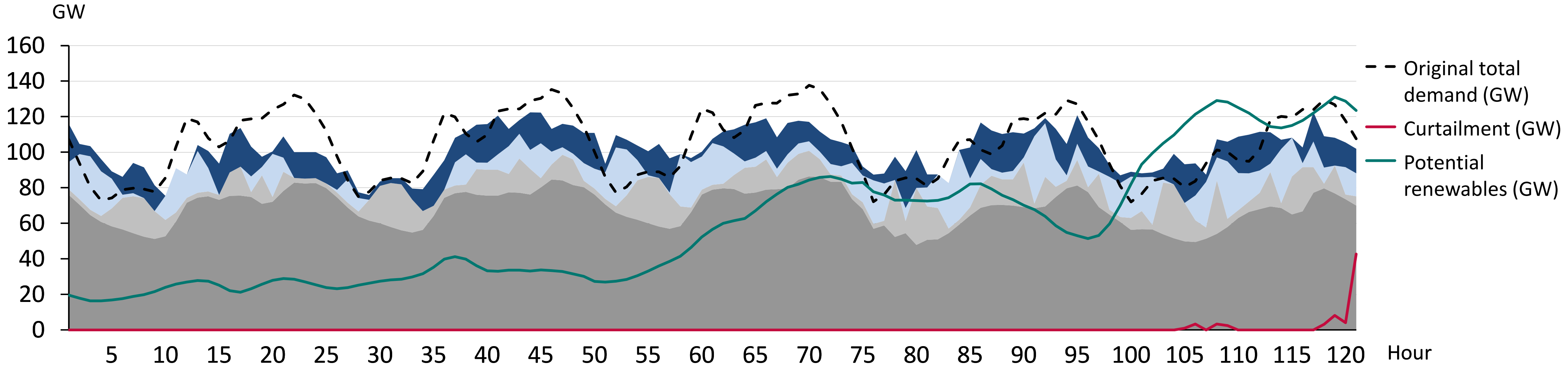
The graph starts from midnight on January 21st (hour 504 of the year). The peak demand occurs in hour 65 of this graph (hour 569 of the year); 4-5pm on January 24th.

100% GSHP scenario: Demand profiles in week of final peak demand

Demand before load shifting



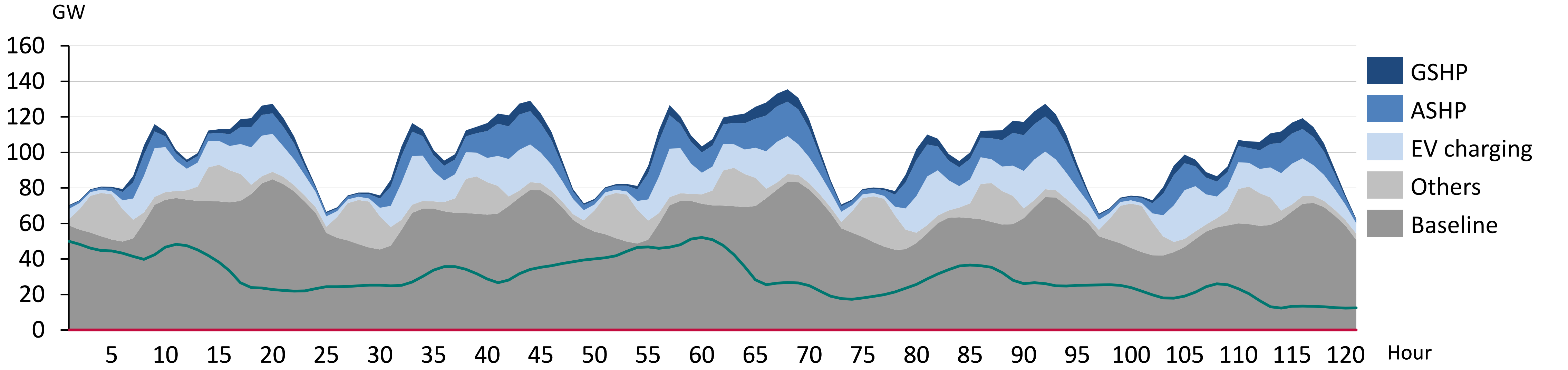
Demand after load shifting



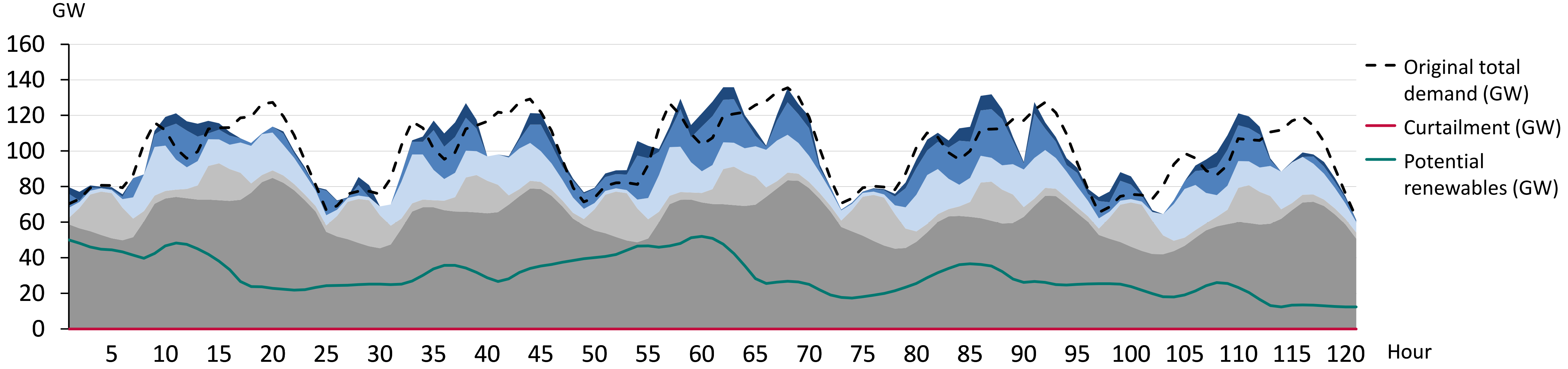
The graph starts from midnight on January 29th (hour 672 of the year). The peak demand occurs in hour 64 of this graph (hour 736 of the year); 3-4pm on January 31st.

Only flexible heating scenario: Demand profiles in week of final peak demand

Demand before load shifting



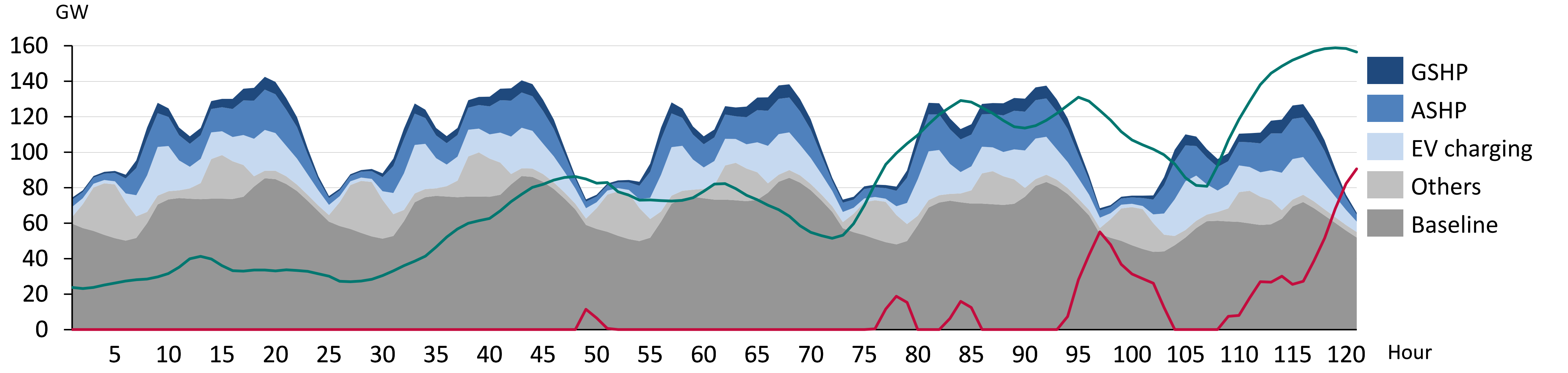
Demand after load shifting



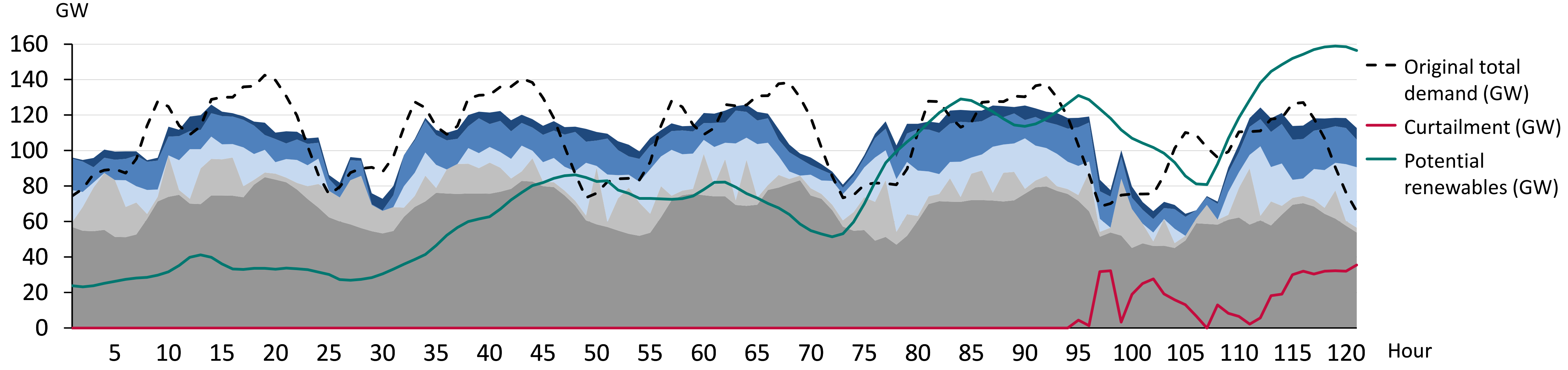
The graph starts from midnight on February 28th (hour 1392 of the year). The peak demand occurs in hour 61 of this graph (hour 1453 of the year); 12-1pm on March 2nd.

38% GSHP & heat batteries scenario (in 50% of homes): Demand profiles in week of final peak demand

Demand before load shifting



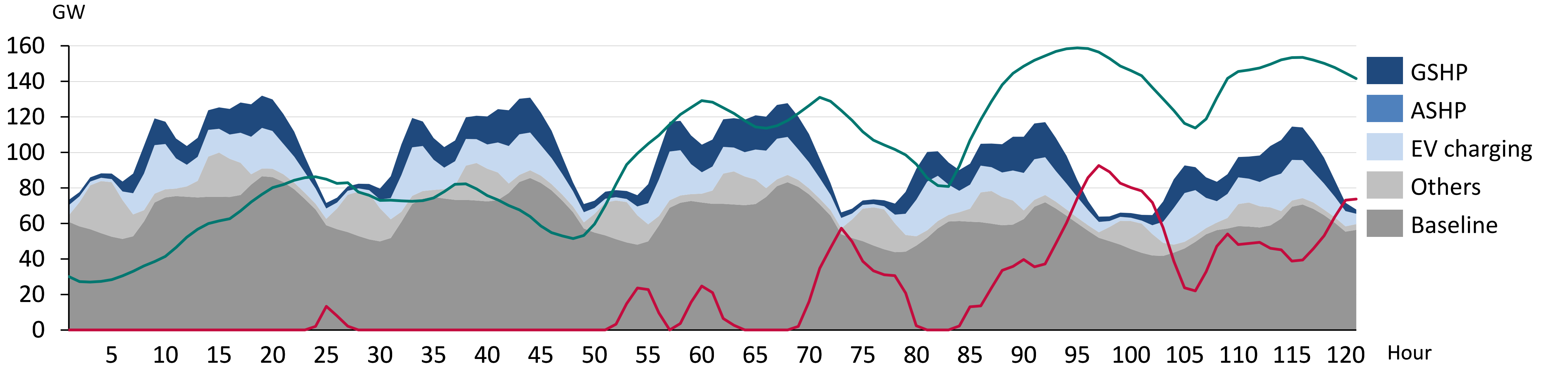
Demand after load shifting



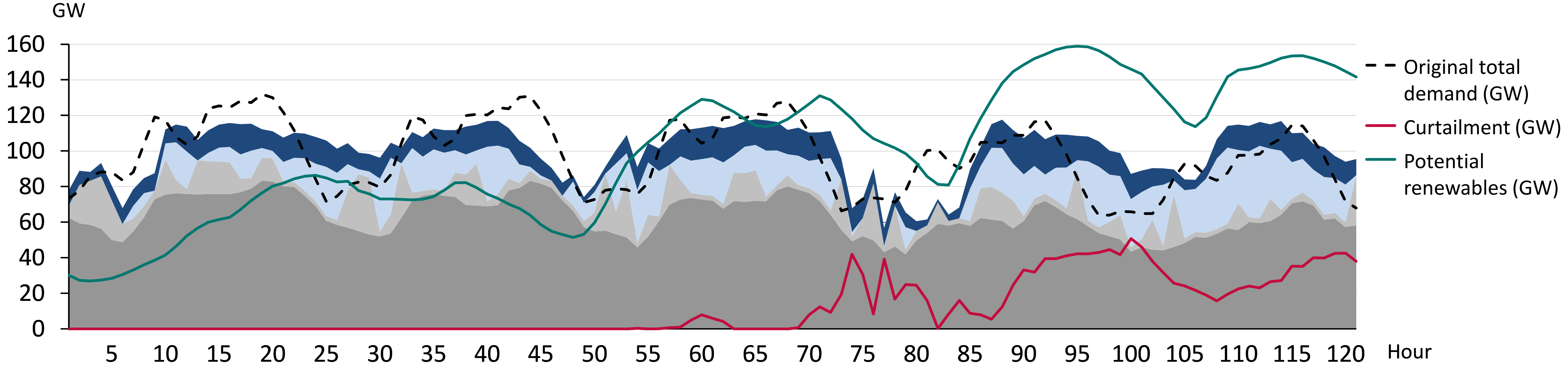
The graph starts from midnight on January 30th (hour 696 of the year). The peak demand occurs in hour 63 of this graph (hour 759 of the year); 2-3pm on February 1st.

100% GSHP & heat batteries scenario (in 50% of homes): Demand profiles in week of final peak demand

Demand before load shifting



Demand after load shifting



The graph starts from midnight on January 31th (hour 720 of the year). The peak demand occurs in hour 64 of this graph (hour 736 of the year); 3-4pm on February 2nd.