The electrification of the built environment and transport through the utilisation of multi-vector community energy systems

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Abstract

‘Electrify everything’ is considered an important strategy to achieve the net-zero carbon emission goal by 2050, eliminating carbon emissions if renewable energy technologies produce the electricity supply. The phenomenon, however, places a considerable power demand increase on the distribution networks. To ensure the security of electricity supply, an efficient energy system and energy demand reduction play a critical role. This research, focusing on the residential sector, delivered an electrified community model through domestic heating and road transport electrification. The electricity demands of an electrified community were investigated and then addressed using a designed multi-vector community energy system performing smart management measures. This community energy system could flatten the demand peaks, decrease electricity demand, integrate an electrified heating network, electricity grid and decentralised generation, and was demonstrated in three models.

Firstly, an electrified heating network model comprising a central ground source heat pump (GSHP), low-temperature district heating (LTDH) system, electric heaters and thermal storage, was established to measure the optimum distribution temperature. This heating network, when using a lower distribution temperature, reduced heat losses and increased the coefficient of performance (COP) of the GSHP. However, due to the hygiene requirement of domestic hot water (DHW) storage, the low-efficiency electric heaters were utilised to boost the storage temperature, which may result in greater overall electricity consumption. This research question was addressed using a scalable model that determined the optimum distribution temperature with the least electricity consumption. Secondly, an electrified community model illustrated hourly electricity demands and performances of a community energy system, which was then used to identify the required degree of housing thermal efficiency improvement (i.e., heating demand reduction). The demands included heating, electric vehicles (EVs) and Electricity (i.e., lighting and appliances). The third model assessed decentralised generation (DG) coupled with battery storage under various levels of housing thermal efficiency improvement. This model defined the installation criteria of DG that maintained the power demand below a targeted power.

The modelling result of the heating network indicated that the demand ratio of DHW to space heating (SH) determined the distribution temperature. In the context of buildings with higher thermal efficiency, a greater distribution temperature was enabled to reduce electricity demand. Furthermore, the electrification of a community increased the maximum electric power on the greatest demand day by over five times, converting heating demands into electricity directly. In contrast, a community energy system, applying an optimised heating

network, EV smart charging and community-scale peak shaving, could possibly reduce the increased peak demand to only a 33% increase. Besides, the result indicated that when the thermal efficiency in buildings was improved by around 70%, the existing distribution network was able to handle an electrified community. A thermal efficiency improvement lower than 70% required support from PV/storage units that offset the demand exceeding the targeted maximum power. This model of PV/storage units was validated through a 12-week assessment, showing the reliability of a community energy system. Ultimately, a modelling tool was developed based on the mentioned models, providing four pathways to attain electrification. Users can adjust specific parameters and databases to align with the local conditions. The results indicated the electricity demands in the highest consumption period, requirements of building a community energy system and investment costs of an electrified community.

In conclusion, this research designed an efficient community energy system that reduced the electricity demand significantly. When accompanied by building performance improvement, this energy system enabled the existing distribution network to accommodate an electrified community. Moreover, the developed modelling tool, flexible with various climates, can guide the government or planner on developing electrified communities.

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Table of Contents

List of Figures

List of Tables

Nomenclature

List of Acronyms

1G: first generation

2G: second generation

3G: third generation

4GDH: fourth generation district heating

ASHP: air source heat pump

AC: alternating current

ADMD: After Diversity Maximum Demand

CO_2: carbon dioxide

CCC: Committee on Climate Change

CHP: combined heat and power

COP: coefficient of performance

CPCs: compound parabolic collectors

c-Si: crystalline silicon

DC: direct current

DG: decentralised generation

DER: distributed energy resource

DHW: domestic hot water

EFC: The number of equivalent full cycles

EPC: Energy Performance Certification

ETCs: evacuated tube collectors

EVs: electric vehicles

FPCs: flat plate collectors

GHG: greenhouse gas

GSHP: Ground source heat pump

HIU: heat interface unit

HPs: heat pumps

HS: heat station

HES: household electricity survey

ICE: Internal combustion engine

LCL: Low carbon London

LTDH: Low-temperature district heating

Li-ion: Lithium-ion

LV: low voltage

MES: Multi-energy system

NTS: National Travel Survey

NOCT: normal operation cell temperature

NTE: nominal terrestrial environment

PV: photovoltaic

SH: space heating

SoC: state of charge

TES: thermal energy storage

UNFCCC: United Nations Framework Convention on Climate Change

V2G: vehicle-to-grid

VPPs: Virtual Power Plants

VBA: Visual Basic for Applications

WtE: Waste-to-Energy

Chapter 1

Introduction

1.1. Overview of decarbonisation policies

Sustainability denotes three interrelated pillars: Economy, Society and Environment. This embodies the responsibility to maintain an ongoing development of the economy whilst ensuring people's welfare and protecting the natural resources of our planet. However, sustainability is nowadays far from being attained due to the significant use of fossil fuel, which emits a considerable amount of greenhouse gas (GHG) and results in climate change. To address this issue, the Climate Change Act 2008 introduced by the UK government legally set the target of decreasing the carbon emissions by at least 80% of 1990 levels by 2050 [1-3]. The target defined as carbon budgets constrains the amount of GHG that the UK can legally emit in a five-year period [4], presented in Table 1-1. Besides, the Paris Agreement which took effect in 2016 aims to strengthen the global response to the threat of climate change to keep the increase in temperature well below 2°C and even further to 1.5°C this century, as announced by United Nations Framework Convention on Climate Change (UNFCCC) [5].

Table 1-1: Carbon budgets [6].

Budget	Carbon budget level (cumulative)	Reduction below 1990 levels
1st carbon budget (2008 to 2012)	3,018 $MtCO_2e$	25%
2nd carbon budget (2013 to 2017)	2,782 $MtCO_2e$	31%
3rd carbon budget (2018 to 2022)	2,544 $MtCO_2e$	37% by 2020
4th carbon budget (2023 to 2027)	1,950 $MtCO_2e$	51% by 2025
5th carbon budget (2028 to 2032)	1,725 $MtCO_2e$	57% by 2030

A 2018 progress report published by the Committee on Climate Change (CCC) disclosed the significant achievement in tackling the environmental issues of GHG emissions that have reduced by around 43% since 1990 [4]. The report also indicated that this high carbon emission reduction was mainly contributed by the power sector, which pointed out the failure of decarbonisation in other sectors such as transport, industry and buildings [4]. A look at the historic data shown in Figure 1-1 suggests that the power sector accounts for 75% of total GHG emission reduction since 2012.

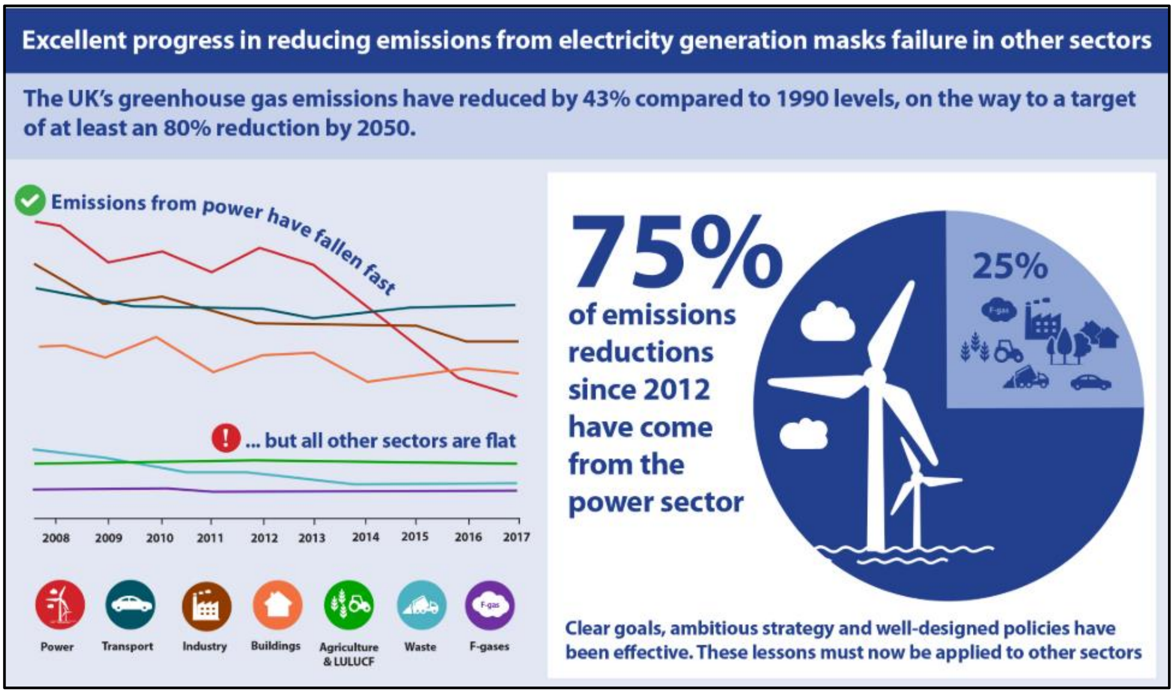

Figure 1-1: The reduction of GHG emissions in the UK [7].

To plan a holistic decarbonisation policy in response to the ambition of the Paris agreement, the UK government requested advice from CCC in 2018. The official advice published in 2019 suggested that the UK should reach a net-zero emission goal by 2050 [8]. Net-zero is considered as a more comprehensive goal that will put the UK at the top of the pile in comparison with other zero-emission goals, according to the CCC announcement [9, 10]:

> ‘By reducing emissions produced in the UK to zero, we also end our contribution to rising global temperatures...but it is essential that the commitment is comprehensive, achieved without use of international credits and covering international aviation and shipping.’

With respect to the financial aspect, the cost of key technologies such as photovoltaic (PV) modules, wind energy systems, electric vehicles (EVs) and Li-ion batteries has decreased rapidly due to the mass deployment [8].

Accordingly, net-zero carbon emission goal is achievable with an annual resource cost within 1-2% of GDP to 2050, which is the same cost as the aim of an 80% reduction of 1990 levels [8]. Based on the recommendation from the CCC, the government, then, passed laws in 2019 to bring all GHG emissions to net zero by 2050.

1.2. Overview of multi-vector energy systems

Power generations that utilise solar and wind systems are predicted to be the mainstream for carbon emission reduction [11]. However, these stochastic energy sources induce a high level of uncertainty to electricity supply networks [12]. To reduce the uncertainty of renewable power generation and improve the stability of electricity grids, the integration of energy supply, demand and storage as a multi-vector energy system is growing importance and ultimately will determine the penetration level of renewable energy resources [13].

A multi-vector energy system can manage both demands (e.g. heating, transport, electricity, etc.) and generations (solar, wind, gas, etc.) at various geography levels (e.g. community, city, region, etc.) by creating interactions between various energy forms, thus, boosting the flexibility and efficiency for the grids as smart grids [14]. The interactions are made by energy conversion units which, for example, can be a combined heat and power (CHP) system that converts gas into electricity and heat simultaneously for a greater energy efficiency [13]. The produced electricity and heat are either delivered to the consumer side for instantaneous demands or stored in electricity and thermal storage units for later use. Furthermore, by converting energy into different forms, renewable resources can be stored for a longer time, thereby increasing their utilisation in energy supply networks. For instance, wind power plants can convert their electricity production into hydrogen for long-term storage. This can mitigate the seasonal production gap [15, 16].

Overall, the benefits of multi-vector energy systems lie in:

- Increasing the conversion efficiency: A CHP system by capturing low-grade waste heat has a greater energy efficiency of around 70%, compared to a 40% efficiency with thermal power generation [17].
- Providing the flexibility of energy systems: Energy conversion units convert energy into different forms for various usages. For instance, heat pumps (HPs) consume electricity to produce heat [13].
- Facilitating the penetration of renewable energy resources: By utilising energy storage units, renewable energy resources can be stored for days or months and fed into grids later with consumers' needs [18].
- Optimising the centralised and decentralised energy grids: Energy systems at various scales such as building, community and region can be integrated as active loads for national scale optimisation.

1.3. Research aims and objectives

'Electrify everything' in this analysis was the solution that attains net-zero GHG emissions by 2050. The aim was to design a scalable, versatile and efficient multi-vector community energy system to manage the supply and demand of an electrified community. To reduce the increased electricity demand within this distribution network and improve the efficiency of decarbonisation, this community energy system must carry out smart control solutions. This research demonstrated the community energy system through three models, including an electrified heating network, an electrified community and decentralisation generation. The modelling works employed the conditions in an average UK dwelling and were validated by utilising a commercial software energyPRO [19]. Subsequently, a modelling tool was developed using Visual Basic for Applications (VBA) code, indicating detailed requirements of establishing community energy systems at various geographical locations.

The key objectives addressed in detail were:

An electrified heating network model (Chapter 5):

1. Establishing a scalable model that can evaluate electricity consumption under various supply temperatures, thereby defining the optimum condition to decrease the power demand. This model can also indicate the tendency of the optimum distribution temperature with the growing thermal efficiency in buildings.

An electrified community model (Chapter 6):

2. Investigating electricity demands of an electrified community, which will be illustrated in an hour-by-hour form for the evaluation with the typical UK distribution network.

3. Applying smart management measures within a community energy system to control the electric power flows in an electrified community model. The performance of a community energy system will be compared with the applications of electric heaters and air source heat pumps (ASHP).

4. Estimating a required degree of housing thermal efficiency improvement, decreasing domestic space heating (SH) demand. This approach will enable the existing distribution network to handle an electrified community.

A decentralised generation (DG) model (Chapter 7):

5. Defining installation criteria of DG coupled with electricity storage, which offsets the electricity demand exceeding the maximum electric power within the electricity grid. This approach will connect with the improvement level of housing thermal efficiency and enable the existing distribution network to handle an electrified community.

A modelling tool of community energy systems (Chapter 8)

6. Establishing a modelling tool that analyses electric power demands in the highest consumption period (i.e., the coldest period), performs smart management measures, considers constraints of the distribution network, indicates capacities of generation and storage units and estimates the investment costs. This modelling tool will enable flexibility about community scale, amount of EVs, energy demands, geographical location, etc.

1.4. Thesis structure

Chapter 2 and 3, literature review, outline background information of designing a community energy system. The policy and analysis from National Grid are firstly depicted, followed by reviewing the effectiveness of the electrification of heating and transport. The system concepts and modelling concepts of multi-vector energy systems are thereafter addressed in detail. Subsequently, the key components including district heating, HPs, EVs and Lithium-ion (Li-ion) battery are elaborated.

Chapter 4, the development of a multi-vector community energy system, illustrates the system configuration of a designed community energy system. A heating network that utilises a system of low-temperature district heating (LTDH) is provided. Besides, core principles such as the community-scale peak shaving, electricity flow management, data control protocol and relation between smart grids are indicated.

Chapter 5, establishing an electrified heating network, defines heat distribution, heat generation and storage units. To measure the optimum operation temperature of an electrified heating network, a systematic modelling approach that evaluates electricity consumptions at various distribution water temperatures is elaborated. In comparison with the conventional way to determine an operation temperature, mainly by assessing heat losses, the systematic modelling approach factors in both the heat losses and the efficiencies of electric heating devices.

Chapter 6, establishing an electrified community, indicates a community energy system that manages electric power flows of an electrified community. Electricity demands covering lighting, appliances, EVs and heat supply are discovered. The community scale is aligned with the typical UK distribution network for illustrating the impact of 100% electrification on the electricity grid. This chapter, moreover, applies smart charging of EVs, defines the capacity of a community battery to perform peak shaving, and proposes an ideal heating supply. Ultimately, the result is reflected in an improvement level of housing thermal efficiency. Therefore, an approach by which the existing distribution network can accommodate the electric power demand of an electrified community is indicated.

Chapter 7, the deployment of decentralised generation (DG), determines installation criteria of DG coupled with battery storage. Housing thermal efficiency defines the installed capacity of DG/storage in a community energy system. A lower level of the thermal efficiency requires greater capacities of DG/storage to maintain electricity consumption under the targeted maximum power. Moreover, based on a compliant model, this chapter demonstrates two optimisation approaches about the electrified heating network, thereby indicating an efficient way to improve the efficiency of this system further.

Chapter 8, the modelling tool of multi-vector community energy systems, introduces a designed modelling tool that indicates the requirements of establishing a community energy system, the hourly consumption power during the highest demand period and the investment costs. This modelling tool enables various parameters for adjustment; hence, users can evaluate an electrified community aligning to their geographical location, consumer behaviour and financial condition. The development flow of a multi-vector community energy system from Chapter 5 to Chapter 8 is summarised in Figure 1-2.

Chapter 9, discussion and conclusion, outlines important observations, addresses methods that can deliver 100% electrification, examines methods that meet the research objectives and presents future directions for improving the community energy system.

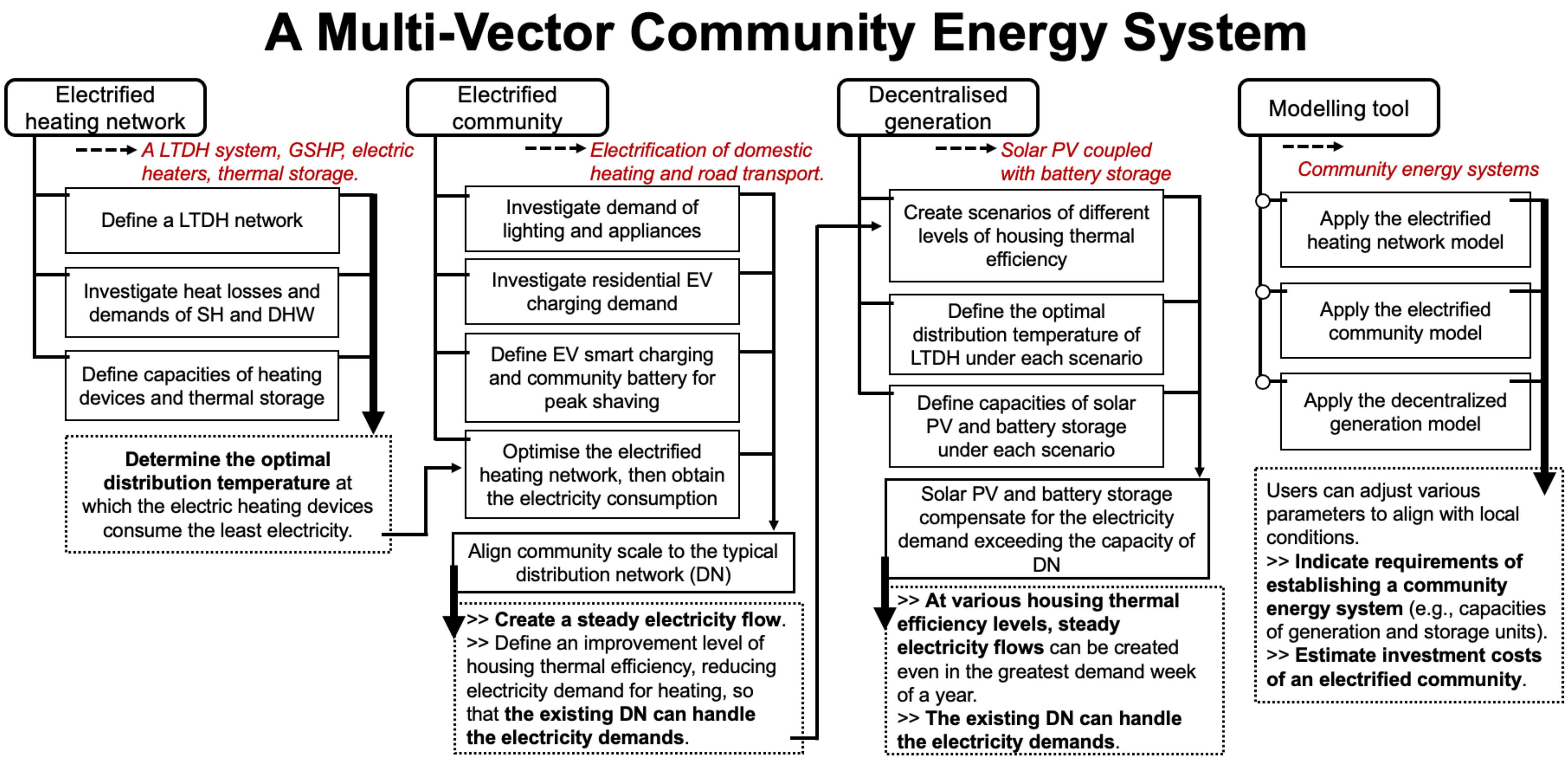

Figure 1-2: The development flow of a multi-vector community energy system.

Chapter 2

Literature Review: Development and Concepts of Energy Systems

This chapter depicts relevant strategies and concepts for establishing a multi-vector community energy system. In 2020, future energy scenarios published by National Grid ESO as the electricity system operator for Great Britain indicates [20]:

- The target of net-zero carbon emissions by 2050 is achievable.
- Hydrogen and carbon capture and storage are required to be implemented.
- Markets must support the investment in flexibility and zero carbon generation.
- Open data and digitalisation support the whole system to achieve net zero.

According to the 2050 scenarios [20], electricity and hydrogen are going to be the primary fuel for transport and heating. Furthermore, ‘efficiency’ is indicated to play a key role, for example, thermal efficiency in buildings that determines the progress of transferring natural gas to low carbon heating solutions, and efficiency of road transport through electric vehicles (EVs) that reduces the energy consumption of travel.

In this chapter, the development of the future electricity system in the UK is studied firstly. This is illustrated with electricity supply and decentralised generation in subsection 2.1. The electrification of transport and heating is the main topic in this research; hence, the effectiveness of adopting this approach to decrease greenhouse gas emissions is reviewed. The current policies of electrifying the transport sector through EVs and implementing electric heating using heat pumps (HPs) are presented. Besides, due to the significant increase in power demand, this chapter indicates the importance of smart control that mitigates detrimental impacts on electric power networks. These are in subsection 2.2.

The growing demand for electricity supply drives the need for various decentralised generations and efficient conversion technologies. Multi-vector energy systems are identified to play a key role in achieving better coordination and increasing their reliability [14]. In section 2.3, the system concepts of multi-vector energy systems interpreted in four different perspectives are introduced, which is followed by the depictions of a modelling concept titled Energy Hubs [21] and control approaches including Microgrids and Virtual Power Plants (VPPs) [14].

2.1. The development of the future electricity system

This section outlines the current status and the projection of the future electricity system in the UK, based on the Future Energy Scenarios 2020 [20]. The report addressed that the high penetration of heat pumps, electric vehicles and electrolysis will raise annual electricity demand significantly. To achieve the target of decarbonisation, power generation must use a vast quantity of stochastic renewable energy to satisfy the power demands, which requires substantial generation capacity to ensure stability. The electricity network safety norm is described as not greater than a 3-hour load loss expectation [20].

Figure 2-1 illustrates the installed electricity generation, storage and interconnection capacities in four scenarios. In 2050, the wind power (green colour), including offshore and onshore, has the largest installed capacity in all scenarios, followed by solar energy (yellow colour). Moreover, to mitigate the uncertainty induced by renewable power generation, the growing trend of storage technology (purple colour) is indicated. This large storage capacity consists of pump hydro, batteries (such as large scale, industrial and residential batteries), compressed air and liquid air storage. The scenario related to a more electrified future was named Consumer Transformation (CT) [20], which in comparison with the 2019 level, enlarged the total generation capacity by 2.8 times.

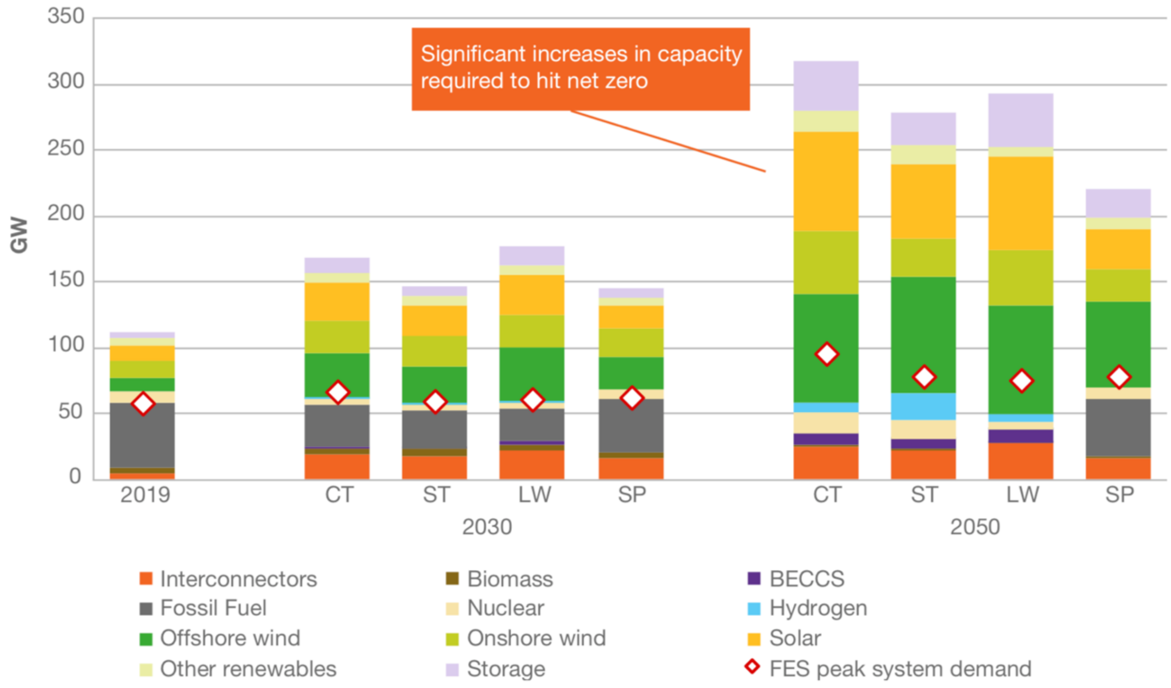

Figure 2-1: Installed electricity generation capacity, plus storage and interconnection in four scenarios, including CT: Consumer Transformation, ST: System Transformation, LW: Leading the Way, and SP: Steady Progression [22].

The report also indicated that power generation is experiencing a transformation from centralised plants to decentralised small-scale solar and wind energy systems [23]. The decentralisation of power generation, called distributed or decentralised generation, is defined as the electricity production within distribution networks or at consumer sides [24]. Figure 2-2 shows the degree of decentralisation, which indicates that up to 42% of the generation could be decentralised by 2050 in the scenario of Leading the Way (LW). This scenario involved a significant lifestyle change, compared to the CT scenario. Furthermore, the large proportion of offshore wind, presented in Figure 2-1, constrained the percentage of decentralised generation. The offshore wind, defined as transmission-connected generation, is linked with the high-voltage grid that includes 275 kV and 400 kV electricity lines [25].

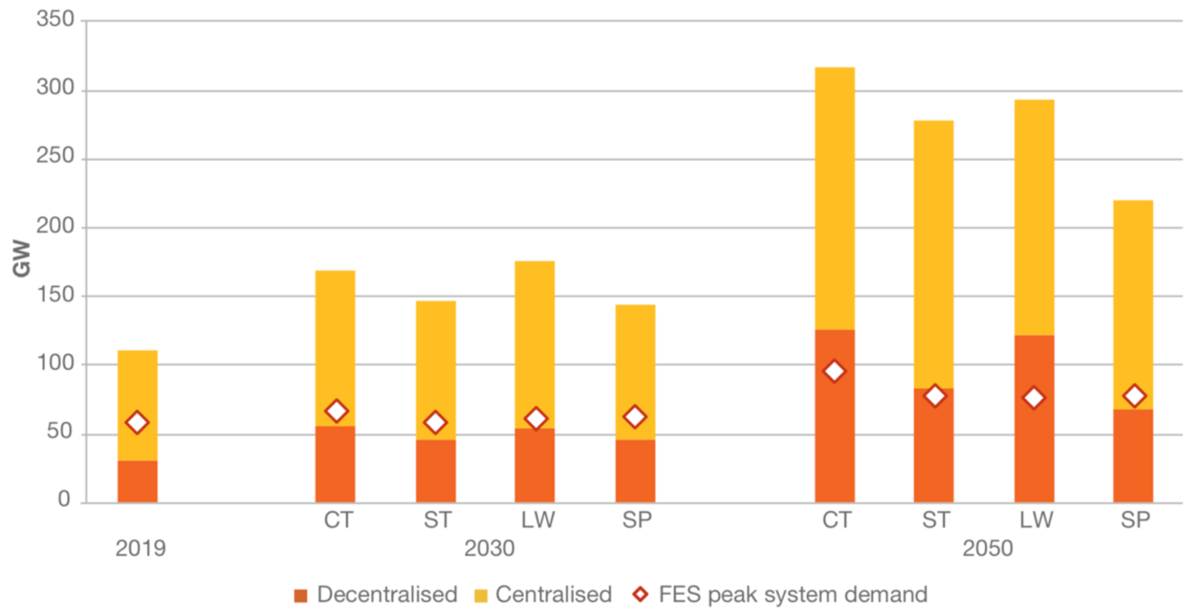

Figure 2-2: Connection location of installed power generation capacities. CT: Consumer Transformation, ST: System Transformation, LW: Leading the Way, and SP: Steady Progression [26].

This section depicted the significant increase in installed electricity generation capacity for decreasing the uncertainty induced by stochastic renewable resources. This implies a high cost of decarbonisation, which needs efficient energy systems to coordinate various types of renewable technologies and subsequently make carbon emission reduction more attainable. In addition, the greater degree of decentralised generation from the installation of small-scale renewable energy systems indicates that the role of the transmission system will be more likely to deliver electricity from a distribution network to another, instead of conveying electricity from transmission connected generation to distribution networks today [20]. This means smaller-scale electricity systems will be essential to optimise the local generations, thereby strengthening the coordination between distribution networks to increase the stability of the national grid supply.

2.2. Electrification of heating and transport

The last section illustrated the correlation between the growing electricity demand and the development of electricity systems. This section discusses the effectiveness of using this electrification approach to decrease carbon emissions, addresses the utilisation of EVs and HPs to achieve the electrified scenario and introduces a method to manage the EVs and HPs.

2.2.1. Overview of electrification of heating and transport

In 2019, the transport sector emitted the most carbon dioxide (CO_2) in the UK, followed by the energy supply and residential sectors [27]. The transport sector, especially road transport, was responsible for 34% of all the emissions. The residential sector accounted for 19%, and around 80% of the residential energy consumption was consumed by domestic space heating (SH) and domestic hot water (DHW) [28].

To reduce the emissions, electrification of road transport and heat generation is regarded as a feasible and successful approach [29, 30]. According to a review of 22 scenarios in 12 studies in Germany [31], Figure 2-3 illustrates the electricity demands related to heating and road transport of each research that represents the electrification levels. The result, including industrial heat (left figure), indicates that a higher heating and transport electrification level can achieve a greater level of GHG emission reduction. Furthermore, when the data excludes industrial heat (right figure), the impact of electrified heat supply on GHG mitigation is reduced. Accordingly, in the industry sector, electrified heat supply plays a vital role in alleviating GHG emissions.

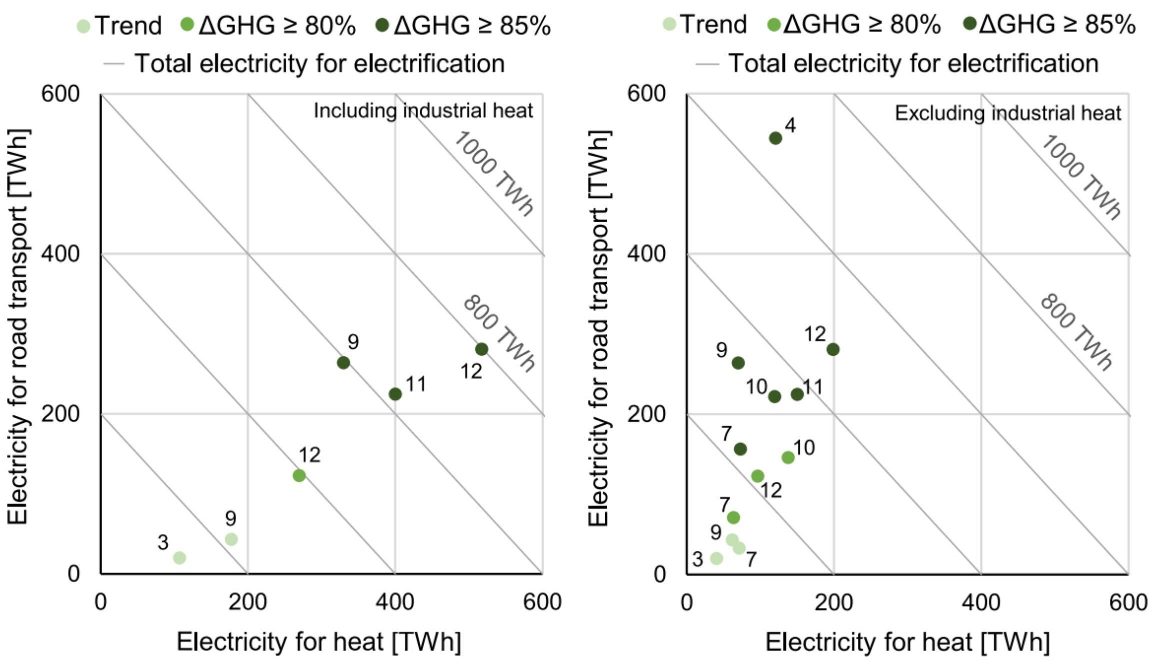

Figure 2-3: Electricity consumptions of heat and road transport include (left) and exclude (right) heat for industrial processes. The points are labelled with the study numbers from reviewed articles [32].

In the same paper [31], Figure 2-4 presents the heating supply from electric heaters and HPs within the 12 studies. The result shows that the electrification of heating in buildings will be dominated by HPs, reflecting a share varying from 75% to 27%. On the other hand, the primary heat generation units for industrial processes are low-efficiency electric heaters, which implies the need for high-temperature HPs or hydrogen-fuelled combined heat and power (CHP) to minimise the electricity demand and facilitate GHG emission reduction.

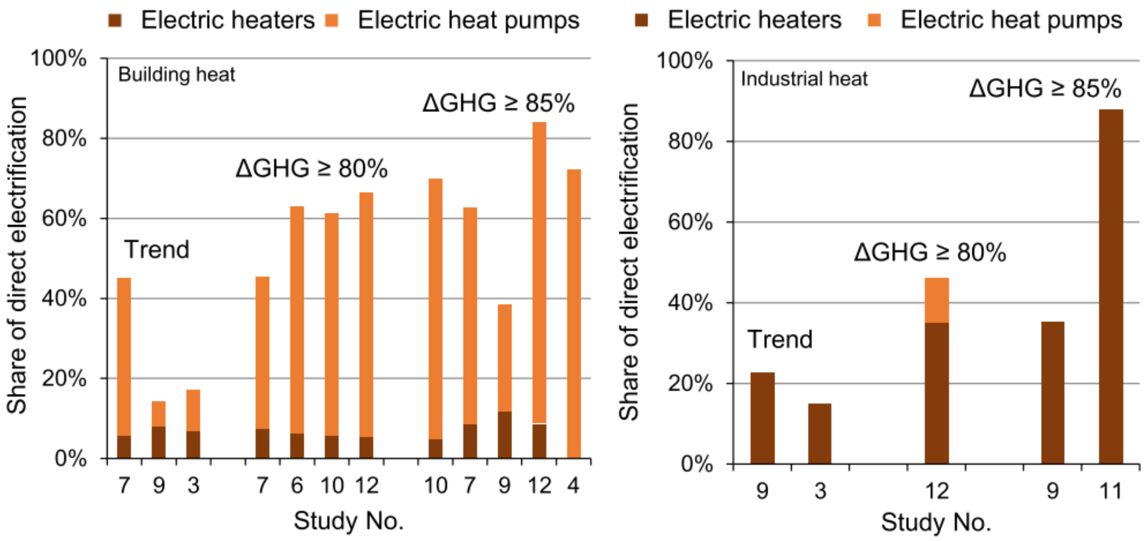

Figure 2-4: Share of electric heaters and heat pumps in building heat (left) and industrial heat (right) [33].

In the UK, electrification of heating and transport has become a common theme to decrease carbon emissions [34, 35]. The biggest challenge is the substantial electricity demand on the delivery of electrified heat supply. A study indicated that peak heating demands can be six times greater than the peak power on the electricity grid, estimated by the heating power supplied by gas networks [34]. Apart from the increased peak power, Figure 2-5 illustrates the historical and projected seasonal electricity consumption. Compared with the 2015 level, the demand gap between summer and winter is predicted to be increased by almost three times, reaching 35 TWh in 2030. This significant consumption gap is about the large demand difference in SH.

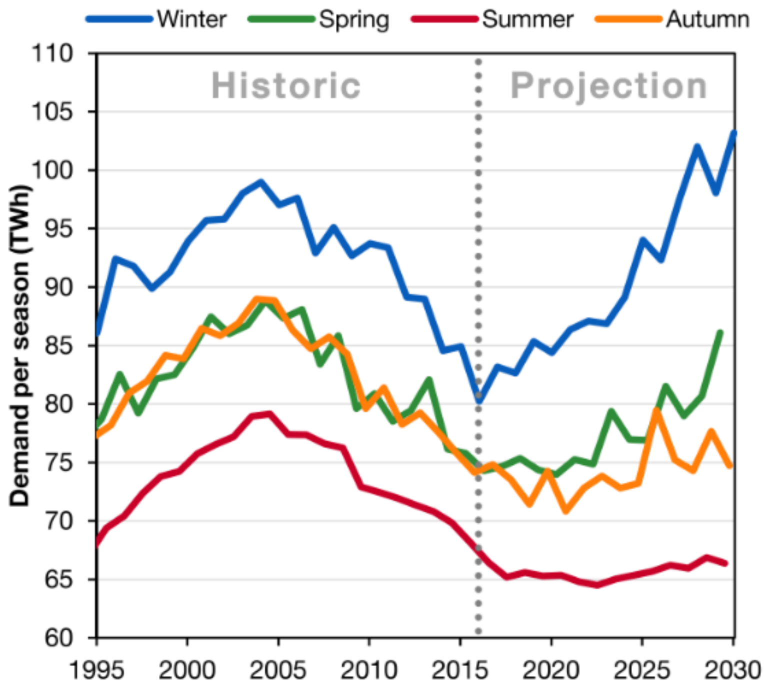

Figure 2-5: The historic evolution and projection of total electricity demand over each season [36].

This subsection indicated that adopting electrification of heating and transport effectively decreased carbon emissions. Theoretically, electrification can eliminate carbon emissions when it attains the degree of 100% using renewable power generations. On this occasion, the electricity demand will be enormous, mainly caused by heat electrification. The following section will point out the policy and feasibility of implementing EVs and HPs for electrifying the transport and heating sectors.

2.2.2. Electric vehicles and heat pumps

To reduce carbon emissions in the road transport sector, the UK government has announced that the sale of diesel, petrol and hybrid cars will be banned from 2035 [37]. Electric vehicles, therefore, are expected to be the primary technology. The number of EVs in the UK may be required to grow from the current 230,000 to 39 million by 2050 [38]. In terms of energy demand, utilising efficient EVs to travel can reduce energy consumption by around 75% by 2050 [20].

In a financial aspect, a projection from the CCC indicated that the lifetime costs of EVs will achieve parity with internal combustion engine (ICE) cars by the mid-2020s because of the rapid reduction in battery costs [39].

Furthermore, by comparing two phase-out plans of ICE cars, Figure 2-6 presents that the 2030 phase-out plan is more profitable than the 2040 phase-out. The net cost of the 2030 phase-out starts being lower than the 2040 plan in 2028, which is mainly contributed by the less high price of EVs and fewer charging infrastructure requirements. (This assessment factors in the upfront vehicle cost, refuelling cost, costs of charging infrastructure, power generation and network reinforcement.) A detailed discussion of EVs such as charger types, charging behaviour and charging demand is presented in section 3.3.

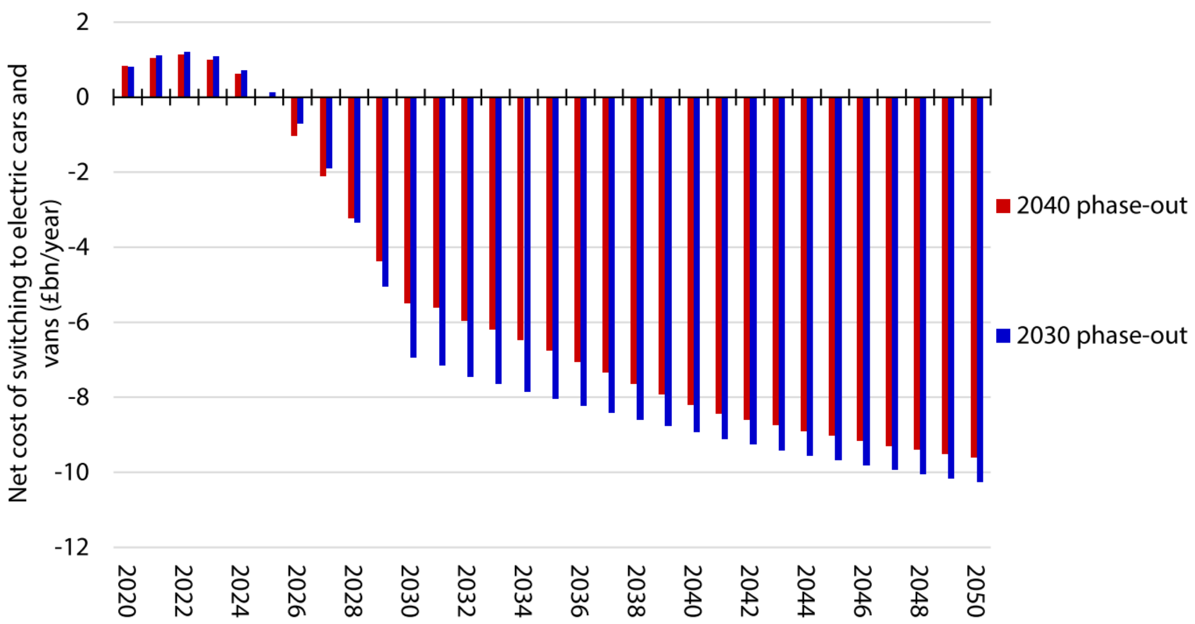

Figure 2-6: The 2030 and 2040 switchover to EVs plans are compared based on net cost assessment [40].

In highly electrified scenarios, HPs that can convert electricity into heat with remarkable efficiency dominate the supply of heating demands in buildings [41]. A study that carried out the impact on transferring gas to an electrical network for heating consumption is shown in Figure 2-7. The non-daily metered (NDM) gas demand indicated by the blue region is related to the consumptions of private, small-scale enterprises and a proportion of public administration, commercial, agricultural and some industrial facilities [42]. This gas usage is reduced by 30% that is converted to electricity consumption.

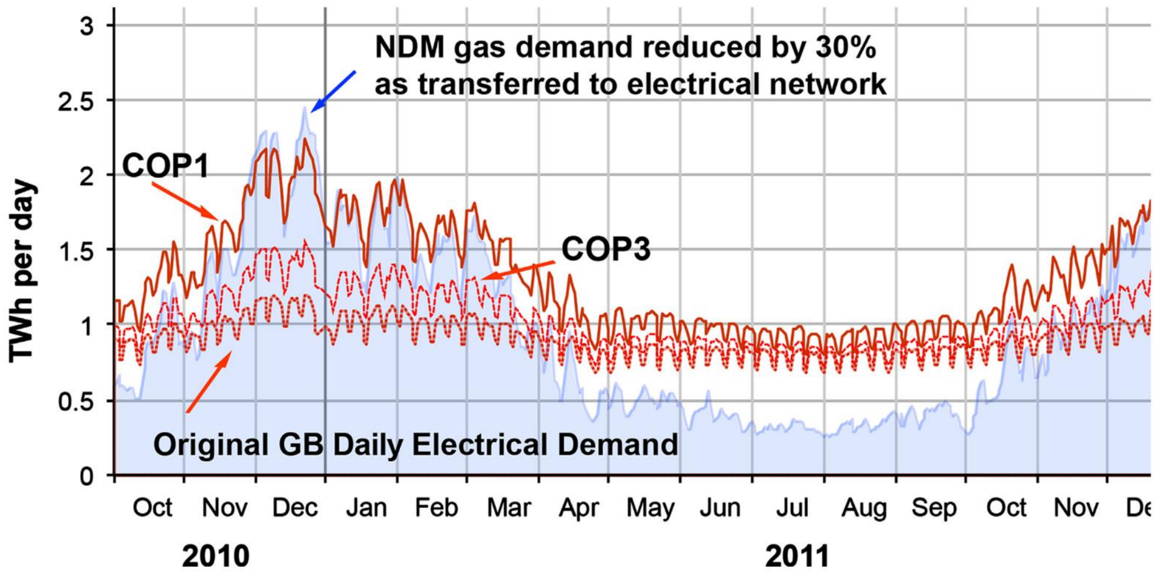

Figure 2-7: Transfer of heat and hot water demands from gas to electrical network [43].

In Figure 2-7, utilising resistive heaters having a coefficient of performance (COP) of 1 to supply the heating demand from the reduced gas usage is illustrated in a line curve. The electric heaters increase the daily power consumption by almost two times during the winter months, compared to the original electricity demand. On the other hand, the condition employing HPs as an alternative performs a COP of 3. Nevertheless, the daily electricity consumption is still increased by around 25% in high demand periods. As these simulation results are presented in everyday use, the instantaneous power demand is predicted to be more significant [42].

To mitigate the impacts of the substantial penetration of HPs on the electricity grid, ‘future energy scenarios’ published in 2020 indicated that 40% of homes will use thermal storage to support heating by 2050 [20]. The storage capacity per household was assumed to be around 8 kWh, which provides heating demand between two and four hours on a peak winter’s day [20].

This section showed the analysis result of EVs and then concluded that EVs would be competitive in financial respect, compared to ICE cars. Also, the growing adoption of HPs indicated the need for support from thermal storage. The next section will introduce a control method for managing the demands of EVs and HPs.

2.2.3. Smart control of EVs and HPs

Smart control of EVs and HPs is essential to alleviate the consumption peak and prevent potential faults in electricity systems. In Figure 2-8 and Figure 2-9, a study illustrates the effectiveness of applying smart control on a cold winter day. The penetration of EVs and HPs is assumed to be 100%, which gives rise to a 52% daily demand increase. In the non-optimised case (Figure 2-8), the peak demand is increased by 92% that comprises a 36% increase for EVs and a 56% increase for HPs. In contrast, by implementing smart charging of EVs and HPs (Figure 2-9), the electricity consumption profile can be steady throughout a day, which results in the peak demand of only a 29% increase [44].

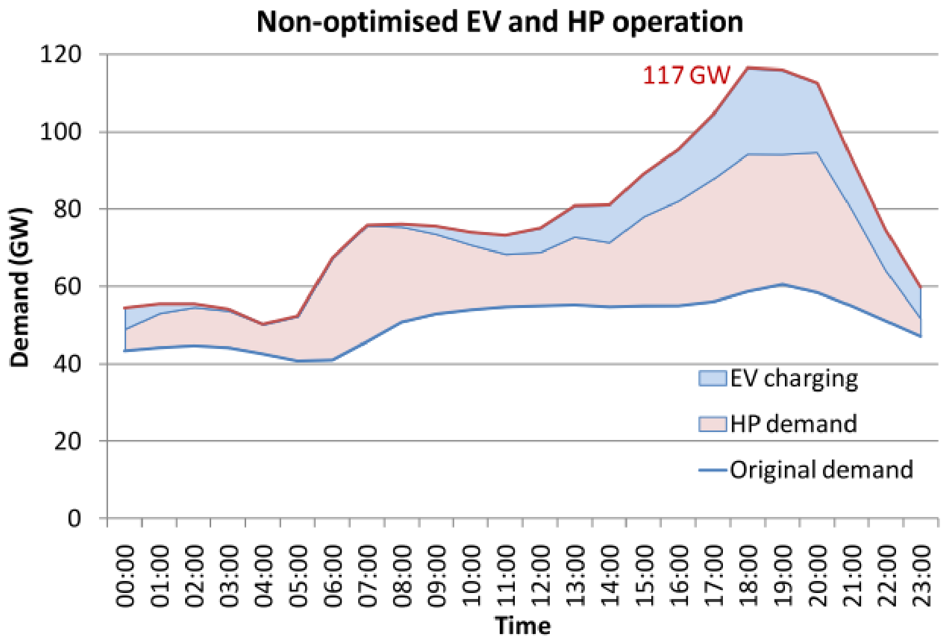

Figure 2-8: EV charging and HP operation in a non-optimised case [44].

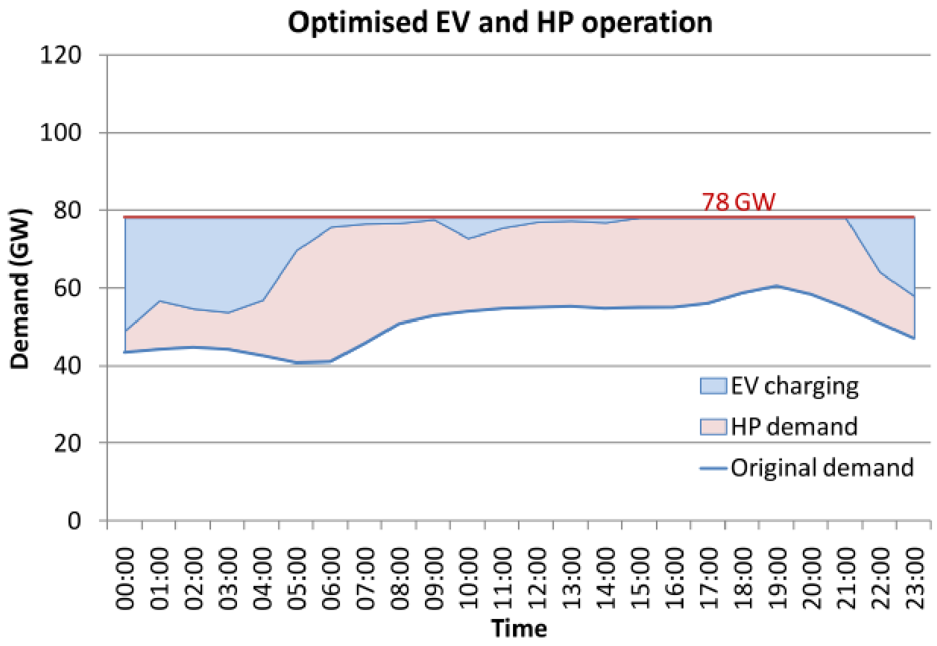

Figure 2-9: EV charging and HP operation in a Smart control case [44].

To indicate the impact of optimised (i.e., smart control) and non-optimised approaches on distribution networks, the percentages of overloaded distribution transformers and reinforced LV feeders in various penetration levels of EVs and HPs were illustrated in Figure 2-10 and Figure 2-11, respectively [44]. The percentage of overloaded transformers shows that the optimised (smart) and non-optimised (BaU) approaches have a considerable difference in the penetration levels of 25% and 50%. However, when the penetration levels reach equal or over 75%, the percentage difference in the two approaches is reduced due to the significant increase in electricity demand. Nonetheless, the power rating of the transformers is expected to be considerably lower for the optimised than for the non-optimised approach. On the other hand, for the reinforced LV feeders (Figure 2-11), the optimised approach presents a lower percentage in each penetration level.

In conclusion, this study indicates the reinforcement within distribution networks is necessary to accommodate the uptake of EVs and HPs, especially on transformers. Furthermore, smart control approaches can effectively reduce the amount of reinforcement on distribution networks.

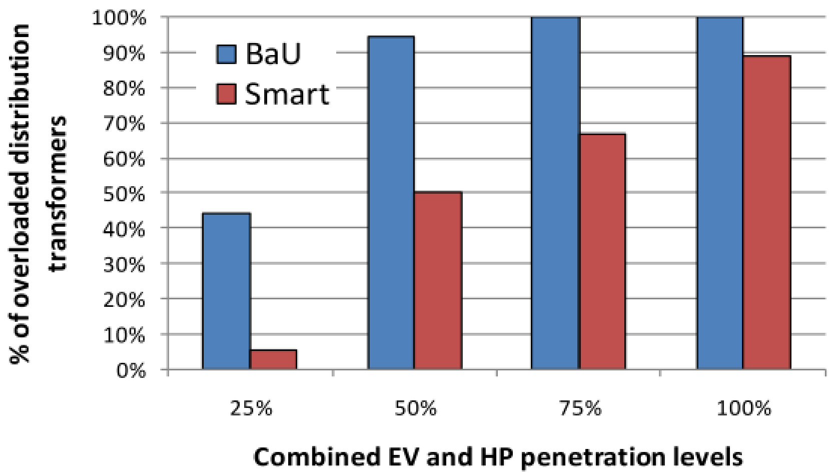

Figure 2-10: Percentage of overloaded distribution transformers, BaU means the non-optimised case [44].

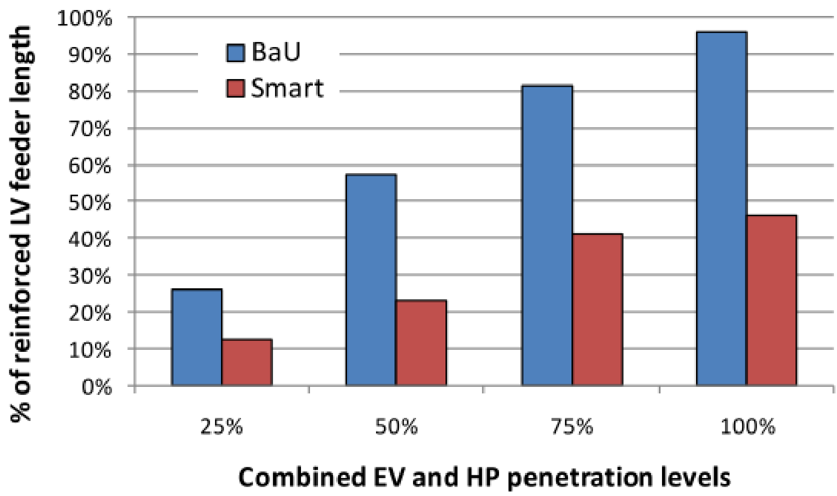

Figure 2-11: Percentage of reinforced LV feeder length, BaU means the non-optimised case [44].

2.3. Multi-vector energy systems

The previous section illustrated strategies and knowledge about the electrification of heating and transport. This section elaborates the concepts of multi-vector energy systems that are the fundamental knowledge for developing community energy systems to progress the electrification.

2.3.1 System concepts

Multi-vector energy systems can be interpreted in the spatial perspective, multi-service perspective, multi-fuel perspective and network perspective [14]. The spatial perspective illustrated in Figure 2-12 indicates the connections between different scales of energy systems. In the smallest block (i.e., the building-level), energy fuels such as natural gas and electricity are received to satisfy the demands of ventilation, heating and appliances. The system can also, for example, utilise PV generation to provide its electricity consumption or deliver the surplus electricity to electric power networks. On a district level, buildings can be linked up by district heating/cooling systems, which may receive energy from a CHP or HP. This concept can be extended to create interactions between cities, regions, and even nations [14].

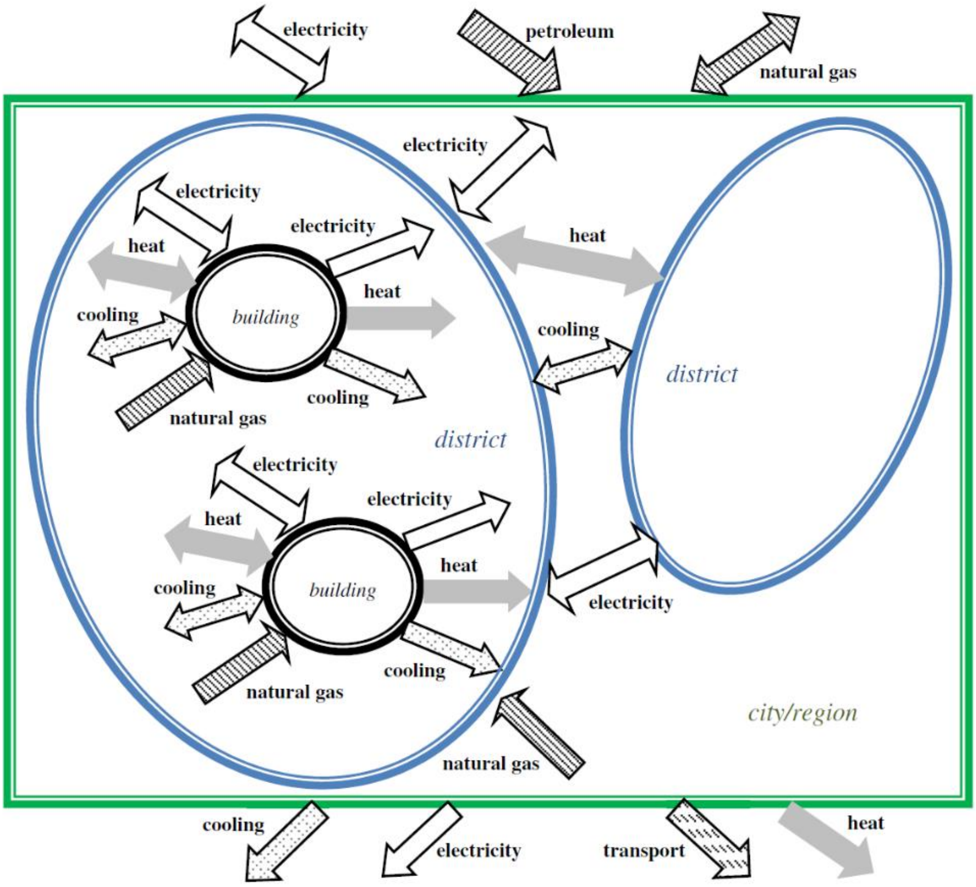

Figure 2-12: The spatial perspective concept [45].

The multi-service perspective, also viewed as a multi-generation concept, considers that an energy system is a platform supplying various applications, shown in Figure 2-13. This concept expects a high energy efficiency that leads to considerable benefits of economy and environment. A CHP is the simplest example of cogeneration, which simultaneously generates power and catches the process heat for thermal demands rather than turning the process heat into waste. According to the statistical data in the UK, the aggregate CHP efficiency can reach 70%, which is a considerable improvement in comparison with a 40% efficiency of the aggregate thermal power generation [17]. The multi-generation concept can also be utilised to produce hydrogen, water, chemicals, and so on [46]. This increases the variety and application of an energy system. For instance, the production of hydrogen provides another way to low carbon transport and long-term energy storage.

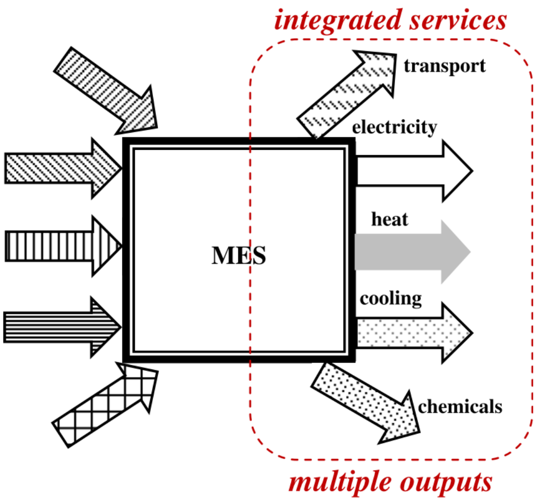

Figure 2-13: The multi-service perspective concept [47].

The multi-fuel perspective indicates that various fuels can be input to energy systems and then converted into specific forms for end-users. Figure 2-14 is an example that uses solar radiation, fuels such as natural gas, hydrogen, etc., and electricity from the electricity grid as the energy sources for the system. The energy forms on the consumer side are electricity and heat. In Figure 2-14, the electricity generated by the PV array and cogeneration unit can supply the demands of appliances and lighting and be stored in the battery for later use. Waste heat from the cogeneration unit supplies heating demands of SH and DHW. The cogeneration unit can be extended to provide cooling demand when an absorption chiller is installed, and then become a trigeneration system.

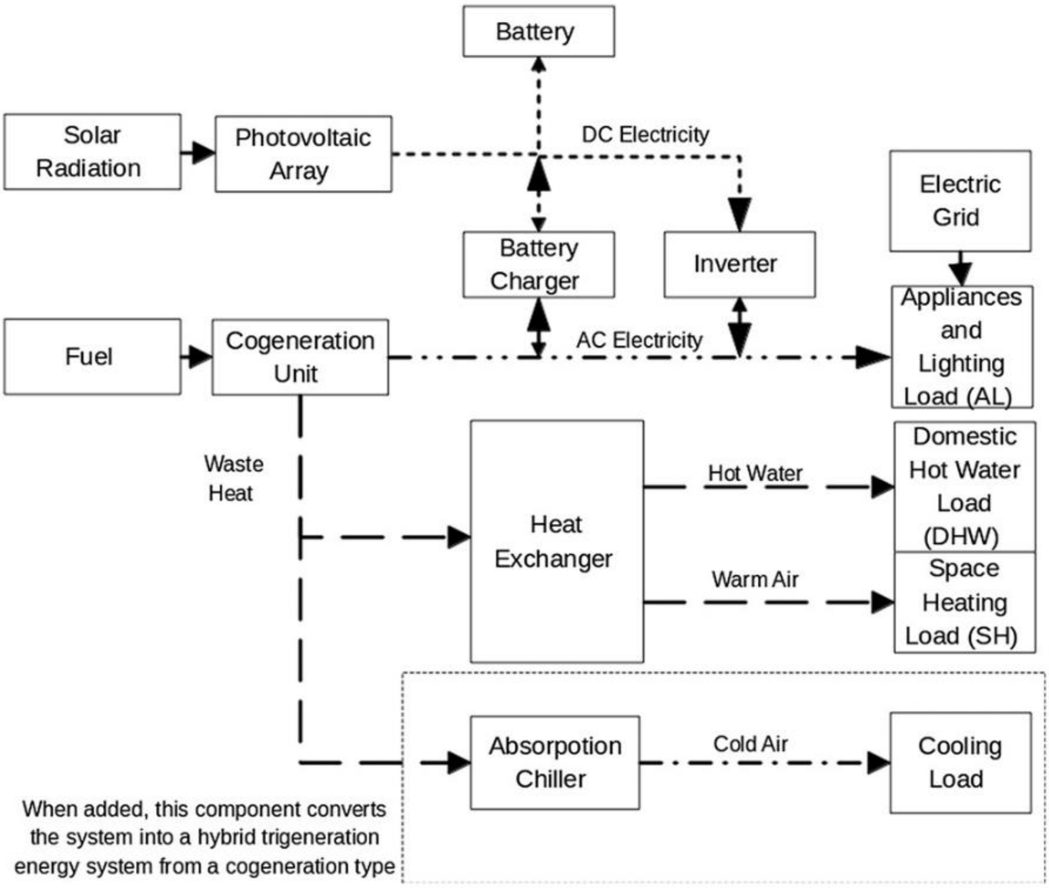

Figure 2-14: Energy distribution of a PV co-generation/tri-generation system; an example of the multi-fuel perspective concept [48].

The network perspective concept shown in Figure 2-15 discusses the interconnections between multi-vector energy systems through different energy forms. Basically, each energy system is viewed as a component that can be modelled and optimised with various geographical levels, consumption forms, and supply fuels. By assembling the energy systems to compose an energy network can facilitate the interactions within internal and external networks, thereby providing a great management approach to smart cities that are highly digital and electrified.

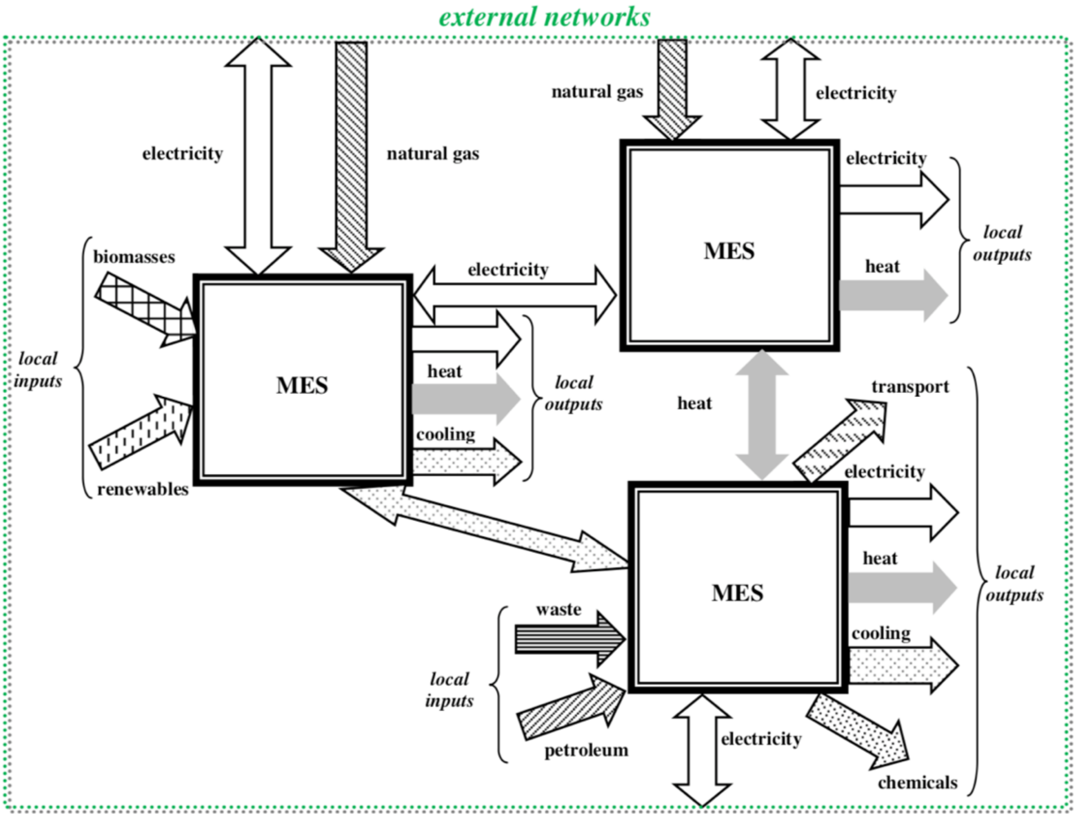

Figure 2-15 The network perspective concept [49].

2.3.2 Modelling concept and control approaches

This subsection introduces a modelling concept Energy Hubs and control approaches including Microgrids and Virtual Power Plants (VPPs) [14]. The Energy Hubs concept is proposed to optimise power flows of different energy carriers according to the perspective of input-output, especially at a district level [50]. Figure 2-16 is a schematic layout of an energy hub. The red dash box is the hub that simulates the energy conversion (i.e., the power to gas, heat pump, CHP and boiler) and storage units (i.e., battery, thermal store and gas tank), which integrates the inputs (i.e., electric power and natural gas) and distributes the outputs (i.e., electricity, heat and gas) to end-users [50]. Using this definition of an energy hub, it is possible to decide the optimal sizes of energy generation and storage units and the optimal relations between various energy systems, thus controlling supply and demand at the lowest expense.

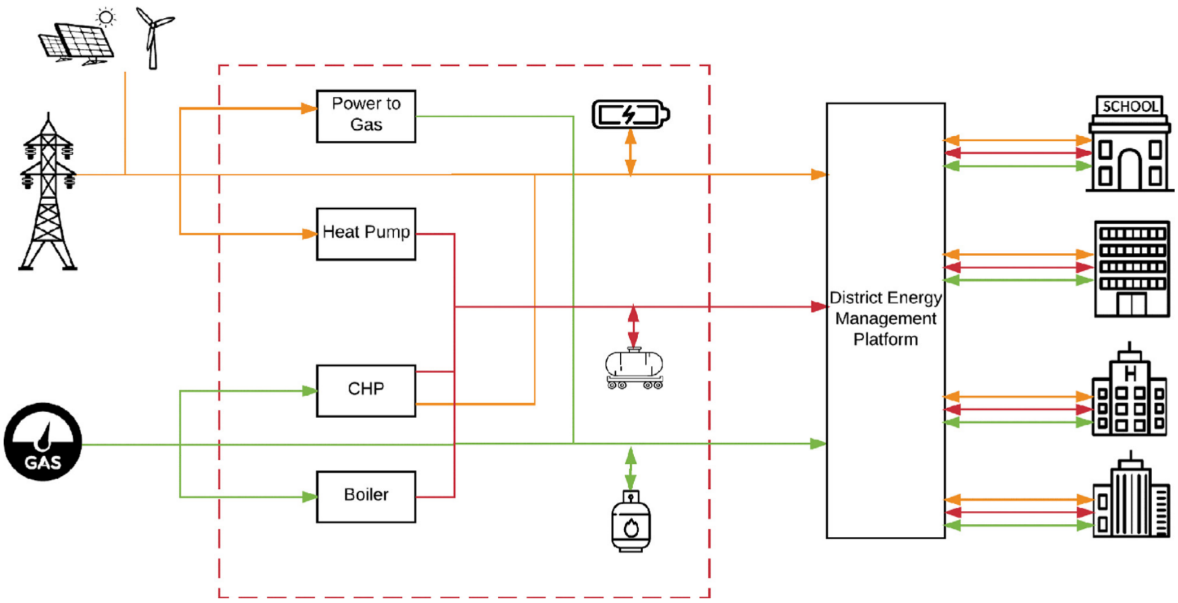

Figure 2-16: The layout of a multi-vector energy hub (yellow, red and green lines indicate electricity, heat and gas respectively) [51].

Microgrids can be defined as a control approach within distribution networks, which not only optimises distributed energy resources (DERs) but also responds to the central power systems [14]. Figure 2-17 illustrates a control configuration of a microgrid that is viewed as a cell on the electric power network. DERs such as the controllable loads, micro-CHP, PV, fuel cell, storage units, and so on are coordinated and optimised by the microgrid central controller (MGCC).

A microgrid can function in two operation modes that are grid-connected and islanded. In a grid-connected mode, the MGCC as the centre of the cell interacts with external systems, for instance, other cells (i.e., microgrids) and power networks. Accordingly, power system operators can monitor and maintain the balance between microgrids. To an islanded mode, the mismatch between the stochastic renewable power generation and uneven demand load induces the challenge of voltage regulation. Energy storage units, in this case, play a critical role in ensuring network stability [52].

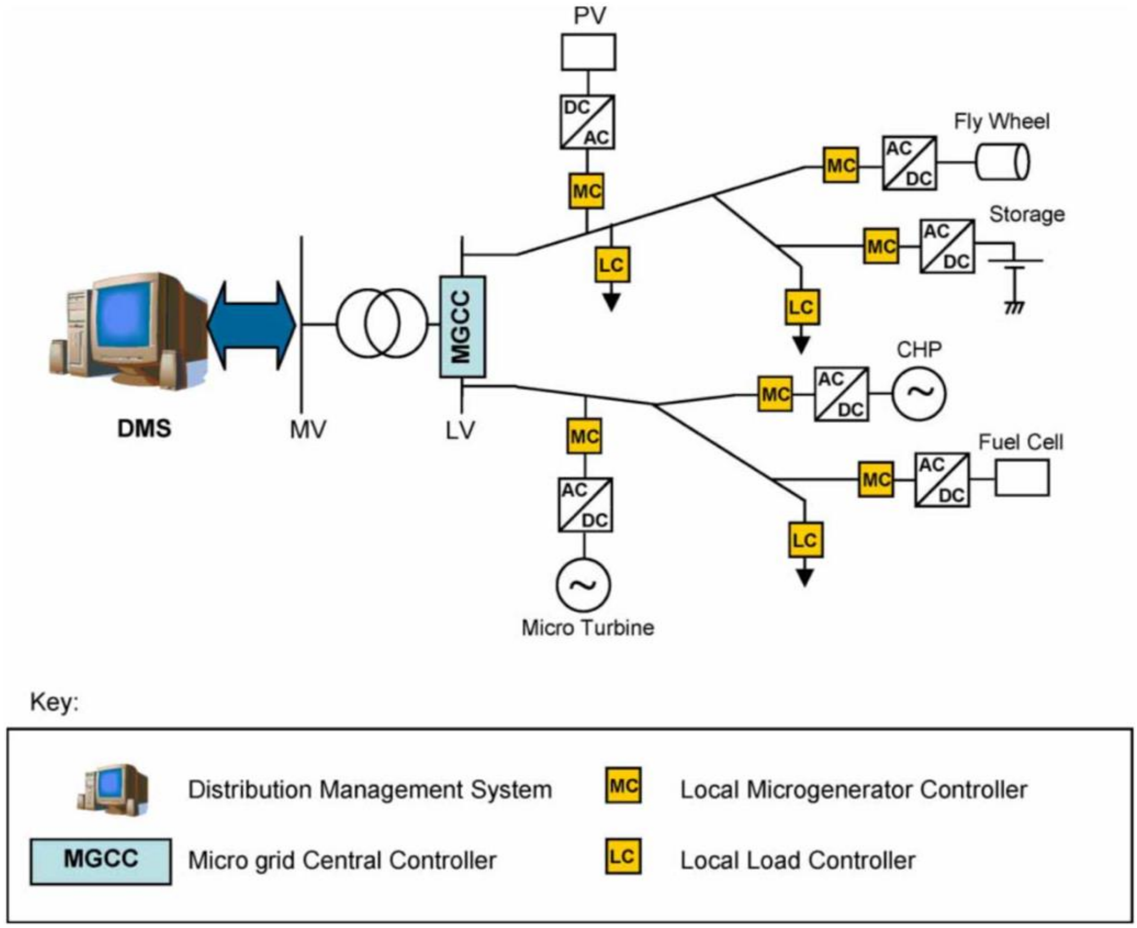

Figure 2-17: A configuration of a microgrid [53].

Briefly, applying the microgrid concept can increase the utilisation of renewable energy resources, boost energy conversion efficiency, improve reliability, and provide active load control [54]. These are essential functions of smart grids.

VPP is a control approach, which indicates the aggregation of DERs to provide services on distribution and transmission networks. This represents the same function as a conventional power plant [14]. Figure 2-18 illustrates a multi-energy VPP that aggregates the CHP, auxiliary boiler and HP to supply various demand loads. From the perspective of users, the VPP acts like a conventional power plant, however offering greater efficiency and flexibility.

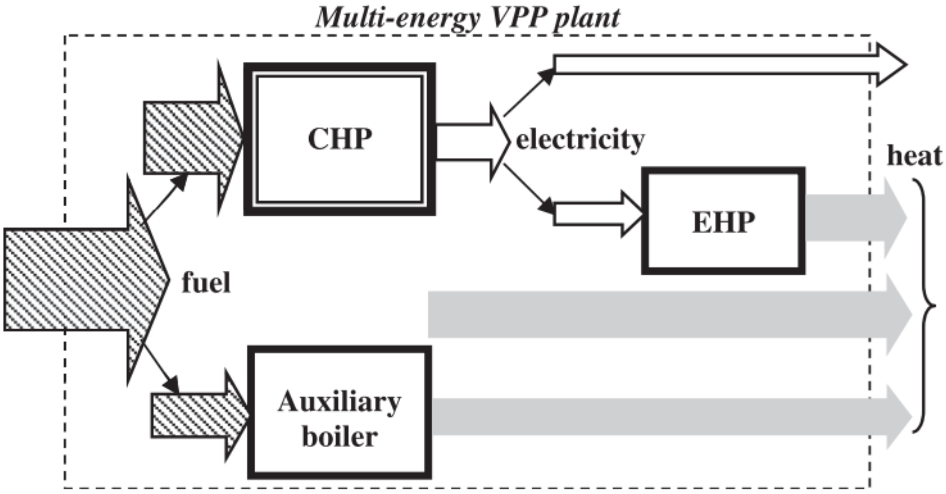

Figure 2-18: An example of multi-energy VPP [55].

To clearly define the microgrid and VPP, Figure 2-19 depicts a schematic electricity network configuration. The light blue circle (left side) representing the integration of DERs within a distribution network can be interpreted as a microgrid, which is a VPP in the perspective of a transmission system operator. In a few words, the microgrid approach focuses on the optimisation of DERs, and the VPP approach illustrates the interactions between the aggregated DERs that is a controllable VPP cell [52].

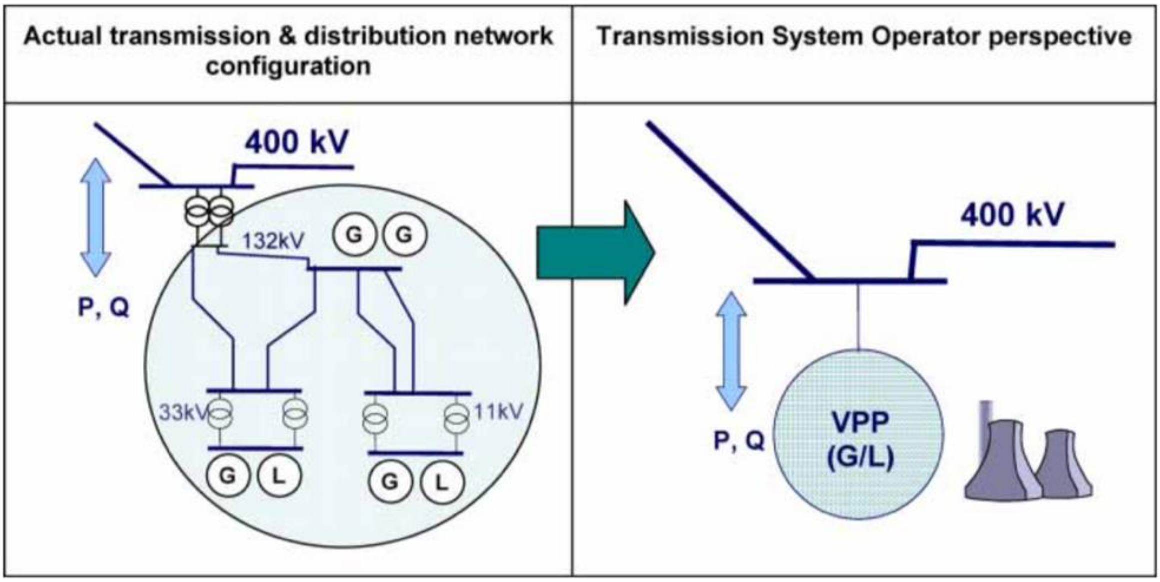

Figure 2-19: An illustration of DERs as a VPP [56].

2.4. Discussion and conclusion

This chapter reviewed the future development of electricity systems in the UK, which indicated a notable increase in the installed capacity of power production by 2050. The predicted installed capacity in the high electrified scenario was 2.8 times larger than in 2019 due to the significant adoption of stochastic renewable energy resources. Wind power systems accounted for the largest proportion of the electricity production, including offshore and onshore. Solar power had the second large share. Also, the phenomenon accompanied by a transformation from centralised to decentralised power production. The highest rate of decentralised generation could reach 42%.

The main topic of this research, electrification of heating and transport, was evidenced to be an effective way to decrease carbon emissions. To attain this goal, the need for high-temperature HPs or hydrogen-fuelled CHP was pointed out for industrial heat supply. In addition, the considerable seasonal demand gap induced by heat electrification implied that greater thermal performance of buildings and higher efficiency of electric heating devices are growing important. In terms of the transport sector, the policy and economic benefit of promoting EVs were indicated. EVs will not only mitigate GHG emissions but also decrease energy consumption for travel.

On the other hand, HPs expected to dominate the heat supply in buildings will be supported by thermal storage. The projection of homes employing thermal storage units was 40% by 2050. This electrification approach is practical, based on the reviewed literature. However, the challenges of considerable power demand, particularly during peak hours, must be tackled. Smart charging of EVs and HPs, therefore, was suggested, maintaining stability and reducing the required network reinforcement of the electricity grid. Within the context of 100% EVs and HPs adoption, smart control can limit daily system peak at a 29% increase in winter, which without smart control, achieves a 92% increase.

Finally, this chapter illustrated the concepts of multi-vector energy systems. The system concepts, including the spatial, multi-service, multi-fuel and network perspectives, indicated that energy systems could manage generation, interaction and conversion between various energy forms in highly electrified and digital grids. The Energy Hubs as a modelling concept optimises energy systems for reaching greater efficiency and reducing the system cost. The Microgrids and VPPs control methods manage distributed energy resources (DERs) and govern the interactions between aggregated DERs, respectively.

Chapter 3

Literature Review: Key Technologies of Energy Systems

This chapter is going to introduce essential technologies for establishing a multi-vector community energy system. Section 3.1 reviews district heating networks that connect homes for efficient heat distribution, including their definition and progression, such as operating temperature, system efficiency, the layout of distribution pipes, etc. In subsection 3.2, the working mechanism and types of heat pumps (HPs) as efficient heating devices are described, followed by the illustration of their efficiencies related to the source and supply temperatures.

Electric vehicle (EV) that reduces carbon emissions in the road transport sector is introduced in subsection 3.3. The focuses are on showing the development of their battery capacity and charger types and investigating the charging behaviour and residential charging demand. This research selects battery storage to store electricity within distribution networks. Thus, in section 3.4, the characteristics and prevalent applications of battery storage are indicated. Finally, a summary of the key concepts and technologies is made in section 3.5.

3.1. District heating networks

District heating has been indicated to be a viable heat supply in a future world, estimated to provide 50% of the entire heating demand by 2050 [57]. A district heating system consists of a network of pipes that connects buildings in a community, town centre or entire city [58], whereby centralised plants and decentralised supply units can provide heating demand or even cooling demand.

A survey indicated that around 80,000 district heating systems had been installed worldwide, which includes about 6,000 systems located in Europe [59]. The earliest heat distribution system that supplied hot water to buildings by utilising a geothermal source was built in Chaude-Aigues, France, in 1334 [59]. The commercial district heating networks were firstly introduced in Lockport and New York cities in the 1870s and 1880s [59]. The development of district heating is based on the distribution temperature, shown in Table 3-1. The first generation (1G) of district heating, which utilised steam as heat carrier and steel as pipe material, gave rise to a considerable amount of heat losses and severe accidents induced by steam leakage. The second-generation (2G) replaced the heat carrier with pressurised hot water, starting from 1930. The operating temperature was decreased but still over 100°C, and the same pipe material was adopted. In the third generation (3G), the temperature of pressurised hot water was reduced further to below 100°C, which starts using pre-insulated steel pipes for reducing labour force at the construction site. In general, the first three generations were supplied by one or few energy centres that consumed fossil fuels as principal energy sources [19]. Besides, because of the high operating temperatures, system heat losses were significant.

Table 3-1: The development of district heating networks [58].

Generations	1G	2G	3G	4G
Period	1880-1930	1930-1980	1980-2020	2020-2050
Heat carrier	Steam	Pressurised hot water	Pressurised hot water	Low temp. water
Temp. range	< 200°C	> 100°C	< 100°C	50-60°C
Pipes	In situ insulated steel pipes	In site insulated steel pipes	Pre-insulated steel pipes	Pre-insulated flexible pipes

Figure 3-1 is an illustration of energy network development. The tendencies indicated for the development of fourth generation district heating (4GDH) are utilising a lower temperature for decreasing heat losses, more prefabricated pipe for construction saving and various types of energy supply for network reliability [58]. This

4GDH, also called low-temperature district heating (LTDH), mainly operates the supply and return temperatures at 50°C and 20°C as annual averages [58]. This low-temperature operation, furthermore, enables the utilisation of low-grade waste heat sources from the industrial process [60].

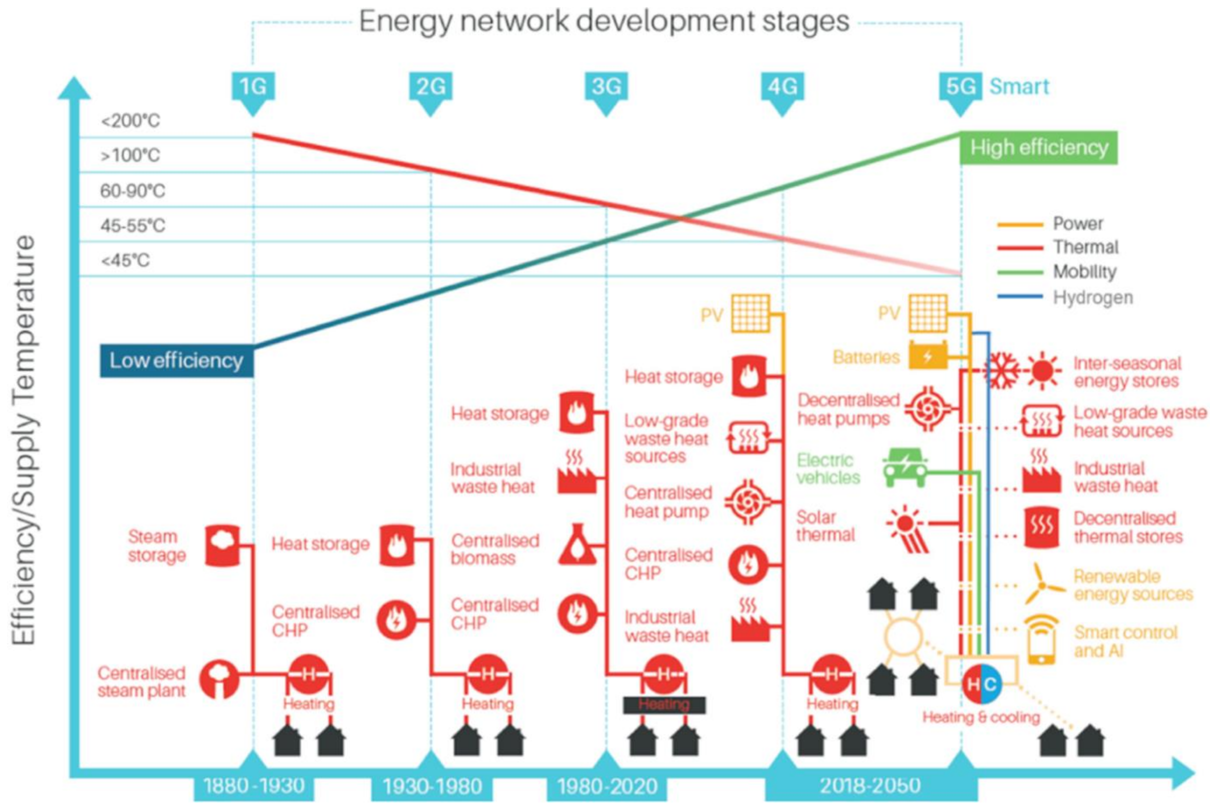

Figure 3-1: An illustration of energy network development stages [61].

In Figure 3-1, the fifth generation (5G) concept described recently indicates that the differences in contrast with 4G are the operation temperature reduced from 50°C to ultra-low temperature (lower than 45°C) and energy supply transferred from a single large plant to decentralised HPs. This ultra-low temperature loop creates the opportunity of sharing the heating and cooling according to the prosumer concept [19, 62]. Besides, the 5G utilises smart control approaches to integrate the thermal and electricity networks, maximise the use of distributed energy resources (DERs) and facilitate the demand-side management (DSM), thereby achieving excellent efficiency [19].

To establish a heating network, the layout of distribution pipes is needed to be addressed. This determines the pressure difference between consumers, linking to the water flows at each consumer location. In a traditional district heating network, the differential pressure in pipes between the first consumer with the shortest distance from the central plant and the last consumer located at the farthest away from the plant is considerable [63]. The flow rate to the very last consumer is often inadequate, which requires valve installation to enhance the flow resistance and, in contrast, control the excess pressure of the first consumer [63]. Another solution to replace the valve throttling is to apply a ring network arrangement. This balances the pressure of distribution pipes, including supply and return lines [64]. The concept of the ring network is to create the same pipe lengths for each consumer.

Figure 3-2 illustrates the traditional layout of a district heating network and new ring network design. The heat station (HS) in both types distributes hot water to homes through the supply line (red line), which ends with the last consumer. In the traditional layout, the return line (blue line) starts from the last consumer and ends at the HS. Unlike the traditional design, the first customer (i.e., DH1) is the starting point of the return line in the ring network, which also ends at the HS.

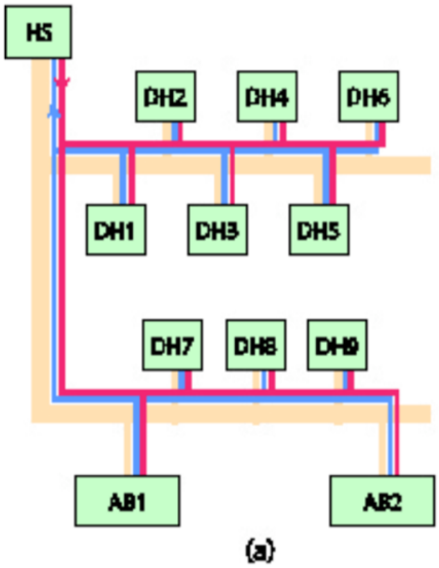

Figure 3-2: (a) The traditional topology of district heating network and (b) ring network design. DH: detached house, AB: apartment buildings, HS: heat station [65].

This section described the fundamental knowledge about district heat networks. A lower distribution temperature and the ring topology are preferable in the present application for decreasing heat losses, increasing the utilisation of low-temperature resources and achieving hydraulic balance.

3.2. Heat pumps (HPs)

A heat pump is a heating installation that is comprised of four major parts, including condenser, expansion valve (i.e., throttle valve), evaporator and compressor [66]. Figure 3-3 shows the structure of a typical heat pump. An operation cycle starts from the evaporator: A low-temperature liquid and vapour mixture with low pressure (i.e., refrigerant) absorbs heat from low-temperature sources (e.g., air, soil, lake, river, etc.) and becomes a low temperature, slightly superheated vapour with low pressure. The compressor then compresses the vapour into a high-temperature, superheated vapour with high pressure. Subsequently, the high-temperature vapour releases heat through the condenser to the consumer side and becomes a high pressure, moderate temperature liquid. The expansion valve finally turns the moderate temperature liquid into a low-temperature liquid and vapour mixture with low pressure, and the cycle is repeated.

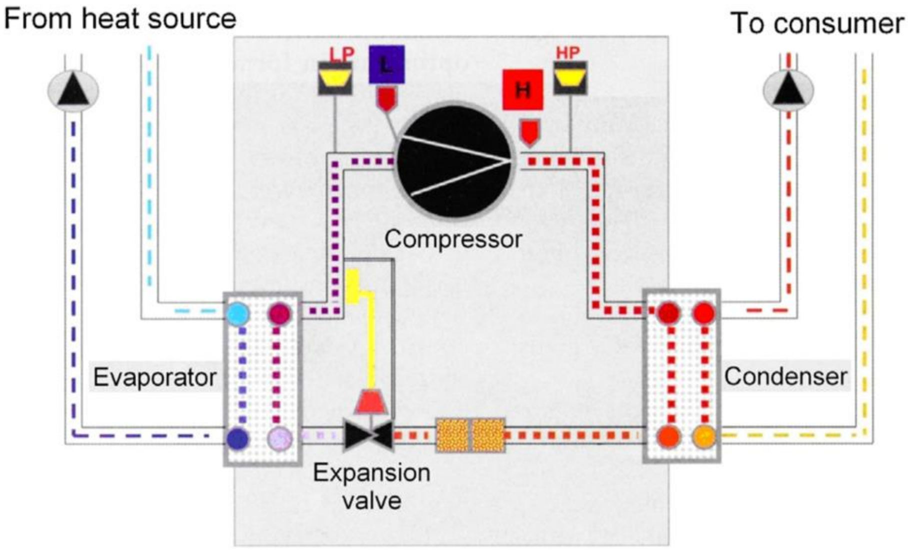

Figure 3-3: An illustration of a heat pump [67].

In the UK, the suitable HP technologies in residential buildings are air source heat pumps (ASHPs) and ground source heat pumps (GSHPs) [68]. Most commercial ASHPs can have a coefficient of performance (COP) ranging from 2 to 4 when a 50°C temperature is produced at the condenser side [68]. (A COP of 2 means an input of 1 kWh electricity can have 2 kWh heat.) The COP of ASHPs is strongly related to the ambient temperature, the temperature at the evaporator side. Using a 7°C ambient temperature as a benchmark, when the temperature is above 7°C, a COP of 3.2 is achievable [69]. However, in the UK, the average monthly temperatures from

November to March are lower than 7°C in most of the time; hence, the average COP is around 2.8 [69]. Another technological problem is the evaporator that is often covered by frost at an ambient temperature below 5°C [68]. A study reports that the COP of an ASHP is dropped from 2.81 to 2.11 after running in a frosting environment for 250 minutes [70].

On the contrary, GSHPs employing pipes to extract heat from soil (i.e., geothermal energy) for heat supply are more stable. Figure 3-4 illustrates the COP variation in relation to the source temperature (t_s) and consumer side temperature (t_u). At a source temperature condition, the COP is varied due to the types of refrigerant, energy losses, etc. When the source temperature is 10°C with a supply temperature of 50°C on the consumer side, a COP of 4 is attainable [71].

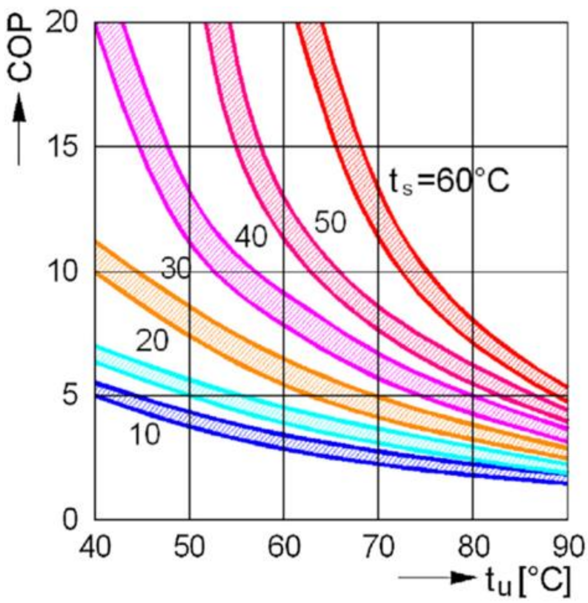

Figure 3-4: The efficiency variation of ground source heap pumps [71].

The arrangements of the pipes (i.e., heat exchanger) extracting heat from soil can be categorised into horizontal and vertical ground loops. For a horizontal ground loop, the pipe network is generally buried underground around 2m and has three common types illustrated in Figure 3-5. A single-tier loop (figure a) is simple but occupies a wide area. This space issue can be alleviated by utilising a double tier loop (figure b), which theoretically enables a 50% reduction of the surface area. For the slinky loop, the trench length is around 20% to 30% of a single-tier loop. Nonetheless, the total pipe length may be doubled for reaching the same thermal performance [68]. In contrast with a horizontal loop, a vertical ground loop can reach a depth of up to 100m. The vertical loop does not occupy a wide surface area, but the cost of drilling is considerable [66].

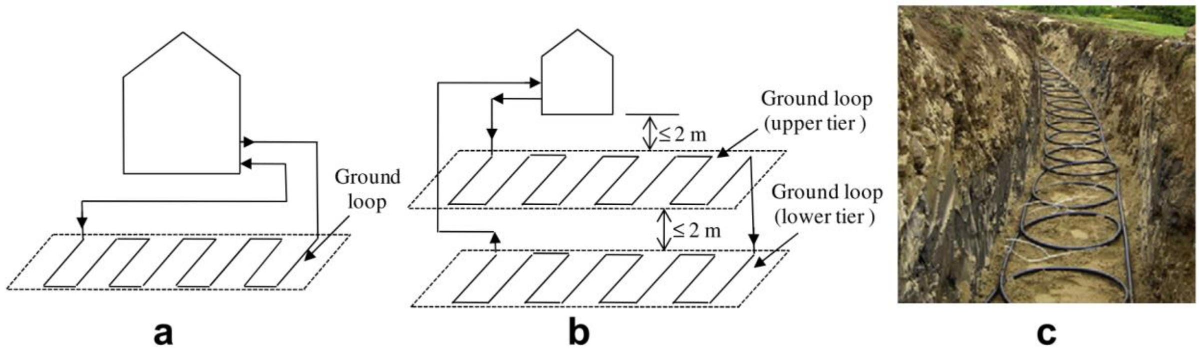

Figure 3-5: Pipe arrangements of GSHP (a) a single tier and (b) a double tier (c) slinky [72].

This section detailed the function and performance of heat pumps. The GSHPs presented excellent efficiency for heat production. In the UK, the average subsurface temperature is between 8°C and 11°C all over a year at a depth of around 15m and remains 8°C and 15°C at a depth of 100m [68]. This subsurface temperature range with an excellent thermal storage capacity of the ground and the long lifespan of GSHPs, about 25 years, allow GSHPs to be a suitable choice for residential heating supply [68]. However, the expensive drilling cost and space issues are required to be addressed.

3.3. Electric vehicles (EVs)

The last section illustrated HPs for the low-temperature heating solution. This section shows the development of the battery capacity of EVs and charger types of charging EVs for low carbon transport. Subsequently, the residential charging behaviour and charging demand of EVs are investigated.

3.3.1. Battery capacities and charger types

The high cost of Li-ion batteries was considered a barrier for developing electric vehicles (EVs). Nonetheless, mass efforts from the industry have successfully decreased the manufacturing price, which makes EVs more affordable and reliable [1]. Figure 3-6 presents the trend of the battery capacity of EVs. The battery capacity has a substantial impact on driving distance. In 2019, the longest driving distance of EVs made by the Tesla Model S was 370 miles (590 km), which is induced by a battery capacity of 100 kWh and an efficiency of 93% [73].

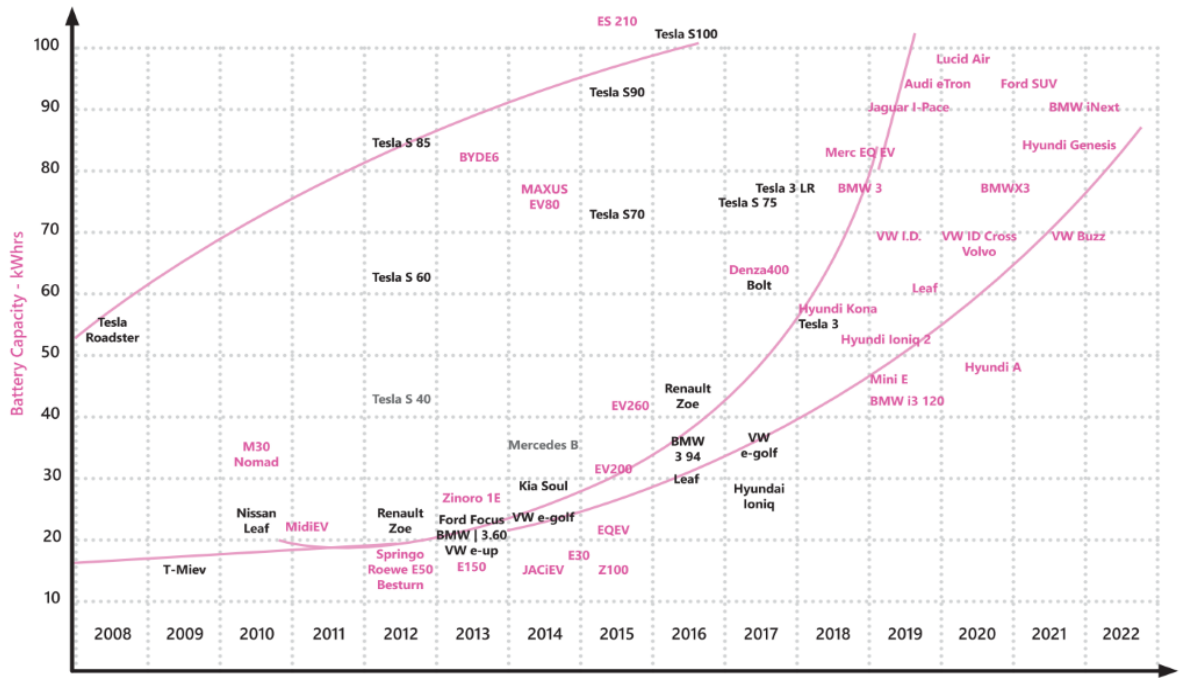

Figure 3-6: The trend of battery capacity of EVs [74].

EVs can obtain electricity from alternating current (AC) or direct current (DC) charging points. However, Li-ion batteries of EVs can only be charged by DC. Accordingly, at an AC charging point, AC supplied to EVs is converted to DC for charging Li-ion batteries. In contrast, a DC charging point converting AC to DC delivers DC to EVs [75]. In general, connector types of EVs are categorised into slow chargers, fast chargers and rapid chargers, shown in Figure 3-7. The charging power of slow chargers is around 3 kW. Fast chargers provide charging power from 7 to 22 kW. These slow and fast chargers utilise AC mode and are limited by the electricity grid. Note that a UK standard domestic single-phase connection (230V) can provide a maximum charging power of 7.4 kW. A commercial three-phase connection (400V) can increase the charging power up to 22 kW [76, 77].

Figure 3-7: Electric vehicle (EV) connector types [78].

The rapid chargers can charge EVs with a power range from 43 to 120 kW. This will be increased to 150 kW firstly and then to 350 kW for the ultra-rapid chargers [78]. Furthermore, survey data shown in Figure 3-8 indicates that fast charging and rapid charging locations are growing rapidly in the UK, which is aligned to the increasing capacity of EVs.

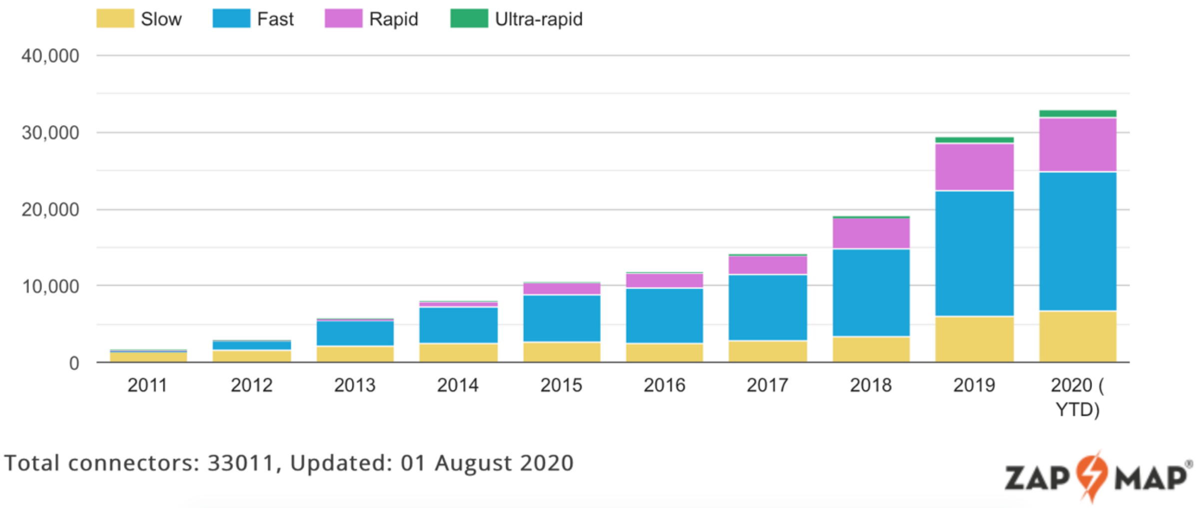

Figure 3-8: Numbers of public charging points by speed [79].

3.3.2. Charging behaviour & charging demand

This subsection illustrates the charging behaviour of EVs based on the Low carbon London (LCL) EV trial [80], including residential and commercial sectors. The statistical data shows that the average daily charging time was shorter than 2 hours. Besides, more than 95% of charging events took less than 5 hours from 9,909 charging cases, presented in Figure 3-9. Most charging events utilised slow chargers having a power of around 2.35 kW. Nevertheless, this result is predicted to be changed with the growth of fast charging points [80].

In terms of the residential sector, the charging behaviour of twenty-two EVs, collected across a year in 2013, is indicated in Figure 3-10. The result of start state of charge (SoC) and end SoC illustrates that individuals begin charging their EVs at different SoCs. On the opposite, the values of end SoC are usually between 90% to 98% [80].

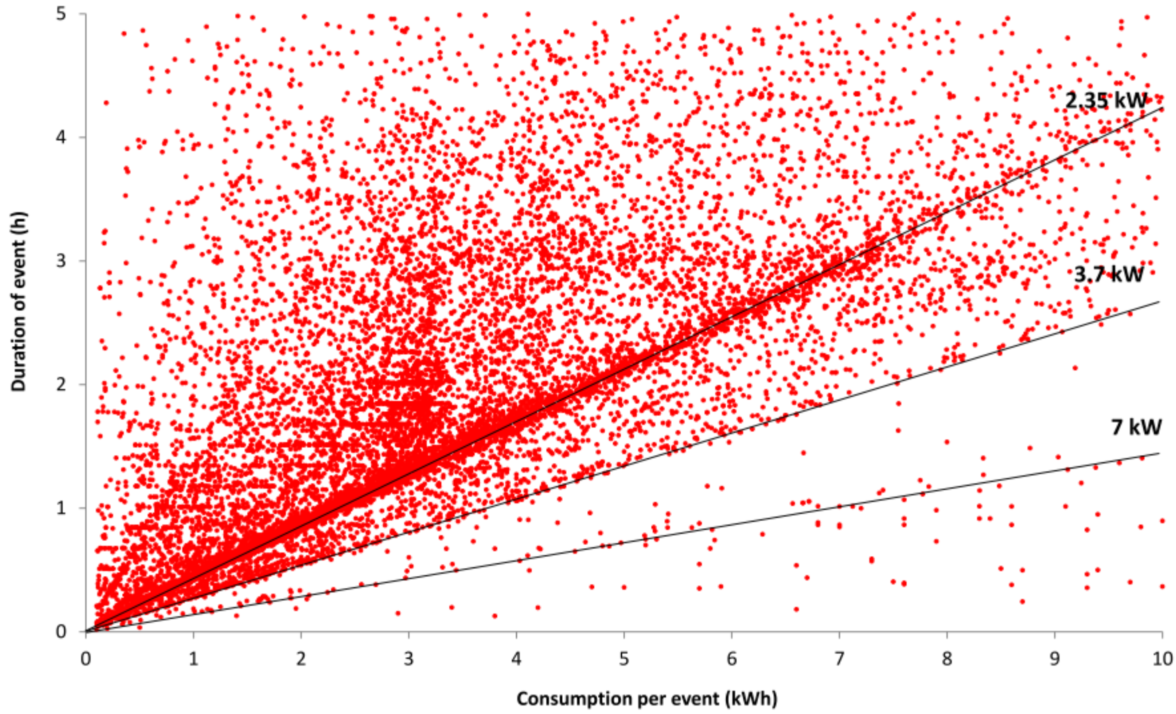

Figure 3-9: The consumption per charging event with the duration of each event [80].

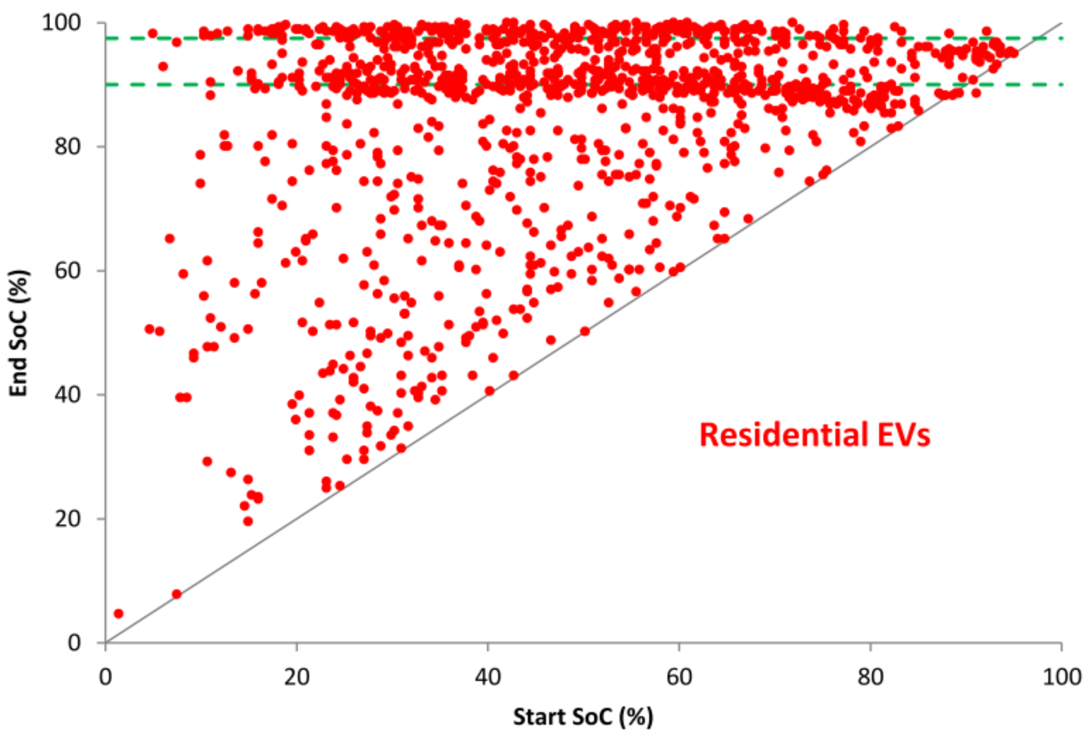

Figure 3-10: The SoC of start charging with the SoC of end charging for residential EVs [80].

In 2019, a survey from the UK government expected that the home would be the charging centre [75]. The statistical data shows that approximately 80% of all EVs are charged at home today [75]. In general, home charging is cheaper and more convenient.

The annual driving demand for each car in UK households (4-wheeled cars only and excluding vans) was 7,600 miles (12,236 km) in 2018 [81]. The average commuting distance from 2008 to 2018 was less than 10 miles (16.1 km) in England [82, 83]. Also, the journeys exceeding 50 miles (80.5 km) account for only 2% [75]. The 2018 top-selling EV in Europe was Nissan Leaf which equips a battery with 38 kWh capacity and 0.27 kWh per mile (0.17 kWh per km) efficiency [84]. As a result, the average daily consumption of an EV is less than 10% of the battery capacity, implying that the majority of EV drivers may charge their EVs at home and never need to access the public charging points.

A comprehensive study of EV charging demand indicated the average annual consumption per EV is 1,760 kWh, that residential charging points account for 75% consuming 1,320 kWh [85]. Figure 3-11 illustrates the demand profile of residential charging for an average EV, which has an average daily consumption of around 3.6 kWh. The daily consumption on weekdays is greater than on weekends. Furthermore, a prominent demand peak between 7 and 8 p.m. occurs on weekdays.

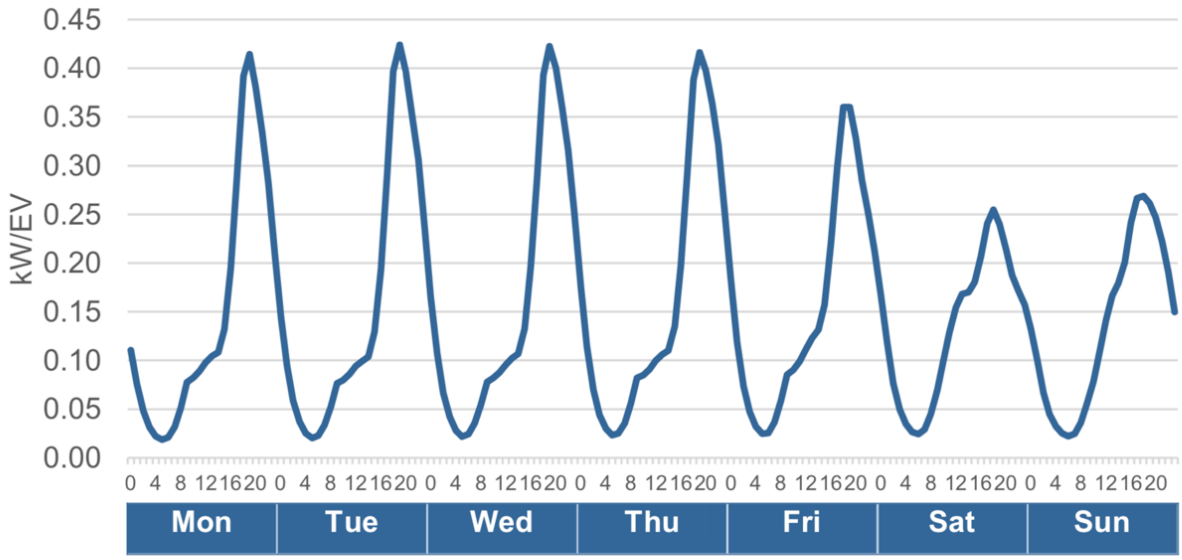

Figure 3-11: Demand profile of residential charging of an average EV, averaged a whole year [86].

3.4. Battery storage

Energy storage is a vital technology that brings flexibility and reliability to intermittent renewable power generation such as solar and wind systems. Currently, dwellings that install PV modules can use the produced electricity or sell the electricity to the electric power network. However, the value of the energy of sale is lower than self-consumption because of high retail prices [87]. A study of the economic benefits of PV-coupled battery systems indicated that the growing electricity price will make the utilisation of batteries more attractive even without subsidies from the government [88].

Lithium-ion (Li-ion) battery that is the mainstream on the market offers stable voltage, long life cycle, high depth of discharge (DoD) and high round trip efficiency (η, the ratio of discharge energy to charge energy) [89]. In contrast, lead-acid (PbA) battery, as the earliest and still widely used rechargeable battery, is advantaged by the cost [87]. By utilising a PV-coupled battery system, the comparison between Li-ion and PbA batteries indicates that the initial cost of a Li-ion battery is higher but more profitable according to its greater round trip efficiency and cycling capability [87]. Note that the Li-ion battery (350£/kWh) was 2.5 times more expensive than PbA (140£/kWh) in the study.

Figure 3-12 illustrates that the cost of Li-ion batteries has fallen by around 85% from 2010 to 2018, which enhances the affordability and profitability of Li-ion batteries. By 2030, the price of a Li-ion battery is expected to reach $62/kWh (35% off comparing with the price in 2018).

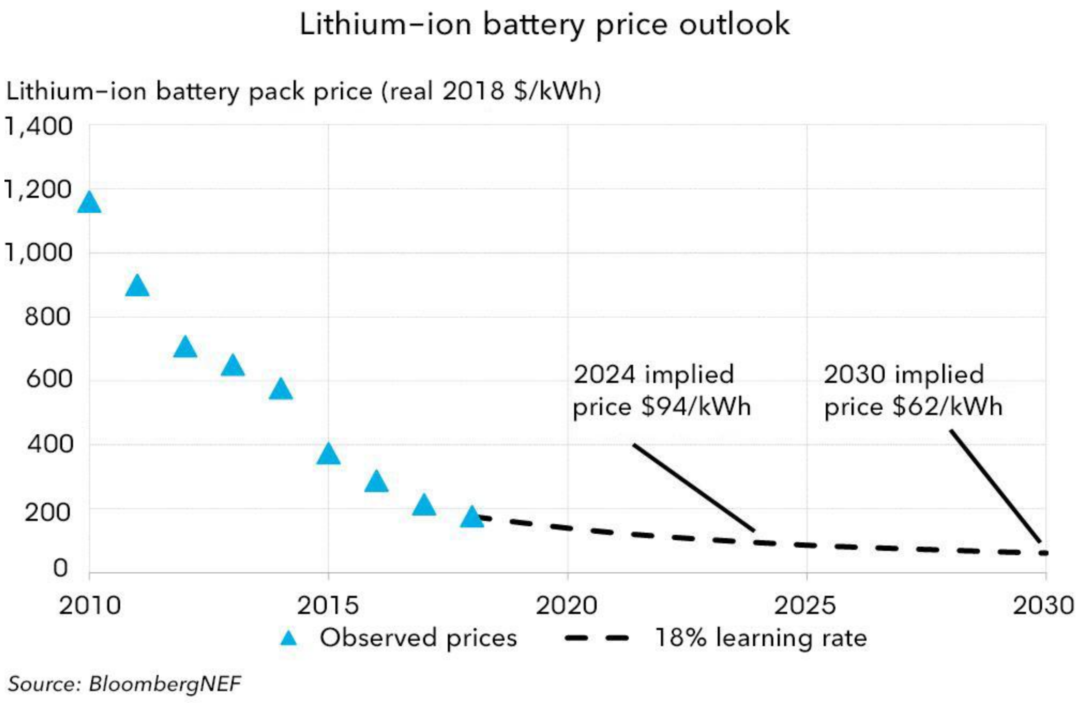

Figure 3-12: The trend and forecast of Li-ion battery price [90].

The outstanding performances of the Li-ion battery on DoD and life cycle are presented in Table 3-2, compared with the PbA battery. DoD indicates the percentage of capacity that a battery can be used before recharging it. Using over the DoD limit will decrease the lifespan of a battery. For Li-ion batteries, most brands can achieve at least a DoD of 90% [91]. On the market, the Tesla Powerwall can achieve a DoD of 100% [92, 93]. Moreover, the life cycle of the Li-ion battery is two times more than the PbA battery.

Table 3-2: The comparison of Pb-A battery and Li-ion battery [92].

Characteristics	Lead-Acid Battery	Lithium-Ion Battery
Preliminary Cost	£2,000	£4,000
Storage Capacity (kWh)	4 kWh	4 kWh
Depth of Discharge (DoD)	50%	90%
Life Cycle	1,800	4,000
Cost / kWh / Cycle = preliminary cost / (storage capacity × DoD × life cycle)	£0.556	£0.278

For Li-ion batteries, fast charging temperature commonly ranges from 5°C to 45°C. Charging batteries at a higher temperature, around 50 °C, would not affect the performance but reduce the service life of the batteries. Charging batteries at a temperature below 0°C will give rise to lithium plating on the anode, which is impossible to be removed with charging and discharging cycles. The lithium plating increases the likelihood of battery failure under vibration or other stressful conditions. Furthermore, cold weather increases the internal resistance of batteries and therefore extends the charging duration [94]. Briefly, the temperature effect is significant for longevity and efficiency.

For application, battery storage can mitigate the increased peak demand induced by the electrification process and compensate for the mismatch between renewable power generation and demand loads [95]. Figure 3-13 is an example of utilising community energy storage (ES) to smooth the grid import. The community grid import after ES (green line) can be viewed as the consumption threshold. Therefore, the battery storage is charged at the duration of the community grid import (red line) lower than the threshold and discharged during the period in which the grid import is greater than the threshold.

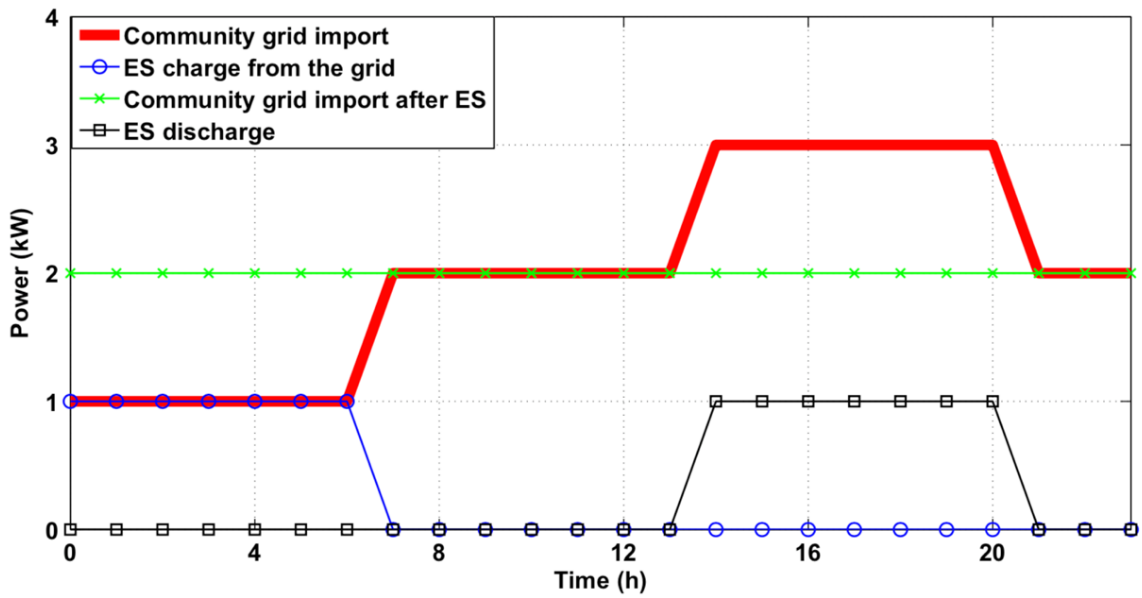

Figure 3-13: An illustration of load shifting by community energy storage (ES) [96].

By installing a battery with 2 kWh capacity in every household, a study showed that the peak power demand in the UK can be decreased by 50% potentially [97]. In the case of the 100% penetration of HPs for DHW and SH consumptions, the peak demand can be maintained at the current level when the battery capacity in each home is increased to 3 kWh [97].

Furthermore, a study employing PV generation with battery storage indicated that the optimum capacity of the battery can be defined through the evaluations of capital cost, maintenance cost, grid import price, solar export reward, consumer demand and generation [95]. In Figure 3-14, based on the research, the optimum storage capacity of 83 kWh of a community is utilised to manage the PV generation and demand. The result illustrates that surplus electricity production can be stored and used to offset the later demand, which reduces the consumption gap in a day (figure b). Also, the study shows that managing to store all the surplus PV generation is not the best economic option (figure a) [95].

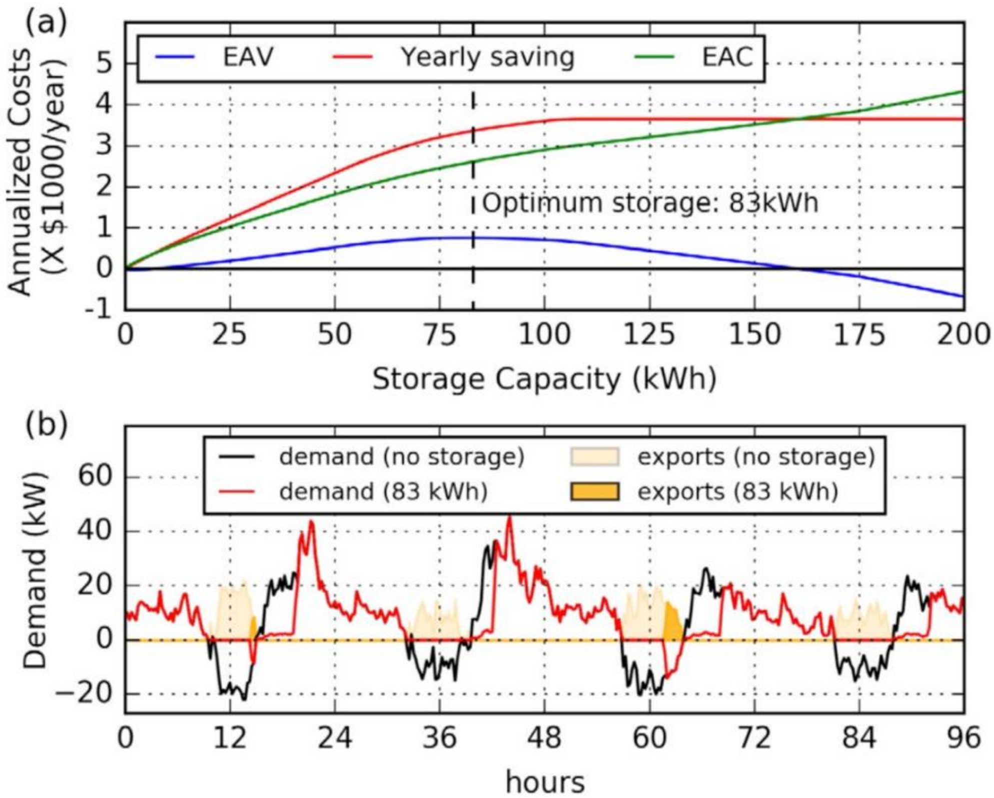

Figure 3-14: (a) The benefit (EAV) and costs (EAC) of battery against battery size and (b) the load profile of the community with and without an 83 kWh battery [98].

3.5. Discussion and conclusion

Based on the reviewed literature, district heating systems can play a crucial role in distributing heat and integrating heating and electricity grids. The operation temperature categorises the five generations of district heating. A lower temperature for heat distribution, reducing heat losses, is the main direction today. This low-temperature supply enables the possibility of using waste heat and high-efficiency HPs. In the UK, the applications of ASHP and GSHP are recommended in residential buildings, which mitigates the increasing electricity demand caused by heat electrification. A GSHP that extracts heat from soil can reach a COP of around 4 when it supplies a temperature at 50°C. Furthermore, due to the relatively steady soil temperature, the COP of a GSHP is more stable than an ASHP.

The development of batteries equipped on EVs is the critical factor determining the EV penetration and driving distance of an EV. In 2019, the longest driving distance of an EV reached 370 miles (590 km). With the growing capacity of EVs, the fast charging and rapid charging locations are increased notably. The investigation of EV charging behaviour and charging demand indicated that the average daily consumption of an EV is less than 10% of its battery capacity. This result implies that EV drivers can charge their EVs at home and never need to access the public charging points.

Battery technology (i.e., Li-ion battery) powers EVs and provides flexibility to the intermittent renewable power generation. In contrast with other battery types, the advantages of Li-ion batteries include excellent round trip efficiency, stable voltage, long life cycle and high DoD. Mass efforts on developing Li-ion batteries have increased the economic benefits of its applications. The cost of a Li-ion battery has been decreased by 85% between 2010 and 2018. Furthermore, the utilisation of Li-ion battery for performing peak shaving has demonstrated that it can keep the peak electricity demand at the original level in the context of 100% HP penetration. This character can be applied to a community energy system, thereby creating a steady electricity flow.

In summary, the critical features elaborated in this chapter will be employed to design a multi-vector community energy system that delivers 100% electrification, applies smart control solutions, and links up buildings.

Chapter 4

The Development of a Multi-Vector Community Energy System

Electrification of heating and transport requires intelligent systems, performing smart management measures to tackle the significant electricity demand [99]. This chapter illustrates a designed multi-vector community energy system that offers excellent efficiency and integrates a heating network, electricity grid and decentralised generation. Subsection 4.1 shows the configuration of a community energy system that links up homes of a community by the distribution network and low-temperature district heating (LTDH) system. The electricity and heating grids are connected through electric heating devices. Energy storage units are utilised to support decentralised generation and the community energy system for reducing the demand power during peak hours.

Heating consumption is responsible for around one-third of greenhouse gas (GHG) emissions in the UK [19]. In this research, an electrified heating network that removes fossil fuels supplies the heating demands of domestic space heating (SH) and domestic hot water (DHW). This heating network is based on an existing LTDH system at the University of Nottingham [100]. Subsection 4.2 introduces the distribution pipes, heat interface units (HIUs), thermal storage units and network arrangement. With a community energy system integrating heating and distribution networks, a concept of a community-scale peak shaving and a control method of electricity flows are illustrated in section 4.3 and 4.4, respectively. To monitor and analyse the supply and demand data of this smart grid, subsection 4.5 depicts a supervisory control and data acquisition (SCADA) system [101]. Community energy systems are developed to address challenges brought by the electrification process. These systems can be optimised at various geographical locations and then be assembled effectively. This is elaborated in the same subsection. Finally, a section of discussion and conclusion is made to deliver key messages of this multi-vector community energy system.

4.1. System configuration

The community energy system, illustrated in Figure 4-1, can be categorised into heating and distribution networks. The linkages between these two networks are created by the ground source heat pump (GSHP) and electric heaters placed in the community substation and household tanks, respectively.

In Figure 4-1, the community substation receives the electricity supply from the electric power network and subsequently distributes the electricity to the GSHP and homes for domestic consumptions. The photovoltaic (PV) modules placed at both community substation and homes are the selected decentralised power generation. The battery storage in the community substation is designed to have a high enough capacity to power the GSHP during peak hours and perform rapid charging of electric vehicles (EVs). The battery storage at home can interact with EVs and power appliances and the immersion heater in the household tank. Furthermore, EV charging at home is determined to utilise a domestic charger for slow charging. Also, they can deliver electricity back to the distribution network through vehicle-to-grid (V2G) technology.

The heating network meets the demands of SH and DHW through the GSHP, LTDH system, electric heaters and thermal storage units. In Figure 4-1, the GSHP placed in the community substation provides heat to a large number of homes, which induces a lower overhead and installation costs than installing GSHPs in every individual home [102]. Moreover, a GSHP is selected because of the ability to perform a COP of 4 that supplies hot water at around 50°C [66].

As the starting point of the LTDH system, the community thermal store stores hot water at a temperature range from 40°C to 65°C. A specific storage temperature is defined by a systematic modelling approach (Chapter 5) according to the network electricity consumption. On the other hand, the DHW tanks (i.e., household tanks) maintaining the water temperature at 60°C is advisable to prevent the legionella issue [103]. This 60°C storage temperature is supplied by the LTDH system and electric heaters. Therefore, when the LTDH system utilises a lower distribution temperature for reducing heat losses, the utilisation of electric heaters for boosting the storage temperature is increased. Unlike the GSHP, the electric heaters have a maximum efficiency of 100%, assumed to have a COP of 1 within models. This lower COP of electric heaters reduces the efficiency of the system and consequently increases electricity consumption.

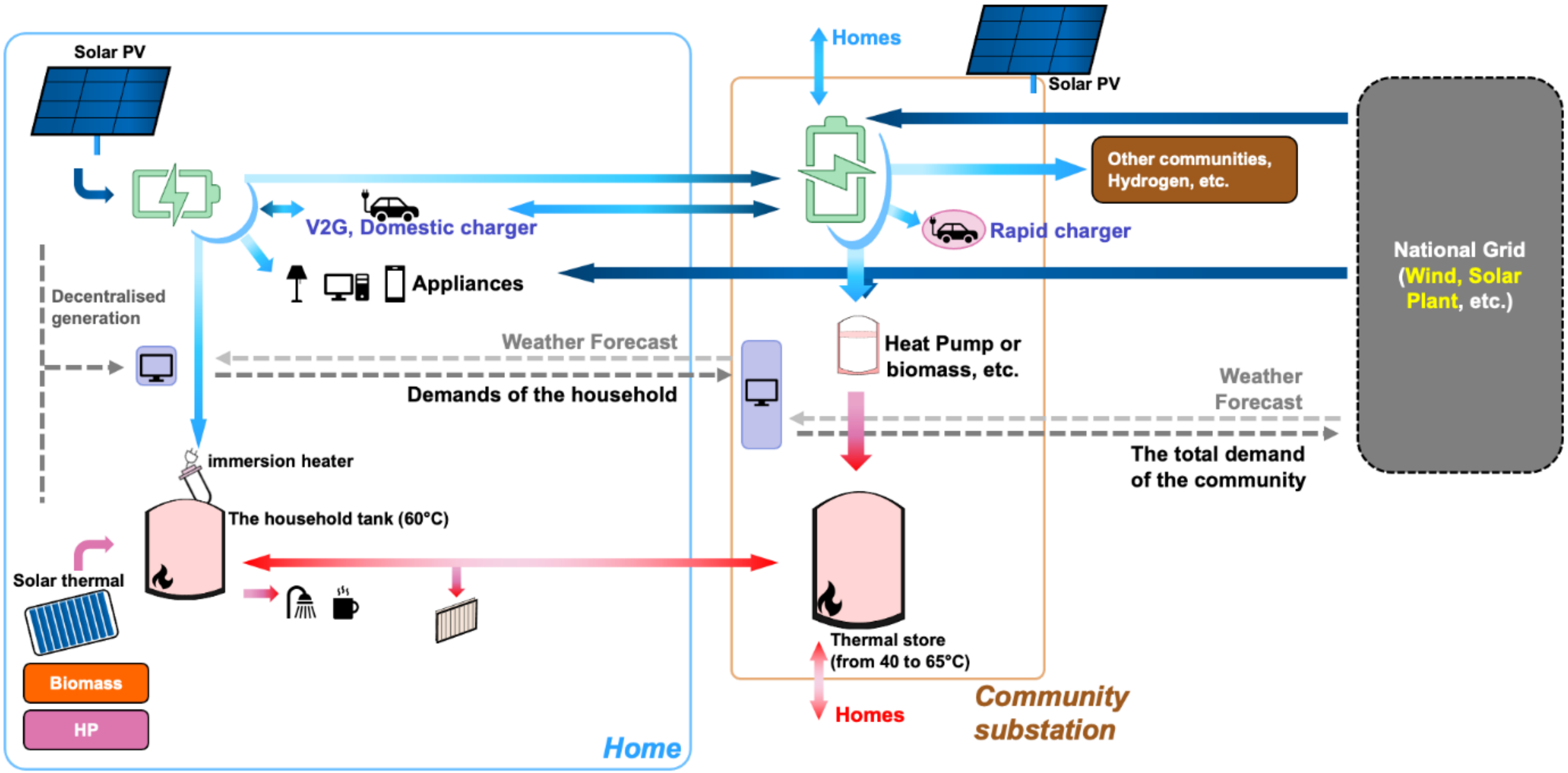

Figure 4-1: The multi-vector community energy system that integrates a heating network, electricity grid and decentralised generation.

In Figure 4-1, the thermal storage units can mitigate peak demand and allow the system to adopt a GSHP and electric heaters with lower electric powers [104]. A study indicated that 40% of homes will use thermal storage to support heating in the UK by 2050 [20]. In addition, the storage units can be operated with other renewable technologies such as solar thermal [105], biomass, etc. for reducing electricity consumption.

Apart from the distribution and heating networks, the community energy system requires a SCADA system [101] to manage the supply and demand. This SCADA system will be able to monitor the weather forecast, calculate the production of decentralised generations and send electricity demand data to the grid. Overall, the multi-vector community energy system is built in several stages, including Chapter **5. Establishing an Electrified Heating Network**, Chapter **6. Establishing an Electrified Community**, Chapter **7. The Deployment of Decentralised Generation** and Chapter **8. The Modelling Tool of Multi-Vector Community Energy Systems**.

4.2. The low-temperature district heating network

District heating systems are often installed in cities to achieve cost-efficient heat distribution. Researches [106, 107] indicated that utilising district heating systems in low dense areas (e.g., small villages) induces significant heat losses and high investment cost. The innovation of LTDH can be a solution to these issues, which makes district heating systems more competitive.

The challenges of developing LTDH systems are indicated [58], which includes:

- The needed renovation on existing buildings to achieve high thermal efficiency.
- The reduction of heat losses on grids by low-temperature supply and better-insulated pipes.
- More utilisation of renewable energy resources to reduce GHG emissions.
- The integration of electricity, gas networks, etc. as a part of a smart energy system.
- The requirements of applicable planning, cost and motivation structure for better operation and investment.

In this research, the simulated LTDH system was based on a heating network installed at the University of Nottingham, illustrated in Figure 4-2 and Figure 4-3. This heating network, linking up seven houses named Creative Energy Homes, is a double loop system [100]. The central thermal store is used to store stochastic renewable generation and supply heating demand during peak hours. Its volume is 10,000 L with polyurethane of 100 mm thickness as insulation material. The thermal conductivity, then, is 0.23 W/mK [100]. The installed heating capacities and energy generation technologies of each building are presented in Table 4-1. The David

Wilson House was selected for the testing of heat exchanger efficiency in Chapter 5. Schematic hydraulic layouts of the central thermal store and David Wilson House can be found in Appendix 1.

In Figure 4-3, the heating network as a double loop system applies the prosumer concept where consumers can buy and sell heat. The consumer loop supplies a water temperature below 60°C and manages the return pipes at 25°C. On the other hand, the prosumer loop that delivers a 25°C water temperature from the central thermal store to homes can obtain heat from distributed heat generation units such as solar thermal, biomass and heat pumps [100]. The heat interface units (HIUs) of generation leg (i.e., prosumer HIUs) are named as Danfoss FlatStation – 3 Series BS Basic Fully Insulated with a 7 kW heating capacity. The network HIUs (i.e., consumer HIUs) are Danfoss FlatStation – 7 Series DS Fully Insulated, that the heating capacity is 7-10 kW for SH and 35 kW for DHW [100]. Moreover, well-insulated twin pipes are selected to connect the Creative Energy Homes. This twin pipe, comparing with a single pipe, can reduce heat losses by around 24-30% [100]. An illustration of the single and twin pipes is shown in Figure 4-4.

This research planned to apply this LTDH system to validate the designed community energy system model. However, the initial testing result showed that the heat transfer efficiency of the HIU located in the central thermal store plant room (Figure 4-2) exceeds 100%. This inaccurate testing result was induced by the erroneous water flow data, which may have been influenced by the rotten metal pipes that connect the thermal store and pumps. Due to lack of funding, this problem cannot be solved, and the critical component, GSHP, cannot be installed. Thus, this research only applied the available testing data at the David Wilson House.

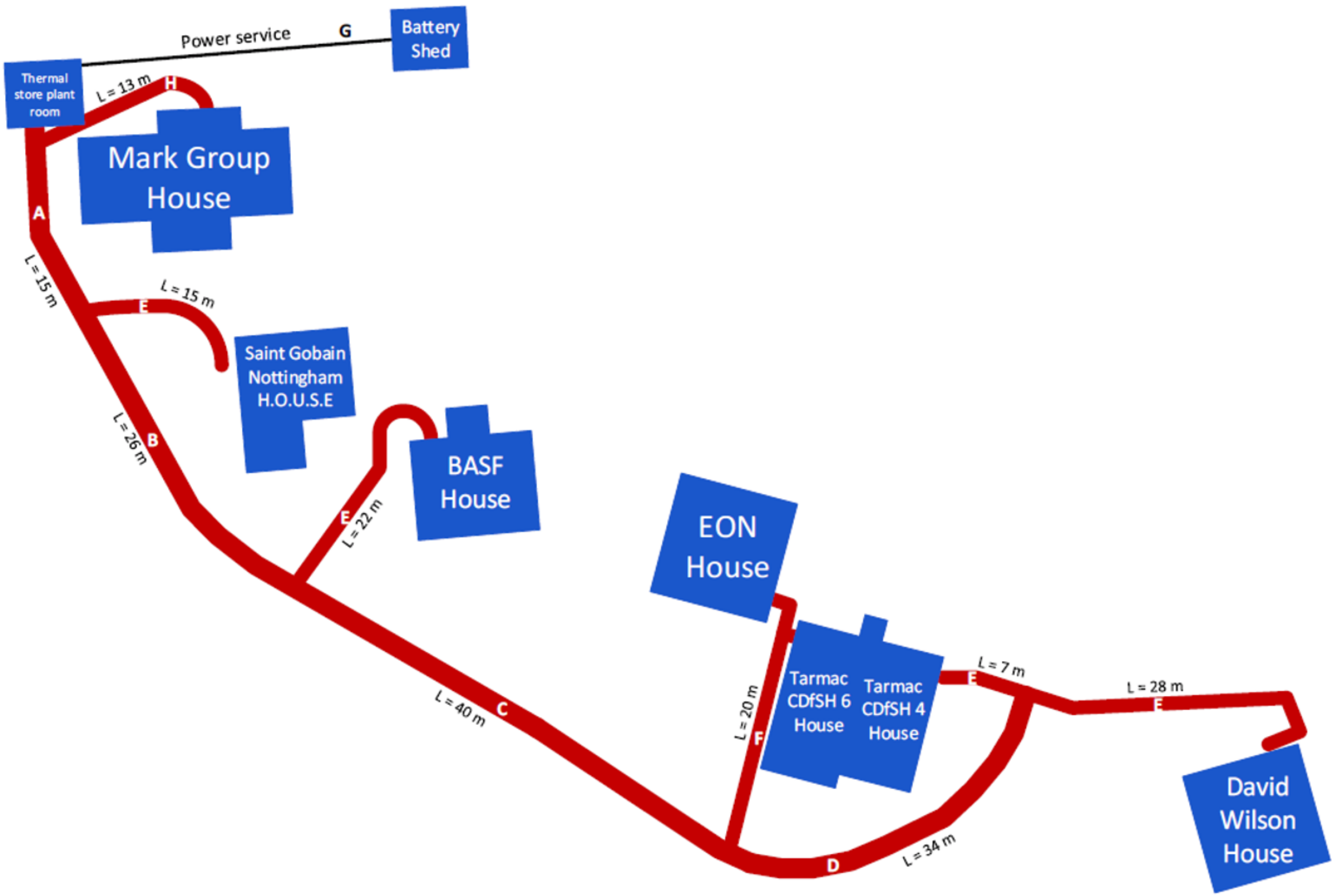

Figure 4-2: An illustration of the low-temperature district heating network with the connected Creative Energy Homes [100].

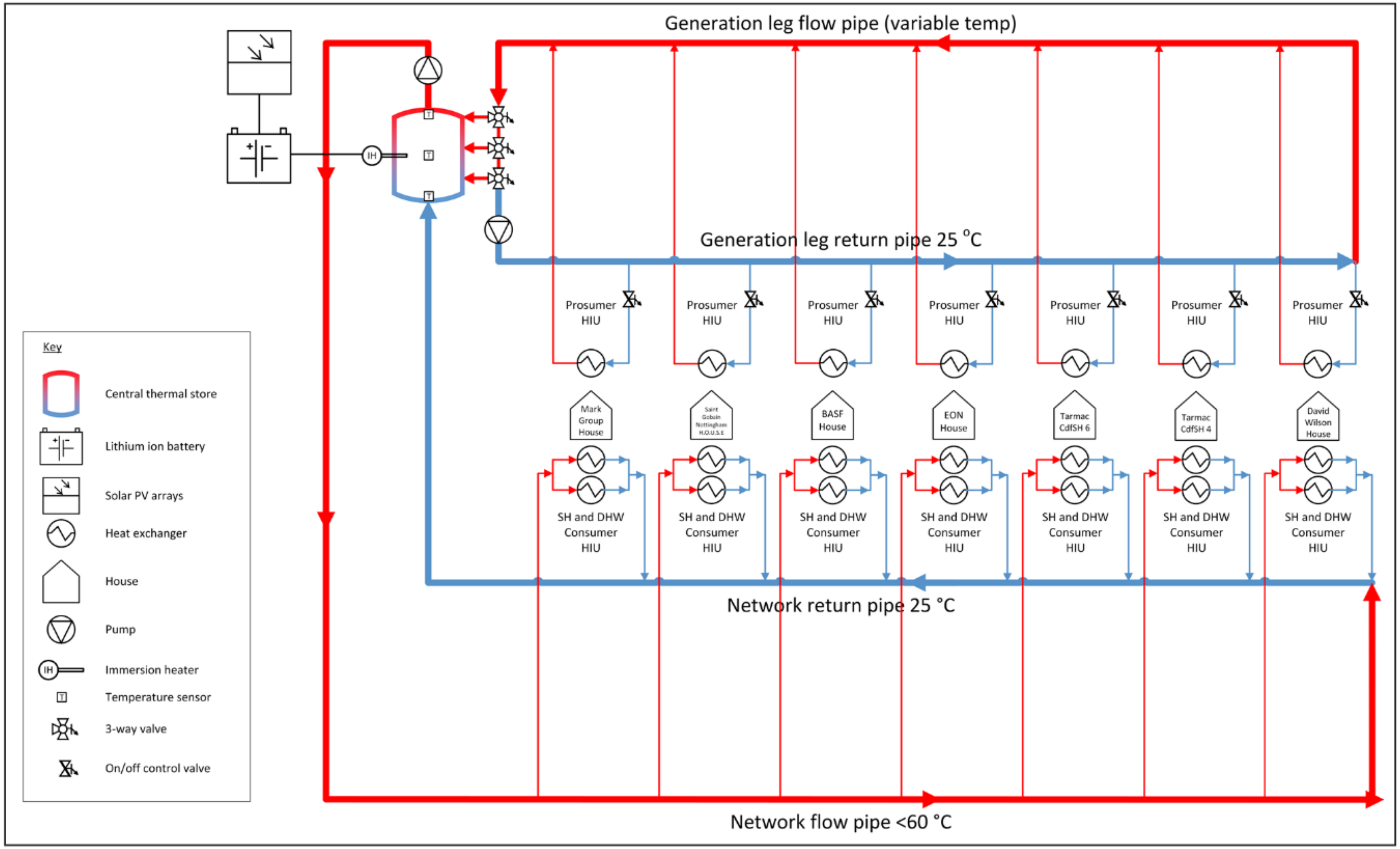

Figure 4-3: A double loop heating network at the University of Nottingham [100].

Table 4-1: Energy production technologies and peak installed capacities of the Creative Energy homes [100].

Building name	Energy production technology	Peak installed capacity (kW)
David Wilson House	Evacuated tube solar thermal collector	4.42
	Gas boiler	24
Mark Group House	Evacuated tube solar thermal collector	4.42
EON House	Gas boiler	12
BASF House	Flat plate solar thermal collector	3.2
Tarmac House (No. 12)	Biomass boiler	15
	Flat plate solar collector	1
Tarmac House (No. 10)	Flat plate solar collector	1
Saint-Gobain Nottingham House	Immersion heater	1.28
Central thermal store	Immersion heater	12
	Total	78.32

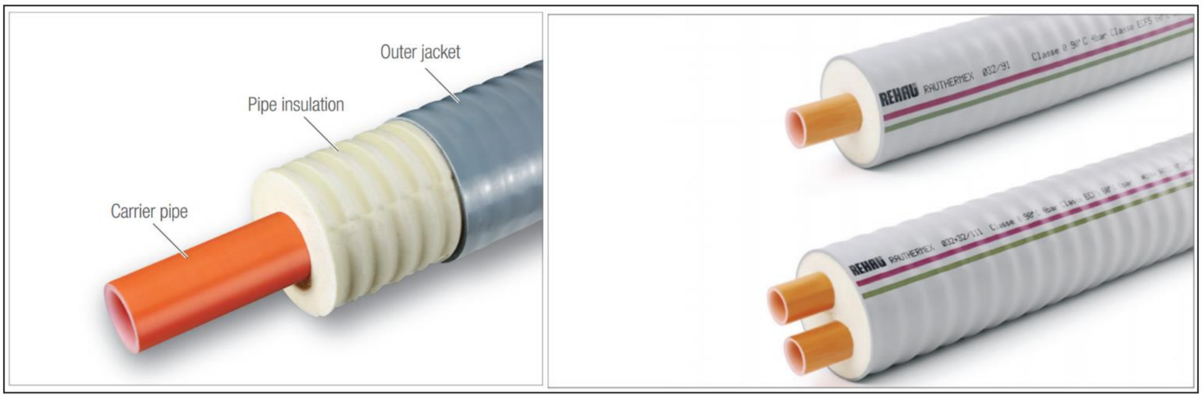

Figure 4-4: RAUTHERMEX pre-insulated bonded pipe main components (left), single pipe and twin pipes (right) [100].

4.3. Community-scale peak shaving

In general, within a distribution network, the output capacity of transformers and thermal limits of power lines constrain the maximum electric power supplied to homes [108]. Installing a community battery is not able to boost this network capacity. Therefore, when the power consumption is greater than the network constraint, the utilisation of a community battery cannot be a solution to meet the demands.

In a community energy system, the integration of storage units, heating and distribution networks enables the community-scale peak shaving, illustrated in Figure 4-5. The maximum output power of the distribution network and the electric power of the GSHP are assumed to be 0.4 MW and 0.12 MW, respectively. Figure 4-5 (a) shows the electricity flows during off-peak hours. The community substation supplies electricity with an electric power of 0.28 MW to homes and the community battery whilst conveying an electric power of 0.12 MW to the GSHP. In Figure 4-5 (b), during peak hours, the distribution network constantly supplies the maximum power of 0.4 MW. At the same time, the community battery discharges its stored electricity with a power of 0.12 MW to the GSHP. From the consumers' perspective, the community substation with a 0.4 MW network capacity provides an electric power of 0.52 MW during peak hours. A steady electricity flow (0.4 MW) throughout a day attains the ideal of peak shaving.

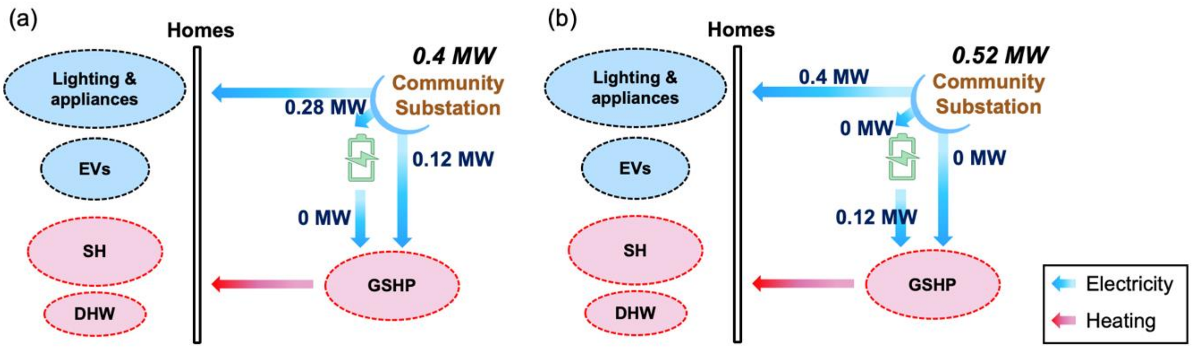

Figure 4-5: The illustration of the community-scale peak shaving in the multi-vector community energy system, (a) off-peak hours and (b) peak hours.

The concept of community-scale peak shaving enables a community to consume the electric power greater than the designed capacity of the electricity grid, employing the community battery (the battery placed at the community substation in Figure 4-1) to supply the power demand for heating. Nonetheless, this approach still has its limitation because the maximum output power of the electricity grid is still 0.4 MW. Thus, when the power demands of the EVs, lighting and appliances in Figure 4-5 exceeds 0.4 MW, a home-based power supply is required, which is the battery located at home in Figure 4-1.

4.4. Electricity flow management

This subsection introduces electricity flow management within a community energy system, which is essential for avoiding overload issues, reducing the reinforcement cost and increasing stability in this distribution network. Electricity consumption of a community is categorised into the appliances, EVs and GSHP, illustrated in Figure 4-6. The appliances are powered by the electricity grid, which is the same as without a community energy system. The utilisation of a home battery is determined to be the primary backup that can offset the increased power demand of a dwelling during peak hours.

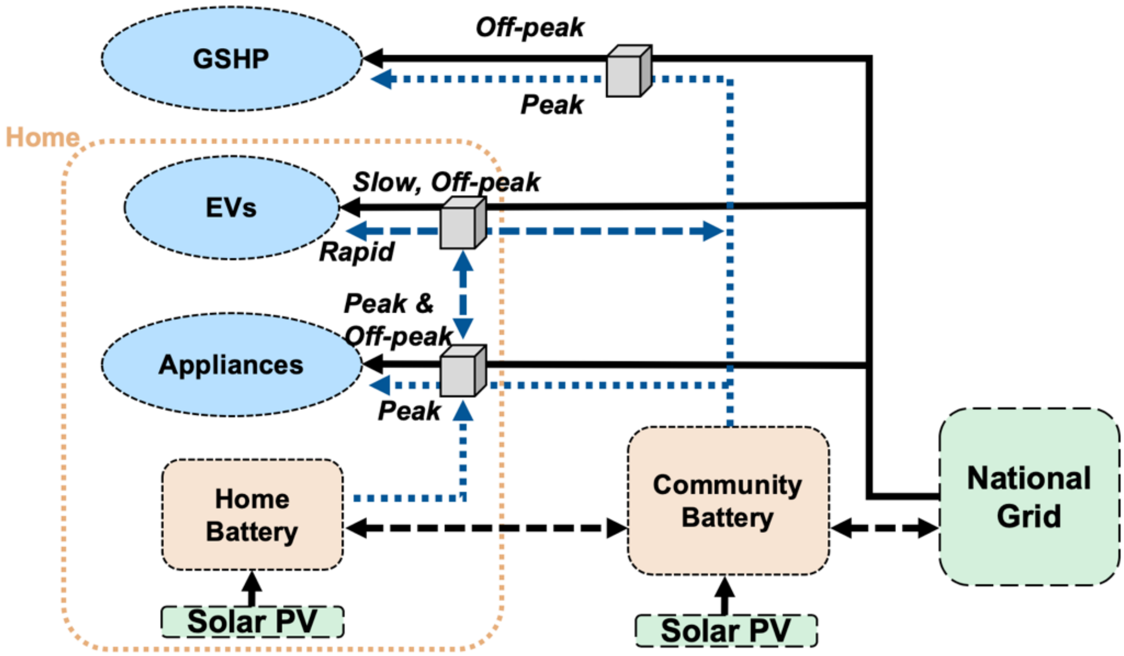

Figure 4-6: An illustration of electricity flow management within a community energy system.

For EV charging, two connector types that include the slow charger at home and rapid charger located at the community substation are assumed. Based on the statistical data [85] depicted in section 3.3.2, the average daily demand of an EV is around 3.6 kWh, which indicates a slow charger with 3 kW power can meet diurnal consumption in less than two hours. On the other hand, rapid charging is provided by the community battery that has a large capacity and performs like a conventional gas station. The maximum charging power of a battery is aligned to its capacity, addressed in detail in section 6.1.5.

To reduce the impact of EV charging on an electricity system, EVs should be charged during off-peak hours (i.e., smart charging) and can be charged by rapid charging at any time; however, with a higher tariff. Another feature of EVs is the V2G technology, which mainly is assumed to support the demand for homes. The GSHP is powered by the electricity grid at off-peak hours and community battery during peak hours, thus realising the community-scale peak shaving.

In Figure 4-6, electricity storage units, community and home batteries, are connected to PV modules. To an individual home, PV production is mainly stored in the home battery, unless the electricity generation exceeds the storage capacity. The surplus electricity is delivered to the community battery that is supposed to link with a community PV system placed in the substation. In the case of total electricity generation of the community greater than the capacity of battery storage, the exceeding electricity can be consumed by the GSHP for heat production and then stored in the thermal store of the LTDH system. The decentralised generation (i.e., PV modules) is aimed to achieve self-consumption but able to convey electricity to the grid.

4.5. Supply and demand data management and a smart grid based on community energy systems

Utilising SCADA systems to monitor and control supply and demand improves the reliability and efficiency of a community energy system coordinated with the electricity grid. SCADA systems are widely used in industrial processes for increasing performance and preventing potential faults in facilities [109]. Early SCADA systems were operated independently without connecting to other systems. Currently, systems are linked together for sharing information, thereby achieving real-time management [110].

An illustration of the supply and demand data management, enabled by a SCADA system, is shown in Figure 4-7. The weather condition received from the National Grid is utilised to predict the output of decentralised generation such as solar PV, solar thermal, etc. and demands of electricity and heating that also correlate with thermal efficiency in buildings, numbers of occupants and EVs. Subsequently, the central control system located in the community substation summarises the monitored data, calculates the conversion efficiency for heat production (e.g., GSHP) and conveys the data of total electricity demand to the National Grid.

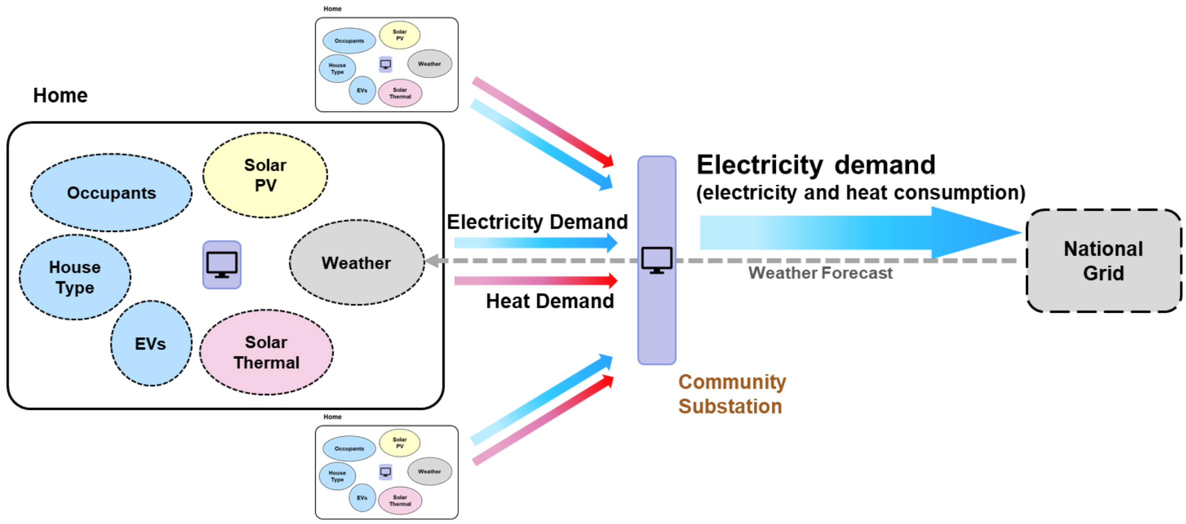

Figure 4-7: The sequence of demand data management.

Multi-vector community energy systems can create an efficient connection between buildings, communities and even regions. This can be interpreted in the spatial perspective [14], shown in Figure 4-8. In a home block, the input of electricity is consumed by EVs, appliances and electric heaters. The input of heat, on the other hand, supplies the consumptions of SH and DHW. In terms of a community level, the homes are linked with the distribution network and LTDH system. A community substation as the control centre of a community receives electric power from the grid and distributes the electricity to homes and the central heat generation unit (e.g., GSHP). This community, managed by a community energy system, is defined as one unit that can interact with other units (i.e., communities) through the electric power network. Therefore, energy systems can be modelled and optimised at different geographical levels, and finally be assembled. This character will provide nations with a great approach to manage smart cities that are highly digital and electrified.

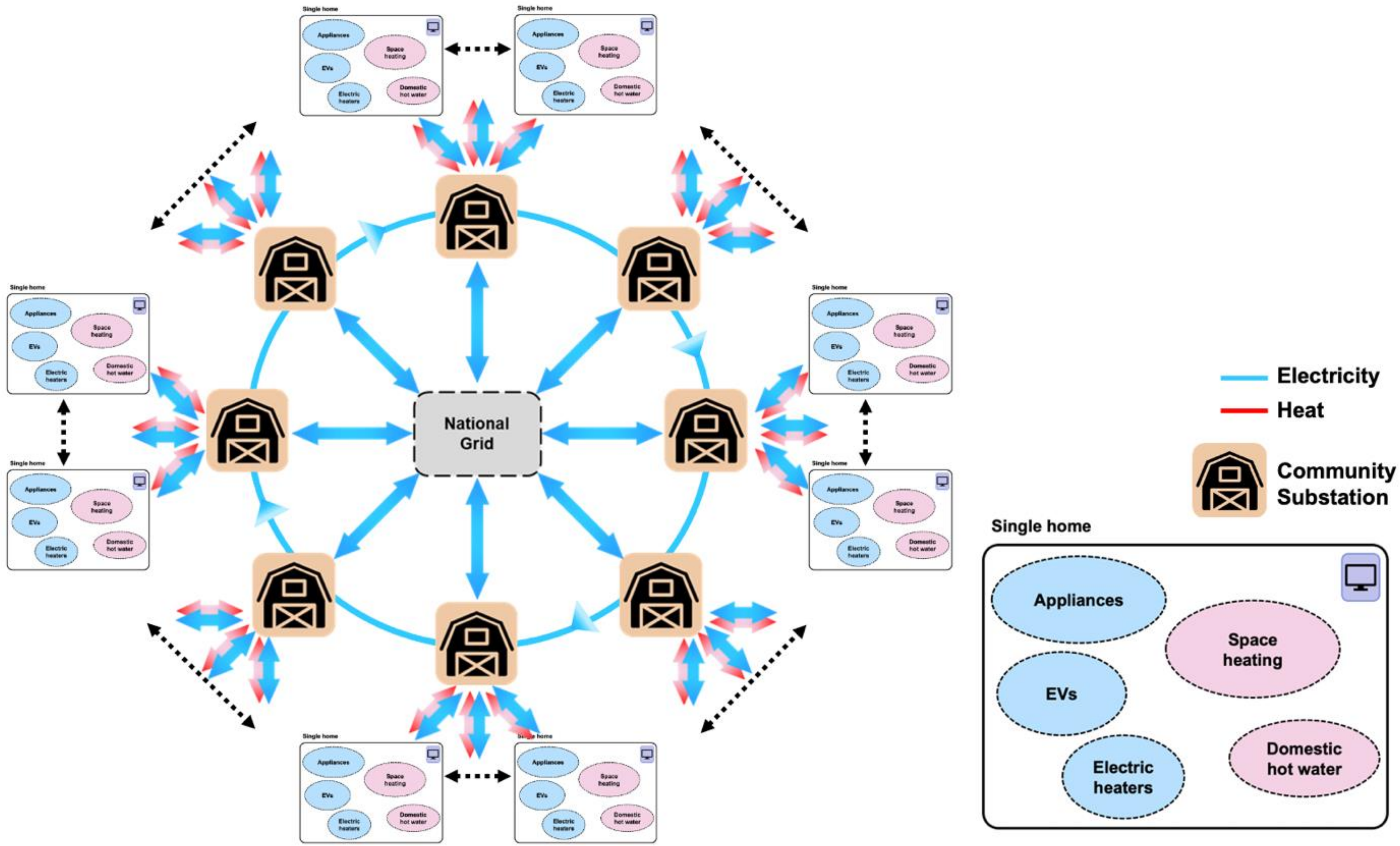

Figure 4-8: The connection of multi-vector community energy systems.

4.6. Discussion and conclusion

This chapter defined a multi-vector community energy system that interacts with the electricity grid, integrates heating and distribution networks, and performs smart control solutions. An efficient electrified heating network is comprised of a GSHP, LTDH system, electric heaters and thermal storage units. On the other hand, EVs, appliances, battery storage, decentralised generation and heat production units are connected within a distribution network of a community.

In this research, the LTDH system, evaluated for establishing an electrified community, is located in the University of Nottingham. The distribution pipes, thermal conductivity of a central thermal store, and efficiency of HIU will be applied to simulation models. Using an electric heating device (i.e., GSHP) to connect heating and distribution networks as well as employing a community battery to power the heating device during peak hours enables the community-scale peak shaving. This presents that with smart management, a consumption power greater than the capacity of the existing electricity network can be met. This approach also creates a steady electricity flow of a community throughout a day. The community battery, apart from powering the heating device, functions as a traditional gas station. This means that the community battery is a rapid charging point which supplies electricity to EVs in a limited time. This function can be realised because the discharge power of a battery is aligned with its capacity.

Moreover, this chapter illustrated a SCADA system that monitors decentralised generation and controls electricity supply to meet consumption. By utilising this SCADA system, electrified communities can share the information with the grid; hence, efficient and real-time system management is achieved. Multi-vector community energy systems are designed to manage domestic heating and electricity consumptions and connect each other with electric power networks. This optimised approach, therefore, attains an excellent efficiency for the 100% electrification.

Chapter 5

Establishing an Electrified Heating Network

Natural gas is currently a significant fuel for meeting domestic heating demands of around 80% in the UK [111]. This primary fuel is going to be removed from supply to attain lower greenhouse gas (GHG) emissions. Electrification of heating is an alternative solution to natural gas. However, this approach presents challenges with a significant increase in electricity demand-supply [11, 42]. A multi-vector community energy system, illustrated in Chapter 4, is employed to tackle the mentioned issue. As the first step of establishing a community energy system, this chapter defines and optimises an electrified heating network. The focus is on the determination of distribution temperature.

In this research, an electrified heating network within a community energy system that supplies domestic space heating (SH) and domestic hot water (DHW) comprised a ground source heat pump (GSHP) [66], low-temperature district heating (LTDH) system [58], electric heaters and thermal storage units (including central thermal store and DHW storage tanks). In terms of a district heating system, the distribution water temperature determines the system efficiency. Applying a lower distribution temperature to reduce heat losses is commonly suggested [112]. However, in an electrified heating network scenario, heat losses are not the only primary factor to define the distribution temperature. The efficiency of heat production is an important element in such a system.

A systematic modelling approach that evaluates heating capacity, heating demands, GSHP capacity, coefficient of performance (COP) of a GSHP, thermal energy storage (TES), heat losses and the utilisation rate of GSHP (high efficiency) and electric heaters (low efficiency) at various distribution temperatures is created and demonstrated on energyPRO [113]. The result will indicate the electricity consumption of this heating network. This model will be tested in projected 2050 scenarios to illustrate the variation of the optimum distribution temperatures (i.e., the least electricity consumption temperature) in a future world. Furthermore, the heating demands are characterised by the demand ratio of DHW to SH that can be reflected in thermal efficiency in buildings and evaluated at various community scales for identifying the scalability.

The following sections in this chapter are elaborated as: Section **5.1 Modelling methodology** depicts the methods of establishing the systematic modelling approach and simulated scenarios. Section **5.2 Results** compares the energy consumptions at various distribution temperatures and indicates the most electricity-saving condition. Section **5.3 Discussion and conclusion** summarises the results and delivers the key messages for establishing an electrified heating network.

5.1. Modelling methodology

This section first defines the heating capacity of an individual home, used to determine the pipe sizes for heat loss evaluation. The heat loss on the heat exchanger, on the other hand, is assessed based on an existing LTDH system in the University of Nottingham. Subsequently, this section investigates monthly consumptions of DHW and SH in average UK dwelling in 2018 and describes the formulas for calculating electricity demands of the GSHP and electric heaters. Applying the data of the greatest consumption month defines the thermal storage capacity and electric power of the GSHP. The COPs of the GSHP at various supply temperatures are illustrated. Finally, the possible DHW and SH demands in 2050 are depicted as scenarios.

5.1.1. Heating capacity in average dwelling

The heating capacity for SH is described by Eq. (1).

$$Q_{SH} = Q_{building} * (\vartheta_i - \vartheta_a) \quad \textbf{(1)}$$

where Q_{SH} is the heating capacity for SH demand (W), $Q_{building}$ is the heat loss per degree C in average UK building (W/°C), ϑ_i and ϑ_a are the indoor and outdoor temperatures (°C). The heat loss data ($Q_{building}$) based on the UK housing survey indicated that if the outdoor temperature is cooler than indoor temperature by 1°C, the average UK building needs 290.4 W of heat to keep a steady indoor temperature in 2011 [114]. This heat loss data in 2011 was utilised to assess the heating capacity because of the latest data in the report. Moreover, the installation of building insulation is experiencing slower than expected progress in the UK since 2012 [115]. The indoor (ϑ_i) and outdoor temperatures (ϑ_a) are defined by the average temperatures in winter in 4 decades. To cover various temperature gaps, the highest indoor temperature, 19°C, and lowest outdoor temperature, 4°C, were selected [114]. As a result, the heating capacity for SH is 4.4 kW.

For DHW, a heating capacity supplying instantaneous consumption is not required due to thermal storage. The heating capacity was determined to meet the consumption in the greatest demand hour. This hour of an average UK dwelling was from 8 to 9 am and consumes around 1 kWh of heat [116]. Accordingly, the heating capacity for SH and DHW demands is 6 kW in a dwelling, equipping an additional 10% capacity.

5.1.2. Heat losses on a low-temperature district heating (LTDH) system

The modelling methods of heat losses on pipes and heat exchanges are introduced in this subsection. The evaluated distribution temperatures range between 40°C and 70°C. The 40°C distribution temperature has been applied to several innovative projects, which can satisfy the SH demand by utilising low-temperature radiators or underfloor heating [63, 117]. Unlike the distribution temperature, the return temperature is always 30°C within the models.

For the pipe heat loss assessment, two pipe types from REHAU were applied, which includes the twin pipe named RAUTHERMEX DUO for accommodating a flow rate lower than 3.6 l/s and single pipe named RAUTHERMEX UNO for a flow rate over 3.6 l/s [118]. The flow rates in each temperature condition were identified by Eq. (2).

$$V = \frac{Q_h}{C_p * (\vartheta_F - \vartheta_R) * \rho} \tag{2}$$

where V is the flow rate (l/s), Q_h is the heat flow (kW), C_p is the specific heat capacity of water (4.18 kJ/kg°C), ϑ_F and ϑ_R are the flow and 30°C return temperatures and ρ is the water density (0.99 kg/l). The heat flow (Q_h) is the heating capacity mentioned in the previous subsection. Therefore, the flow rate (V) is variable to the distribution temperature. The 40°C distribution temperature resulting in the highest flow rate was used to determine the pipe size.

The pipe sizes with various flow rates were defined by applying a pressure loss table [118]. The procedures of measuring pipe sizes are: (1) calculating the flow rate, (2) reflecting the data on the pressure loss table, and (3) selecting the pipe with the pressure loss lower than 200 Pa/m [118]. Table 5-1 presents the recommended pipe sizes aligning with flow rates and thermal transfer coefficients (U).

Table 5-1: The correlation between flow rate, pipe size and thermal transfer coefficient [118].

Types of pipe	Flow rate (l/s)	Pipe size (mm)	U (W/m°C)
RAUTHERMEX DUO	< 0.1	20x1.9	0.116
	< 0.19	25x2.3	0.139
	< 0.38	32x2.9	0.183
	< 0.68	40x3.7	0.211
	< 1.25	50x4.6	0.195
	< 2.35	63x5.8	0.238
	< 3.6	75x6.8	0.28
RAUTHERMEX UNO	< 5.9	90x8.2	0.206
	< 10	110x10	0.296
	< 14	125x11.4	0.303
	< 18	140x12.7	0.308
	< 29	160x14.6	0.303

The layout of the heating network for pipe heat loss assessment is illustrated in Figure 5-1. This determines the lengths of pipes and is presented as units that one unit is comprised of one main pipe and two branch pipes. Only one branch pipe in a unit is also applicable.

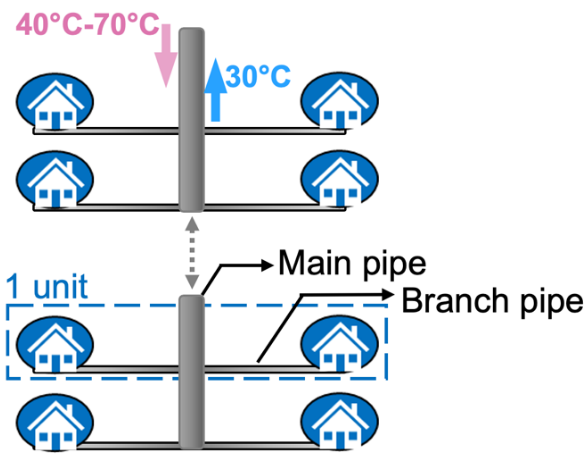

Figure 5-1: The layout of the heating network for pipe heat loss assessment.

The branch pipes are assumed to be the same for each dwelling. The required heating capacity in a dwelling (6 kW) indicates that the flow rate is 0.14 l/s at 40°C supply temperature. Thus, the pipe size and U value of the branch pipes are 25x2.3 mm and 0.139 W/m°C, shown in Table 5-1. On the other hand, the flow rate of the main pipe is the flow rate of a branch pipe multiplied by the number of dwellings. The community-scale is 20 dwellings for the twin pipe evaluation at the beginning of the simulation. Larger communities are evaluated and presented in subsection 5.2.3. In the case of 20 dwellings, the flow rate of a branch pipe (0.14 l/s) multiplied by 20 dwellings is 2.8 l/s. The main pipe size and U value, therefore, are 75x6.8 mm and 0.28 W/m°C, respectively.

The formula for the heat loss calculation is described by Eq. (3), where Q_{pipe} is the pipe heat loss per meter (W/m), U is the thermal transfer coefficient (W/m°C), ϑ_O is the average operating temperature (°C), and ϑ_S is the assumed soil temperature 10°C.

$$Q_{pipe} = U * (\vartheta_o - \vartheta_s) \quad \textbf{(3)}$$

The calculation of heat losses (Q_{loss}) on branch and main pipes is given by Eq. (4).

$$[U_{branch} * (\vartheta_o - \vartheta_s) * l_{branch} * N_{branch} + U_{main} * (\vartheta_o - \vartheta_s) * l_{main} * N_{main}] * h_o = Q_{loss} \quad \textbf{(4)}$$

where l_{branch} and l_{main} are the lengths of a branch pipe and main pipe (m) in a unit, N_{branch} and N_{main} are the numbers of the branch pipes and main pipes in a heating network and h_o is the annual operation hours (i.e., 8,760 hours).

The pipe heat loss is induced in the LTDH system that utilises GSHP to provide heat. Thus, by dividing the heat loss (Q_{loss}) with the COP of the GSHP (COP_{GSHP}) obtains the electricity consumption of the GSHP (E_{GSHP}), as described by Eq. (5).

$$E_{GSHP} = \frac{Q_{loss}}{COP_{GSHP}} \quad \textbf{(5)}$$

The heat transfer efficiencies of heat exchangers, representing the heat losses on heat exchangers, at various temperatures are illustrated in Figure 5-2. The data is gained by testing the LTDH system introduced in section 4.2, which uses a heat exchanger named Danfoss FlatStation – 3 Series BS Basic Fully Insulated. The actual water temperature at the consumer side is also discovered and shown in Figure 5-3. The methods of applying this data to models are addressed in the following subsections.

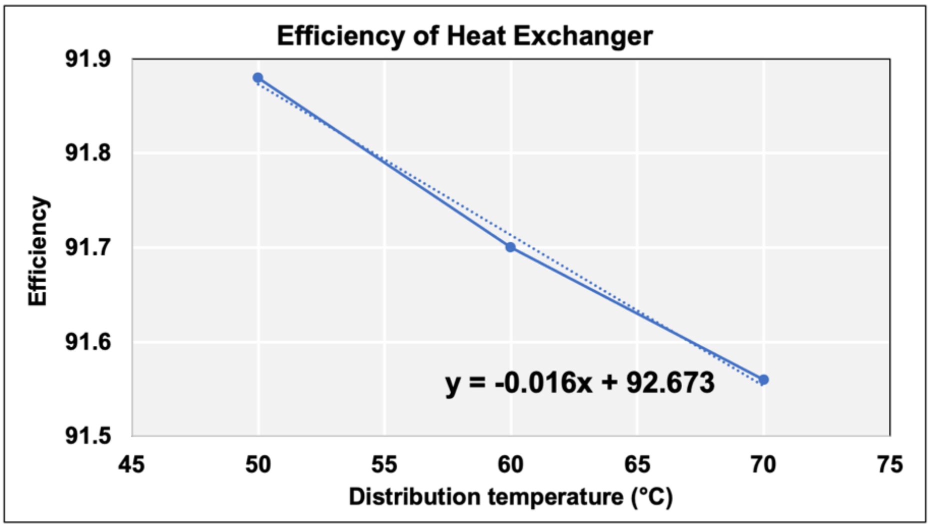

Figure 5-2: The heat transfer efficiency of the heat exchanger.

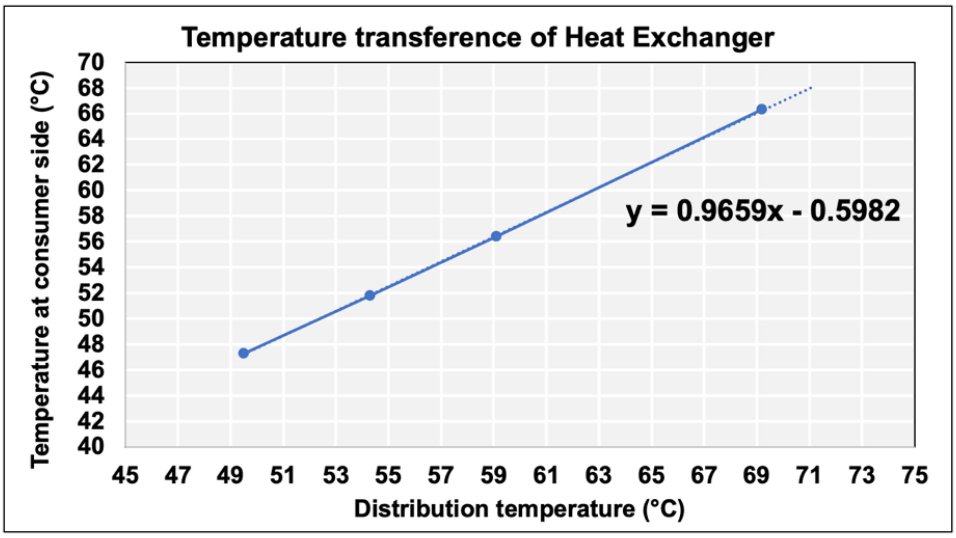

Figure 5-3: The temperature transference of the heat exchanger.

5.1.3. Domestic hot water (DHW) consumption

The energy consumption for DHW is related to the water volume, cold inlet temperature, hot water delivery temperature and mainly determined by the number of occupants. The number of occupants in an average UK dwelling is around 2.4 [119]. A survey monitoring approximately 120 dwellings indicated that the daily hot water consumption volume is about 108 litres/day in a dwelling with 2.4 occupants [116]. The monthly hot water consumption volumes in an average UK dwelling were derived from the same survey, illustrated in Figure 5-4. The month with the greatest hot water demand is December, attaining 3,676 litres. In contrast, the lowest hot water consumption month is July, consuming 2,689 litres.

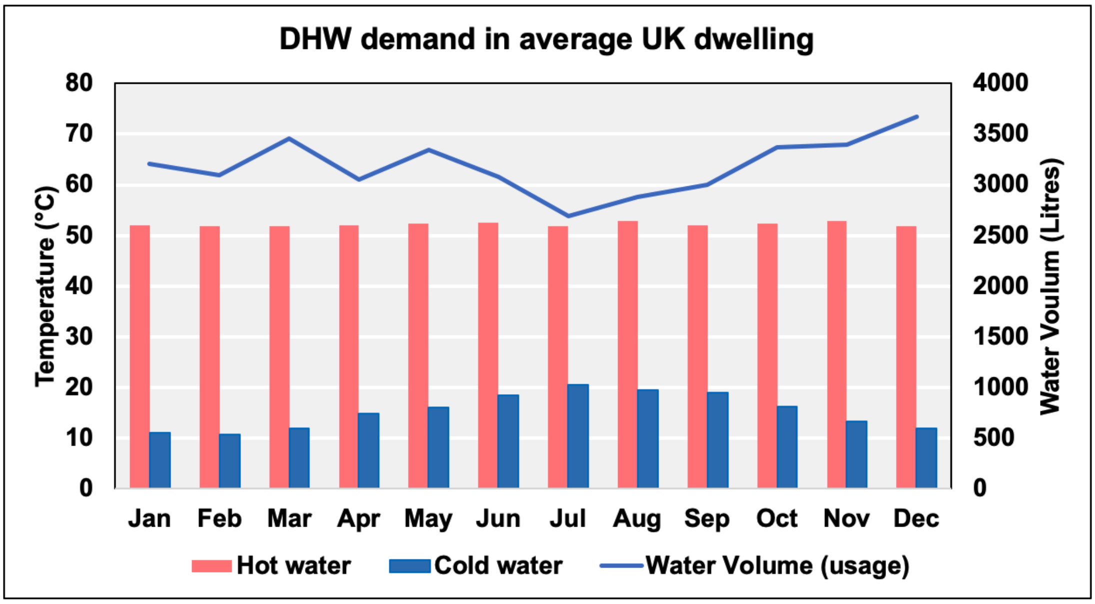

Figure 5-4: The monthly hot water consumption volume, cold water inlet temperature and hot water delivery temperature in the UK [116].

Figure 5-4, furthermore, shows the cold inlet temperature and hot water delivery temperature [116]. The variation of the cold inlet water temperature is related to the ambient temperature. The lowest and highest cold inlet temperatures are around 10.7°C in February and 20.5°C in July. In comparison with the cold inlet temperature, the hot water delivery temperature is relatively stable, around 52°C.

Accordingly, the monthly energy consumptions of DHW can be obtained by the heat capacity formula given by Eq. (6).

$$Q = m * C * \Delta T \qquad \textbf{(6)}$$

where Q is the heat capacity (kJ), m is the mass (kg), C is the specific heat (kJ/kg°C) and ΔT is the temperature difference (°C). As a result, the annual energy consumption of DHW is 1649.1 kWh in an average UK dwelling.

The DHW consumption is supplied by two sources including the LTDH system and electric heaters. The heat provided by electric heaters is calculated by Eq. (7), where $Q_{heaters}$ is the heat supply from electric heaters (kJ), $\vartheta_{setting}$ is the setting temperature on household tanks (i.e. 60°C), ϑ_{tank} is the actual water temperature delivered to household tanks (°C) and m_{tank} is the mass of water in household tanks (kg). The actual water temperature delivered to household tanks is derived from the equation shown in Figure 5-3.

$$Q_{heaters} = (\vartheta_{setting} - \vartheta_{tank}) * C_p * m_{tank} \quad \textbf{(7)}$$

The COP of electric heaters is 1 within models; hence, the electricity consumption of electric heaters is equal to their heat production. To gain the amount of heat supplied by the LTDH system (Q_{LTDH}), the DHW consumption (Q_{DHW}) is subtracted by the heat supply from electric heaters ($Q_{heaters}$), given by Eq. (8).

$$Q_{LTDH} = Q_{DHW} - Q_{heaters} \quad \textbf{(8)}$$

To factor in the heat loss of heat exchangers, the heat provided by the LTDH system (Q_{LTDH}) is divided by the efficiency ($\eta_{exchanger}$) of the heat exchangers presented in Figure 5-2. The calculation formula is Eq. (9), where $Q_{DHW\ LTDH}$ is the final heat consumption of the DHW supplied by the LTDH system. Finally, the electricity consumption of the GSHP generating heat to the LTDH system is calculated by dividing the final heat consumption with the COP of the GSHP, which is the same formula as Eq. (5).

$$Q_{DHW\ LTDH} = \frac{Q_{LTDH}}{\eta_{exchanger}} \quad \textbf{(9)}$$

5.1.4. Space heating (SH) consumption

In 2018, the SH consumption in average UK dwelling consumed 3.86 times more energy than DHW consuming 1649.1 kWh [120]. Thus, the annual consumption of the SH was 6365.4 kWh. To generate the data of monthly demands, the external and internal temperatures are required to be defined and input to energyPRO.

The hourly external temperature was found from ERA5 that is an online dataset covering the climate variables (e.g., air temperature, solar radiation, wind speed, etc.) on earth since 1979 [121]. On the other hand, the desired indoor temperature has been maintained at around 17-18°C after 1997 [114]. Research has highlighted that exposure to low indoor temperatures causes chronic respiratory diseases, thereby increasing winter mortality in the UK [122]. To keep people staying in good health and comfortable living condition, the bedroom temperature should be above 18°C [123, 124], which is the target temperature of the SH.

Figure 5-5 illustrates the monthly consumptions of the SH and DHW in an average UK dwelling. The greatest consumption month of the SH is the coldest month, February. This consumes 1,081 kWh. In contrast, the lowest consumption month is July, reaching 40 kWh.

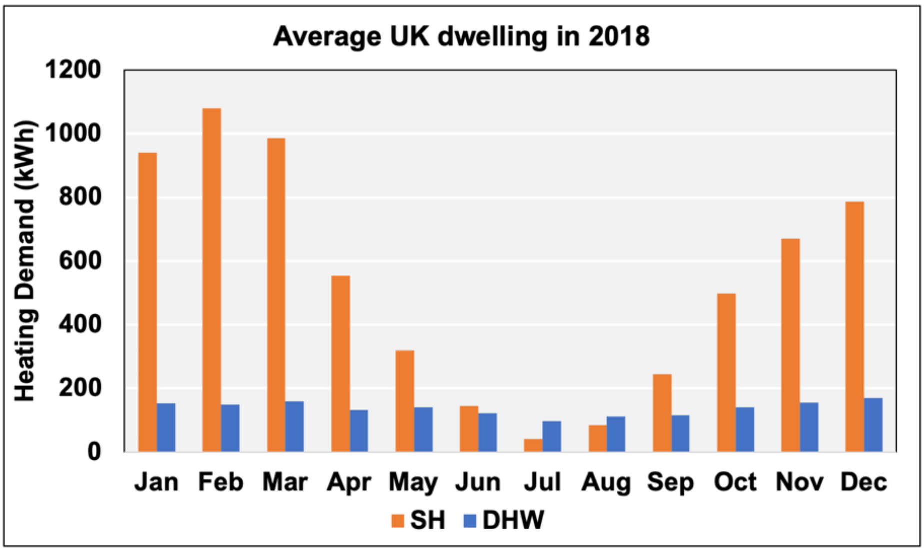

Figure 5-5: The monthly energy consumptions of the SH and DHW in average UK dwelling in 2018 [116, 120].

The final consumption of the SH, considering heat loss on heat exchangers, is calculated by dividing the SH demand with the efficiency of the heat exchangers. This applied Eq. (9). The SH demand is supplied by only the LTDH system. Therefore, by dividing the final consumption with the COP of the GSHP obtains the electricity consumption for SH, described by Eq. (5).

5.1.5. Thermal energy storage (TES)

Thermal energy storage (TES) can increase reliability and reduce the peak demand of heating networks [125]. It is often used to store the heat production of solar thermal devices [105]. In this research, a water-based TES was selected to store the energy generated by the GSHP due to its being cost-effective and the ability to store thermal energy for days or months [126].

The collective volume of the thermal store in the community substation is calculated by the heat capacity formula Eq. (6). In this chapter, the thermal storage capacity is defined to store the average daily demand in the greatest consumption month, thereby enabling the smart control of the heating network. Figure 5-5 indicates the highest consumption month is February, which consumes 1228.7 kWh in an average dwelling. Thus, the daily storage capacity is 43.9 kWh, derived from the February consumption divided by the number of days in February. The storage temperatures are aligned with the distribution temperatures, shown in Table 5-2. Furthermore, the utilisation rate of the thermal store is assumed to be 80%, enabling a 20% consumption buffer. Table 5-2 presents the volumes of the community thermal store at each storage temperature in a community with 20 dwellings.

Table 5-2: Volumes of community thermal store at various storage temperatures.

Storage temperature (°C)	40	50	60	65	70
Volume of thermal store (m^3)	94.5	47.2	31.5	27.0	23.6

Return temperature (°C): 30, Utilisation rate: 80%, Number of homes: 20

5.1.6. Ground source heat pump (GSHP)

A GSHP is the primary heating technology in the electrified heating network due to great and stable COP. Besides, a GSHP can provide cooling demand in summer, which is expected to be essential with climate change. For instance, the extreme weather condition recorded in the UK in 2018 showed that the lowest temperature fell to -14°C, with the high ambient temperature reached above 35°C in June and July [127]. Nowadays, the heating demand is still much higher than the cooling demand in the UK; hence, this research focused on the heating strategy.

The electric power of the GSHP is defined by Eq. (10) where P_{GSHP} is the electric power of the GSHP, Q_d is the average daily demand in the greatest consumption month, h_o is the operation hours and N_{homes} is the number of homes.

$$P_{GSHP} = \frac{Q_d}{COP * h_o} * N_{homes} \quad \textbf{(10)}$$

The average daily demand (Q_d) derived from the data in Figure 5-5 is 43.9 kWh. The COP of a GSHP is in relation to the source temperature and supply temperature [66]. The source temperature representing soil temperature is assumed to be 10°C. The COP of a GSHP, then, is defined to be 4 when the supply temperature is 50°C [66]. To obtain COPs at various supply temperatures, this condition with a COP of 4 is applied to energyPRO. Also, the operation hours of the GSHP (h_o) are decided to be 7 hours starting from midnight to 7 am; off-peak hours. Table 5-3 shows the COPs and electric powers of the GSHP in a community with 20 dwellings.

Table 5-3: COPs and electric powers of the GSHP at various supply temperatures.

Supply temperature (°C)	40	50	60	65	70
COP	4.66	4	3.52	3.33	3.16
GSHP electric capacity (kW)	26.9	31.3	35.6	37.7	39.7

Return temperature (°C): 30, Soil temperature (°C): 10, Number of homes: 20

5.1.7. The 2050 scenarios

The 2050 scenarios were applied to deliver a simulation result that shows the variation of the optimum distribution temperature with the future development of the built environment and discovers the correlation between SH and DHW demands that can be employed to build a scalable model.

The selected scenarios were in different consumption levels of SH and DHW. For SH, the demand has a high likelihood decreased with the increasing ambient temperature and housing thermal efficiency [128]. Due to the purpose of illustrating the distribution temperature trend, the evaluation included higher SH demand conditions.

For DHW, consumption can be reduced by improving the efficiency of appliances. However, greater demand for DHW is also possible to emerge according to the observed trend: the ‘high-flow’ shower [128, 129].

Table 5-4 presents the scenarios and demands of an average dwelling. The selected UK 2050 scenarios include three DHW demand levels: the 25% increase, 2018 level and 25% reduction. In each DHW condition, there are five levels of SH demand, ranging from 50% increase to 50% reduction. These percentage changes are calculated based on the heating consumptions in 2018.

Table 5-4: The scenarios and heating demand in an average dwelling.

Scenarios	Conditions	SH demand (kWh)	DHW demand (kWh)
2018		6365.4	1649.1
2050 Level 1 (DHW +25%)			
1	SH +50%	9548.2	2061.3
2	SH +25%	7956.8	2061.3
3	SH +0%	6365.4	2061.3
4	SH -25%	4774.1	2061.3
5	SH -50%	3182.7	2061.3
2050 Level 2 (DHW +0%)			
6	SH +50%	9548.2	1649.1
7	SH +25%	7956.8	1649.1
8	SH -25%	4774.1	1649.1
9	SH -50%	3182.7	1649.1
2050 Level 3 (DHW -25%)			
10	SH +50%	9548.2	1236.8
11	SH +25%	7956.8	1236.8
12	SH +0%	6365.4	1236.8
13	SH -25%	4774.1	1236.8
14	SH -50%	3182.7	1236.8

5.2. Results

To analyse the electrified heating network, the heating consumptions in the UK in 2018 were applied to the systematic modelling approach. Results include the pipe heat loss, energy sources supplied to DHW, electricity demand of the heating network and the demonstration model on energyPRO. Subsequently, the selected 2050 scenarios were input to the modelling approach, thereby illustrating the variation of the optimum distribution temperature. Finally, electricity consumptions in various demand ratios of DHW to SH were evaluated to identify the critical factor defining the supply temperature, which also considered different community scales to present scalability.

5.2.1. Analysis and demonstration of the electrified heating network

The annual heat loss on pipes was evaluated with various lengths of the main pipes and distribution temperatures ranging from 40°C to 70°C. The community-scale was 20 dwellings, and the branch pipes were fixed at 5m. Figure 5-6 (a) shows that the heat loss is increased with the increasing pipe length and distribution temperature. Utilising a 40°C distribution temperature can save around 38% heat loss annually at all pipe length conditions, compared to a 70°C supply temperature. Furthermore, the results of network heat consumptions indicate a 40°C distribution temperature reduces the consumptions by only 3% and 15% at the 5m and 100m main pipe length conditions, illustrated in Figure 5-6 (b).

The LTDH system and electric heaters supply DHW demand. The demand percentages from each energy source at supply temperatures of 40°C, 50°C and 60°C were calculated and illustrated in Figure 5-7. Conditions with a distribution temperature equal to or greater than 65°C can eliminate the usage of electric heaters; hence, they were omitted. The result illustrates that electric heaters provide 49% of the annual DHW consumption when the distribution temperature is 40°C. Applying the 50°C distribution temperature reduces the utilisation rate of electric heaters to 27% of the yearly consumption. This is decreased further to only 6 % when the distribution temperature is 60°C.

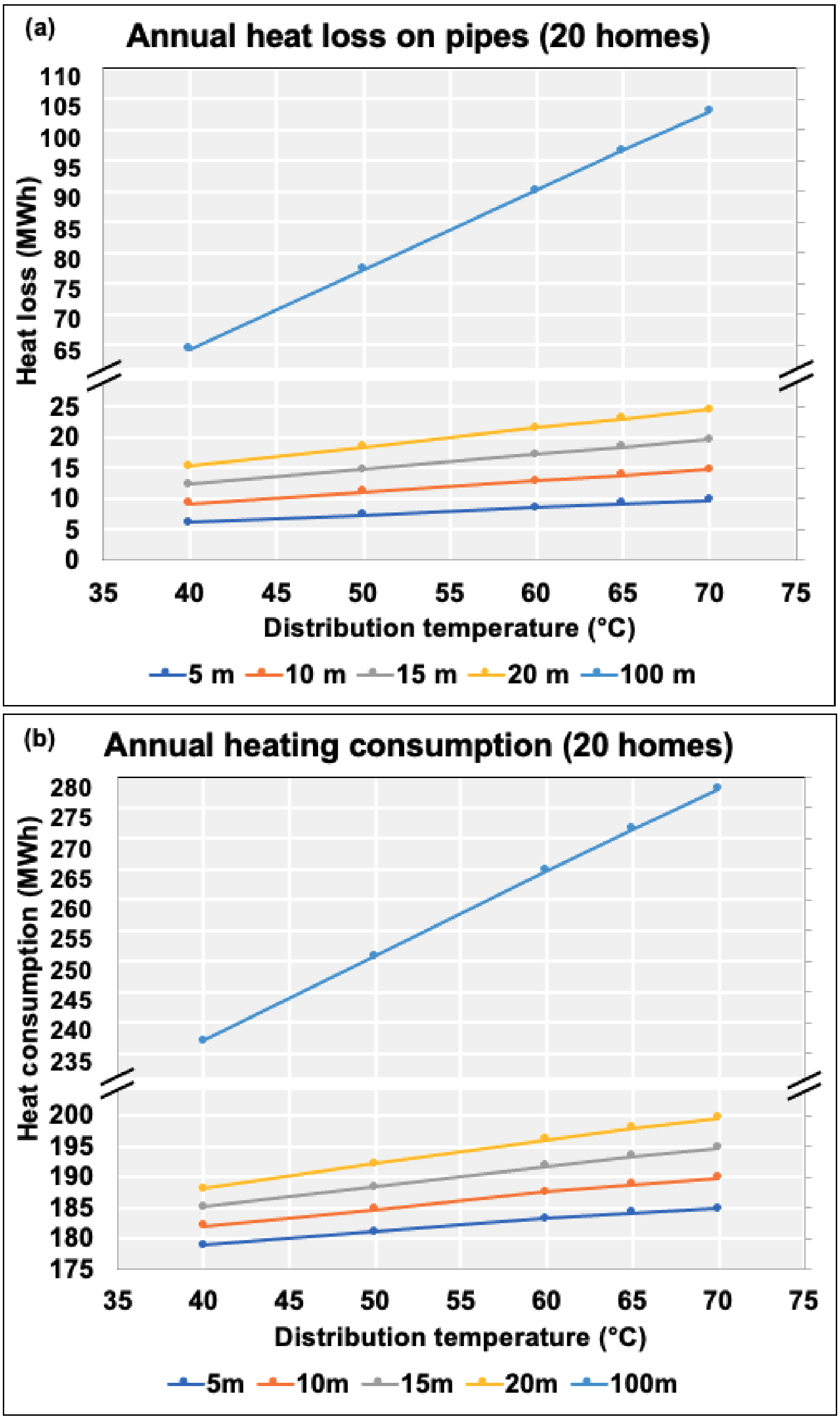

Figure 5-6: The (a) pipe heat losses and (b) network heat consumptions of a 20-home community with various distribution temperatures and pipe lengths.

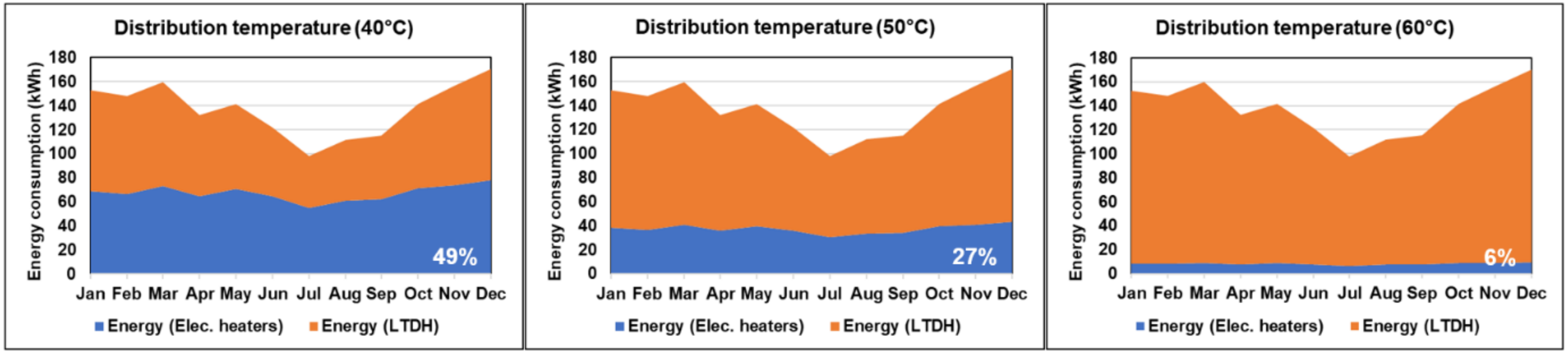

Figure 5-7: For DHW preparation, the demand percentages from the LTDH and electric heaters at various distribution temperatures in a single home.

The following evaluations present the annual electricity consumption of the heating network, including the GSHP and electric heaters. Figure 5-8 illustrates the impact of the main pipe lengths on electricity consumption in a 20-dwelling community. The result shows a similar tendency to that in Figure 5-6. The electricity saving amount between 40°C and 70°C is around 28% at the 100m pipe length condition (light blue line). At the 5m pipe length condition (blue line), the electricity saving amount between 40°C and 70°C is 13% approximately. Table 5-3 indicates that the COPs of the GSHP reach 4.66 and 3.16 at the 40°C and 70°C supply temperature conditions, respectively. This means the greater efficiency of supplying the lower temperature enhances electricity saving. (Note that, for the rest of modelling works, the unit lengths of the main and branch pipes are assumed to be 10 m and 5 m, respectively.)

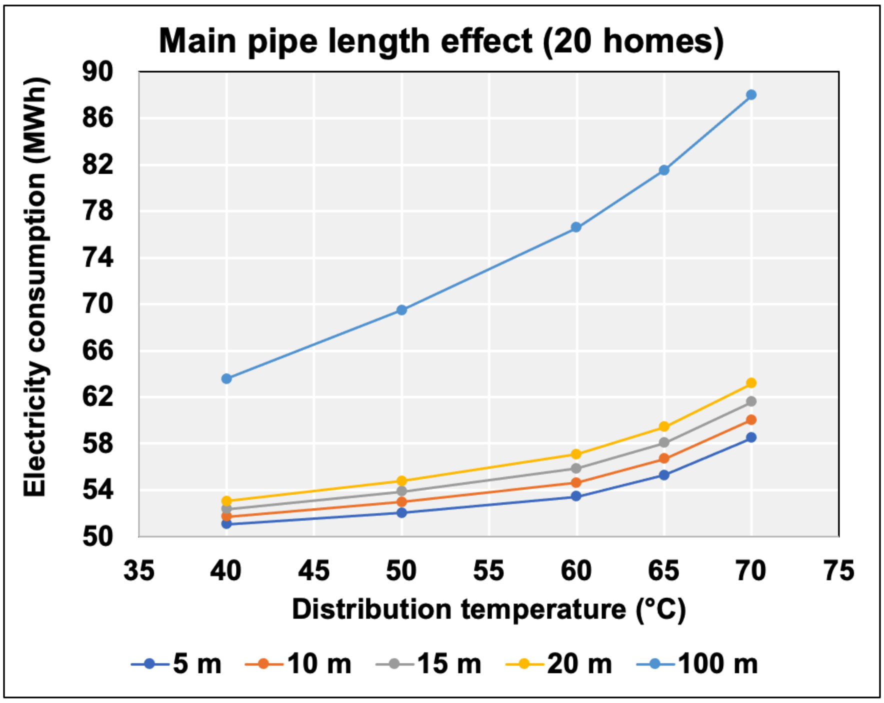

Figure 5-8: The electricity consumptions at various distribution temperatures and pipe lengths in a community with 20 dwellings.

To ensure the accuracy of the systematic modelling approach, the model of the 10m pipe length condition (orange line) in Figure 5-8 was selected and demonstrated on energyPRO. Table 5-5 summarises the modelling results. The energy demands of the SH provided by the LTDH are the same in each distribution temperature, while the

DHW demands are varied. The total demand of the DHW is 33 MWh approximately. When the distribution temperature is 40°C, around 49% of the total demand (16.1 MWh) is met by the electric heaters.

In Table 5-5, the heat losses on the heat exchangers and distribution pipes are increased with the increasing distribution temperature. The hours of operating the GSHP is a night-time condition that accounts for over 97%. In addition, operating the distribution temperature at 40°C can save 4.9 MWh of electricity annually, compared with that at 65°C.

Table 5-5: The modelling results of a community with 20 dwellings on energyPRO.

Low-temperature district heating	40°C	50°C	60°C	65°C
SH demand (MWh)	127.3	127.3	127.3	127.3
DHW demand (MWh)	16.9	23.9	31	33
Heat losses (MWh)				
SH heat exchanger	11	11.3	11.5	11.6
DHW heat exchanger	1.4	2.1	2.8	3
Distribution pipes	9.2	11	12.8	13.8
GSHP electricity consumption (MWh)	35.6	43.9	52.7	56.6
Hours of GSHP operation (h)				
Day_07:00-00:00	18	23	29	46
Night_00:00-07:00	1407	1478	1553	1619
Water tanks at home _ DHW (60°C)				
Electric heaters consumption (MWh)	16.1	9	1.9	0
Total electricity consumption (MWh)				
GSHP & Electric heaters	51.7	52.9	54.6	56.6

The modelling configuration applied to various distribution temperatures is illustrated in Figure 5-9. Due to the software constraint, the thermal storage unit (i.e., community thermal store) delivering heat to another thermal storage unit (i.e., household tank) is not possible within energyPRO. Therefore, the DHW demand must be split into two sites according to the energy sources (i.e., LTDH and electric heaters), Figure 5-9. The methodology of separating the DHW demand is depicted in subsection 5.1.3.

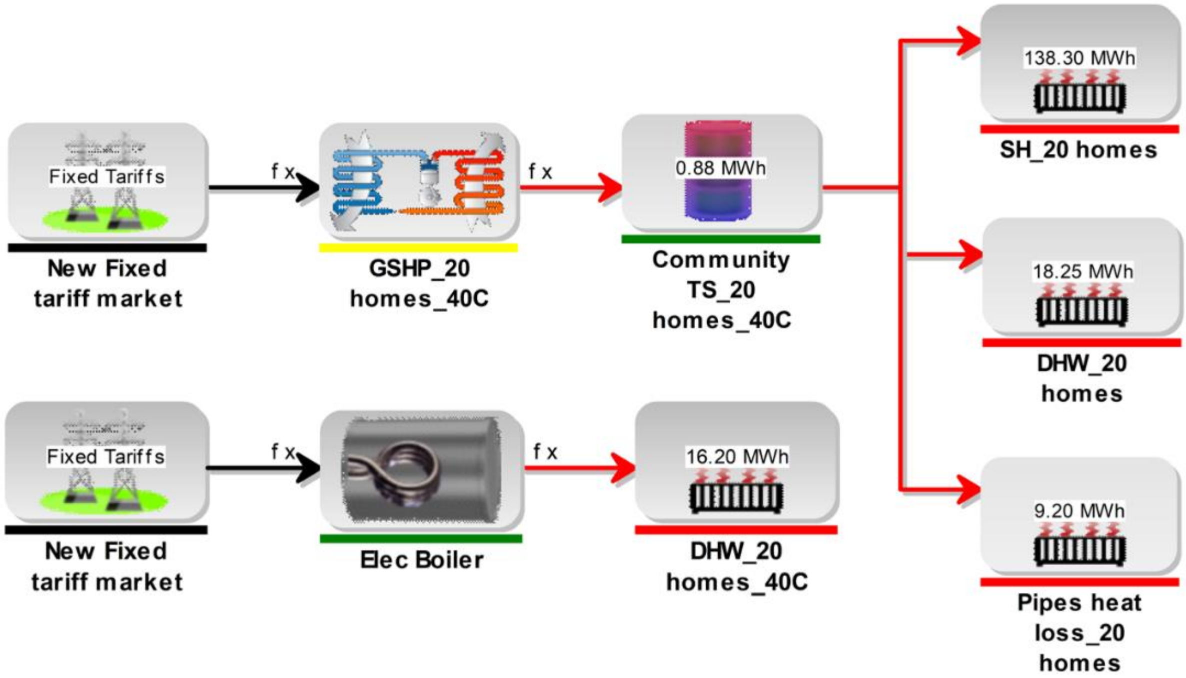

Figure 5-9: The configuration of the electrified heating network on energyPRO.

At the top part of Figure 5-9, the GSHP powered by the electric power network supplies heat to the community thermal store. The thermal store meets the heating demands of the SH and DHW and pipe heat loss. The lower section of Figure 5-9 indicates that electric heaters boost the water temperature in household tanks to 60°C. The heating consumption values in Figure 5-9 are aligned to the 40°C condition in Table 5-5. The SH consuming around 138 MWh comprises the SH demand and heat loss on the SH heat exchanger at the 40°C condition. The DHW consumption of around 18 MWh consists of the DHW demand from the LTDH and heat loss on the DHW heat exchanger.

The heating and electricity consumption profiles based on the model in Figure 5-9 are shown in Figure 5-10. The greatest consumption month is presented. The upper graph in Figure 5-10 shows that the GSHP provides most of the heat to the community thermal store at night (yellow colour). The electric heaters generate heat with the demand of the DHW (green colour). The central graph represents the electricity consumption of the GSHP and electric heaters. The electric power fluctuation is lower than the heating power fluctuation of the GSHP and electric heaters because of the great COP of the GSHP. The lower graph illustrates that the capacity of the community thermal store can store adequate heat for later use. Briefly, the designed electrified heating network successfully fulfils the SH and DHW demands of a community.

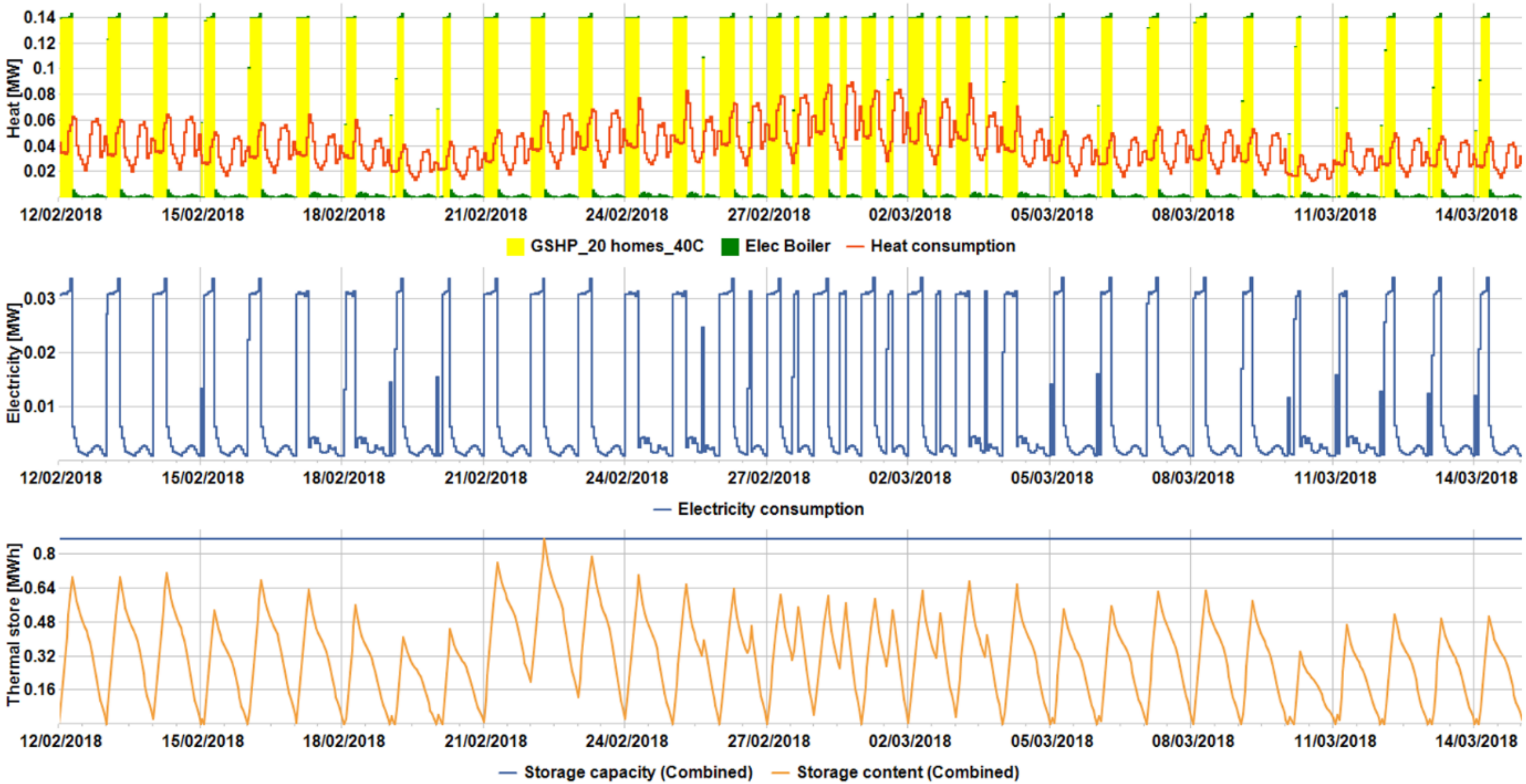

Figure 5-10: The heating demand, electricity load curve and thermal energy storage during the highest consumption period.

5.2.2. Distribution temperature determination in 2050 scenarios

The 2050 scenarios with differing demands of DHW and SH are evaluated in this subsection. Figure 5-11 indicates the electricity consumptions of the 2018 scenario and 2050 scenarios with DHW demand 25% greater than the 2018 level (level 1). The community-scale is 20 dwellings. The result shows that the distribution temperature of the electrified heating network should be 40°C in the 2018 scenario for the least electricity consumption (blue line). However, when the DHW demand is increased by 25%, the benefit of adopting the 40°C distribution temperature is decreased, illustrated by the yellow line. With the 25% increase in DHW demand, the SH increased by 50% scenario (green line) indicates a 13 MWh electricity saving when a 40°C distribution temperature is utilised, compared with the 70°C condition. The orange line representing the 25% SH reduction starts showing the benefit of using a higher distribution temperature; the 60°C condition consumes the least electricity. When the SH demand attains a 50% reduction (grey line), the 60°C distribution temperature can save approximately 5 MWh of electricity annually, in contrast with the 40°C condition.

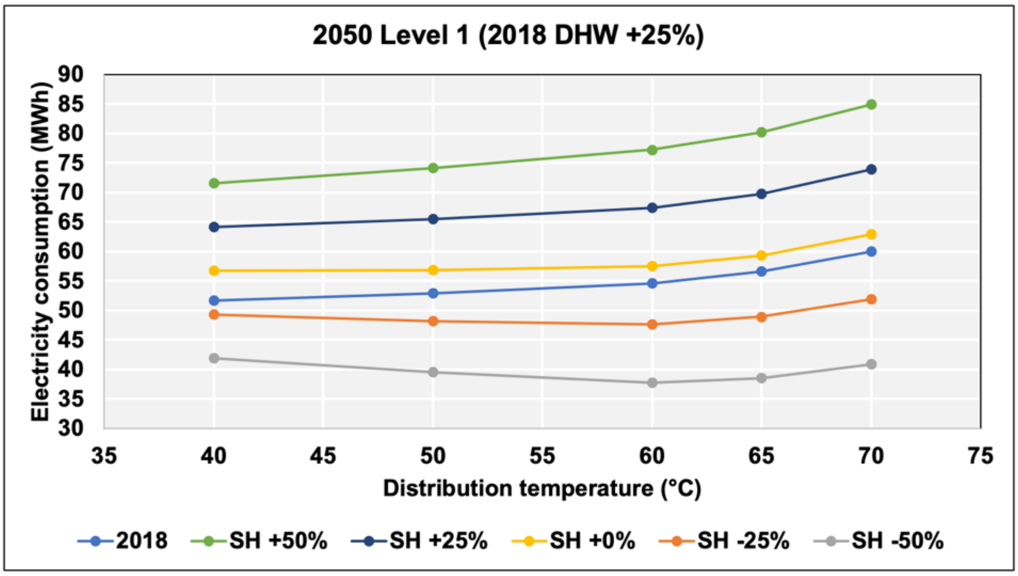

Figure 5-11: The electricity consumptions of the electrified heating network at various SH demand levels in a 20-dwelling community, the DHW demand is 25% higher than 2018 level.

Figure 5-12 illustrates the electricity consumptions of the level 2 scenarios in 2050; the DHW demand is the same as the 2018 level. The SH increased by 50% scenario (green line) indicates that the 40°C distribution temperature can save up to 16 MWh of electricity annually, compared to the 70°C condition. Overall, the tendency described in Figure 5-12 is similar to that in Figure 5-11, but the benefit of utilising the 60°C distribution temperature appears only when the SH demand is decreased by 50%. This 60°C distribution temperature, comparing with the 40°C condition, induces 1.94 MWh electricity saving annually. Figure 5-12 also presents a clear trend: The electricity consumptions at higher temperatures are decreased faster than at lower temperatures when the demand of the SH is declined. In other words, SH reduction promotes a greater distribution temperature.

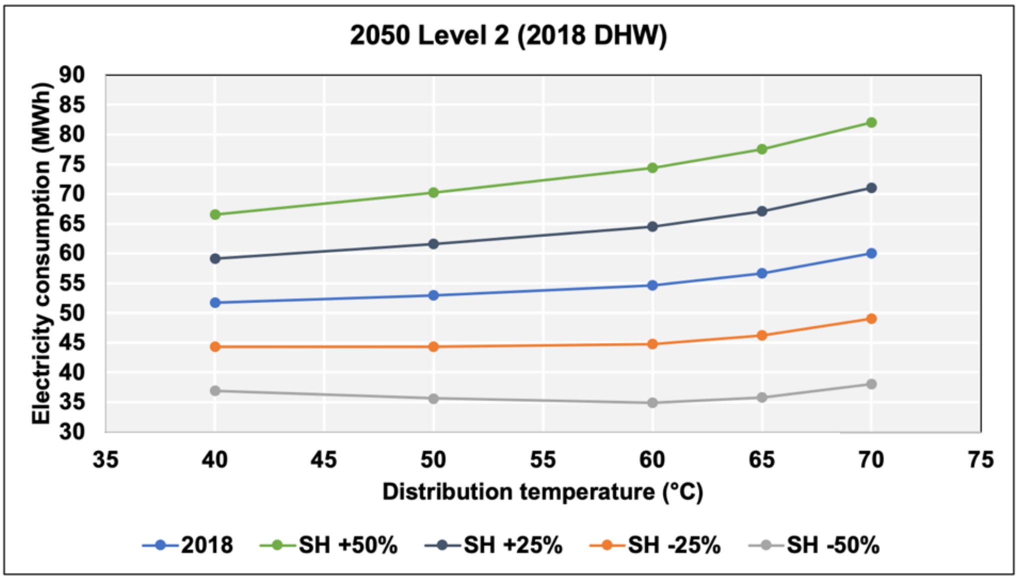

Figure 5-12: The electricity consumptions of the electrified heating network at various SH demand levels in a 20-dwelling community, the DHW demand is the same as the 2018 level.

Comparing with the 2018 scenario, the DHW demand in the level 3 scenarios in 2050 is reduced by 25%, indicated in Figure 5-13. The scenario with a 50% SH demand increase (green line) shows that the electricity consumption gap between 40°C and 70°C distribution temperatures is 19 MWh. Based on the scenarios with a 50% SH demand increase (green lines) in the three DHW levels, electricity saving between the lowest and highest distribution temperatures is increased with the reducing DHW demand. Moreover, with a 50% SH reduction, the least electricity consumption temperature is 60°C in level 1 (Figure 5-11) and level 2 (Figure 5-12), but level 3 (Figure 5-13) shows that the least consumption condition is 50°C. As a result, reducing the DHW demand enhances the benefit of applying the low distribution temperature.

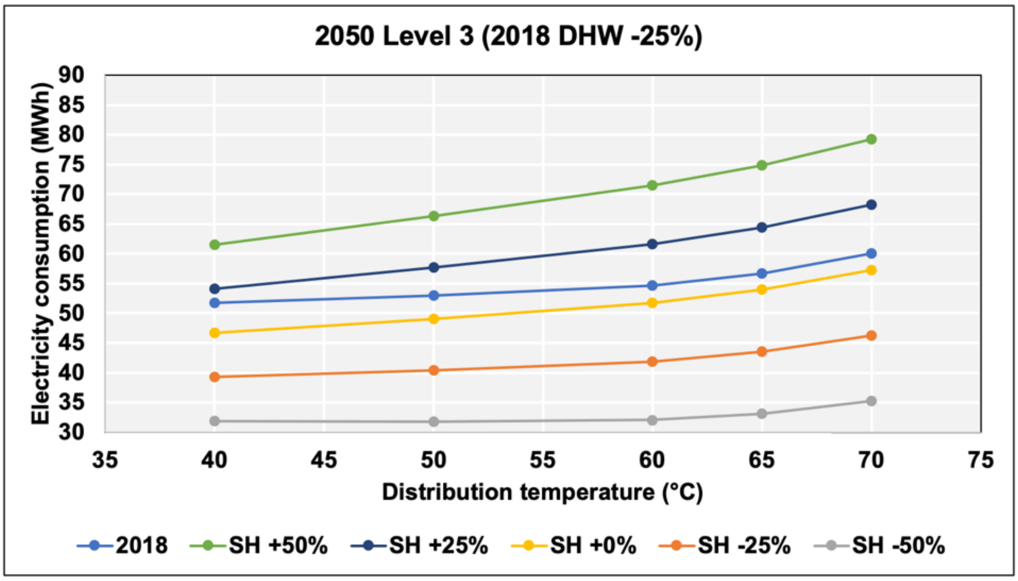

Figure 5-13: The electricity consumptions of the electrified heating network at various SH demand levels in a 20-dwelling community, the DHW demand is 25% less than 2018 level.

5.2.3. Distribution temperature determination based on demand ratio of DHW to SH

This subsection illustrates the factor defining the distribution temperature and identifies the scalability of the modelling approach. The correlation between the DHW and SH is represented as demand ratios of DHW to SH such as 1 to 0.5, 1 to 1, 1 to 2, 1 to 2.5, 1 to 3.86, and 1 to 4.5. The various rates of SH can be reflected in the thermal efficiency levels in buildings. The ratio of 1 to 3.86 is the DHW to SH demand ratio in 2018. SH consumption has a high likelihood to be reduced gradually [128]. Therefore, this section selects only one condition (i.e., the ratio of 1 to 4.5) as an example when the SH demand is increased in the future. The other conditions like 1 to 1, 1 to 2 and 1 to 2.5 are considered thermal efficiency improved by around 75%, 50% and 35%, respectively. To form a comprehensive analysis, two other DHW demand levels are evaluated, including 25% more and 25% fewer consumptions than the 2018 level. The community scales of 15, 20, 25, 70 and 120 dwellings are also factored into models. Finally, the modelling results are presented in radar figures.

The results with the increased 25% DHW consumption are illustrated in Figure 5-14. The annual DHW demand is 2.06 MWh in an average dwelling. When the demand ratio of DHW to SH is 1 to 3.86 in a community, the optimum distribution temperature is 40°C in all community scales. The temperature selection of the communities with 15 and 20 dwellings is changed from 40°C to 60°C when the rate of the SH demand is decreased to 2.5. Ultimately, the optimum temperature reaches 65°C when the ratio of DHW to SH is 1 to 0.5. For the larger communities, the optimum distribution temperature shows a clear increasing trend from 40°C, 45°C, 55°C to 60°C with the declining SH demand rate.

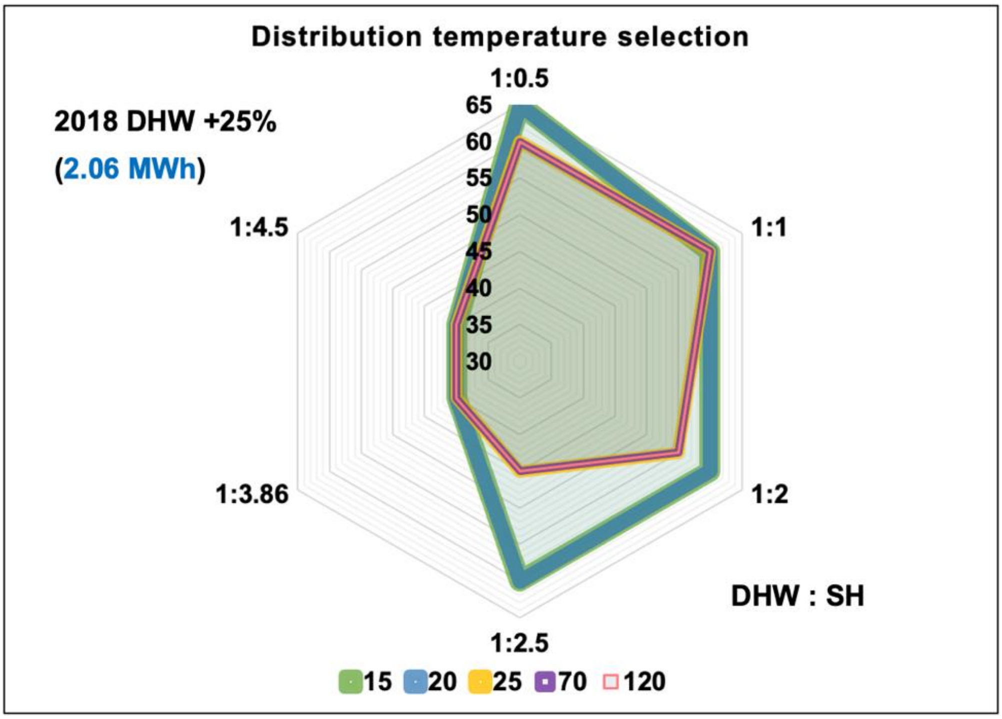

Figure 5-14: The distribution temperature selection in various ratios of DHW to SH and community scales, the DHW demand is 25% greater than the 2018 level.

Figure 5-15 indicates the optimum distribution temperatures with the same DHW consumption at the 2018 level in an average dwelling. The high rated SH conditions (equal to or over 3.86) should select a 40°C distribution temperature to achieve the best electricity saving. Furthermore, the results indicate similarity to Figure 5-14, where the optimum temperatures become higher quickly with reducing SH requirement in the smaller communities. The distribution temperatures for greater scales communities are increased gradually from 40°C, 50°C to 60°C.

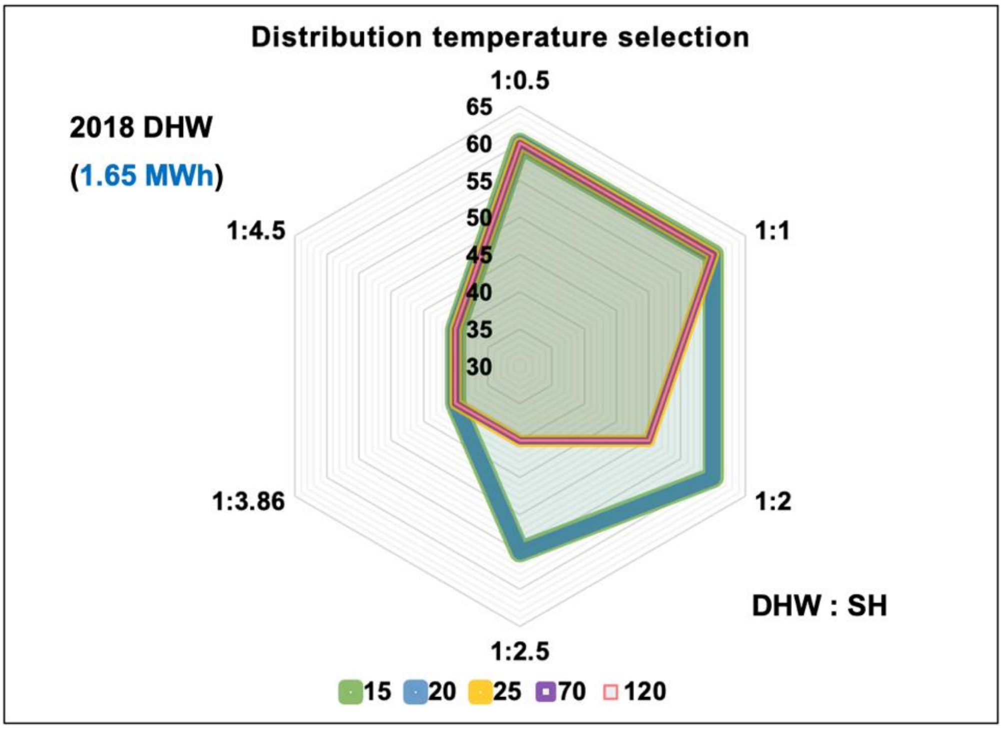

Figure 5-15: The distribution temperature selection in various ratios of DHW to SH and community scales, the DHW demand is the 2018 level.

According to the results indicated in Figure 5-14 and Figure 5-15, the total heating demand, including DHW and SH, is not the factor in defining the distribution temperature. For instance, the total heating demand at the ratio of 1 to 2.5 in Figure 5-14 is greater than the same ratio in Figure 5-15 because of the higher DHW consumption. Nevertheless, in the bigger communities, the least electricity consumption temperature in Figure 5-14 (i.e., 45°C) is greater than in Figure 5-15 (i.e., 40°C). In contrast, by comparing the total heating demand at the same DHW consumption level, a community with greater total heating demand applies a lower supply temperature for electricity saving. For example, in the larger communities in Figure 5-15, the ratio of 1 to 2.5 consumes more heating energy than the ratio of 1 to 2, but a lower supply temperature (i.e., 40°C) is indicated.

The distribution temperature selection with the DHW demand 25% lower than the 2018 level in an average dwelling (1.24 MWh) is presented in Figure 5-16. In the smaller communities, the optimum distribution temperature attains 60°C when the ratio of DHW to SH is 1 to 2. In the bigger communities, the distribution temperature should be 40°C in most of the conditions. The temperature reaches 60°C when the SH and DHW consume the same amount of energy.

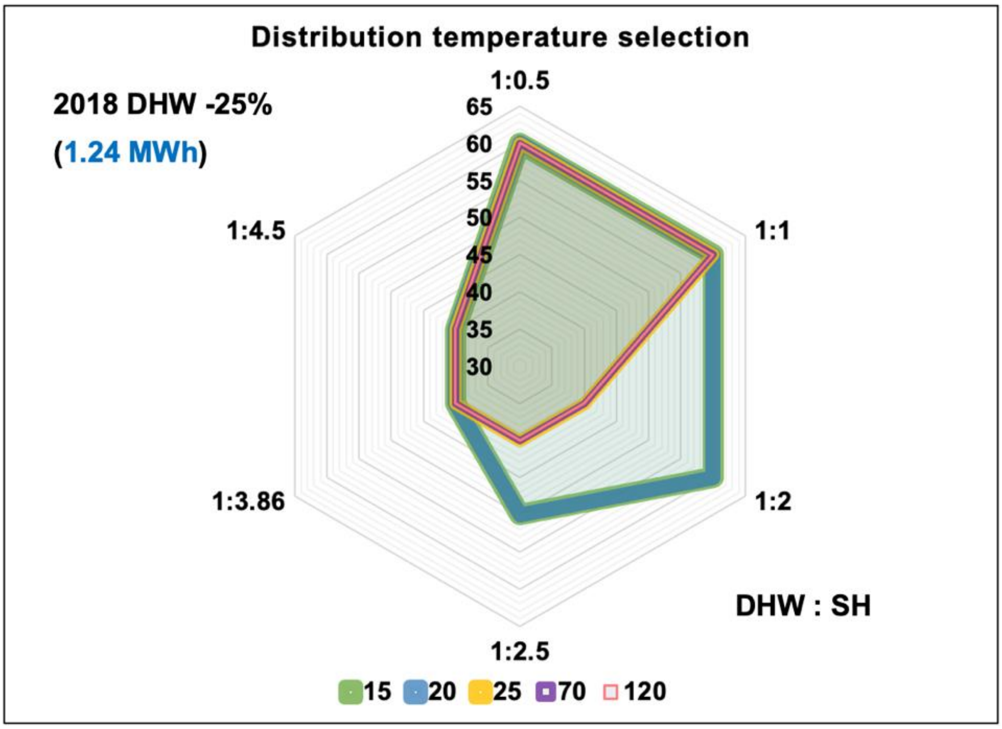

Figure 5-16: The distribution temperature selection in various ratios of DHW to SH and community scales, the DHW demand is 25% less than the 2018 level.

Based on the results, the scalability of the modelling approach is demonstrated. The supply temperatures by selection are the same when communities use the same demand ratio of DHW to SH. The reason that the optimum temperature conditions are different between the larger and smaller communities is: The smaller communities utilising ‘twin pipe’ as the distribution pipes induce less pipe heat loss, unlike the larger communities adopting two ‘single pipe’. This lower pipe heat loss means that the influence of the low-efficiency electric heaters is more significant; the advantage of utilising a lower distribution temperature is reduced.

5.3. Discussion and conclusion

This chapter established a systematic modelling approach measuring the optimum distribution temperature with the least electricity consumption to optimise an electrified heating network providing DHW and SH demands of a community. An electrified heating network analysis showed that if the distribution temperature is reduced from 60°C to 40°C for heat loss reduction, the utilisation rate of the low-efficiency electric heaters for DHW preparation is increased from 6% to 49%. This induces a significant deterioration in system performance. Accordingly, the supply temperature should not be determined by only considering heat losses; the efficiency of heat production is also an essential factor.

The modelling results of the 2050 scenarios indicated that increasing DHW demand or decreasing SH demand promote a greater supply temperature. In the context of higher thermal efficiency in buildings, a greater distribution temperature would be enabled due to the reduced collective SH demand of a community. For instance, the optimum distribution temperature was 40°C in the 2018 scenario. This was increased to 60°C when housing thermal efficiency was improved by 50%. By utilising a 60°C distribution temperature gave rise to 1.94 MWh of electricity saving annually in a 20-dwelling community. This saved electricity can provide at least one dwelling's annual heating demand.

Furthermore, the demand ratio of DHW to SH is the key to define the distribution temperature. The total heating demand of a community is not an essential factor. The result showed that a community with higher heating demand may adopt a greater distribution temperature for the electricity saving, comparing with the scenarios consuming the same ratio of DHW to SH. However, in the scenarios using the same energy for DHW, a higher heating demand community attained the most electricity saving by applying a lower distribution temperature. The scalability of this systematic modelling approach was demonstrated. The result indicated that the supply temperatures by selection are the same when communities consume the same demand ratio of DHW to SH. These distribution temperatures only are varied with the types of distribution pipes.

This chapter demonstrated the determination of annual distribution temperature. This can be extended further to the monthly or even daily temperature selections by developing this modelling approach. Moreover, the modelling approach did not consider the heat loss of thermal storage because this consumption is easier to be mitigated and much lower than the heat losses on pipes and heat exchangers. This heat loss assessment of thermal storage is viewed as an optimisation item for further development.

The simulation model of multi-vector community energy will be established in a modelling tool in an Excel workbook, elaborated in Chapter 8. Figure 5-17 is the screenshot of the modelling tool that illustrates the calculation results of an electrified heating network.

	P	Q	R	S	T	U	V	W	X	Y
1				**40C**	**45C**	**50C**	**55C**	**60C**	**65C**	
2			DHW consumption	1649.079	1649.079	1649.0788	1649.079	1649.079	1649.079	
3		**Per household**	water in tank (kg)	31618.24	31618.24	31618.239	31618.24	31618.24	31618.24	
4			SH consumption	6365.444	6365.444	6365.444	6365.444	6365.444	6365.444	
5			households	384	384	384	384	384	384	
6			distribution T	40	45	50	55	60	65	
7			soil T	10	10	10	10	10	10	
8			T(return 30C, soil 10C)	**25**	**27.5**	**30**	**32.5**	**35**	**37.5**	
9			length branch pipe, m	5	5	5	5	5	5	
10			branch U	**0.139**	**0.139**	**0.139**	**0.139**	**0.139**	**0.139**	
11			length main pipe, m	10	10	10	10	10	10	
12			main U	**0.308**	**0.308**	**0.308**	**0.308**	**0.308**	**0.308**	
13			branch number	**384**	**384**	**384**	**384**	**384**	**384**	
14			main number	**192**	**192**	**192**	**192**	**192**	**192**	
15			hours	8760	8760	8760	8760	8760	8760	
16			W to kW	1000	1000	1000	1000	1000	1000	
17			annual heat loss	annual hea	annual hea	annual heat	annual hea	annual hea	annual heat loss	
18				**375909.1**	**413500**	**451090.94**	**488681.9**	**526272.8**	**563863.7**	
19										
20			DHW							
21			Energy (from Elec. Boiler)	**309612.5**	**241528.6**	**173444.59**	**105360.6**	**37276.66**	**0**	
22			Energy (from LTDH) kWh	**323633.7**	**391717.7**	**459801.66**	**527885.6**	**595969.6**	**633246.3**	
23			Energy demand before HIU							
24			HIU efficiency	**92.033**	**91.953**	**91.873**	**91.793**	**91.713**	**91.633**	
25			DHW, Energy (from LTDH) kWh	**351649.7**	**425997.7**	**500475.29**	**575082.7**	**649820.2**	**691067.9**	
26										
27			SH							
28			Energy (from LTDH) kWh	**2444331**	**2444331**	**2444330.5**	**2444331**	**2444331**	**2444331**	
29			Energy demand before HIU							
30			HIU efficiency	**92.033**	**91.953**	**91.873**	**91.793**	**91.713**	**91.633**	
31			SH, Energy (from LTDH) kWh	**2655928**	**2658239**	**2660553.7**	**2662872**	**2665195**	**2667522**	
32										
33			COP	**4.67**	**4.30**	**4.00**	**3.74**	**3.52**	**3.33**	
34			DHW + SH							
35			Enerygy consumption of GSHP	**725279.6**	**813695.4**	**904113.51**	**996625.2**	**1091295**	**1178069**	
36			**Total Electricity (Elec. Boiler + GSHP)**	**1034892**	**1055224**	**1077558.1**	**1101986**	**1128571**	**1178069**	
37			**MWh**	**1034.892**	**1055.224**	**1077.5581**	**1101.986**	**1128.571**	**1178.069**	
38										
39	**Energy demand per household**									
40	DHW	SH		DHW	ratio	SH				
41	1.649078784	6.365444105		1649.079	3.86	6365.444				
42	1649.078784	6365.444105								
43	**Households**									
44	384									
45	**Water in tank (kg) per household**			DHW:SH		384				
46	31618.23904				3.86	**40**	°C			
47										
48					Ele heaters	**309.61253**	MWh			
49					GSHP	**725.27962**	MWh			
50					Total	**1034.8921**	MWh			

Figure 5-17: Screenshot of the modelling tool – The calculation results of an electrified heating network, including the heating demands, electricity consumption and temperature selection.

Chapter 6

Establishing an Electrified Community

This chapter aims to deliver a community energy system that performs the best possible efficiency to an electrified community. Heating and electricity grids are connected (subsection 4.1). Besides, smart management of electric vehicles (EVs) and heating supply (subsection 2.2.3) and peak shaving of using batteries (subsection 4.3) are all employed.

Firstly, the demands of an average UK dwelling are investigated and presented in an hour-by-hour model. This is categorised into Electricity for lighting and appliances, residential charging demand of EVs and an electrified heating network for domestic space heating (SH) and domestic hot water (DHW). The hourly consumptions of the Electricity and EVs are obtained by using national statistical data and consumption profiles from validated simulation tools or real-world physical studies. The electricity demand of the heating network was illustrated in Chapter 5. The community-scale is aligned with the number of dwellings supplied by a low voltage (LV) substation within the typical UK distribution network [130].

Subsequently, the percentage of EV smart charging is determined. The EV charging and Electricity demands are used to define the capacity of a battery as a community battery to perform a community-scale peak shaving (subsection 4.3). The operation of an electrified heating network (Chapter 5) is optimised in this chapter to create an ideal heating supply. These mentioned smart managements are utilised to flatten the consumption power of an electrified community in the greatest demand week, the coldest week. This greatest power consumption is then utilised to estimate the required improvement level of housing thermal efficiency, reducing the collective SH demand. Consequently, the existing distribution network can accommodate the electricity demands of an electrified community.

In this chapter, the smart management measures of a community energy system are applied using calculation formulas established on an Excel workbook. This optimised energy system for an electrified community is then demonstrated on a commercial software, energyPRO [19].

The following sections in this chapter are elaborated as: Section **6.1 Modelling methodology** depicts the methods of collecting data, settings of the instruments in the modelling works and methodology of arranging the energy flows. Section **6.2 Results** indicates the modelling results including residential energy demands, applications of the electrified heating network and community battery, and the required improvement level of thermal efficiency in buildings. Section **6.3 Discussion and conclusion** discusses the impact of 100% electrification on a community and summarises the key messages of establishing an electrified community.

6.1. Modelling methodology

This section investigates the electricity demands, including Electricity (i.e., lighting and appliances), EV charging and electrified heating network, and illustrates the typical UK distribution network to define the scale of an electrified community. Besides, the percentage of EV smart charging, the capacity of a community battery for peak shaving, and Li-ion battery characteristics are defined.

6.1.1. Electricity demand for lighting & appliances

To evaluate an electrified community, the electricity demand for lighting and appliances, represented as Electricity, was investigated. The after diversity maximum demand (ADMD) is the metric defining the average peak electricity consumption in a group of dwellings [131]. The calculation method is the peak demand in the group divided by the number of dwellings. In the UK, the ADMD typically is lower than 2 kW with the connected dwelling number greater than 20 [132] and then reaches a steady state when the number of dwellings exceeds 50 [133]. Accordingly, the consumption profile of the Electricity can be generated by a group of dwellings over 50 and subsequently applied to various community scales.

In this research, an open-source software named CREST [134] was utilised to produce the load curves of the Electricity. The load curves were generated by assuming the dwelling number to be 100 and converting the data in a minute resolution to hourly resolution, which can be categorised into four quarters and separated by weekdays and weekends. The quarterly data of weekdays was obtained by averaging data of 3 days in the middle of each month and then averaging the three months in each quarter. For instance, the data of weekdays in January in 2018 was gained by the data on 13th, 14th, and 15th. On the other hand, the quarterly data of weekends utilised 2 days in the middle of each month. Figure 6-1 and Figure 6-2 are the hourly demand profiles on weekdays and weekends, respectively.

Monthly consumptions per dwelling are illustrated in Figure 6-3, according to the domestic energy trend in 2018 [135]. The highest and lowest consumption months were in January and July, which consumed around 393.5 kWh and 233.7 kWh. This data was used to generate monthly consumptions in a community with 384 dwellings, aligning with the typical UK distribution network. These monthly consumptions with the demand profiles were input to enegyPRO; hence, the electricity load curve across a whole year was produced. (The typical UK distribution network is elaborated in subsection 6.1.3.)

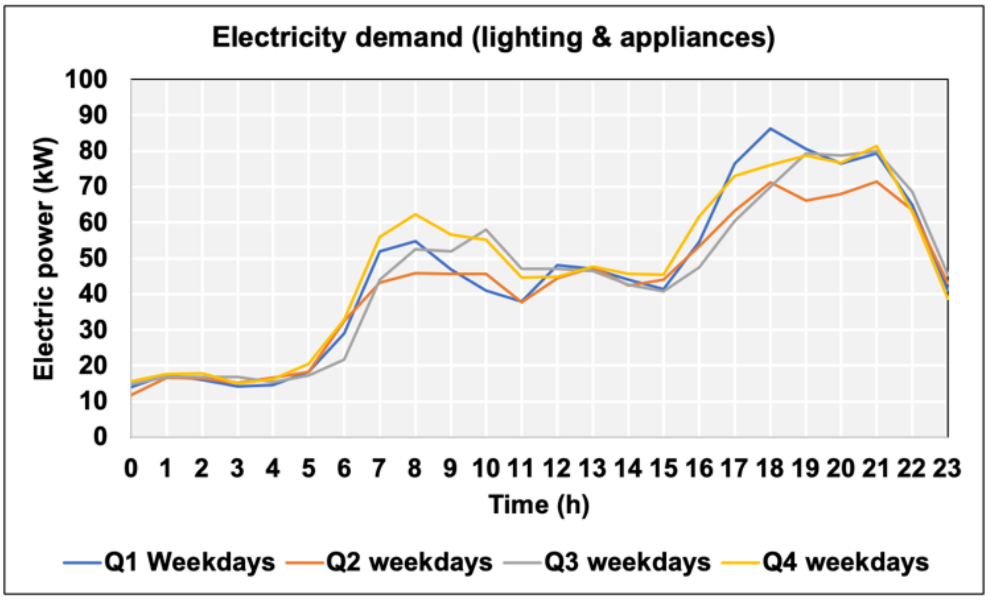

Figure 6-1: The quarterly electricity demand profiles of 100 dwellings in the UK in weekdays.

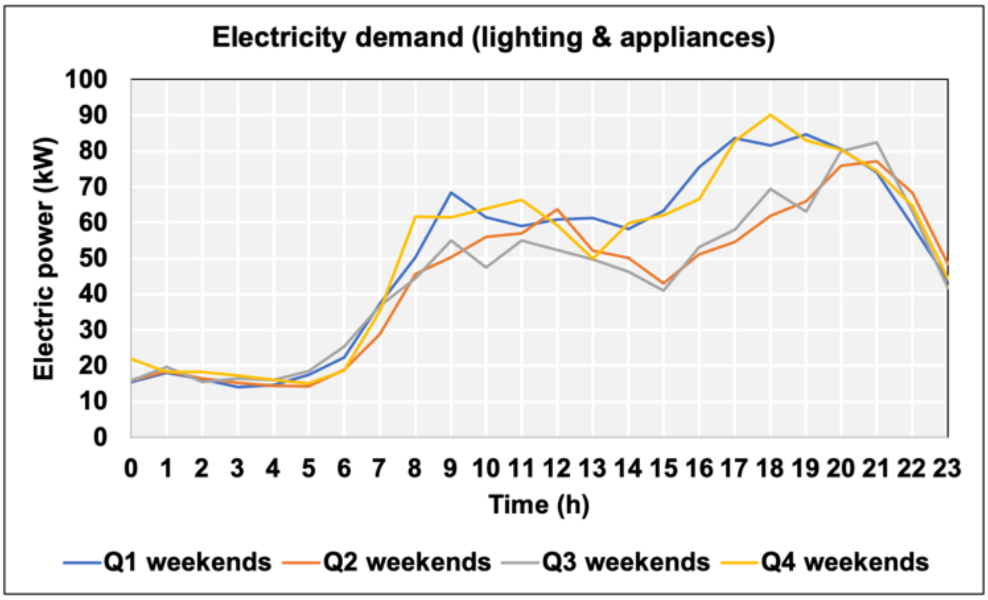

Figure 6-2: The quarterly electricity demand profiles of 100 dwellings in the UK in weekends.

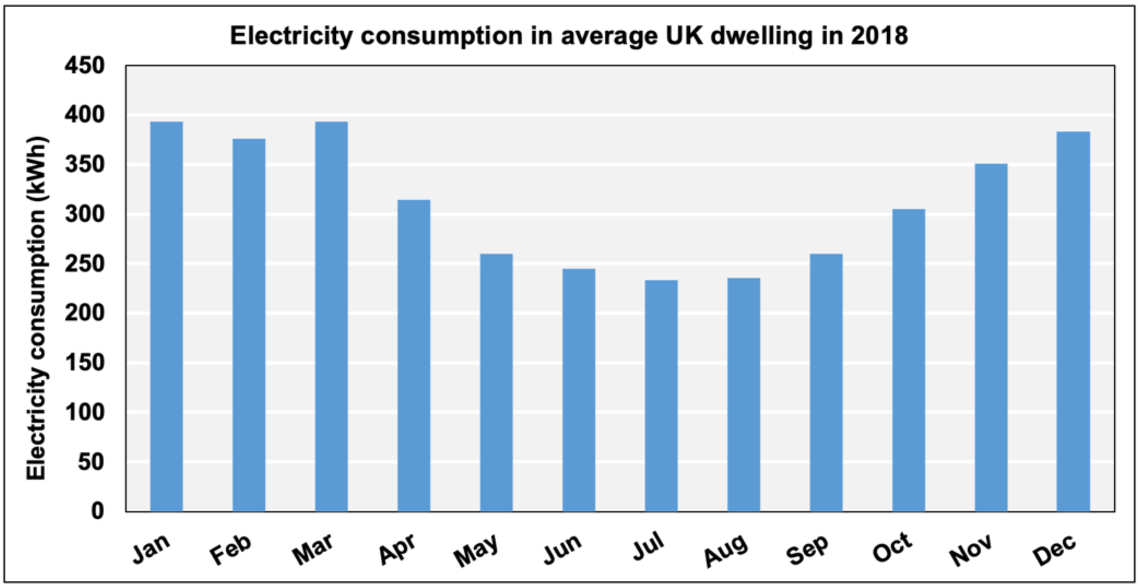

Figure 6-3: The monthly consumptions of the Electricity (i.e., lighting and appliances) in average UK dwelling in 2018 [135].

6.1.2. Residential charging demand of EVs

This subsection introduces the method of producing the hourly residential charging demand of EVs. The data generation requires demand profiles and monthly consumptions to be imported to energyPRO. In the UK, a study of EV charging behaviour [85] indicated the load curves of residential charging and daily demands across a full year of an EV. The average annual charging demand per EV was 1,760 kWh that 75% (1,320 kWh) was supplied by residential charging points [85]. For the monthly consumptions per EV, the daily demands were aggregated by month, shown in Figure 6-4. The result illustrates that the average consumption of an EV in January was around 130.2 kWh, the highest. In contrast, the lowest consumption month, August, consumed around 88.4 kWh.

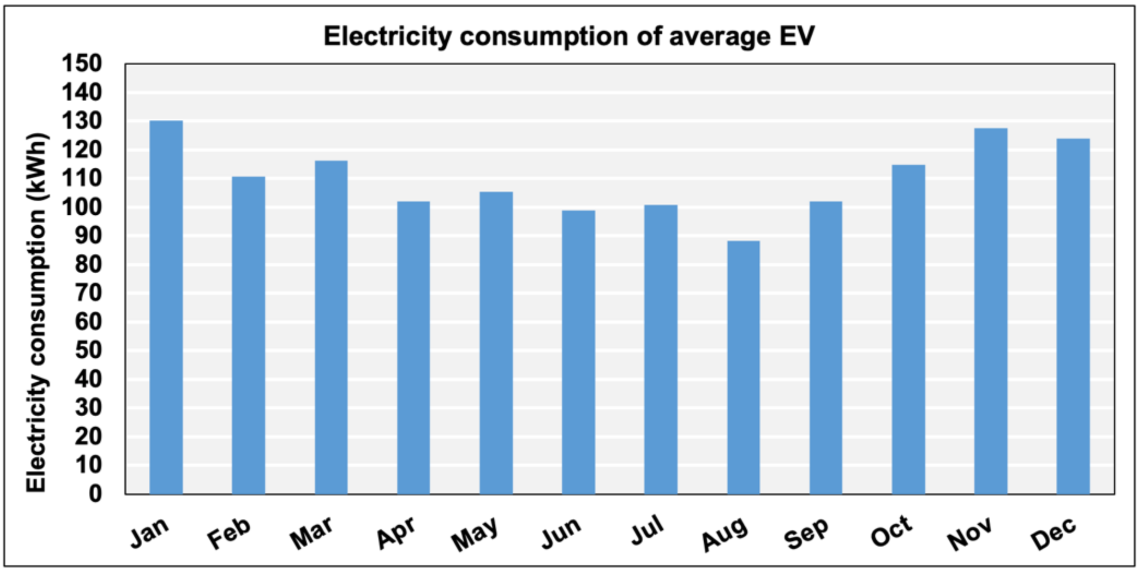

Figure 6-4: The monthly electricity consumptions for residential charging per EV [85].

In 2018, the average number of cars or vans per household was 1.21 in the UK [136]. Therefore, the number of EVs in an electrified community with 384 households was determined to be 465. This was reflected in the monthly consumptions, then input to energyPRO.

6.1.3. The typical UK distribution network

The typical layout of a distribution network is presented in Figure 6-5. The 33 and 11 kV distribution networks are defined as medium voltage, and the 433 and 230 V are low voltage distribution networks [23, 137]. The 33/11 kV substation, also called the primary substation, is equipped with two transformers. Each transformer can output a maximum apparent power of 15 MVA. The 33/11 kV substation exports electricity through six 11 kV feeders. Each feeder is connected to eight 11/0.433 kV substations (i.e., LV substation; secondary substation). One

11/0.433 kV substation provides 384 houses with electricity. Moreover, the 11/0.433 kV transformer can output a maximum apparent power of 500 kVA [130]. Accordingly, in the modelling works, the number of households in an electrified community was 384. The instantaneous electric power was restricted to 500 kW (assumed power factor is 1).

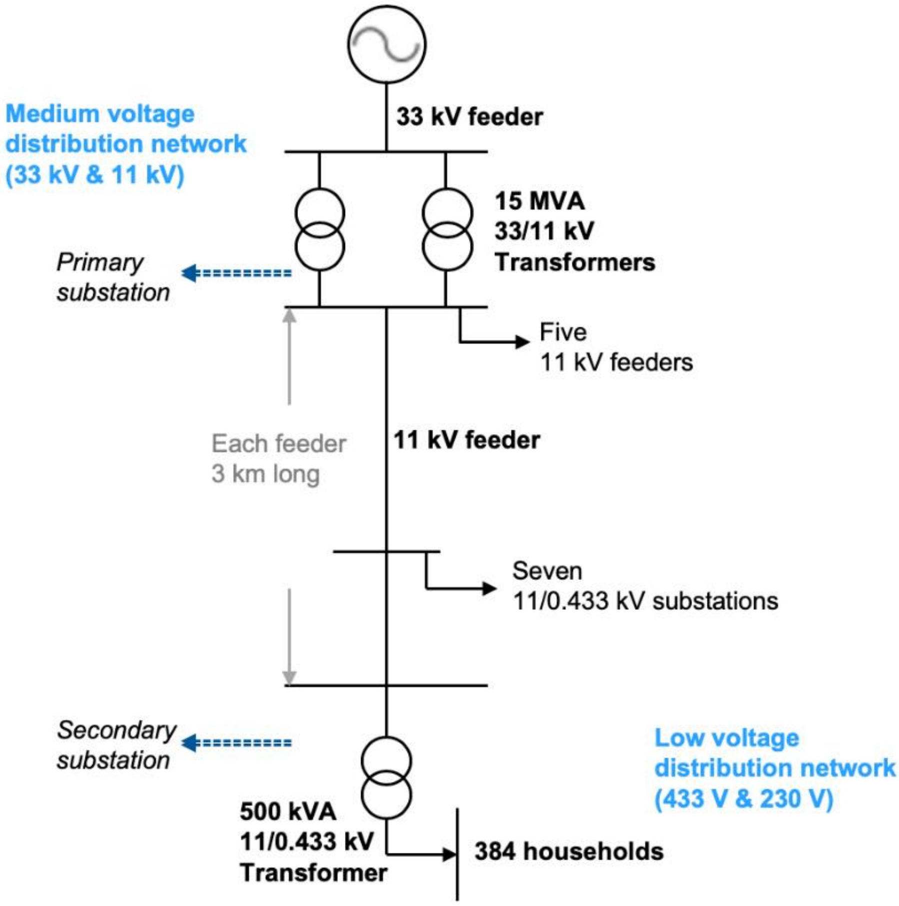

Figure 6-5: A typical distribution network in the UK [23, 130].

6.1.4. EV smart charging and community battery

To apply smart charging to the EVs in the electrified community, the electricity consumptions, including 384 dwellings and 465 EVs from previous subsections, are illustrated in Figure 6-6. This demand profile reflects the greatest overall demand day, which is the coldest day in 2018, without smart charging. Figure 6-6 shows that the mean electric power is around 0.28 MW (green dash line). The highest demand peak exceeding the 0.5 MW capacity of a LV substation (red dot line) is 0.59 MW.

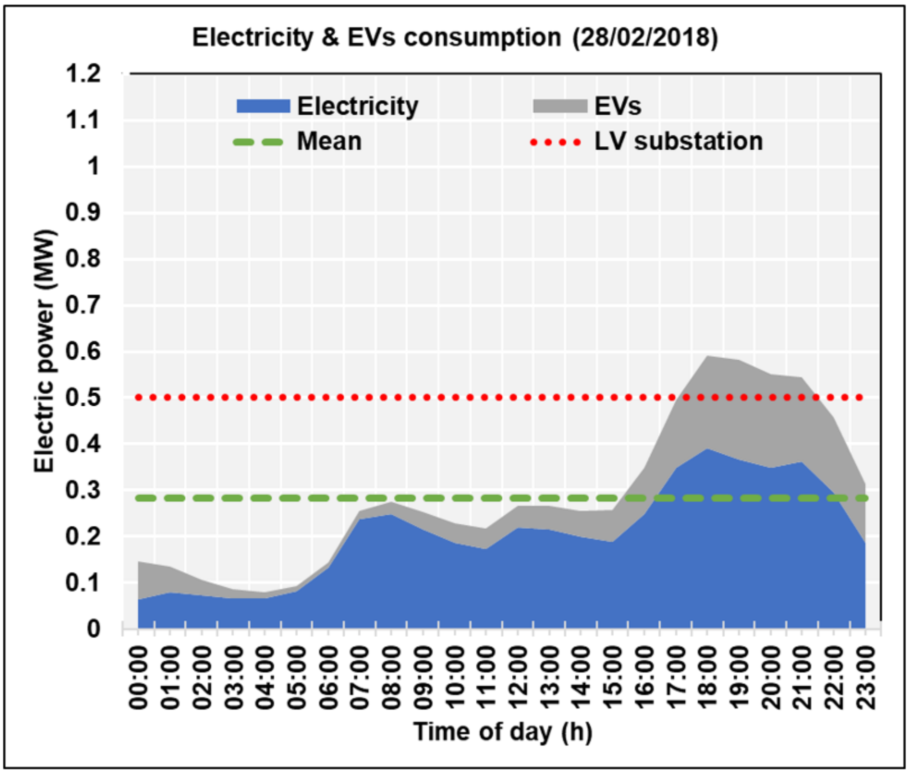

Figure 6-6: The Electricity (i.e., lighting and appliances) demand in 384 dwellings and the residential charging demand of 465 EVs.

A study indicated that the percentage of EVs adopting smart charging by 2050 could be over 75% in the UK [138]. This chapter assumes that EVs utilising smart charging is 50%. To apply the 50% smart charging, the consumption of EVs from 17:00 to 23:00 in Figure 6-6 was reduced by 50%. This removed consumption, then, was evenly allocated to 8 hours from 23:00 to 07:00. The demand profile with 50% smart charging is shown in Figure 6-7. The peak consumption power lower than the maximum capacity of a LV substation is 0.49 MW approximately.

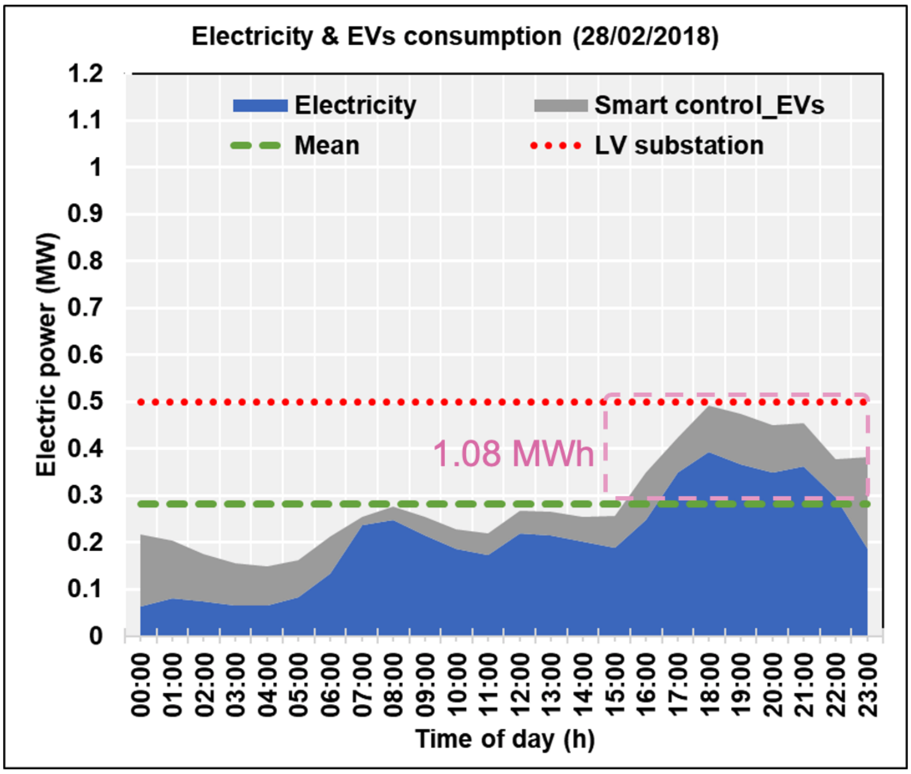

Figure 6-7: The Electricity (i.e., lighting and appliances) demand in 384 dwellings and the residential charging demand of 465 EVs with 50% smart charging.

Electricity storage can be utilised to shift photovoltaic (PV) production and perform peak shaving [139]. It is recognised as a more cost-effective way to enhance the ability of distribution networks as compared to a conventional network reinforcement [140]. Figure 6-7 illustrates that the electricity consumption over the mean electric power (0.29 MW) is around 1.08 MWh. Therefore, battery storage targeted to smooth the electricity demand profile was determined to have a capacity of 1.27 MWh, which enabled a 15% demand buffer.

Based on the configuration of a community energy system in Figure 4-1, battery storage is grouped into the community and home batteries. The capacities of each battery category are defined by the distribution network constraint. In this research, according to the peak power without the electrification (i.e., the Electricity in Figure 6-7), the targeted maximum power of an electrified community is 0.4 MW. Thus, in Figure 6-7, the demand exceeding 0.4 MW is supposed to be supplied by the batteries located in homes. The capacity of the community battery, then, is aligned to the demand greater than the mean consumption power but lower than the target 0.4 MW. This community battery is utilised to perform the community-scale peak shaving (section 4.3).

6.1.5. Li-ion battery

Li-ion battery was selected as the electricity storage unit within a community energy system. To evaluate Li-ion battery on energyPRO, parameters that include charging and discharging powers, charging and discharging efficiencies and state of charge (SOC) were required to be defined. The charging and discharging rates are expressed as the C rate, which indicates the correlation between electric power and capacity. The charging rate of most Li-ion batteries is not over 1C, and charging at 0.8C or less is the recommended value from manufacturers [141, 142]. In other words, a battery with a capacity of 1 MWh can be safely charged at a maximum power of around 1 MW. The discharging rate is usually greater than the charging rate for Li-ion batteries. Many small and medium-scale batteries can achieve a discharging rate of at least 1.5C, and the Li-titanate battery is possible to perform a 10C discharging rate [97, 142, 143]. In this chapter, the Li-ion battery is utilised to smooth the demand profile of the Electricity and EVs. The demand data shown in Figure 6-7 indicated that the charging and discharging powers over 0.21 MW (i.e., the difference between the maximum power and mean electric power) are not required, meaning that a battery capacity higher than 0.21 MWh can supply high enough power for peak shaving in the electrified community.

The charging and discharging efficiencies were assumed to be 92.2%, which is typical for battery storage [97]. Most of the Li-ion batteries on the market have a depth of discharge (DoD) of around 90% [91]. In the simulation, the utilisation rate of the Li-ion battery was assumed to be 85%, giving a 15% demand buffer.

6.1.6. Electricity demand of an electrified heating network

An electrified heating network within a community energy system was defined through a ground source heat pump (GSHP), low-temperature district heating (LTDH) system, electric heaters and thermal storage units (Chapter 5). The energy demand and optimisation approach of this heating network are the focuses in this subsection.

The annual consumptions of SH and DHW per dwelling were 6365.4 kWh and 1649.1 kWh, respectively, based on the statistical data in 2018 (Chapter 5). The scale of the electrified community was 384 dwellings, which resulted in annual SH and DHW demands of 2444.3 MWh and 633.2 MWh.

At the beginning of the simulation, the electric power of the GSHP was defined as 520 kW that produces heat during off-peak hours (7 hours). On the other hand, electric heaters generating heat energy aligned with the DHW demand. The central thermal store can store the average daily demand of the community in the coldest month. The storage capacity with an 80% utilisation rate was 21 MWh. Besides, the storage temperature was 40°C, which is the same as the distribution temperature of the LTDH system. These setting values were determined by a systematic modelling approach (Chapter 5).

In contrast, the optimisation approach, defined as the ideal heating supply, operated the GSHP and electric heaters constantly in the greatest consumption week (i.e., the coldest week). The collective electric powers of the GSHP and electric heaters were 220 kW and 41 kW, respectively. The method of obtaining these power values will be elaborated with an electricity consumption curve of the electrified community, presented in the results section 6.2.2. Moreover, the community thermal store was determined to store half of the average daily demand in the coldest month. The storage capacity can be reduced because of the constant operation. As a result, the capacity of the community thermal store was 10.5 MWh with the same storage temperature of 40°C. Table 6-1 summarises the optimisation conditions of the community energy system and the demands of the electrified community.

Table 6-1: The optimisation conditions of the multi-vector community energy system and demand data in the electrified community.

Conditions	
Number of dwellings	384
Number of EVs	465
Battery capacity (MWh)	1.27
Percentage of smart charging (%)	50
Electric power of GSHP (kW)	220
Collective electric power of electric heaters (kW)	41
Thermal store capacity (MWh)	10.5
Temperature of heating network (°C)	40
Annual demand	
SH (MWh)	2444.3
DHW (MWh)	633.2
Electricity demand of lighting and appliances (MWh)	1439.6
EVs (MWh)	614.1

6.2. Results

This section firstly illustrates the energy demands of a community in hourly resolution across a whole year. The impact of an electrified community on the electricity grid is shown by converting the energy demands into electricity, with different COPs for SH supply. Subsequently, an electrified community model utilises a community energy system applying smart management measures to manage the electricity flows. Finally, the power consumption in the greatest demand week is used to define the required improvement level of housing thermal efficiency. A community energy system with housing thermal efficiency improvement demonstrates an electrified community on the typical UK distribution network.

6.2.1. Energy demands in a community

The energy consumptions of a 384-dwelling community are illustrated in hourly resolution in Figure 6-8. The demand of the EVs (grey line) lower than the Electricity (light blue line; lighting and appliances) and Heat (orange line) consumptions is relatively stable throughout the year. The seasonal demand gap appears obviously on the Electricity and becomes significant on the Heat. Note that the Heat, including SH and DHW, is the heating consumption at the consumer side, not the electricity demand for heat production. Overall, the greatest demand week starts at the end of February, and the lowest consumption week is at the end of July.

Figure 6-9 shows the energy consumptions in the highest demand week, also the coldest week in 2018. The consumption of the EVs (grey colour) indicates that the weekdays consume more energy than the weekends because of the commute demand. Unlike the EVs, the Electricity consumption (blue colour) at the weekends is greater than on the weekdays, which is understandable since people spend a longer time at home at weekends. The heating demand (orange colour) is strongly correlated with the ambient temperature. The coldest day in 2018 is Wednesday in Figure 6-9. The average ambient temperature at the day is -4.6 °C approximately. On the other hand, the lowest heating consumption day in the coldest week is Sunday, which has an average daily temperature of around 3.1°C. Note that the temperatures are based on the records in Nottingham in the UK. Moreover, the maximum total consumption power (black dash line) reaches 2.14 MW. The average consumption power (green dash line) is around 1.19 MW.

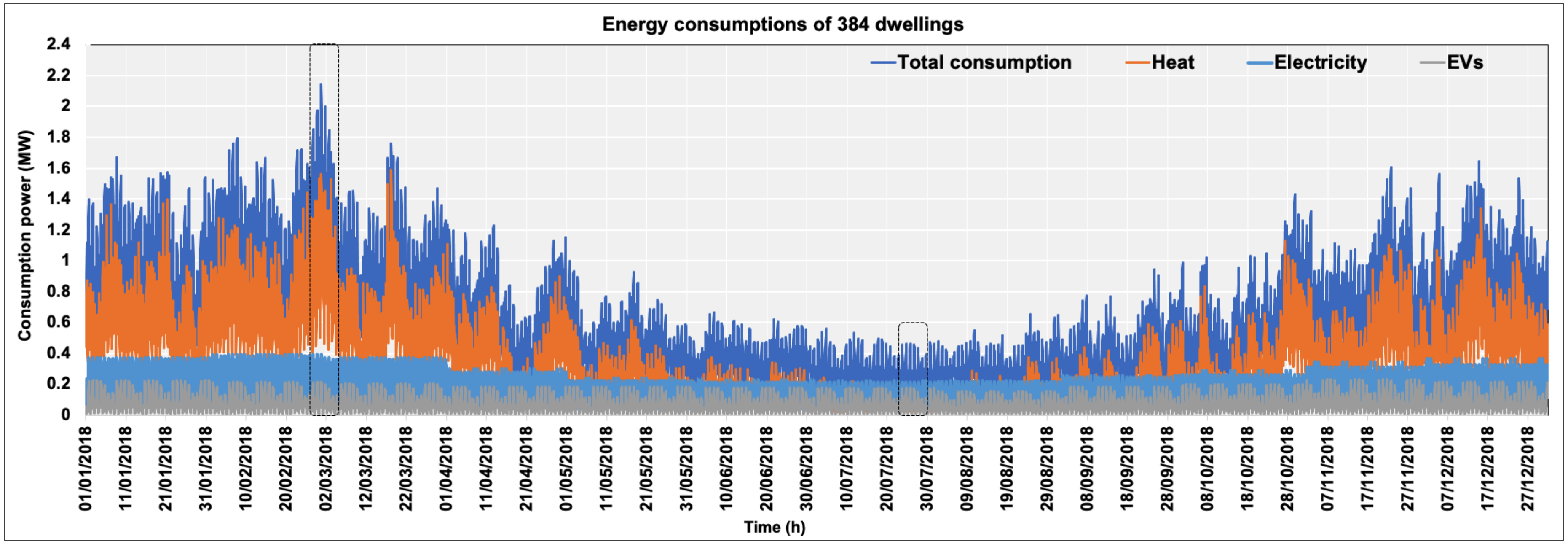

Figure 6-8: The energy consumptions of a 384-dwelling community in 2018

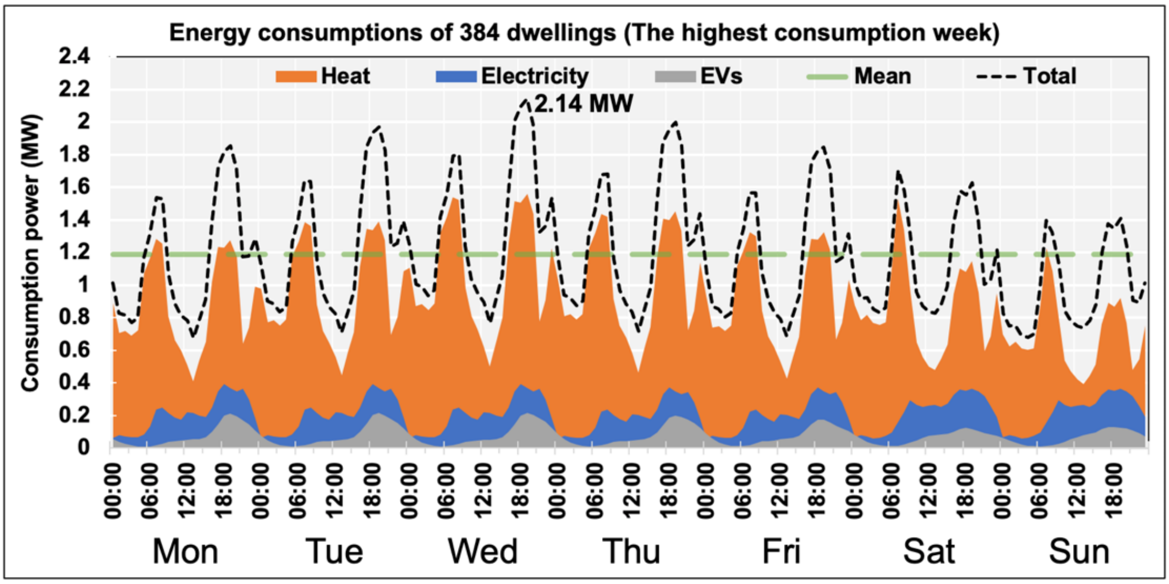

Figure 6-9: The highest energy consumption week in 2018; the coldest week in 2018.

Figure 6-10 illustrates the lowest consumption week in 2018. The Heat demand that consumes the least energy mainly comes from DHW usage. The maximum peak of the total consumption is only 0.46 MW. The mean consumption power is 0.24 MW. In comparison with the greatest demand week, the lowest consumption week uses nearly five times less energy. This considerable seasonal difference is primarily caused by SH demand.

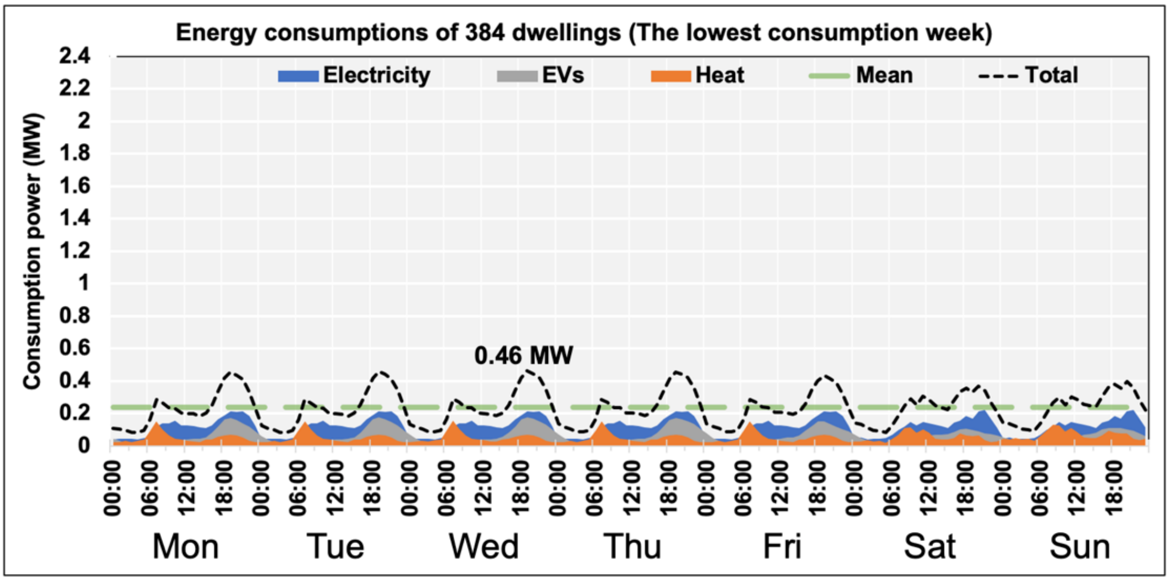

Figure 6-10: The lowest energy consumption week in 2018.

To investigate the impact of electrification on the electric power network, the electric power demands in the highest consumption day (i.e., the coldest day) are indicated in Figure 6-11. The conditions are evaluated with different COPs of heat generation to meet the SH demand. The COP 1 condition (Figure 6-11 top) can be viewed as the SH demand supplied by electric heaters. The maximum and mean consumption powers of the COP 1 condition are 2.14 MW and 1.35 MW, respectively. On the other hand, the COP 3 condition (Figure 6-11 bottom) is reflected in the utilisation of air source heat pumps (ASHPs). Consequently, the maximum power is reduced to 1.17 MW while the average demand is decreased to 0.7 MW.

Comparing with the maximum power created by the Electricity (i.e., without the electrification; the Elec. in Figure 6-11), the COP 1 and COP 3 conditions increase the peak demand by 5.4 times and 2.9 times, respectively. Furthermore, the mean consumption of the Electricity that is represented by the blue dash line in Figure 6-11 is 0.21 MW. As a result, the average demands of the 100% electrification (grey dash lines) with the COP 1 and COP 3 conditions are around 6.4 times and 3.3 times greater than the mean power of the Electricity.

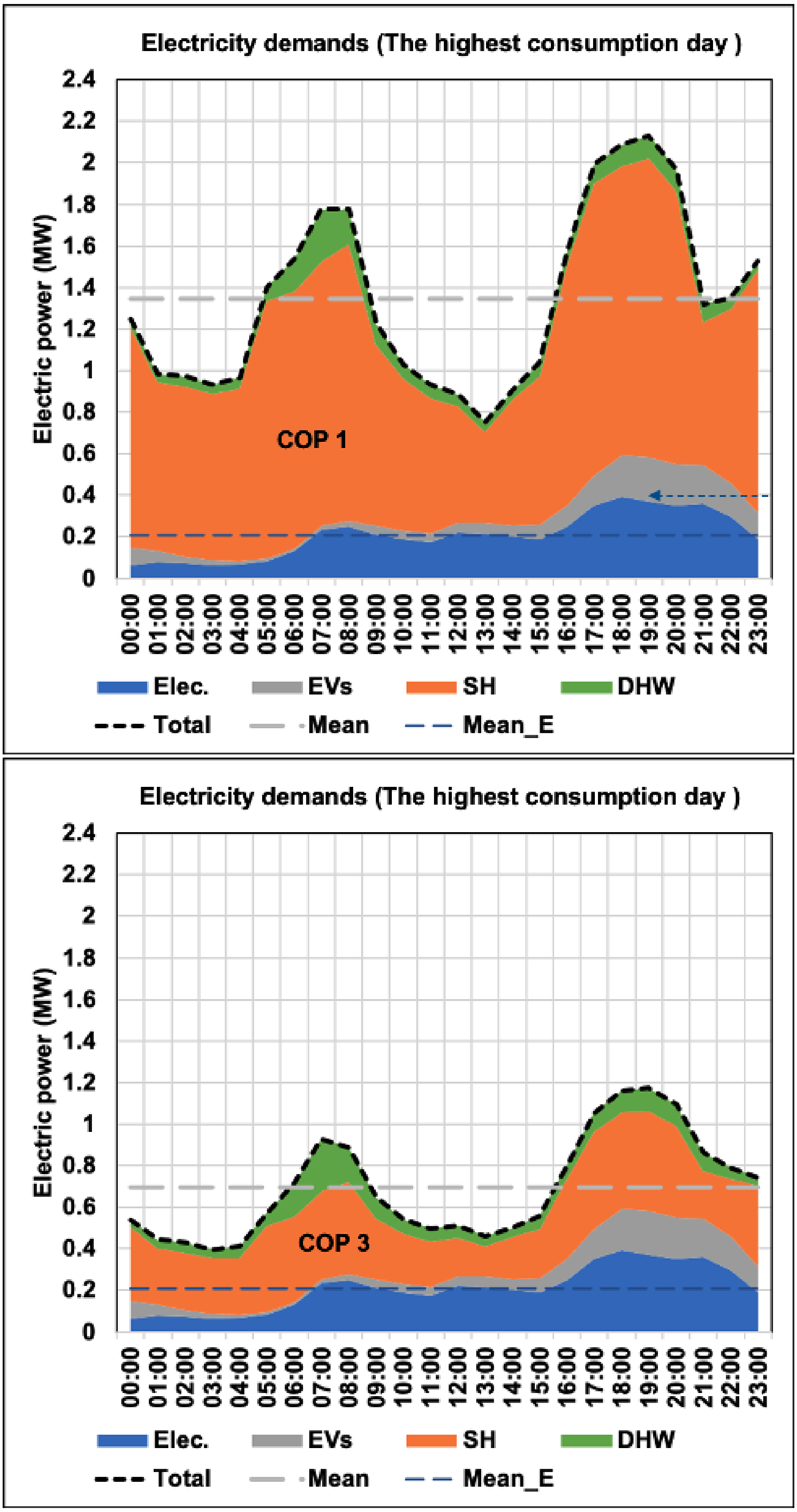

Figure 6-11: The electricity consumptions under different COPs for SH demand, in a community with 384 dwellings.

6.2.2. An electrified community with a community energy system

In an electrified community managed by a community energy system, the power demands of the Electricity and EVs were the same as the data shown in the previous subsection. On the other hand, the electricity consumptions for SH and DHW were induced by a GSHP and electric heaters in an electrified heating network. The GSHP providing heat for both heating demands had a COP of 4 when the supply temperature is 50°C. The electric heaters were assumed to have a COP of 1 for meeting the partial DHW demand (Chapter 5).

Figure 6-12 illustrates the electricity demands of the electrified community in the greatest consumption week. The maximum total consumption power (black dash line) reaches 0.91 MW. The mean electric power (green dash line) is around 0.54 MW. Moreover, the GSHP is operated mainly during the off-peak hours (00:00-07:00) to mitigate the peak consumption, which is effective. However, the power fluctuation of the total consumption is significant.

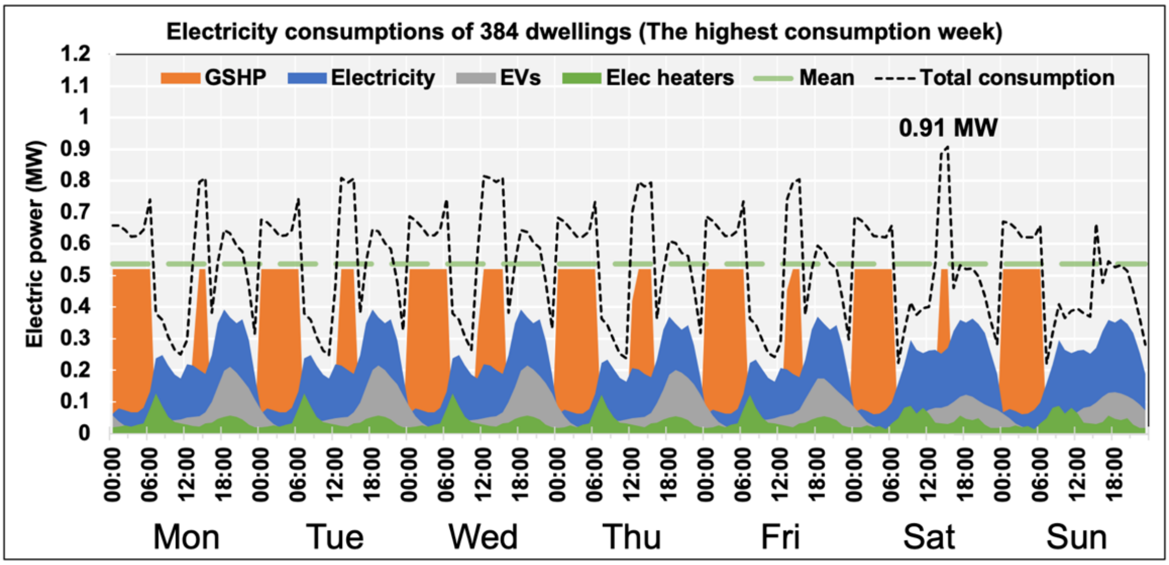

Figure 6-12: The electricity consumptions of an electrified community with the multi-vector community energy system.

The ideal heating supply was defined to optimise the electricity flow of the heating network. The method of producing this ideal heating supply was to collect the electricity consumptions of the GSHP and electric heaters in the highest demand week (i.e., Figure 6-12), then evenly distribute the consumptions to this week. In Figure 6-13, electricity consumptions of the ideal heating supply, Electricity and EVs are illustrated with a stacked area figure. The result shows that the electric power of the GSHP (orange colour) operated constantly should be at least 213 kW. Comparing with Figure 6-12, the electric power of the GSHP is reduced from 0.52 MW (orange colour in Figure 6-12) to around 0.21 MW. Moreover, the maximum power is slightly decreased to around 0.85 MW. The power fluctuation of the total consumption is smaller and more simple.

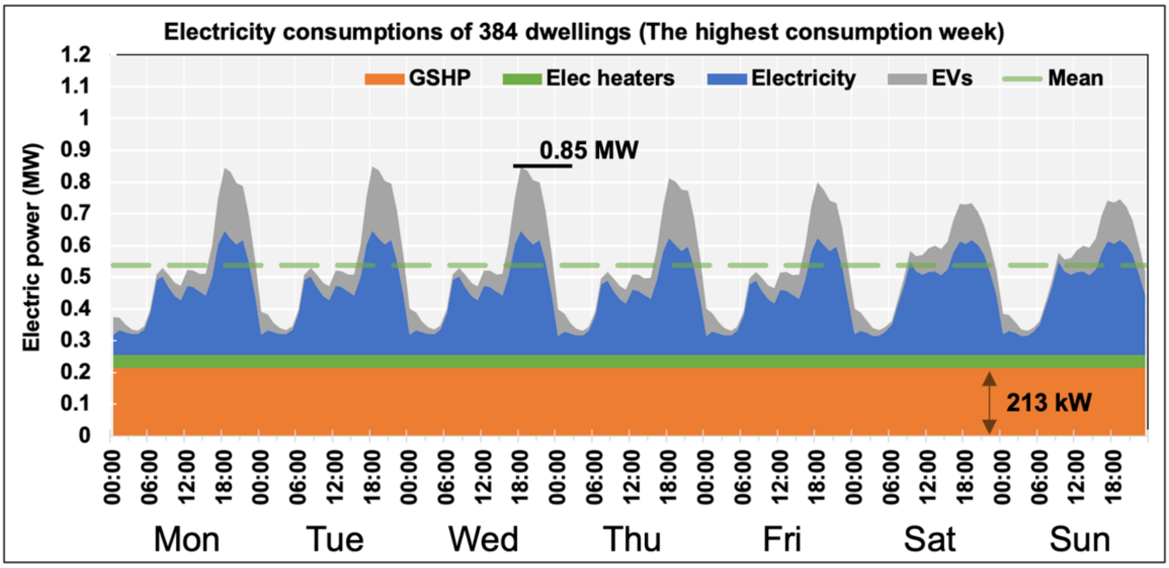

Figure 6-13: The electricity consumptions of an electrified community with the ideal heating supply in the highest consumption week.

A model including the ideal heating supply, smart charging of 50% EVs, and application of the community battery was demonstrated on energyPRO. Figure 6-14 is the modelling configuration that the electric power network (i.e., New Fixed tariff market) connects with the electrified heating network, EVs, Electricity and community battery. The heating network utilises the GSHP and electric heaters to supply heat for the demands of SH and DHW and heat losses. The GSHP and electric heaters are separated into two sites due to the software constraint. Nonetheless, the result is accurate (Chapter 5). Based on Figure 6-13, the electric power of the GSHP should be greater than 213 kW; hence, electric power of 220 kW was determined. The detailed conditions are summarised in Table 6-1.

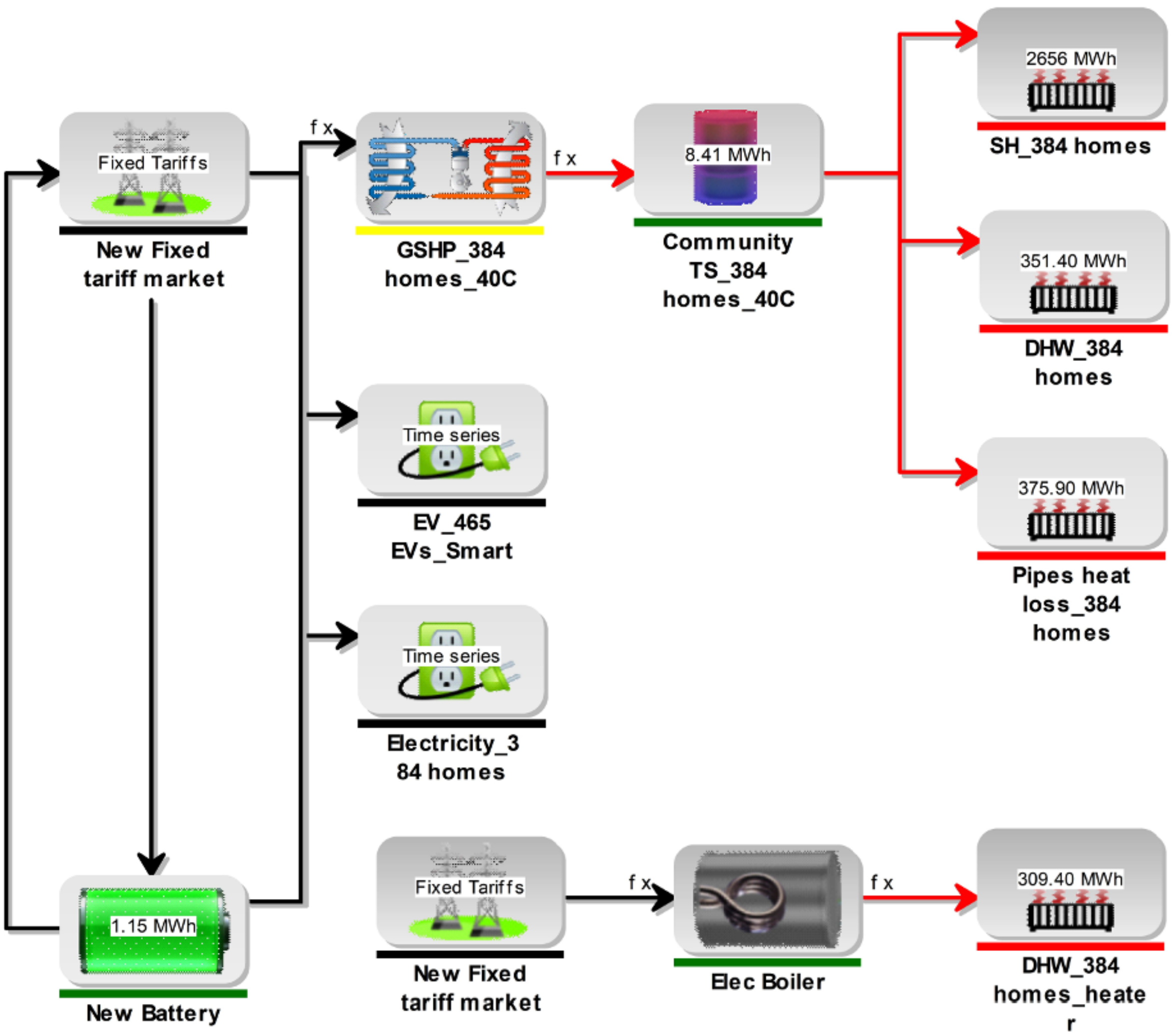

Figure 6-14: The simulated configuration of the multi-vector community energy system with the ideal heating supply, EV smart charging and community battery.

Figure 6-15 illustrates the simulation results. The first graph representing the heat production and consumption indicates the GSHP (yellow colour) produces heat constantly during the highest consumption week (i.e., the middle of the graph). The heating power generated by the GSHP is not adequate to meet the instantaneous heating demand (red line). Nevertheless, the utilisation of thermal storage (i.e., the third graph) successfully compensates for the insufficient supply.

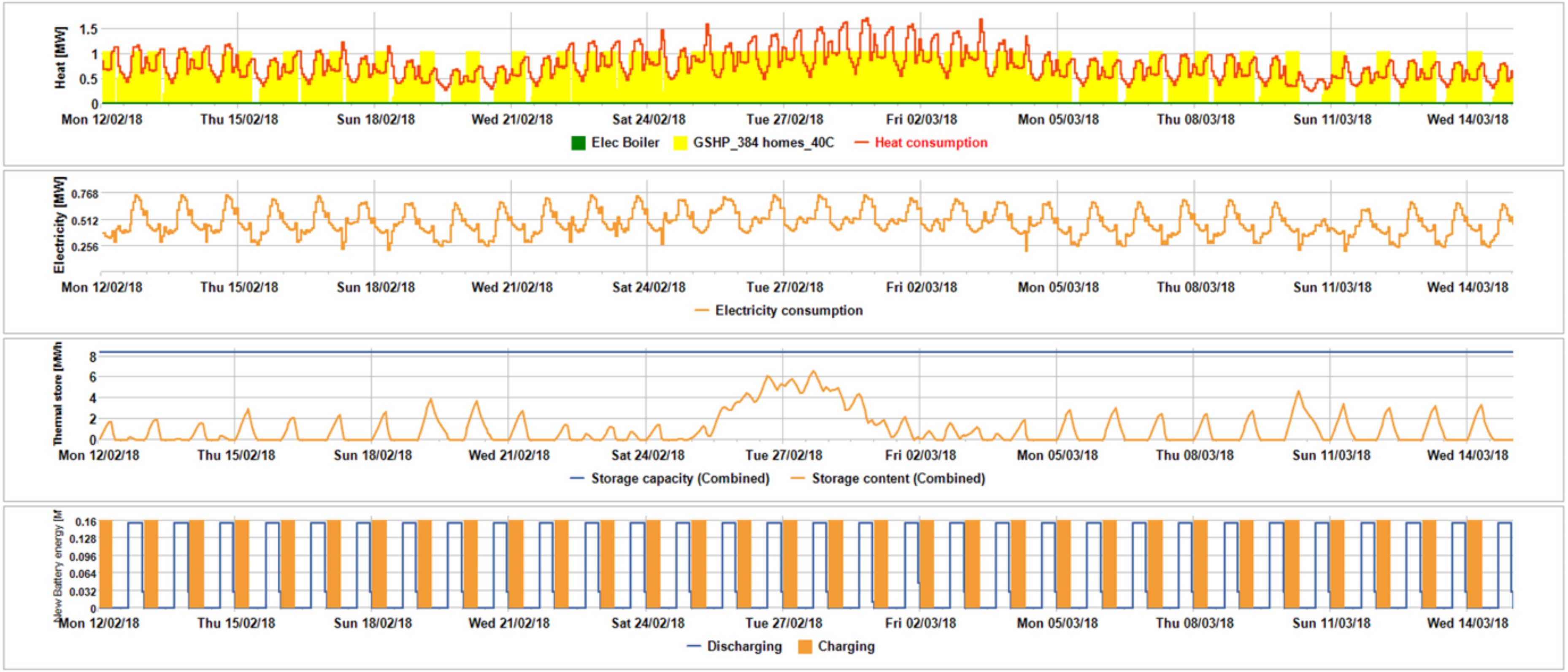

Figure 6-15: The simulation results of the multi-vector community energy system with the ideal heating supply, EV smart charging and community battery.

In Figure 6-15, the second graph is the electricity consumption of an electrified community, showing that the maximum power reaches around 0.75 MW. The fourth graph illustrates the charging and discharging cycles of the community battery. For a demonstration model, the charging period is from midnight to 7 am, that the charging power is set at 175 kW with a 92.2% efficiency. The discharging period is from 16:00 to midnight, which has a discharging power of 170 kW with a 92.2% efficiency.

For a detailed analysis, the data in the greatest consumption week shown in Figure 6-15 was transferred to an Excel worksheet and illustrated in Figure 6-16. The maximum power of the stacked area is around 0.75 MW on Wednesday. The mean power demand is 0.53 MW (green dash line). Moreover, using the community battery to perform peak shaving indicates that the highest demand peak (black line) is reduced to around 0.64 MW. It is noteworthy that the community battery is operated by a simple control method (the two black dash lines). This implies that the total consumption power can be further decreased with a better battery control system and potentially constrained at around the Mean.

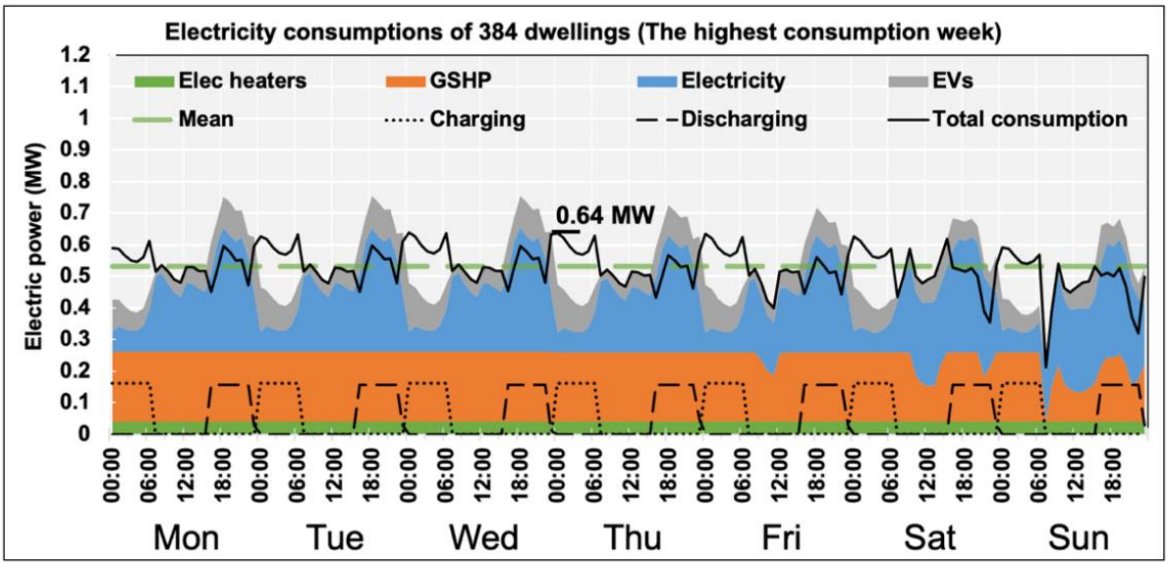

Figure 6-16: The electricity consumptions of an electrified community with the multi-vector community energy system performing the ideal heating supply, EV smart charging and peak shaving.

6.2.3. An electrified community with a community energy system and housing improvement

This subsection is going to evaluate a community energy system with the typical UK distribution network, thereby indicating the required level of thermal efficiency improvement in buildings. As a result, by utilising a community energy system and improving the thermal efficiency of buildings, the existing distribution network can accommodate the electricity demands of an electrified community.

A LV substation within the typical UK distribution network has an output power of 0.5 MW (section 6.1.3). In this research, the targeted maximum power of an electrified community was 0.4 MW, which was aligned to the peak consumption without the electrification (section 6.1.4). To estimate the improvement level of the thermal efficiency, the electricity consumptions within the greatest demand week shown in Figure 6-16 were converted into the bar chart in Figure 6-17.

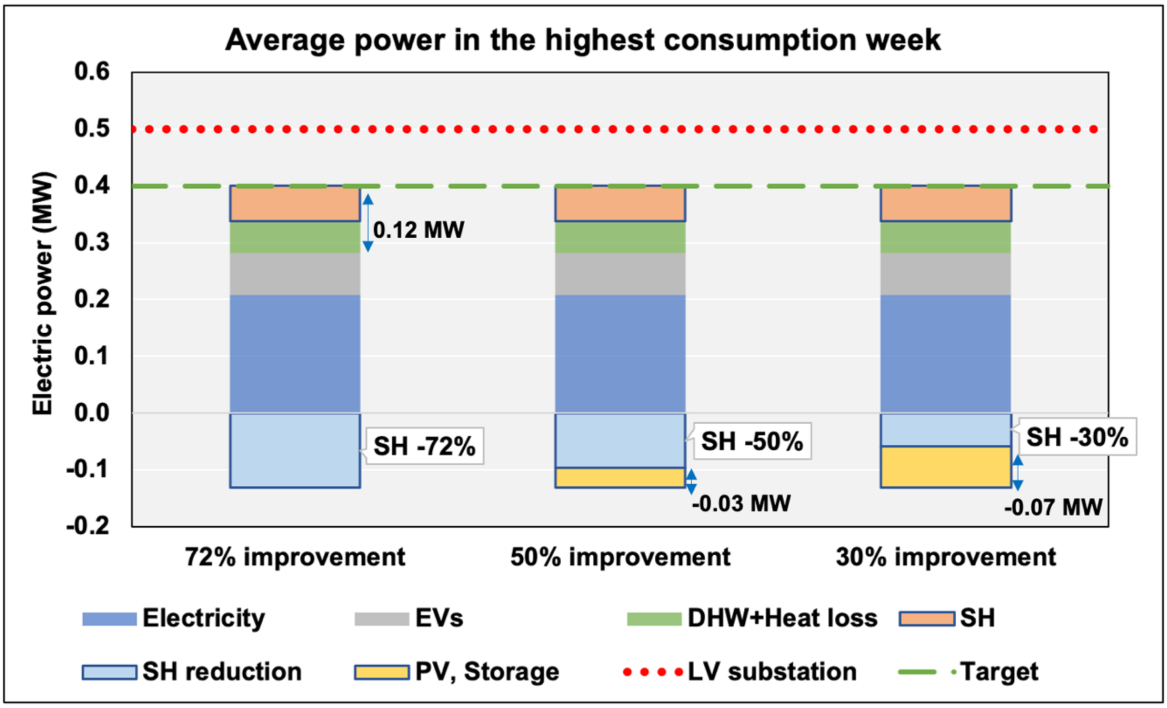

Figure 6-17: The electricity consumptions of an electrified community in the highest demand week with different improvement levels of thermal efficiency in buildings.

This bar chart, Figure 6-17, assumes that the electricity consumptions are steady, which is attainable by employing a community energy system. The method of producing these ideal electricity flows was the same as generating the ideal heating supply in subsection 6.2.2. Furthermore, the electric power demand of the GSHP in Figure 6-16 is split into SH and DHW with heat loss, based on the systematic modelling approach of an electrified heating network (Chapter 5). The consumption of the GSHP for DHW demand with heat loss is then added to the consumption of electric heaters that only supply partial DHW demand. This is presented as the DHW + Heat loss (green colour) in Figure 6-17. The electric powers of the Electricity, EVs, DHW + Heat loss and SH are around 0.21 MW, 0.07 MW, 0.06 MW and 0.06 MW, respectively. The maximum power is constrained at the target (0.4 MW). Thus, the power demand exceeding the target is required to be reduced, which is represented by the 'SH reduction' and 'PV (generation), Storage' at the negative y-axis.

In Figure 6-17, three levels of thermal efficiency improvement, compared with the housing thermal efficiency in the UK in 2018, are evaluated. The powers of SH reduction (light blue colour) from the left bar to the right bar are 0.13 MW, 0.1 MW and 0.06 MW. The left bar illustrates that the target of constraining the electric power at 0.4 MW can be achieved by a 72% SH demand reduction, equivalent to a thermal efficiency improvement of 72%. This bar chart also indicates the maximum electric power of the GSHP. By the addition of the DHW + Heat loss and SH powers determines the electric power of the GSHP (0.12 MW). Note that the electric power of electric heaters is not shown because of their relatively low consumption. According to the systematic modelling approach (Chapter 5), the utilisation rate of electric heaters is varied with the distribution temperature of the LTDH. The 72% SH demand reduction should utilise a distribution temperature of 60°C by the selection, which results in electric heaters only supplying 6% of the DHW demand.

The other two conditions of housing thermal efficiency improvement in Figure 6-17 require the utilisation of PV generation and storage (yellow colour) to offset the exceeding demands. In the 50% improvement (middle bar), the average power of the PV, Storage in the greatest consumption week is around 0.03 MW. This requirement of the PV, Storage power is increased to around 0.07 MW when the housing thermal efficiency is only improved by 30% (right bar). The simulations of the 50% and 30% improvements with PV generation and storage will be illustrated in Chapter 7.

To demonstrate a community energy system with thermal efficiency improvement in buildings, this chapter applied a simulation model with 70% improvement on energyPRO. The modelling configuration was the same as Figure 6-14. The differences were: (1) The SH demand was reduced by 70%. (2) The electric power of the GSHP was decreased from 0.22 MW to 0.12 MW. (3) The distribution temperature was increased from 40°C to 60°C.

(4) The capacity of thermal storage was reduced from 10.5 MWh to 4.04 MWh, derived from the systematic modelling approach in Chapter 5.

Figure 6-18 indicates the modelling result in the greatest demand week. The maximum power of the stacked area is around 0.62 MW. The mean consumption power (green dash line) meets the target at 0.4 MW. Besides, the community battery utilising a simple control method (two black dash lines) manages the total consumption power (black line) at a power range lower than the LV substation (0.5 MW). The total consumption can be potentially constrained at the target power (green dash line) with a better battery control system.

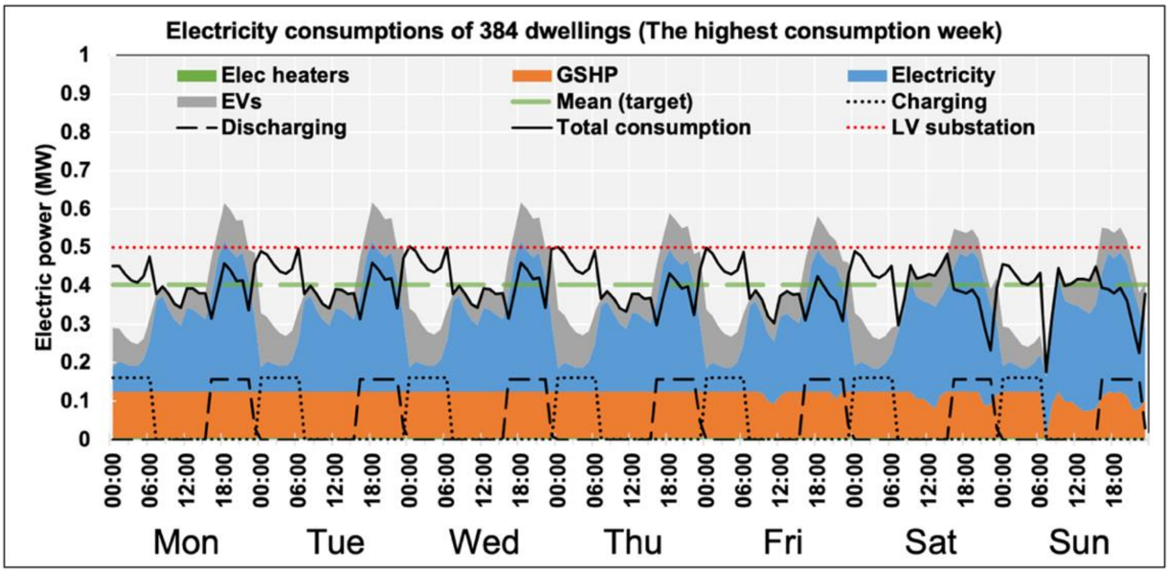

Figure 6-18: The 70% thermal efficiency improvement with the community energy system performing the ideal heating supply, EV smart charging and peak shaving.

6.3. Discussion and conclusion

To establish an electrified community model, this chapter investigated annual residential demands in a 384-dwelling community, including the Electricity (i.e., lighting and appliances), EVs and heating. The result indicated the greatest consumption week in winter consumed almost 5 times more energy than the lowest week in summer. This significant seasonal difference was mainly driven by the SH demand, implying that higher heat generation performance and greater housing thermal efficiency are the key factors to mitigate the demand gap.

By converting energy demands into electricity consumptions, the result showed that the maximum power in the highest demand day (i.e., the coldest day) could reach around 2.14 MW if the SH and DHW demands were supplied by electric heaters having a COP of 1. The utilisation of ASHPs was assumed to have a COP of 3 for SH supply, which reduced the peak demand to around 1.17 MW. Nevertheless, this power demand was still 2.9 times greater than the scenario without the electrification of domestic heating and road transport (0.4 MW).

In contrast, a community energy system that utilised an electrified heating network to meet SH and DHW demands decreased the peak power to around 0.91 MW. The heating network was comprised of a GSHP, LTDH system, electric heaters and thermal storage units. Despite the reduction of peak power, the power fluctuation of the total consumption was significant. To optimise this community energy system, the GSHP and electric heaters were operated constantly in the greatest consumption week. This approach, defined as the ideal heating supply, showed that: (1) The maximum demand power was reduced to 0.85 MW. (2) The electric power of the GSHP can be decreased from 0.52 MW to 0.22 MW. (3) The power fluctuation of the total consumption was smaller and more simple. By utilising a GSHP having a lower electric power reduces the system cost. Besides, a more stable power flow indicates that the system is easier to be managed. This decreases the cost and increases the reliability.

To demonstrate a community energy system performing the best possible efficiency to an electrified community, the ideal heating supply, smart charging of 50% EVs and community-scale peak shaving were applied to the model. The result showed that the maximum power was reduced further to around 0.64 MW. This is only 60% greater than the peak demand (0.4 MW) without the electrification. A 33% increase in the peak demand is attainable with a better battery control system, which constrains the consumption at the mean power of 0.53 MW.

Finally, the evaluation of a community energy system with the typical UK distribution network indicated that around 70% thermal efficiency improvement in buildings, compared with the UK housing thermal efficiency in 2018, was required. The demonstration model showed the power consumption was lower than the 0.5 MW capacity of a LV substation even in the greatest demand week. The average power met the target of 0.4 MW. Accordingly, the typical UK distribution network can accommodate the electricity demands brought by an electrified community when a multi-vector community energy system performing smart managements and the thermal efficiency improvement in buildings are employed.

The simulation model of an electrified community will be established in a modelling tool, elaborated in Chapter 8. The calculations cover the electricity demands of the Electricity, EVs and an electrified heating network and the community-scale peak shaving, shown in Figure 6-19, Figure 6-20, Figure 6-21 and Figure 6-22.

	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
4						per dwelling	homes				**Ratio**	Monthly			
5		months	TWh	MWh	households	MWh						3.748913	Obtained annual data from sheet 1		
6		Jan	10.86	**10860000**	27600000	**0.393**					**10.495796**	**0.393**	**393.478**		
7		Feb	10.38	**10380000**		**0.376**					**10.031893**	**0.376**	**376.087**		
8		Mar	10.85	**10850000**		**0.393**					**10.486131**	**0.393**	**393.116**		
9		Apr	8.67	**8670000**		**0.314**					**8.3792404**	**0.314**	**314.130**		
10		May	7.18	**7180000**		**0.260**					**6.9392094**	**0.260**	**260.145**		
11		Jun	6.75	**6750000**		**0.245**					**6.52363**	**0.245**	**244.565**		
12		Jul	6.45	**6450000**		**0.234**					**6.2336909**	**0.234**	**233.696**		
13		Aug	6.49	**6490000**		**0.235**					**6.2723495**	**0.235**	**235.145**		
14		Sep	7.17	**7170000**		**0.260**					**6.9295448**	**0.260**	**259.783**		
15		Oct	8.41	**8410000**		**0.305**					**8.1279598**	**0.305**	**304.710**		
16		Nov	9.69	**9690000**		**0.351**					**9.3650333**	**0.351**	**351.087**		
17		Dec	10.57	**10570000**		**0.383**					**10.215521**	**0.383**	**382.971**		
18						**3.749**					100	MWh	kWh		
19														Max demand month	
20														**Weekly**	
21														**0.094021739**	
22														MWh	

Figure 6-19: Screenshot of the modelling tool – The calculation results of the Electricity (i.e., lighting and appliances) demand, including monthly electricity demands, demand percentages of each month and the weekly demand in the maximum demand month.

	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
1		**per EV**		per day			monthly			**Ratio**	Monthly			
2			months	kWh		kWh	MWh				1.32075	Obtained annual data from sheet 1		
3			Jan	4.2	31	**130.2**	**0.1302**			**9.858035**	**0.130**	**130.2**		
4			Feb	3.95	28	**110.6**	**0.1106**			**8.37403**	**0.111**	**110.6**		
5			Mar	3.75	31	**116.25**	**0.11625**			**8.801817**	**0.116**	**116.25**		
6			Apr	3.4	30	**102**	**0.102**			**7.722885**	**0.102**	**102**		
7			May	3.4	31	**105.4**	**0.1054**			**7.980314**	**0.105**	**105.4**		
8			Jun	3.3	30	**99**	**0.099**			**7.495741**	**0.099**	**99**		
9			Jul	3.25	31	**100.75**	**0.10075**			**7.628242**	**0.101**	**100.75**		
10			Aug	2.85	31	**88.35**	**0.08835**			**6.689381**	**0.088**	**88.35**		
11			Sep	3.4	30	**102**	**0.102**			**7.722885**	**0.102**	**102**		
12			Oct	3.7	31	**114.7**	**0.1147**			**8.68446**	**0.115**	**114.7**		
13			Nov	4.25	30	**127.5**	**0.1275**			**9.653606**	**0.128**	**127.5**		
14			Dec	4	31	**124**	**0.124**			**9.388605**	**0.124**	**124**		
15						1320.75	**1.32075**			100	MWh	kWh		
16													Max demand month	
17													**Weekly**	
18													**0.02765**	
19													MWh	

Figure 6-20: Screenshot of the modelling tool – The calculation results of residential EV charging demand, including monthly electricity demands, demand percentages of each month and the weekly demand in the maximum demand month.

	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP
1	***Improvement***			**40C**	**45C**	**50C**	**55C**	**60C**	**65C**	
2	72%		DHW consumption	1649.079	1649.079	1649.079	1649.079	1649.079	1649.079	
3			water in tank (kg)	31618.239	31618.24	31618.239	31618.24	31618.24	31618.24	
4			SH consumption	1793.067	1793.067	1793.067	1793.067	1793.067	1793.067	
5			households	384	384	384	384	384	384	
6			distribution T	40	45	50	55	60	65	
7			soil T	10	10	10	10	10	10	
8			T(return 30C, soil 10C)	**25**	**27.5**	**30**	**32.5**	**35**	**37.5**	
9			length branch pipe, m	5	5	5	5	5	5	
10			branch U	**0.139**	**0.139**	**0.139**	**0.139**	**0.139**	**0.139**	
11			length main pipe, m	10	10	10	10	10	10	
12			main U	**0.308**	**0.308**	**0.308**	**0.308**	**0.308**	**0.308**	
13			branch number	**384**	**384**	**384**	**384**	**384**	**384**	
14			main number	**192**	**192**	**192**	**192**	**192**	**192**	
15			hours	8760	8760	8760	8760	8760	8760	
16			W to kW	1000	1000	1000	1000	1000	1000	
17				annual heat l	annual hea	annual heat	annual hea	annual hea	annual heat loss	
18				**375909.12**	**413500**	**451090.94**	**488681.9**	**526272.8**	**563863.7**	
19										
20			DHW							
21			Energy (from Elec. Boiler)	**309612.528**	**241528.6**	**173444.59**	**105360.6**	**37276.66**	**0**	
22			Energy (from LTDH) kWh	**323633.725**	**391717.7**	**459801.66**	**527885.6**	**595969.6**	**633246.3**	
23			Energy demand before HIU							
24			HIU efficiency	**92.033**	**91.953**	**91.873**	**91.793**	**91.713**	**91.633**	
25			DHW, Energy (from LTDH) kWh	**351649.652**	**425997.7**	**500475.29**	**575082.7**	**649820.2**	**691067.9**	
26										
27			SH							
28			Energy (from LTDH) kWh	**688537.674**	**688537.7**	**688537.67**	**688537.7**	**688537.7**	**688537.7**	
29			Energy demand before HIU							
30			HIU efficiency	**92.033**	**91.953**	**91.873**	**91.793**	**91.713**	**91.633**	
31			SH, Energy (from LTDH) kWh	**748142.16**	**748793.1**	**749445.08**	**750098.2**	**750752.5**	**751408**	
32										
33			COP	**4.66**	**4.29**	**3.99**	**3.73**	**3.52**	**3.32**	
34			DHW + SH							
35			Enerygy consumption of GSHP	**316724.639**	**369968.3**	**426327.31**	**485745**	**548168.2**	**603435.7**	
36			**Total Electricity (Elec. Boiler + GSHP)**	**626337.167**	**611496.9**	**599771.91**	**591105.6**	**585444.8**	**603435.7**	
37			**MWh**	**626.337167**	**611.4969**	**599.77191**	**591.1056**	**585.4448**	**603.4357**	
38										
39										
40				DHW	ratio	SH				
41				1649.079	1.09	1793.067				
42										
43										
44										
45				DHW:SH		384				
46					1.087314	**60**	°C			
47										
48				Ele heaters	37276.66	**37.276659**	MWh			
49				GSHP	548168.2	**548.16817**	MWh			
50				Total		**585.44483**	MWh			
51										

Figure 6-21: Screenshot of the modelling tool – The calculation results of an electrified heating network with the housing thermal efficiency improved by around 70%, including the heating demands, electricity consumption and temperature selection.

	A	B	C	F	G	H	I	J	K	L	M	N	O	P	Q	R	T
1																	
2	**Peak shaving storage**												demand over target				
3					LV substation	Mean	EVs	Electricity	EV+Elec		Storage(over mean)		Target				
4		LV substation	0.5	00:00	0.5	0.290	0.153	0.064	**0.217**	**-0.073**	**0**		0.4	**-0.183**	**0**		
5		Mean	0.289583	01:00	0.5	0.290	0.123	0.079	**0.203**	**-0.087**	**0**		0.4	**-0.197**	**0**		
6		Targeted electric power	0.4	02:00	0.5	0.290	0.102	0.073	**0.176**	**-0.114**	**0**		0.4	**-0.224**	**0**		
7		Mean EVs	0.081449	03:00	0.5	0.290	0.090	0.065	**0.155**	**-0.135**	**0**		0.4	**-0.245**	**0**		
8		Mean Elec	0.208134	04:00	0.5	0.290	0.083	0.067	**0.150**	**-0.140**	**0**		0.4	**-0.250**	**0**		
9				05:00	0.5	0.290	0.080	0.083	**0.163**	**-0.127**	**0**		0.4	**-0.237**	**0**		
10		Utilisation rate of battery	0.85	06:00	0.5	0.290	0.081	0.132	**0.213**	**-0.077**	**0**		0.4	**-0.187**	**0**		
11				07:00	0.5	0.290	0.018	0.237	**0.254**	**-0.035**	**0**		0.4	**-0.146**	**0**		
12				08:00	0.5	0.290	0.027	0.249	**0.277**	**-0.013**	**0**		0.4	**-0.123**	**0**		
13				09:00	0.5	0.290	0.040	0.213	**0.253**	**-0.037**	**0**		0.4	**-0.147**	**0**		
14				10:00	0.5	0.290	0.042	0.186	**0.228**	**-0.062**	**0**		0.4	**-0.172**	**0**		
15				11:00	0.5	0.290	0.044	0.173	**0.218**	**-0.072**	**0**		0.4	**-0.182**	**0**		
16				12:00	0.5	0.290	0.049	0.219	**0.268**	**-0.022**	**0**		0.4	**-0.132**	**0**		
17				13:00	0.5	0.290	0.052	0.215	**0.267**	**-0.023**	**0**		0.4	**-0.133**	**0**		
18				14:00	0.5	0.290	0.054	0.201	**0.255**	**-0.035**	**0**		0.4	**-0.145**	**0**		
19				15:00	0.5	0.290	0.067	0.188	**0.256**	**-0.034**	**0**		0.4	**-0.144**	**0**		
20				16:00	0.5	0.290	0.100	0.249	**0.349**	**0.059**	**0.059**		0.4	**-0.051**	**0**		
21				17:00	0.5	0.290	0.074	0.349	**0.422**	**0.133**	**0.133**		0.4	**0.022**	**0.022**		
22				18:00	0.5	0.290	0.100	0.393	**0.493**	**0.203**	**0.203**		0.4	**0.093**	**0.093**		
23				19:00	0.5	0.290	0.107	0.367	**0.474**	**0.185**	**0.185**		0.4	**0.074**	**0.074**		
24				20:00	0.5	0.290	0.102	0.349	**0.450**	**0.161**	**0.161**		0.4	**0.050**	**0.050**		
25				21:00	0.5	0.290	0.091	0.361	**0.453**	**0.163**	**0.163**		0.4	**0.053**	**0.053**		
26				22:00	0.5	0.290	0.080	0.296	**0.376**	**0.087**	**0.087**		0.4	**-0.024**	**0**		
27				23:00	0.5	0.290	0.195	0.187	**0.382**	**0.093**	**0.093**		0.4	**-0.018**	**0**		**located at substation**
28							MW	MW				Battery rated capacity				Battery rated capacity	Battery rated capacity
29											**1.083**	**1.27**			**0.292305**	**0.34**	**0.93**

Figure 6-22: Screenshot of the modelling tool – The calculation for the community-scale peak shaving, including the electricity demands of the Electricity (i.e., lighting and appliances) and EVs and the battery storage capacities.

Chapter 7

The Deployment of Decentralised Generation Coupled with Storage Units

In an electrified community, the electricity demand on the highest consumption day could be over six times larger than the scenario without the electrification when energy demands are converted into electricity directly (Chapter 6). This considerable demand exceeds the maximum capacity of a low voltage (LV) substation in the typical UK distribution network [130]. Applying decentralised generation (DG) coupled with storage units within a multi-vector community energy system and thermal efficiency improvement in buildings can be a solution to ensure the security of electricity supply. This is demonstrated in this chapter.

Solar photovoltaic (PV), the selected DG in this research, has been indicated to be a key technology that will produce clean energy in the UK [144]. With the government subsidies and declining cost of PV systems, the cumulative PV capacity has been over 13.3 GW at the end of 2019 [145]. Around 20% of the total installed capacity was identified to be small scale (0 to 4 kW) installations, such as rooftop PV systems [145, 146]. The size of a residential PV system in the UK is often determined by the maximum available installation area and the available budget combined with the financial support from the government [147, 148]. The installed capacity of national average is 2.9 kW [149].

A community energy system, illustrated in Figure 4-1, has been introduced and demonstrated in previous chapters. With this community energy system, the peak power demand induced by an electrified community can be constrained at only a 33% increase potentially on the highest consumption day. Furthermore, to enable the typical UK distribution network to accommodate the demand, an improvement of housing thermal efficiency (i.e., reducing SH consumption) and/or an installation of DG coupled with storage units (i.e., providing extra electricity supply) are required (Chapter 6).

In this research, the capacity of DG is sized to offset the power demand exceeding the targeted maximum power within the distribution network and varied with the improvement level of thermal efficiency in buildings. This chapter demonstrates the concept using the demand data in average UK dwelling in 2018. The required capacities of DG/storage units and other facilities (e.g., GSHP, thermal storage, etc.) in a community energy system are calculated, then input to a demonstration model on energyPRO [19].

Finally, to reduce the electricity demand of an electrified community, two optimisation approaches of the electrified heating network within a community energy system are evaluated. These include solar thermal collectors placed at home for domestic hot water (DHW) consumption and distribution temperature management delivering two different water temperatures for meeting domestic space heating (SH) and DHW demands.

The following sections in this chapter are elaborated as: Section **7.1 Modelling methodology** depicts the scenarios and methods of evaluating the DGs and optimisation approaches. Section **7.2 Results** summarises the modelling results of the DG/storage units with three thermal efficiency improvement levels and the two optimisation approaches. Section **7.3 Discussion and conclusion** compares the modelling results and delivers the key findings.

7.1. Modelling methodology

This section outlines the scenarios that were conducted to evaluate the decentralised generation. These scenarios apply different capacities of a heating network, PV modules and electricity storage to supply the demands of an electrified community. This section defines the capacities of the mentioned components and illustrates the two optimisation approaches.

7.1.1. Scenarios – Thermal efficiency improvement levels and optimisation approaches

The modelling scenarios were categorised by improvement levels of thermal efficiency in buildings and related to the typical UK distribution network. A LV substation within the typical UK distribution network can supply a maximum power of 0.5 MW. The electric power in an electrified community was targeted at not exceeding 0.4 MW, aligned to the peak demand without the electrification. Moreover, the LV substation commonly provides 384 dwellings with electricity; hence, the community scale was defined (Chapter 6).

In Chapter 6, Figure 6-17 illustrated the average electric power demands in the greatest consumption week in 2018. Those steady electricity flows were attainable by utilising a community energy system. The left bar indicated that the target (0.4 MW) could be achieved through a thermal efficiency improvement scenario of around 70%. The 30% and 50% thermal efficiency improvements were the other two scenarios that require the utilisation of PV/storage units. To ensure that the distribution network is operated at safe conditions, even if the scenario of having no PV production occurred in the greatest demand week, PV and electricity storage systems were both required. The 50% improvement (middle bar) showed that the electric power of the PV, Storage (yellow colour) is 0.03 MW. The PV, Storage power was increased to 0.07 MW when housing thermal efficiency is improved by only 30%.

Based on the 70% thermal efficiency improvement, two optimisation approaches of the electrified heating network are evaluated. Solar thermal collectors placed at home as one of the scenarios were utilised to maintain the DHW storage at the advised temperature (60°C) for preventing the legionella issue [103]. Another scenario, defined as distribution temperature management, delivered water temperatures of 40°C and 65°C separately to homes through a low-temperature district heating (LTDH) system within a day. This approach eliminated the utilisation of low-efficiency electric heaters. Table 7-1 summarises the scenarios in this chapter.

Table 7-1: The scenarios based on the thermal efficiency improvement.

<table>
<tr><th>Scenarios</th><th colspan="2">Conditions</th></tr>
<tr><td>1</td><td colspan="2">30% thermal efficiency improvement</td></tr>
<tr><td>2</td><td colspan="2">50% thermal efficiency improvement</td></tr>
<tr><td>3</td><td colspan="2">70% thermal efficiency improvement</td></tr>
<tr><td>4</td><td rowspan="2">70% thermal efficiency improvement</td><td>Solar thermal collectors</td></tr>
<tr><td>5</td><td>Distribution temperature management</td></tr>
</table>

7.1.2. An electrified heating network

This subsection defines the electric powers of a GSHP and distribution temperatures of a LTDH system for supplying the heating demands in each scenario. Thermal efficiency in buildings determines the SH demand in a community. In terms of a GSHP as the primary heat generation unit, its electric power was aligned with the average consumption power of the SH and DHW + Heat loss in Figure 6-17. The 70% improvement scenario has been demonstrated with a GSHP of 0.12 MW electric power (section 6.2.3). In contrast, the SH demand of the

50% improvement scenario was greater and required the power supply from PV/storage units. The electric power of the GSHP, therefore, was defined by the consumptions of the DHW + Heat loss, SH and PV, Storage in Figure 6-17. As a result, the electric power of the GSHP was increased to 0.15 MW. The 30% improvement scenario showed that the electric power of the PV, Storage is 0.07 MW; hence, the electric power of the GSHP should be 0.19 MW.

By utilising a systematic modelling approach (Chapter 5), the demand ratio of DHW to SH was indicated to be a key factor to determine the supply temperature of an electrified heating network. Therefore, the scenarios with various SH demands required different distribution temperatures to attain the optimum electricity saving condition. Figure 7-1 illustrates the distribution temperature selection of a 384-dwelling community at various demand ratios. The ratio of DHW to SH representing the 2018 level is 1 to 3.86 [120]. The scenarios with 30%, 50% and 70% thermal efficiency improvements are described in ratios of 1 to 2.7, 1 to 2 and 1 to 1.2. The optimum distribution temperatures in each condition are 40°C, 50°C and 60°C, respectively.

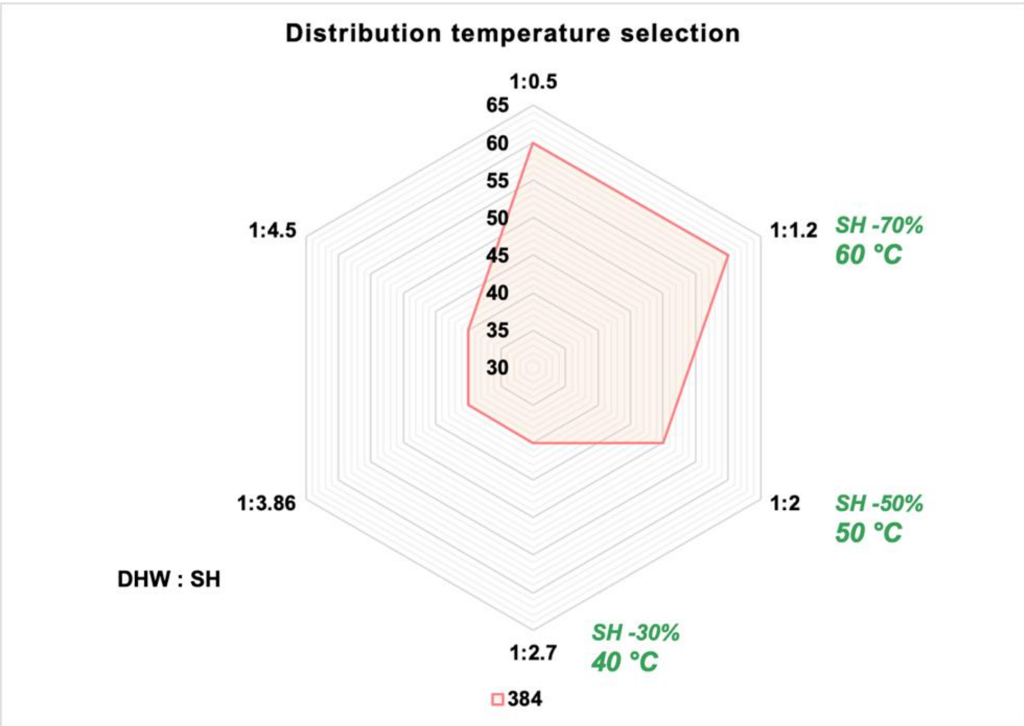

Figure 7-1: The distribution temperature selection of a 384-dwelling community in various improvement levels of thermal efficiency in buildings (i.e., various SH demands).

7.1.3. Photovoltaic (PV) modules

For the simulation of PV modules on energyPRO, this subsection defines parameters such as orientation angle, inclination angle, temperature coefficient and nominal operating cell temperature (NOCT). The orientation and inclination angles determine the amount of direct sunlight received by a PV panel. In this research, the PV modules are assumed to directly face south with an inclination angle of 38°, based on the latitude of Nottingham [150, 151].

The temperature coefficient is in relation to material properties. Wafer based crystalline silicon (c-Si) modules as the most prevalent products on the PV market [152] were selected in this research. The temperature coefficient of a c-Si module is around 0.004 $°C^{-1}$ [153]. The definition of the NOCT is the temperature that a PV panel reached under the open-circuit condition (no external load connected) and nominal terrestrial environment (NTE). The conditions of NTE are the (1) intensity of sunlight: 800 W/m^2, (2) air temperature: 20°C, (3) wind speed: 1 m/s, and (4) mounting: open rack, the module faces directly to solar noon [154]. The NOCT of a typical PV panel ranges from 45 to 48°C [155] and was assumed to be 46°C within the models.

In this research, PV generation was aimed at compensating for the power demand exceeding the targeted import electricity. Figure 6-17 indicates that the average power of PV modules in the greatest consumption week should be 0.07 MW when the thermal efficiency is improved by 30%. The 50% improvement, on the other hand, is 0.03 MW. The formula for scaling the PV modules is described by Eq. (11)

$$P_{PV} = \frac{P_r * h_D}{h_{sun}} \tag{11}$$

, where P_{PV} is the peak power generated by the PV modules, P_r is the required power that offsets the electricity demand over the target power in each scenario, h_D is the hours in a day (24 hours) and h_{sun} is the daily peak sun hours illustrated in Appendix 2. The daily peak sun-hours in February were utilised to scale the PV modules because the highest consumption week in 2018 was at the end of February. As a result, the peak powers of PV modules were 647 kWp and 304 kWp in the 30% and 50% improvement levels, respectively.

7.1.4. Electricity storage

The functions of electricity storage are performing peak shaving and storing adequate electricity for the greatest demand week. In Chapter 6, by utilising Li-ion battery, the required capacity for implementing peak shaving in a 384-dwelling community was around 1.08 MWh, determined by the consumptions of Electricity (i.e., lighting and appliances) and EVs with 50% smart charging. The capacity of the installed battery within the community energy system was 1.27 MWh, with an 85% utilisation rate.

The required storage capacity for the highest consumption week was defined by the improvement levels of thermal efficiency in buildings. Figure 6-17 indicated that the powers of battery storage are the same as PV modules (yellow colour; PV, Storage). In the 30% improvement scenario, the required battery capacity was around 12.23 MWh, which was derived from the multiplication of the storage power and hours per week. Thus, the installed battery capacity within the community energy system was 14.39 MWh, with an 85% utilisation rate. The storage capacity of the 50% improvement scenario was around 5.74 MWh; hence, the installed capacity applying an 85% utilisation rate was 6.76 MWh.

Table 7-2 summarises the modelling conditions in the three levels of thermal efficiency improvement. The battery 1 is utilised to perform daily peak shaving. The battery 2 maintains the electricity consumption within this distribution network under the maximum import power (0.4 MW). The TES capacity, storing half of the average daily demand in the coldest month, can be gained by applying the method in subsection 5.1.5. The annual energy demands are depicted in Chapter 6.

Table 7-2: The conditions in the three levels of thermal efficiency improvement in buildings.

Thermal efficiency improvement	30%	50%	70%
GSHP electrical capacity (MW)	0.19	0.15	0.12
LTDH supply temperature (°C)	40	50	60
TES capacity (MWh)	7.74	5.89	4.05
Battery capacity (MWh)	14.39	6.76	1.27
Battery 1	1.27	1.27	1.27
Battery 2	13.12	5.49	-
Peak power of PV systems (kWp)	647	304	-
Annual energy demands			
Electricity (MWh)			1439.6
EVs (MWh)			614
DHW (MWh)			633.2
SH (MWh)	1711	1222.2	733.3
Total	4397.8	3909	3420.1

Battery utilisation rate: 85%, Number of dwellings: 384

7.1.5. Solar thermal collectors

Solar thermal collectors that convert solar radiation into heat are often installed on water heating systems. The heat production is delivered to SH or DHW instruments by the fluid flowing through the collectors. The fluid can be air, oil or water and is commonly water with glycol [156, 157]. The three common types of solar collectors are flat plate collectors (FPCs), evacuated tube collectors (ETCs) and compound parabolic collectors (CPCs). FPCs and ETCs are widely adopted on small-scale applications [157]. Due to the utilisation of vacuum-packed collectors, ETCs have a greater efficiency for generating a high temperature than FPCs, but the cost of ETCs is also higher. In addition, the ETCs are less affected by the weather conditions; hence, they are recommended in cold climates [158].

In this research, the utilisation of solar thermal collectors reduced the electricity consumption of electric heaters in household tanks. The household tanks are maintained at 60°C for the DHW storage. The simulated location of the models was assumed to be in Nottingham in the UK. Thus, ETCs were selected. In future practical use, as an optimisation approach, the scale of the ETCs should be determined by the lowest DHW consumption month, because an oversized system gives rise to unnecessary costs. The lowest consumption month was July in 2018 (Chapter 5). The equation for scaling the ETCs is shown in Eq. (12)

$$A = \frac{Q_{DHW}}{\eta * h_{sun\ Jul.}} \quad \textbf{(12)}$$

, where A is the total area of the collectors (m^2), Q_{DHW} is the daily demand of the DHW (kWh), η is the conversion factor (0.7 kW_{th}/m^2 [159, 160]), $h_{sun\ Jul.}$ is the average daily peak sun hours in July. (The value of the conversion factor (η) was defined in order to compare the installed capacity of solar thermal collectors with other renewable energy sources. This value can be applied to unglazed collectors, FPCs and ETCs [159].) As a result, the scale of the ETCs was 128 m^2.

7.1.6. Distribution temperature management

The possible energy saving on heating networks by utilising the variable supply temperature has been indicated [161, 162]. In general, the supply temperature varies with the outdoor temperature and matches the demand on the consumer side. A greater heating consumption during peak hours is usually a short duration in a day. Accordingly, heating networks could adopt a higher distribution temperature to meet the greater demand during peak hours and a lower temperature for energy saving during off-peak hours [161].

This research employed an electrified heating network to provide the demands of SH and DHW. Supplying the SH consumption with a lower distribution temperature can decrease heat losses and increase the coefficient of performance (COP) of the GSHP (Chapter 5). On the other hand, due to the application of DHW storage (i.e., household tanks), a 60°C storage temperature is advisable to prevent the legionella issue (Chapter 4). A greater supply temperature, then, was utilised to meet the DHW demand and thus removed the usage of low-efficiency electric heaters.

By applying different water temperatures in a LTDH system within a day is defined as distribution temperature management. The low and high distribution temperatures are assumed to be 40°C and 65°C. The 40°C supply temperature has been adopted in several projects, which meets the SH consumption with low-temperature radiators or underfloor heating [63, 117]. The 65°C temperature ensures that the 60°C storage temperature can be achieved without the utilisation of electric heaters.

For a demonstration model, the operation durations of each temperature were determined to be 12 hours in a day. The hours of supplying the high temperature were split into two periods which are from 00:00 to 06:00 and 10:00 to 16:00, illustrated in Figure 7-2. The remaining 12 hours were for the low-temperature condition. The two periods of utilising the high temperature were chosen because the SH demand was relatively low. This means that most of the heat energy in these hours was delivered to household tanks for DHW storage.

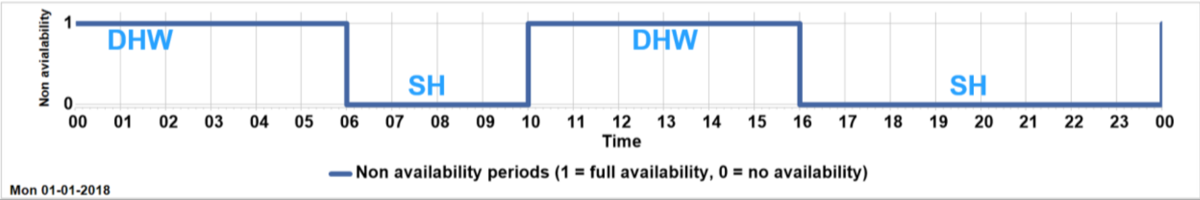

Figure 7-2: The available periods of the GSHP for supplying 65°C water temperature.

7.2. Results

This section presents the modelling results of PV coupled with storage units, including the analyses in the highest demand week and 12 weeks in winter. Subsequently, the evaluation of solar thermal collectors and distribution management is illustrated and compared.

7.2.1. Decentralised generation with thermal efficiency improvement in buildings

In Chapter 6, the scenario of 70% thermal efficiency improvement indicated that the typical UK distribution network could accommodate the electricity demands of an electrified community without the support from PV/storage units. This utilised a multi-vector community energy system, including battery storage and an electrified heating network, to create steady power flows.

The 50% improvement scenario, requiring the application of the PV/storage units, was demonstrated on energyPRO, shown in Figure 7-3. The PV modules and electric power network supply electricity to the batteries, EVs and Electricity (i.e., lighting and appliances). On the other hand, the GSHP and electric heaters powered by the electricity grid meet the demands of SH and DHW and heat losses (Figure 7-3 right). The simulated conditions and consumptions are presented in Table 7-2.

In Figure 7-3, the electricity and heating networks are split for efficient modelling, which means this system configuration is not the actual arrangement of a community energy system. Nevertheless, the modelling result was accurate. For instance, the Battery_1 as the community battery placed in the community substation was designed to power the GSHP during peak hours, thereby achieving the community-scale peak shaving (subsection 4.3). The operation of discharging the community battery during peak hours was the same, but the discharged electricity was delivered to the Electricity and EVs demands.

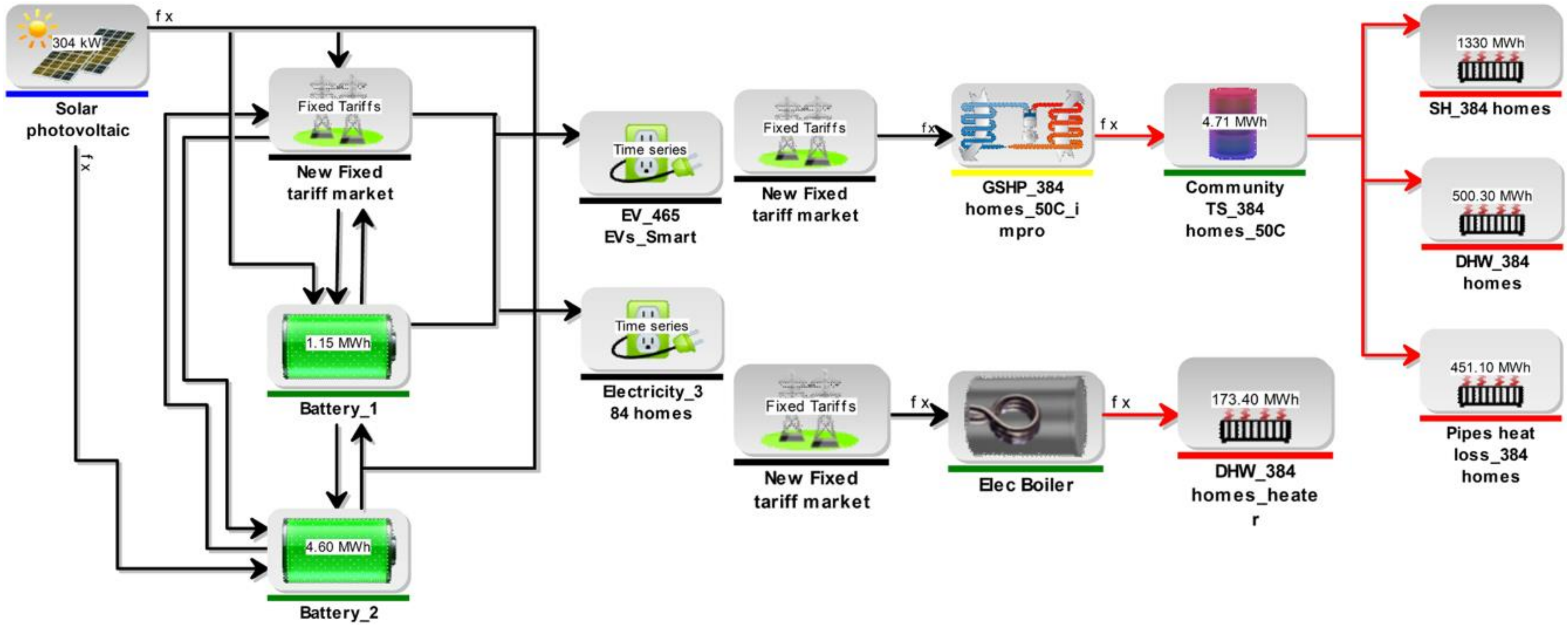

Figure 7-3: The modelling configuration of the multi-vector community energy system with the 50% thermal efficiency improvement and decentralised generation.

The modelling result is illustrated in Figure 7-4, which shows the total electricity consumption of a 384-dwelling community and PV generation in the greatest demand week. The average consumption power without the PV production (grey dash line) is 0.45 MW. This is reduced to 0.41 MW (black dash line) by factoring in the supply from the PV system. The greatest peak reaches around 0.67 MW on Wednesday evening. The highest production time of the PV modules is around noon, which induces the lowest demand on Wednesday at around 0.11 MW. Therefore, the daily demand gap is about 0.56 MW.

Figure 7-4, moreover, presents that the required battery capacity to smooth the load curve with PV generation (black line) is 1.47 MWh. This 50% improvement scenario is designed to have a total capacity of the batteries at 6.76 MWh, which indicates a steady power consumption is attainable.

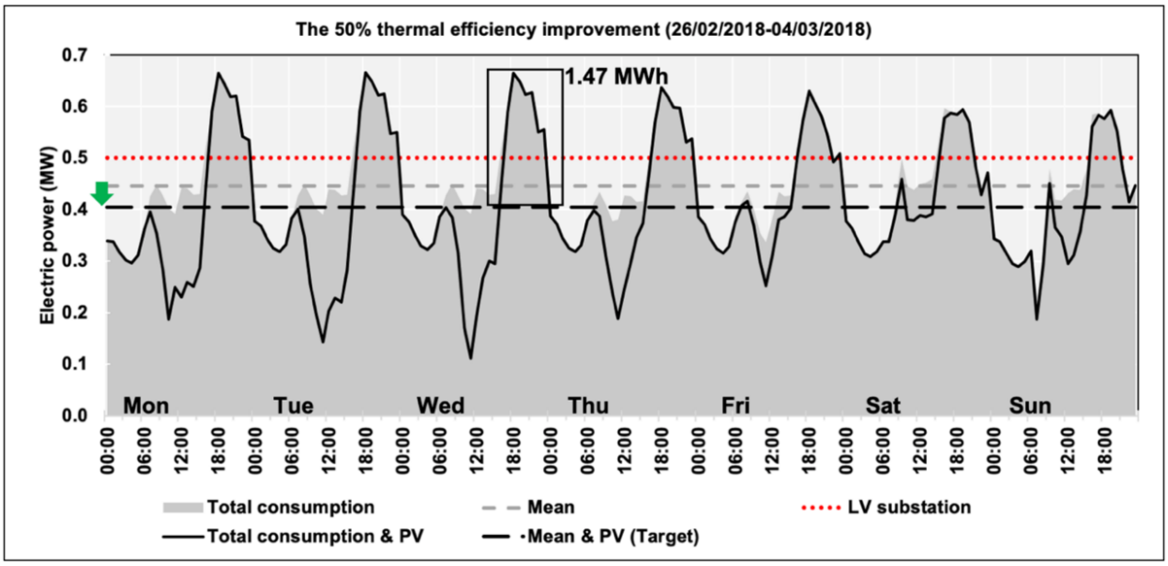

Figure 7-4: The 50% thermal efficiency improvement with the PV generation in the highest consumption week.

By utilising the same modelling configuration of the 50% improvement scenario, the modelling result of the 30% improvement scenario could be obtained, shown in Figure 7-5. (The modelling configuration of the 30% improvement scenario is in Appendix 3) The mean consumption power without the PV generation (grey dash line) is 0.48 MW in the greatest demand week. Nonetheless, the electricity supply from the PV modules reduces the average power to 0.39 MW (black dash line). On Wednesday, the highest peak reaches around 0.72 MW in the evening. The lowest consumption appears as a negative value -0.21 MW at noon. Consequently, the daily demand gap is about 0.93 MW, which shows a 66% increase compared to the 50% improvement scenario. Moreover, based on the total capacity of batteries in the 30% improvement scenario (14.39 MWh), the daily peak shaving that requires 2 MWh battery capacity can be performed.

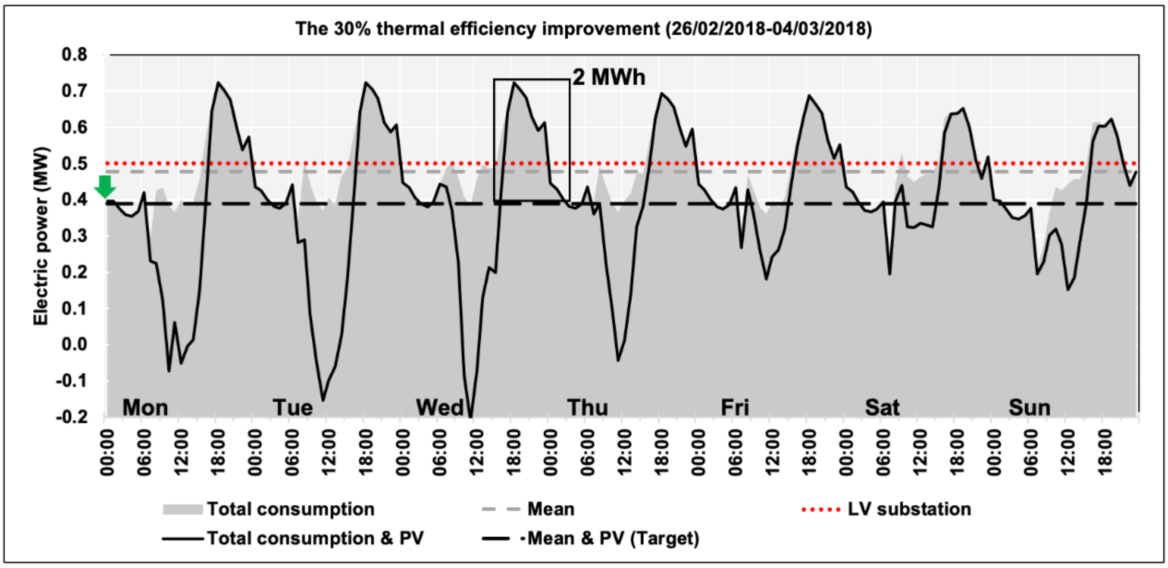

Figure 7-5: The 30% thermal efficiency improvement with the PV generation in the highest consumption week.

The evaluation of the greatest consumption week indicated that the application of a community energy system with housing thermal efficiency improvement can maintain the average demand power at around the targeted maximum power. To validate the reliability of the designed model, a 12-week assessment in winter was applied.

In the 70% improvement scenario, the electricity demands of an electrified community with 384 dwellings are illustrated in Figure 7-6. This 12-week assessment shows that the weekly consumptions are equal to or less than the target power (0.4 MW). Thus, the distribution network can accommodate the power demands of this electrified community without the support from PV systems.

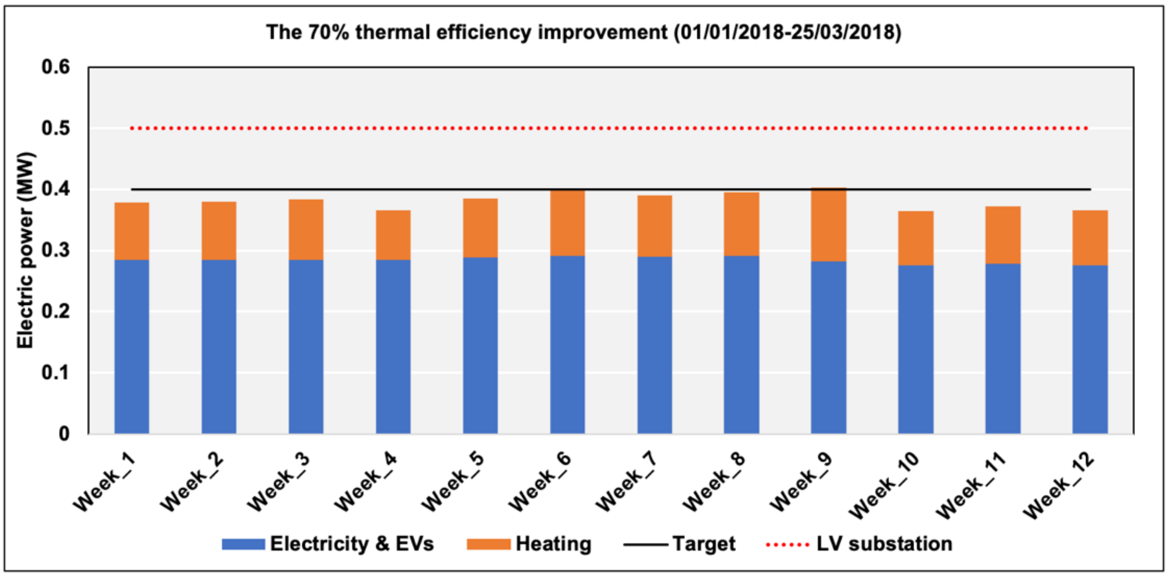

Figure 7-6: The electricity demands of a 384-dwelling community with the 70% thermal efficiency improvement in 12 weeks.

Figure 7-7, representing the 50% improvement scenario, indicates the PV generation and power demands within the 12 weeks. The weekly consumptions less than the target (0.4 MW) are only week 4, week 10 and week 12. The electricity supplied by PV modules is illustrated with the secondary axis, which offsets the power demand exceeding the target, except for week 9 (i.e., the greatest consumption week; Figure 7-4). Nonetheless, the demand in week 9 is only 5 kW higher than the target power after subtracting the PV generation from the total electricity consumption. The exceeding power demand, then, is 0.84 MWh. This can be met by the battery storage having 6.76 MWh capacity.

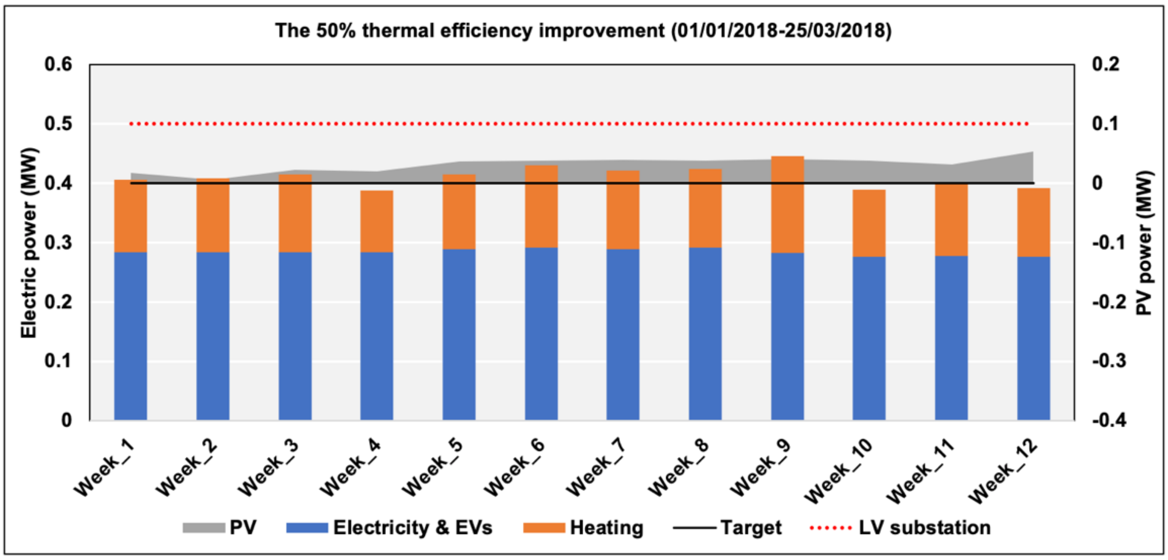

Figure 7-7: The electricity demands of a 384-dwelling community with the 50% thermal efficiency improvement and PV generation in 12 weeks.

Figure 7-8 shows the electricity demands and PV generation of the 30% improvement scenario. The electricity consumptions in the 12 weeks are all greater than the target power (0.4 MW). Nevertheless, the exceeding power demands can be compensated by the PV production, except for week 2. By subtracting the PV generation from the total consumption, the demand power greater than 0.4 MW is around 17 kW in week 2. Thus, the extra electricity demand is 2.9 MWh. This can be supplied by the 14.39 MWh battery storage scaled with the greatest consumption week in Figure 6-17.

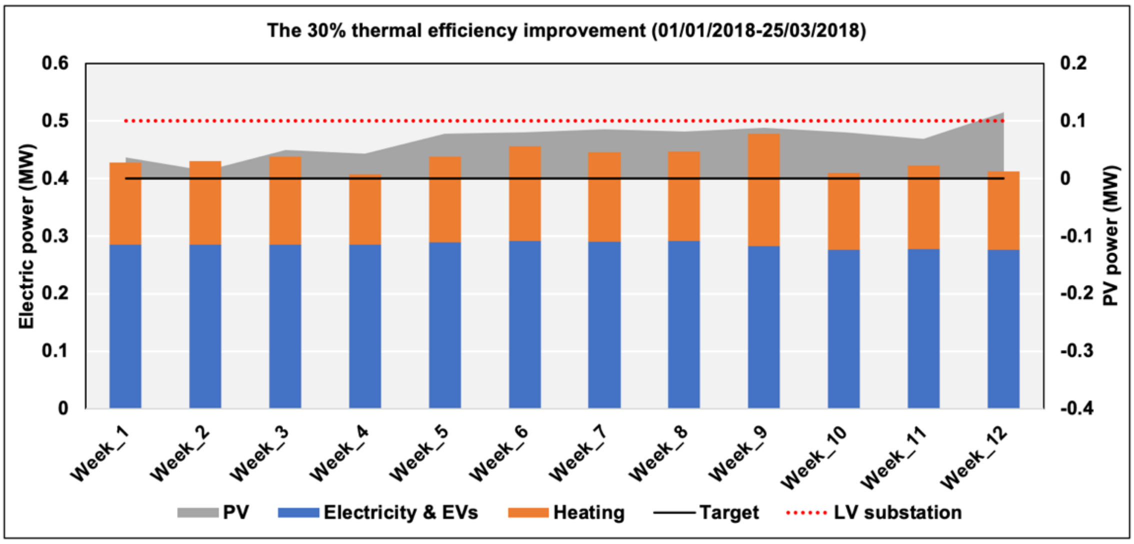

Figure 7-8: The electricity demands of a 384-dwelling community with the 30% thermal efficiency improvement and PV generation in 12 weeks.

The modelling results of the thermal efficiency improvement scenarios are summarised in Table 7-3. The annual electricity demands of Electricity (i.e., lighting and appliances) and EVs are the same in all scenarios. The increase in thermal efficiency reduces the demand for SH and subsequently influences the optimum distribution temperature of the LTDH system, thus changing the utilisation rate of electric heaters (Chapter 5). As a result, the annual electricity consumptions of the GSHP are at a similar level. In contrast, the consumptions of the electric heaters are decreased with the increased thermal efficiency.

Table 7-3: The summarised data of the three thermal efficiency improvement levels.

Thermal efficiency improvement	30%	50%	70%
Annual electricity demand			
Electricity & EVs (MWh)			2053.6
GSHP (MWh)	562.5	574.3	563.1
Electric heater (MWh)	308.7	172.9	37.1
Total	2924.8	2800.8	2653.8
Annual energy generation			
PV (MWh)	780.8	366.3	-
Exported electricity (MWh)	116	0	-
Imported electricity (MWh)	2260	2434.5	2653.8

For the PV generation, the 30% improvement scenario having PV modules with 647 kWp can produce electricity at around 780.8 MWh annually. In the 50% improvement scenario, the annual electricity generation from the 304 kWp PV modules is around 366.3 MWh. Furthermore, the 30% improvement scenario exports around 116 MWh of electricity to the distribution network. The 50% improvement scenario indicates a 100% self-consumption of the PV production; the exported electricity is 0. Finally, the imported electricity of the 30% improvement scenario (2,260 MWh) is the lowest due to the greatest PV generation.

7.2.2. The optimisation approaches based on the 70% thermal efficiency improvement in buildings

Based on an electrified community with 384 dwellings and a 70% thermal efficiency improvement in buildings, this subsection illustrates the modelling results of the optimisation scenarios. Figure 7-9 shows the modelling configuration of an electrified heating network that utilises ETCs to reduce the utilisation of low-efficiency electric heaters for the DHW storage. The electricity grid integrated with this heating network is not presented because of the same configuration as Figure 7-3.

In Figure 7-9, the GSHP supplies heat to the community thermal store that stores and distributes the heat to the consumptions of SH, DHW and heat losses. Due to the application of ETCs, a 40°C distribution temperature as the lowest temperature condition within models was selected to minimise heat losses of the LTDH system. The DHW consumption is split into two sites according to the procedure of DHW production; that city water is preheated by the LTDH system and then boosted to 60°C in DHW storage units (Chapter 5). The bottom side of Figure 7-9 shows that electric heaters and ETCs supply DHW storage (i.e., household tank). The detailed information of this model can be found in Table 7-4.

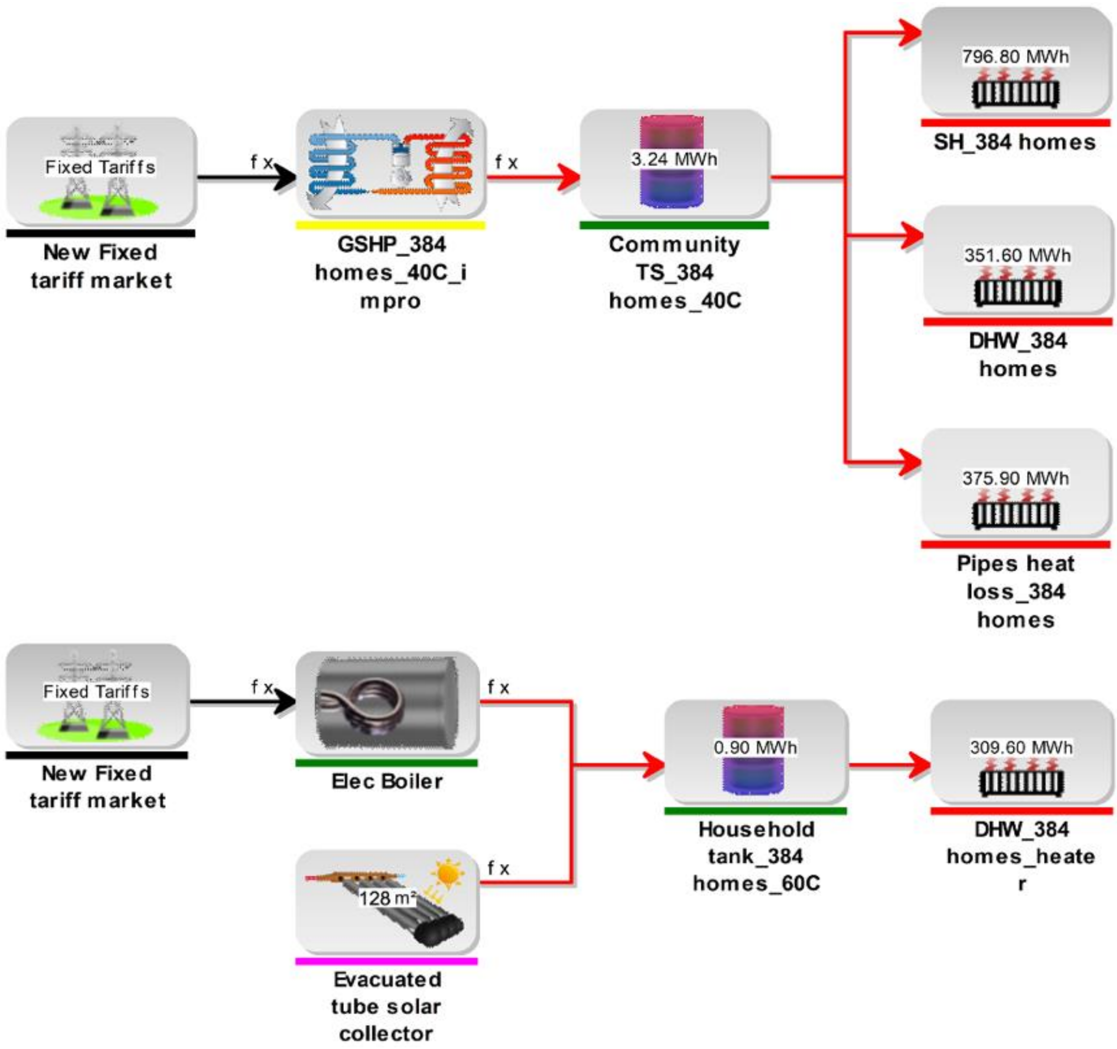

Figure 7-9: The modelling configuration of the heating network with the application of evacuated tube collectors (ETCs).

Figure 7-10 presents the modelling results of the ETCs in the highest production month, July. The first graph indicates the heating consumption of the community and heat generations of the electric heaters and ETCs. The ETCs (pink colour) supplies most of DHW demand, and their intense production period is around midday. The second graph is the electricity consumption of the electric heaters, which provides around 36% of the DHW demand in July. Finally, in the third graph, the capacity of household tanks can store all the heat produced by the ETCs for later use.

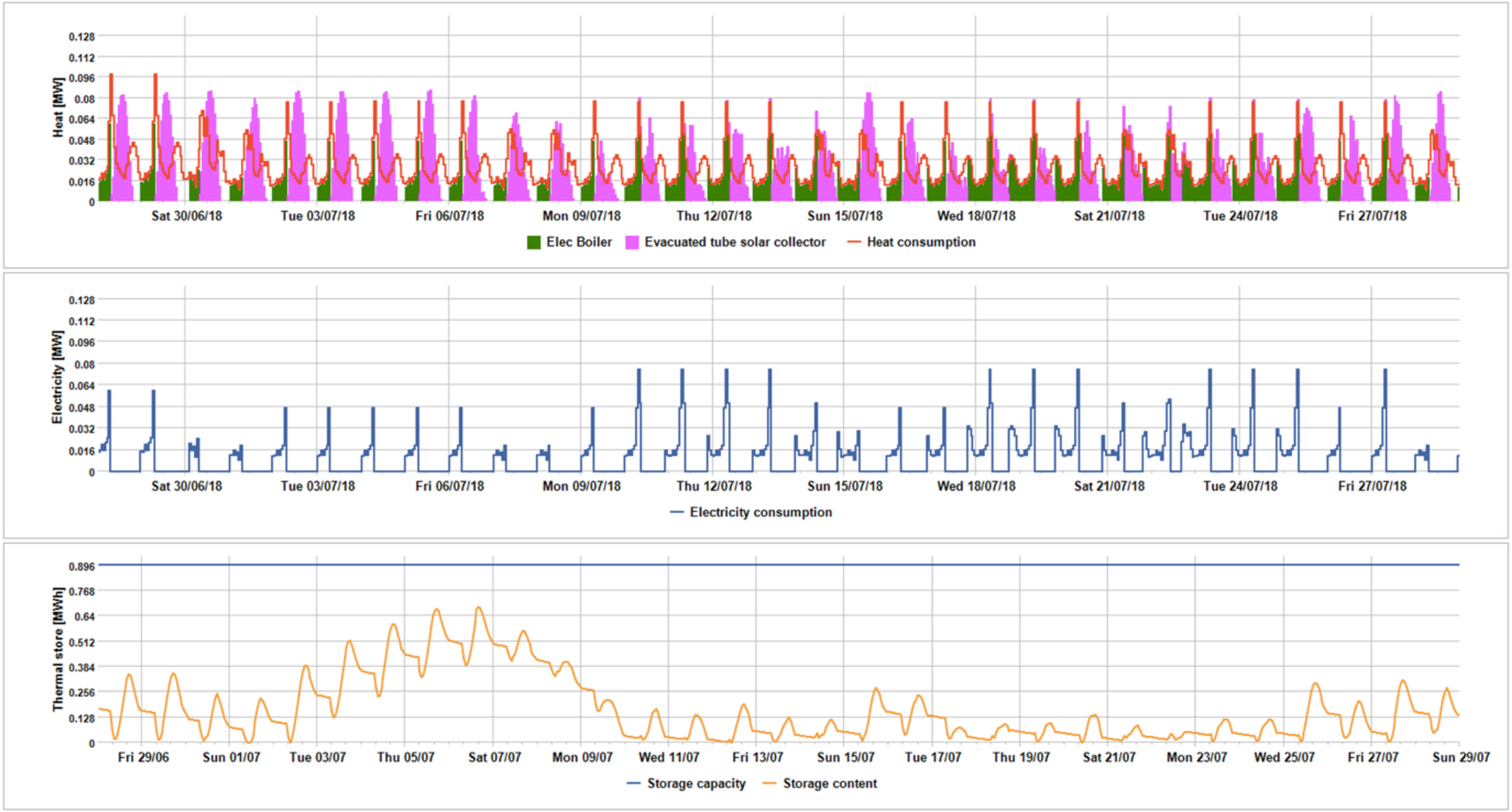

Figure 7-10: The modelling results of the heating network with the application of evacuated tube collectors (ETCs).

The modelling configuration of the distribution temperature management that supplies 40°C and 65°C water temperatures separately within a day is illustrated in Figure 7-11. The electricity network is omitted due to the same configuration as Figure 7-3. The heating network is grouped into two portions, including the SH and the DHW with SH, based on the distribution temperatures.

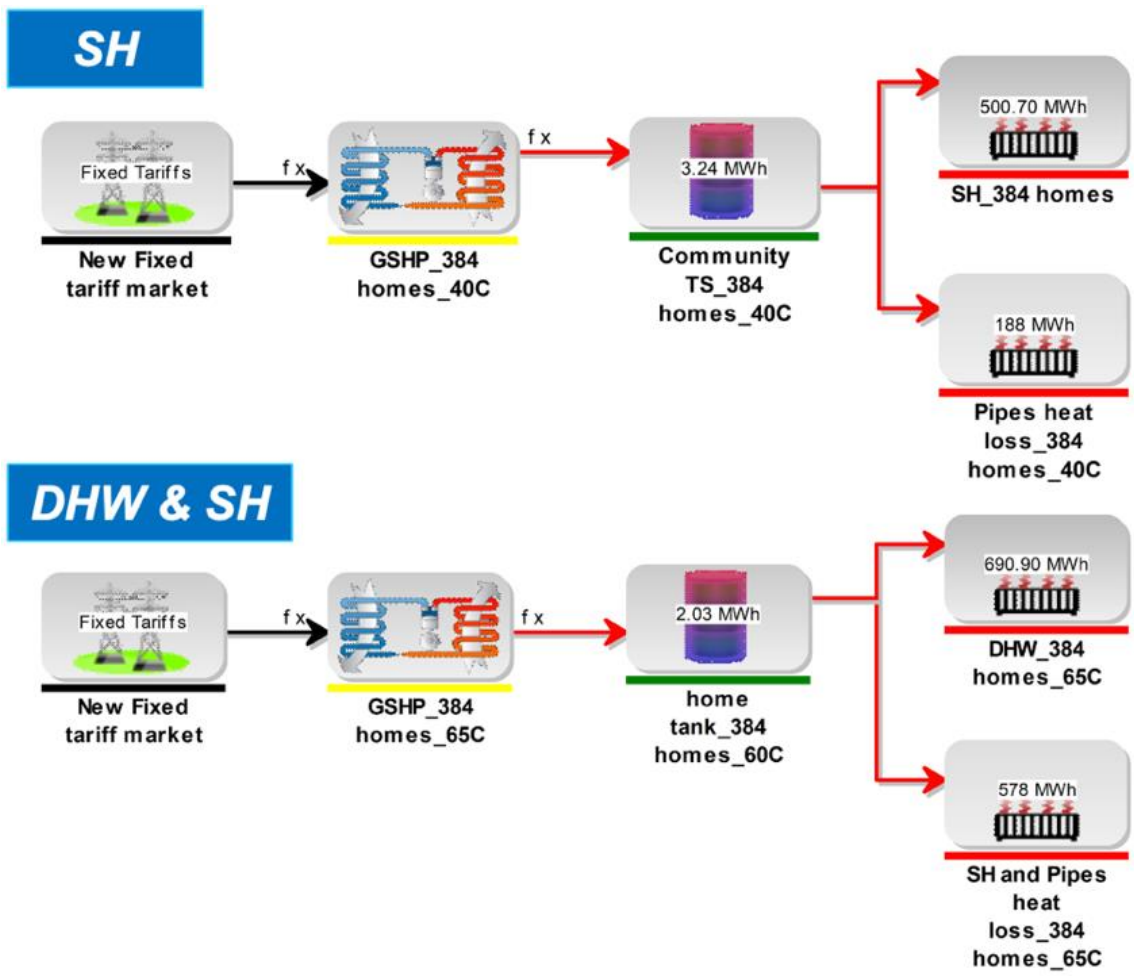

Figure 7-11: The modelling configuration of the distribution temperature management.

In the SH site of Figure 7-11, the 40°C water temperature generated by the GSHP is stored in the community thermal store and delivered to homes through the LTDH system. The heat, then, is consumed by the SH demand and distribution heat losses. On the other side, because of the software constraint, a thermal store (i.e., community thermal store) cannot be operated to provide heat to another thermal store (i.e., household tanks). Therefore, when the GSHP produces the 65°C water temperature, the heat is immediately supplied to the SH demand in the timeframe and household tanks for the regular storage of DHW. Based on this, the community thermal store placed between the GSHP and household tanks can be removed without affecting the modelling results.

Figure 7-12 shows the modelling results in 30 days, including the greatest consumption week in 2018. The first graph indicates the heating network only supplying heat for the SH demand. The GSHP (yellow colour) generates the 40°C water temperature in two periods within a day from 06:00 to 10:00 and 16:00 to 00:00. The second graph indicates the GSHP producing 65°C water temperature can meet the SH consumption in the 12 hours and daily DHW demand.

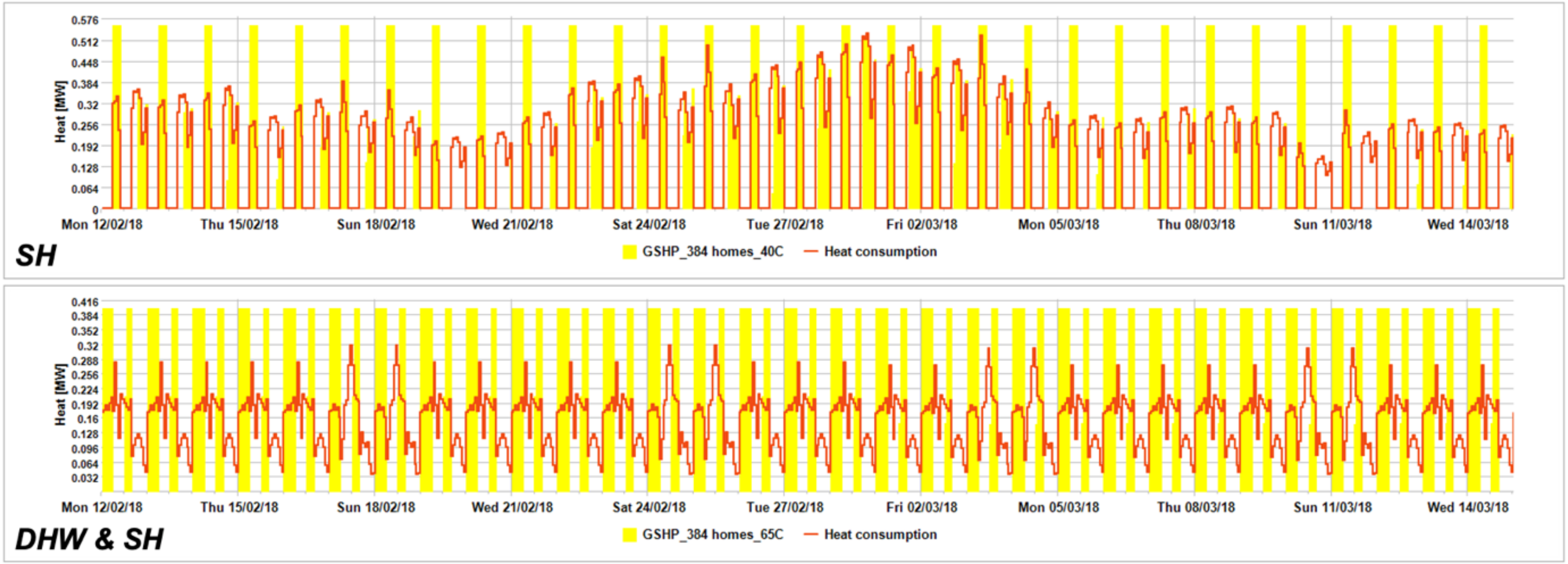

Figure 7-12: The heating consumption of the distribution temperature management.

Table 7-4 summarises the evaluated conditions and modelling results of the optimisation approaches in comparison with the 70% thermal efficiency improvement scenario. Scenario 4 (i.e., application of ETCs) indicates the lowest electricity demand of the GSHP, but the greatest consumption of electric heaters due to the utilisation of low distribution temperature (40°C). Furthermore, the ETCs of a 128 m^2 area can generate heat energy of around 91.6 MWh annually. This heat generation reduces the heating demand supplied by electric heaters. As a result, the electricity demand for heating (grey area) of scenario 4 is around 562.5 MWh, which is lower than scenario 3 consuming 600.2 MWh.

Table 7-4: The summarised data of the optimisation scenarios comparing with the 70% thermal efficiency improvement.

Scenario	3	4	5
Thermal efficiency improvement			70%
GSHP electrical capacity (MW)			0.12
LTDH supply temperature (°C)	60	40	40, 65
Thermal store capacity (MWh)			4.05
Batteries capacity			1.27
Total area of ETCs (m^2)	-	128	-
Annual electricity demand			
Electricity & EVs (MWh)			2053.6
GSHP (MWh)	563.1	331.6	533.4
Electric heater (MWh)	37.1	230.9	0
Total	2653.8	2616.1	2587
Solar thermal (MWh)	-	91.6	-

In Table 7-4, scenario 5, representing the distribution temperature management, is operated at two distribution temperatures. Instead of utilising the low-efficiency electric heaters, this scenario meets the heating demands using the efficient GSHP. Consequently, the annual electricity consumption for heating that consumes 533.4 MWh is the least, comparing with the other scenarios.

7.3. Discussion and conclusion

This chapter suggested that in an electrified community managed by a multi-vector community energy system, the installation criteria of DG/storage units should be defined by the capacity of a distribution network and the thermal efficiency in buildings.

The modelling result of a 384-dwelling community showed that the 70% improvement scenario required a battery capacity of 1.27 MWh to perform peak shaving, thereby enabling the distribution network to accommodate the electricity demand. On the other hand, the 50% and 30% improvement scenarios used PV generation and battery storage (including the 1.27 MWh capacity) to constrain the total consumption under the target power. The battery storage in these two scenarios implemented peak shaving and assured that this electricity grid was operated at safe conditions, even if the circumstance of having no PV production occurred in the greatest consumption week.

The reliability of the community energy system supported by PV/storage units was demonstrated through a 12-week assessment in winter. The result illustrated that the power supply from PV modules can compensate for the demand exceeding the targeted maximum power in most of the weeks. The consumption that cannot be offset by PV production was met by the battery storage.

Furthermore, because the PV production is during the daytime and charging EVs at home is the most popular option for EV drivers [75], the required battery storage in the 50% and 30% improvement scenarios could not be replaced by EV storage. A community energy system that can flatten the consumption power of an electrified community has been demonstrated in Chapter 6. Based on the preconditions: ‘EVs cannot store the PV generation’ and ‘electric power demand is steady’, EVs exporting electricity to the distribution network (i.e., vehicle to grid; V2G) may not have a practical purpose. Accordingly, in a highly electrified scenario with an efficient community energy system, EVs charged by PV generation at public places is recommended. This means the electric power produced by PV modules can be delivered to different communities, cities and so on, where the electricity is required or deposited.

This chapter compared two optimisation approaches based on the 70% improvement scenario to mitigate the electricity demand about the electrified heating network. The result indicated that the annual electricity demand for heating could be saved around 6.3% and 11.1% by ETCs and distribution temperature management, respectively. The temperature control approach, therefore, is advisable.

The simulation model evaluating various improvement levels of the housing thermal efficiency in an electrified community will be established in a modelling tool (Chapter 8), which is related to an electrified heating network and PV/storage units. The calculation results are illustrated in Figure 7-13 and Figure 7-14.

	AR	AS	AT	AU	AV	AW	AX	AY	AZ	BA
1	***Plan to improve***			**40C**	**45C**	**50C**	**55C**	**60C**	**65C**	
2	50%		DHW consumption	1649.079	1649.079	1649.079	1649.079	1649.079	1649.079	
3			water in tank (kg)	31618.239	31618.24	31618.239	31618.24	31618.24	31618.24	
4			SH consumption	3174.950	3174.950	3174.950	3174.950	3174.950	3174.950	
5			households	384	384	384	384	384	384	
6			distribution T	40	45	50	55	60	65	
7			soil T	10	10	10	10	10	10	
8			T(return 30C, soil 10C)	**25**	**27.5**	**30**	**32.5**	**35**	**37.5**	
9			length branch pipe, m	5	5	5	5	5	5	
10			branch U	**0.139**	**0.139**	**0.139**	**0.139**	**0.139**	**0.139**	
11			length main pipe, m	10	10	10	10	10	10	
12			main U	**0.308**	**0.308**	**0.308**	**0.308**	**0.308**	**0.308**	
13			branch number	**384**	**384**	**384**	**384**	**384**	**384**	
14			main number	**192**	**192**	**192**	**192**	**192**	**192**	
15			hours	8760	8760	8760	8760	8760	8760	
16			W to kW	1000	1000	1000	1000	1000	1000	
17				annual heat	annual hea	annual heat	annual hea	annual hea	annual heat loss	
18				**375909.12**	**413500**	**451090.94**	**488681.9**	**526272.8**	**563863.7**	
19										
20			DHW							
21			Energy (from Elec. Boiler)	**309612.53**	**241528.6**	**173444.59**	**105360.6**	**37276.66**	**0**	
22			Energy (from LTDH) kWh	**323633.72**	**391717.7**	**459801.66**	**527885.6**	**595969.6**	**633246.3**	
23			Energy demand before HIU							
24			HIU efficiency	**92.033**	**91.953**	**91.873**	**91.793**	**91.713**	**91.633**	
25			DHW, Energy (from LTDH) kWh	**351649.65**	**425997.7**	**500475.29**	**575082.7**	**649820.2**	**691067.9**	
26										
27			SH							
28			Energy (from LTDH) kWh	**1219180.8**	**1219181**	**1219180.8**	**1219181**	**1219181**	**1219181**	
29			Energy demand before HIU							
30			HIU efficiency	**92.033**	**91.953**	**91.873**	**91.793**	**91.713**	**91.633**	
31			SH, Energy (from LTDH) kWh	**1324721.3**	**1325874**	**1327028.4**	**1328185**	**1329343**	**1330504**	
32										
33			COP	**4.66**	**4.29**	**3.99**	**3.73**	**3.52**	**3.32**	
34			DHW + SH							
35			Enerygy consumption of GSHP	**440473.86**	**504390.6**	**571087.99**	**640554.2**	**712771.5**	**777607.3**	
36			**Total Electricity (Elec. Boiler + GSHP)**	**750086.38**	**745919.1**	**744532.58**	**745914.8**	**750048.1**	**777607.3**	
37			**MWh**	**750.08638**	**745.9191**	**744.53258**	**745.9148**	**750.0481**	**777.6073**	
38										
39										
40				DHW	ratio	SH				
41				1649.079	1.925287	3174.950				
42										
43										
44										
45				DHW:SH		384				
46					1.925287	**50**	°C			
47										
48				Ele heaters	173444.6	**173.44459**	MWh			
49				GSHP	571088	**571.08799**	MWh			
50				Total		**744.53258**	MWh			
51										

Figure 7-13: Screenshot of the modelling tool – The calculation results of an electrified heating network with the housing thermal efficiency improved by 50%, including the heating demands, electricity consumption and temperature selection.

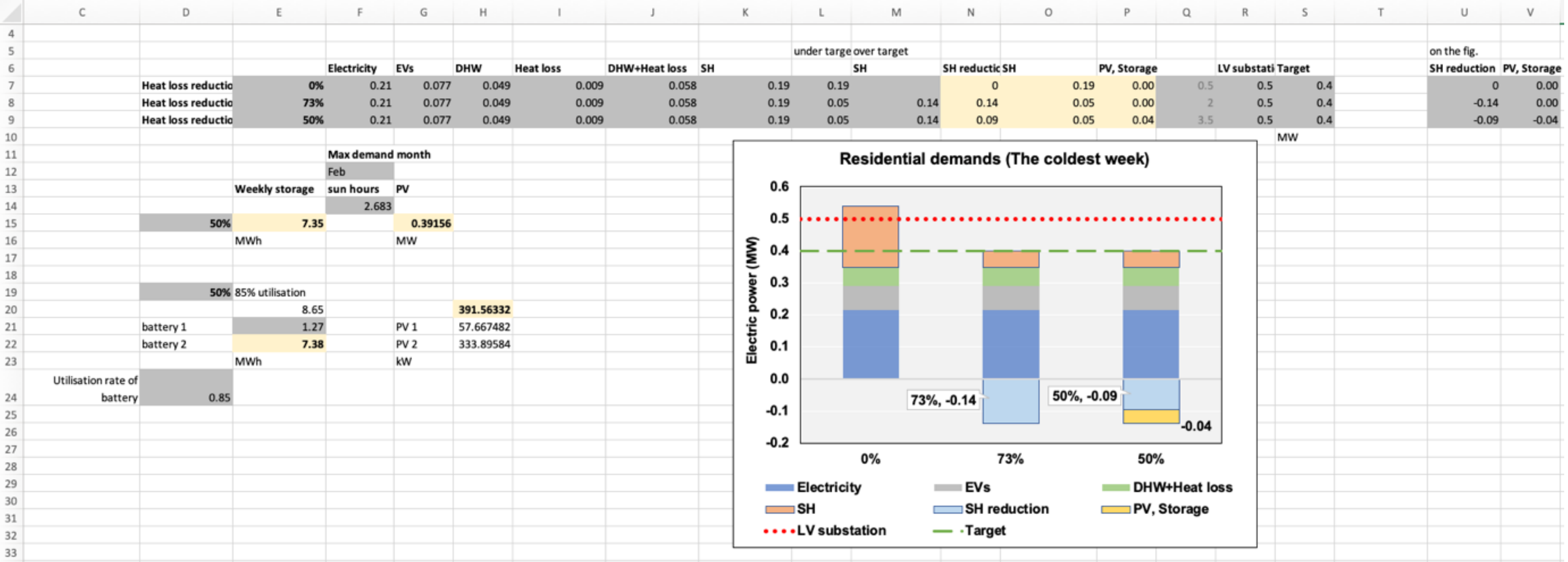

Figure 7-14: Screenshot of the modelling tool – The calculation results of showing the average power demands under different thermal performances of buildings in the coldest week and the capacities of PV/storage units.

Chapter 8

The Modelling Tool of Multi-Vector Community Energy Systems

A multi-vector community energy system, aiming to deliver 100% electrification as an alternative solution to fossil fuels, was depicted, validated and demonstrated from Chapter 4 to Chapter 7. This chapter will connect the simulation models, thereby developing a modelling tool for community energy systems. This modelling tool is established on an Excel workbook using VBA code and demonstrated by employing the data in the UK in 2018.

The modelling tool can indicate approaches that attain domestic heating and road transport electrification by analysing a community's heating and electricity demands. The models consider the efficiencies of heat generation units, the thermal and electricity storage, the low-temperature district heating (LTDH) system, the demand profiles of space heating (SH), domestic hot water (DHW), electric vehicles (EVs) and basic electricity (i.e., lighting and appliances), the decentralised generation (DG) and the capacity of a distribution network. Moreover, to create steady electricity flows of an electrified community, this modelling tool can perform EV smart charging (subsection 6.1.4), manage community-scale peak shaving (subsection 4.3), and process the ideal heating supply of an electrified heating network (subsection 6.2.2).

For establishing an electrified community giving rise to considerable electricity demand, the maximum power supply of a distribution network and the thermal efficiency in buildings determine the feasibility. When electricity consumption exceeds the targeted maximum power within the distribution network, the modelling tool indicates the necessary degree of improving thermal efficiency in buildings, reducing SH demand. Users can also decide an improvement level of the thermal efficiency and thus obtain a customised result.

Apart from the system design, energy flow management and housing thermal efficiency improvement, this modelling tool illustrates the investment cost of the distribution network reinforcement, building retrofit and community energy system that includes DG, electricity and heating networks. A community energy system using district heating, community battery and community thermal storage is designed for the government or planner on developing an electrified community. Therefore, the cost assessment only focuses on the initial cost required to build an electrified community. The operation cost, maintenance cost and payback period are not considered in this research.

The following sections in this chapter are elaborated as: Section **8.1 Demand setting** introduces the setting categories of the modelling tool. Section **8.2 Heating parameters** depicts key parameters about the heating network in models. Section **8.3 Electricity parameters** describes key parameters in models, related to the electricity network. Section **8.4 Cost parameters** illustrates the reference data for cost assessment. Section **8.5 Results** elaborates the outcomes of the modelling tool and compares the modelling results of each scenario. Section **8.6 Discussion and conclusion** indicates the key findings and contributions of the modelling tool. Section **8.7 Validation of the modelling tool of multi-vector community energy systems** validates the electricity consumptions of a community, indicated in the modelling tool.

8.1. Demand setting

Demand setting is a worksheet in the modelling tool, which categorises the variables as the community, district heating and annual demands per unit, shown in Figure 8-1. The category of the community enables users to change the constraint of a low voltage (LV) substation and determine the maximum power within this distribution network. For instance, in Figure 8-1, the LV substation can provide a maximum power of 0.5 MW. The targeted maximum power is 0.4 MW, equipping a 20% consumption buffer. Besides, the numbers of dwellings and EVs in a community and the percentage of EVs participating in smart charging are adjustable.

In Figure 8-1, the district heating category includes the return temperature, soil temperature and lengths of pipes. The temperature values are input as annual averages. For the distribution pipes, flexible pipes from a manufacturer [118] were selected and included as a part of the database to evaluate annual heat losses. The layout of this district heating network was presented in Figure 5-1. The supply temperature is not a variable to users because its optimum temperature (i.e., the most electricity saving condition) is indicated by the systematic modelling approach (Chapter 5) covered in this modelling tool.

Community	LV substation	0.5	MW
	Targeted power on LV substation	0.4	MW
	Homes	384	numbers
	EVs	465	numbers
	Smart charging	50	%
District heating	Return temperature	30	°C
	Soil temperature	10	°C
	Length branch pipe	5	m
	Length main pipe	10	m
Annual demands per unit	Space heating	6.365	MWh
	Plan to improve	50	%
	COP (efficiency)	1	
	Domestic hot water	1.649	MWh
	Household tank temperature	60	°C
	Lighting and appliances	3.749	MWh
	EVs	1.321	MWh

Figure 8-1: Screenshot of the modelling tool - The variables that users can adjust on the demand setting sheet.

The annual demands per unit in Figure 8-1 is the energy demands of each consumption item in the average dwelling. This includes the SH, DHW, lighting and appliances and EVs. In the same category, the Plan to improve describes the improvement level of housing thermal efficiency, thereby defining the SH demand in one of the scenarios. For instance, if Plan to improve is determined to be 50%, the SH demand of the input value such as 6.365 MWh in Figure 8-1 is reduced by 50%. Furthermore, the COP represents the efficiency of heat generation for SH consumption in one of the scenarios. The household tank temperature as DHW storage temperature affects the optimum distribution temperature of an electrified heating network.

8.2. Heating parameters

This section indicates the COP of a ground source heat pump (GSHP) and hourly heating profiles of DHW and SH. GSHP, as one of the essential components in a community energy system, defines the efficiency of an electrified heating network. The COP of a GSHP is varied with the source temperature and temperature at the consumer side (i.e., supply temperature) [66]. In the modelling tool, the source temperature (i.e., soil temperature) is set at 10°C. The COP, then, is controlled by the supply temperature (subsection 5.1.6). The correlation between the COP and supply temperature is illustrated by a formula shown in Figure 8-2.

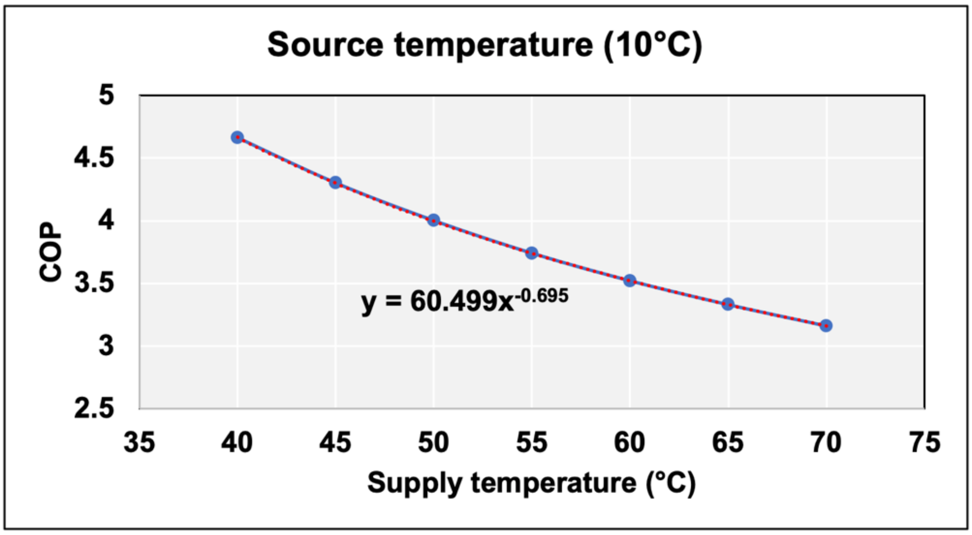

Figure 8-2: Screenshot of the modelling tool - The COPs of a ground source heat pump at various supply temperatures [66], with a source (i.e., soil) temperature of 10°C.

Demand profiles of DHW and SH are utilised to evaluate the maximum power within a day. The DHW consumption curve was defined by a survey that monitored hot water usage of 251 households in England [163]. In Figure 8-3, the heating power load on the greatest consumption day (i.e., the coldest day) in 2018 is illustrated, according to the settings in Figure 8-1. The result, for example, in a workday, shows that the hour consuming the most energy in a community with 384 dwellings is from 7 to 8 am. This demand peak attains 0.25 MW approximately.

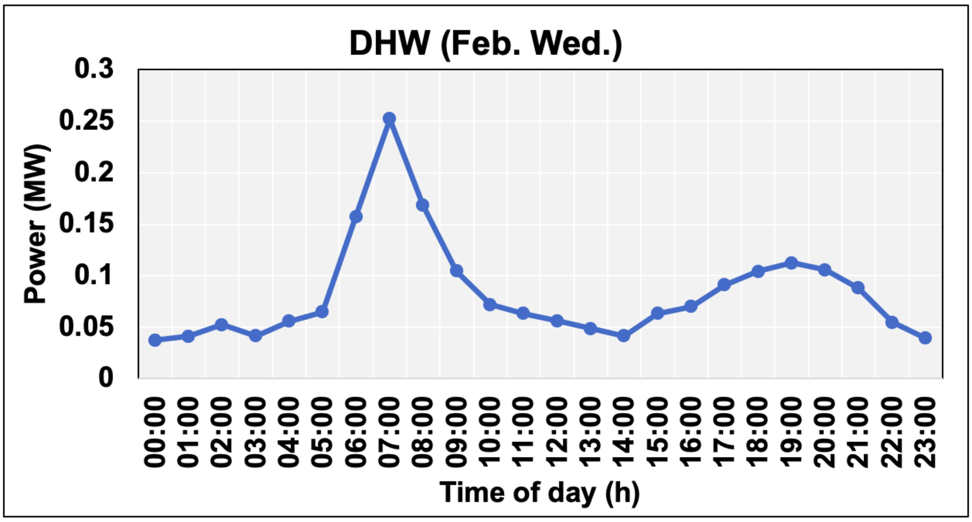

Figure 8-3: Screenshot of the modelling tool - The demand profile of DHW in a 384-dwelling community in the highest consumption day in 2018.

The heating power demand for SH is strongly correlated with ambient temperature. In the modelling tool, the hourly external temperature of Nottingham in the UK was used, illustrated in Figure 8-4. The coldest day reached around -6.9°C in February. This temperature data is adjustable, meaning that users can enter their local weather conditions into the models.

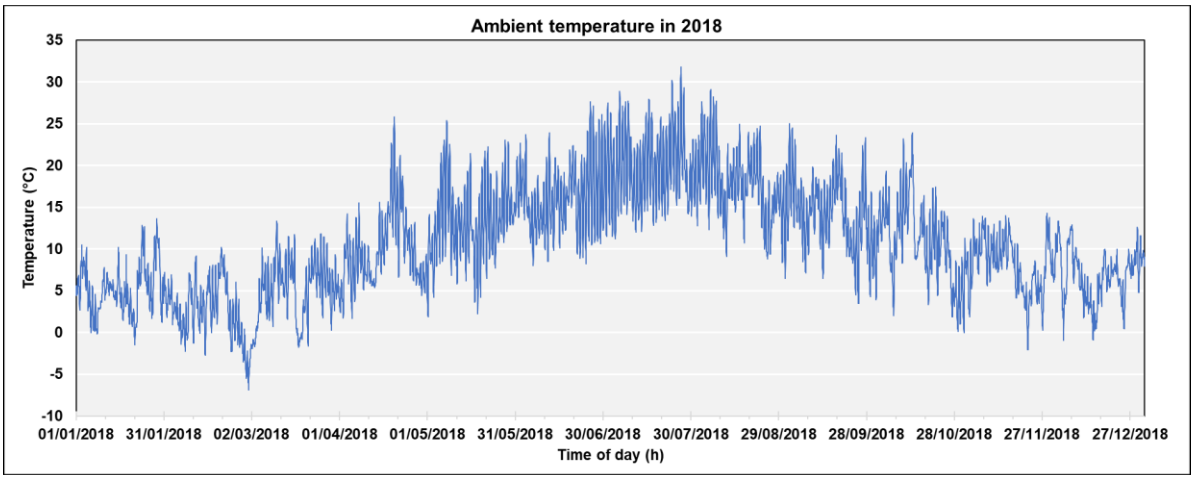

Figure 8-4: The ambient temperature of Nottingham in 2018.

By utilising a survey based on 251 households [163], Figure 8-5 indicates the demand profile on the coldest day in 2018. This workday consumption induced by a 384-dwelling community shows two large peaks in the morning and evening. The greatest peak power is around 1.4 MW.

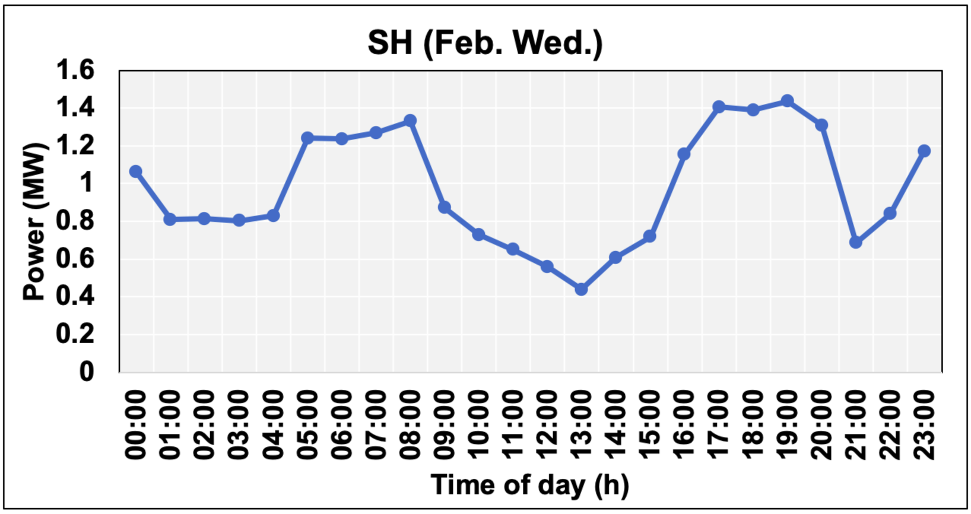

Figure 8-5: Screenshot of the modelling tool - The demand profile of SH in a 384-dwelling community in the highest consumption day in 2018.

8.3. Electricity parameters

This section illustrates the residential charging profile of EVs and the consumption profile of the Electricity (i.e., lighting and appliances). A study [85] named EV charging behaviour recorded the hourly charging demands at residential charging points in the UK. By applying this data, the consumption of 465 EVs is illustrated in Figure 8-6. The maximum power demand without smart control is 0.22 MW from 7 to 8 pm. The method of applying smart charging of EVs to models was introduced in section 6.1.4. In Figure 8-6, by utilising smart control of 50% EVs, the greatest demand peak appears between 23:00 to midnight. This consumes 0.2 MW approximately.

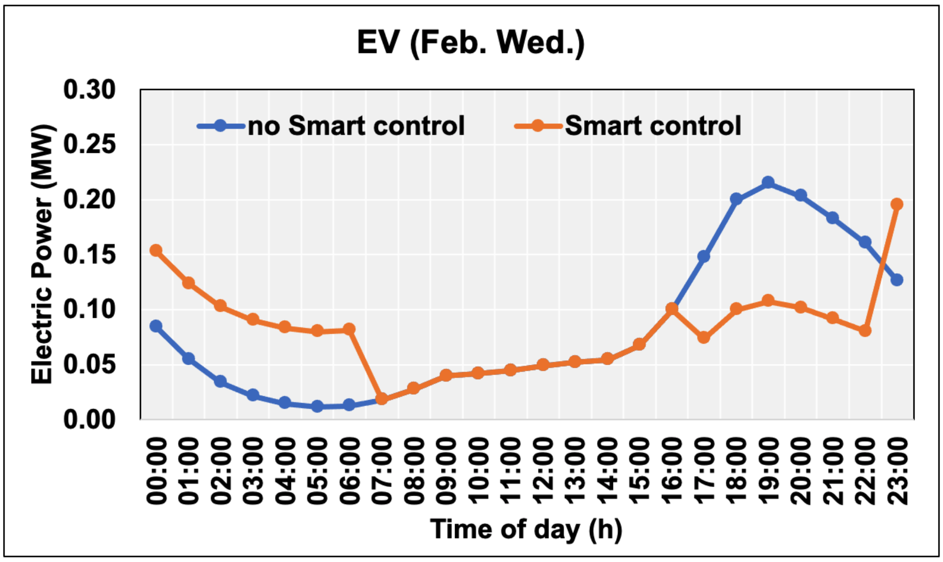

Figure 8-6: Screenshot of the modelling tool - The residential charging demand of 465 EVs in the highest consumption day in 2018.

The consumption profile of the Electricity was derived from an open-source software named CREST [134]. The method of applying this software was indicated in subsection 6.1.1. Figure 8-7 illustrates the hourly demand powers in a community with 384 dwellings on the coldest day in 2018. The greatest peak attains around 0.4 MW between 18:00 and 19:00.

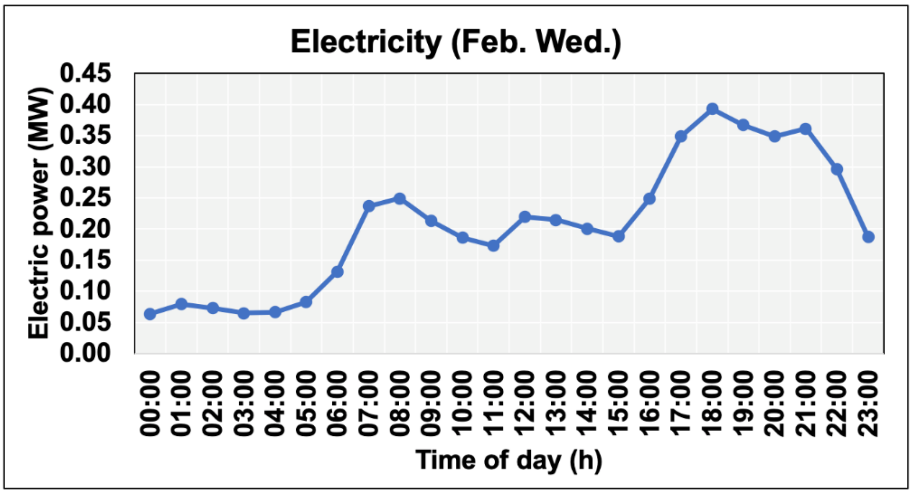

Figure 8-7: Screenshot of the modelling tool - The electric power demand of Electricity (i.e. lighting and appliances) in the highest consumption day in 2018.

8.4. Cost parameters

This section depicts the cost parameters for establishing an electrified community, including the distribution network reinforcement, GSHP, district heating system, Li-ion batteries, PV modules and domestic building retrofit. The reinforcement cost within a distribution network was derived from a statement of WESTERN POWER DISTRIBUTION [108], shown in Table 8-1. The voltage range of a distribution network is from the 230V low voltage to 132 kV high voltage [164]. The configuration and schematic figure of the electricity grid can be found in subsection 6.1.3 and Appendix 4. The cost estimation procedure in the modelling tool begins from the secondary substation, the primary substation, to the 132/33 kV substation. Besides, replacing a larger transformer has a higher priority than the establishment of a new substation.

Table 8-1: Costs of the distribution network [108].

132/33 kV substation					
Transformer					
	kVA	90,000			
	Cost (£)	1,500,000			
33 kV feeder					
	kVA	24,000			
	Cost (£)	500,000			
Primary substation		33/11 kV			
Transformer					
	kVA	24,000			
	Cost (£)	1,500,000			
New substation					
	kVA	10,000	24,000		
	Cost (£)	760,000	2,000,000		
11 kV feeder					
	kVA	5,000	7,700	8,000	
	Cost per m (£)	50	100	100	
Circuit breaker					
	Cost (£)	50,000			
Secondary (LV) substation		11/0.433 kV			
Transformer replacement					
	kVA	500	800	1000	
	Cost (£)	10,000	16,000	20,000	
New LV substation					
	kVA	315	500	800	1000
	Cost (£)	24,000	33,917	50,000	60,721

In general, to achieve a large output of heat, GSHPs with an electric power of 40 kW or 60 kW are cascaded [165]. Therefore, the prices of 40 kW and 60 kW GSHPs were employed to create a formula that represents the correlation between cost and electric power of a GSHP, illustrated in Figure 8-8. This cost estimation includes the installations of HP units and horizontal ground collector pipes.

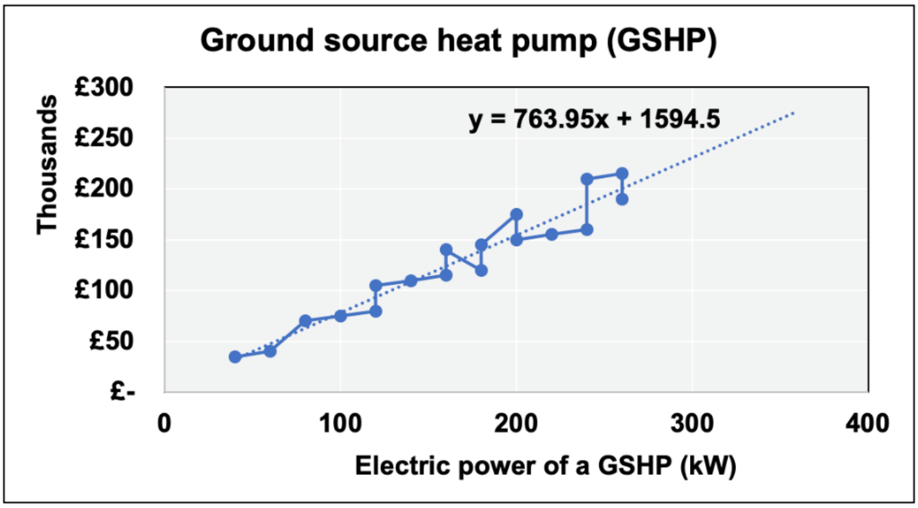

Figure 8-8: Screenshot of the modelling tool - Cost of a GSHP [165].

The cost of a district heating network was estimated based on a survey [166] of existing heating networks in the UK. Table 8-2 shows the costs of each component within a heating network. The substation cost is about the collective heating capacity of dwellings in a community. The calculation formulas of heating capacity, pipe lengths and thermal storage were addressed in Chapter 5 and covered in this modelling tool.

Table 8-2: Cost of a district heating network [166].

Network capital cost	
Network – buried	
Cost per m (£)	468
Network – pipes	
Cost per m (£)	169
Substation cost	
Cost per kW (£)	35
Domestic HIUs cost	
Cost per dwelling (£)	1075
Heat meter cost	
Cost per dwelling (£)	579
Thermal store cost	
Cost per m^3 (£)	843

The price of a Li-ion battery is defined by its capacity. In the modelling tool, a battery capacity of 1 kWh cost £118 for the cell and pack [167]. The cost of small-scale solar PV, the installed capacity ranging from 0 to 4 kW, was £1,562 per kW according to national statistical data [168]. This included the price of the PV generation equipment, the cost of installing and connecting to electricity supply and the value-added tax (VAT).

For the cost estimation of building retrofit in an electrified community, the data from Energiesprong (i.e., energy leap), an approach improving building efficiency, was employed [169]. Energiesprong claimed to potentially eliminate 41% of carbon emissions of UK housing stock. Its insulation method could enable a 90% reduction of the current SH demand in an individual home [169]. In 2018, the first Energiesprong installations in the UK cost around £75,000 per home, which is projected to be decreased to about £35,000 by 2025.

By applying this efficient approach to decrease SH demand, not all the houses in an electrified community are needed to be retrofitted to achieve the indicated improvement level of housing thermal efficiency, meaning that the target is more attainable. This research utilised the predicted prices in 2025 to estimate the cost of a domestic building retrofit. Table 8-3 presents the prices, including overheads, site costs, façade, roof and profit. (Overheads refer to the cost of running the company. Site costs are related to the installation cost. Façade and roof costs link to the material costs.)

Table 8-3: Costs of domestic building retrofit [169].

Items	Profit	Roof	Façade	Site costs	Overheads
Cost per home (£)	2,000	500	12,500	5,700	5,500

8.5. Results

In the modelling tool, the results are categorised into four options, shown in Figure 8-9. The first option is developing an electrified community without a multi-vector community energy system and housing thermal efficiency improvement. By the utilisation of a community energy system is defined to be the second option. The third and fourth options apply both a community energy system and thermal efficiency improvement to an electrified community. These two options consider the capacity of a distribution network. Thus, by adopting these approaches, the distribution network can accommodate the electric power demand of an electrified community. The third option uses thermal efficiency improvement in buildings to reduce electricity consumption for SH. In the fourth option, the level of thermal efficiency improvement is determined by the Plan to improve in Figure 8-1. This option requires extra PV/storage units to support the community energy system.

An electrified community	Energy system	Housing thermal efficiency	
Opt. 1	X	X	
Opt. 2	V	X	
Opt. 3	V	Condition 1	72%
Opt. 4	V	Condition 2	50%

Figure 8-9: Screenshot of the modelling tool - The four options of an electrified community.

For system design, Figure 8-10 shows the requirements of a community energy system according to the settings in Figure 8-1. The electric power, supply temperature, COP of a GSHP, and capacities of thermal storage units are indicated for the heating network. The capacities of PV modules and battery storage units are illustrated for providing decentralised electricity generation and storage, respectively.

	Heating_GSHP			Thermal storage		
An electrified community	Electrical power	Supply temperature	COP (efficiency)	Tank	Tank	**1** household tank
Opt. 1	**0**	**0**	**0**	**0**	**0**	**0**
Opt. 2	**0.24**	**40**	**4.67**	**907.02**	**10.53**	**0.116**
Opt. 3	**0.11**	**60**	**3.52**	**111.54**	**3.89**	**0.116**
Opt. 4	**0.15**	**50**	**4.00**	**254.10**	**5.90**	**0.116**
	MW	°C		m3	MWh	m3
						One dwelling

DG	Electricity storage			
PV	Battery_1	B1_Substation	B1_Homes	Battery_2
0	**0**	**0**	**0**	**0**
0	**1.27**	**0.93**	**0.34**	**0**
0	**1.27**	**0.93**	**0.34**	**0**
349.37	**1.27**	**0.93**	**0.34**	**6.45**
kWp	MWh			MWh

Figure 8-10: Screenshot of the modelling tool - The requirements of establishing a community energy system.

In Figure 8-10, the Battery_1 is defined by the demand load of EVs and Electricity (i.e., lighting and appliances). Based on the concept of the community-scale peak shaving (section 4.3), the Battery_1 should be split and then installed at the community substation and homes. This is aligned with distribution network capacity. Furthermore, the comparison between Opt.3 and Opt. 4 shows that extra DG (i.e., PV generation) and storage (i.e., Battery_2) are required in Opt. 4 due to the lower level of housing thermal efficiency.

By applying the system parameters in Figure 8-10, the electric power demands of an electrified community are illustrated in Figure 8-11. The Opt.1 without a community energy system indicates the maximum power is around 2.1 MW on the greatest consumption day. The COP of the heat generation unit that meets the SH demand is adjustable and defined in the demand setting sheet (Figure 8-1).

In Figure 8-11, the consumption powers of Opt. 2, 3, and 4 can be managed at a steady state in the highest demand week by utilising a community energy system. The Opt. 2 shows that if the housing thermal efficiency remains the same, the electricity demand exceeds the capacity of this distribution network. On the other hand, by improving housing thermal efficiency, the consumption power of the Opt. 3 can be reduced to meet the target power. The Opt. 4 that aligns to the 50% thermal efficiency improvement requires extra PV/storage units to maintain the consumption power under the target.

To illustrate the impact of EV smart charging on the electricity grid, the power demands of Electricity and EVs are shown in this modelling tool. Users can apply various percentages of smart charging to the model. A 50% smart charging is indicated in Figure 8-12 as an example.

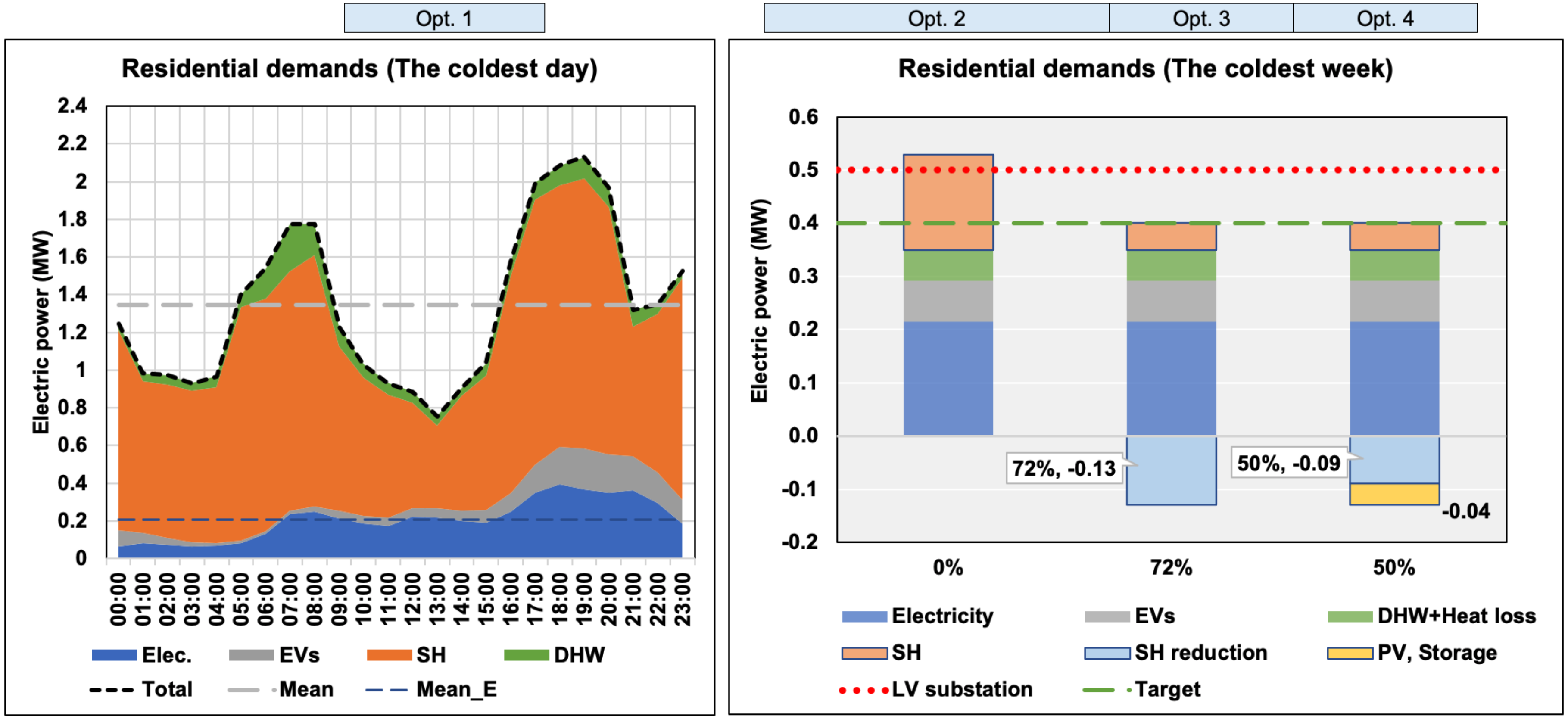

Figure 8-11: Screenshot of the modelling tool - Electric power demands of the four options in the highest consumption period.

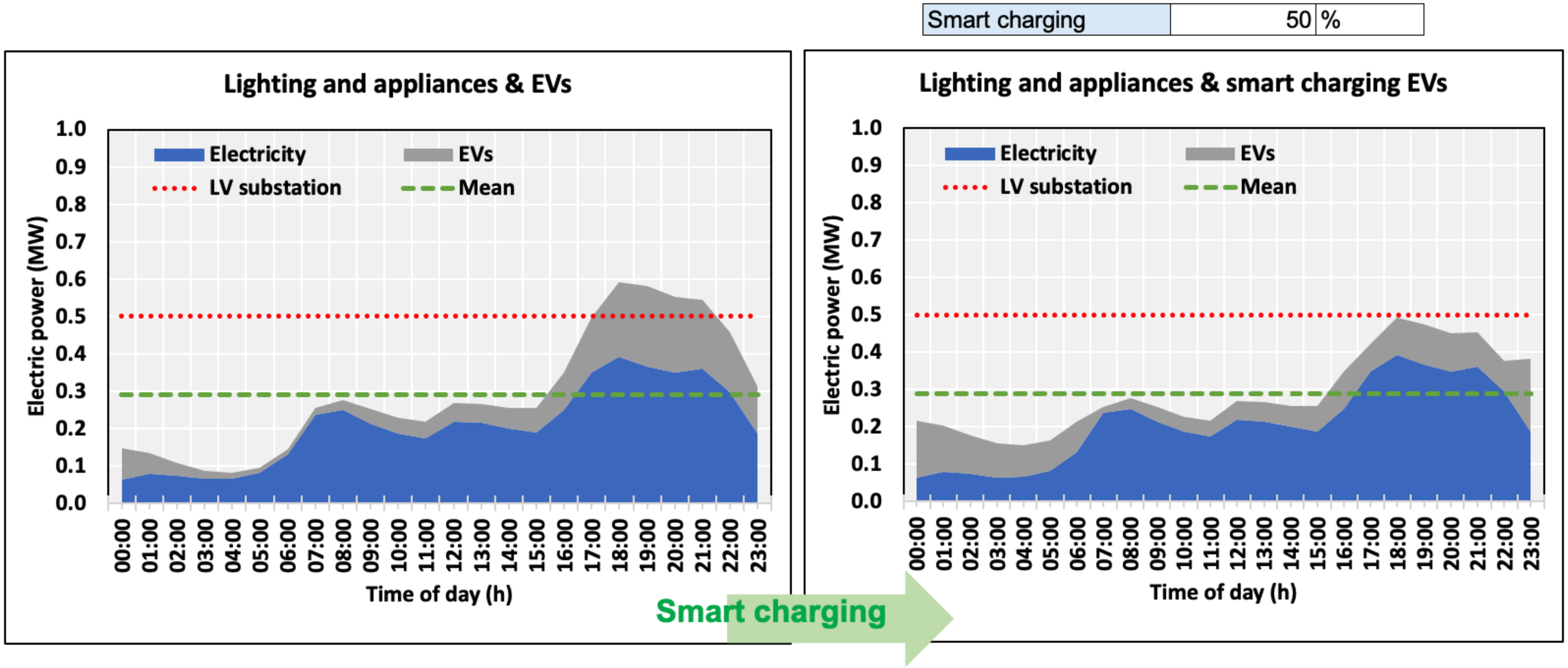

Figure 8-12: Screenshot of the modelling tool - Electric power demands of Electricity (i.e., lighting and appliances) and EVs, without and with EV smart charging.

The investment costs of each option were estimated, including the distribution network reinforcement, community energy system and housing thermal efficiency improvement. Figure 8-13 presents the reinforcement cost on the electricity grid, which is averaged by electrified communities in a distribution network. In the Opt. 1, the cost attains £515 thousand. This can be reduced to £74 thousand in the Opt.2 due to the utilisation of a community energy system.

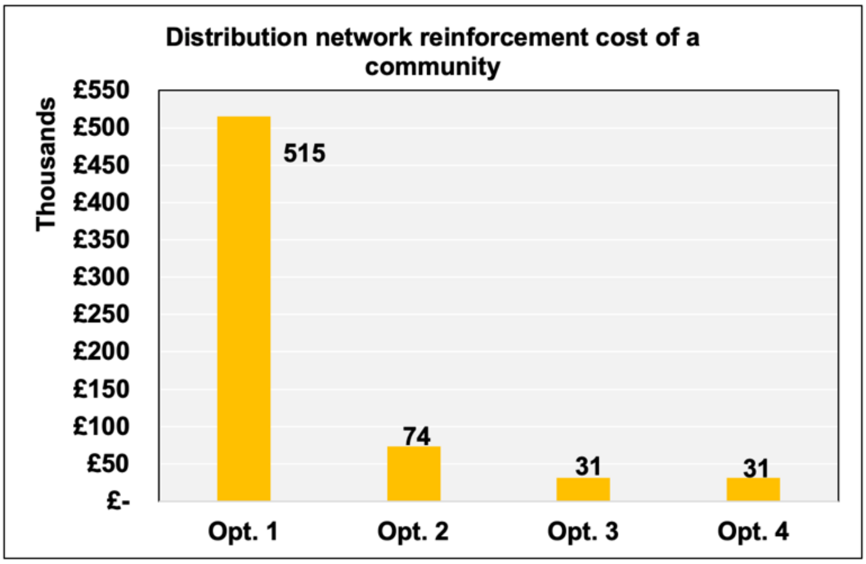

Figure 8-13: Screenshot of the modelling tool - The distribution network reinforcement cost of a community.

By improving housing thermal efficiency and applying PV/storage units, the Opt. 3 and 4 can meet the target power (0.4 MW). However, the collective electricity demand of electrified communities in a distribution network exceeded the maximum capacity of transformers in the typical UK primary substation (in Figure 6-5). This induces the £31 thousand of the Opt. 3 and 4 in Figure 8-13.

For Opt. 2, 3 and 4, the costs of reinforcing a distribution network, establishing a community energy system and enhancing housing thermal efficiency are aggregated and illustrated in Figure 8-14. The Opt. 2 indicates that the greatest cost is the district heating within a community energy system, which costs up to £4.2 million. The following costs from high to low are the GSHP, Li-ion battery and distribution network.

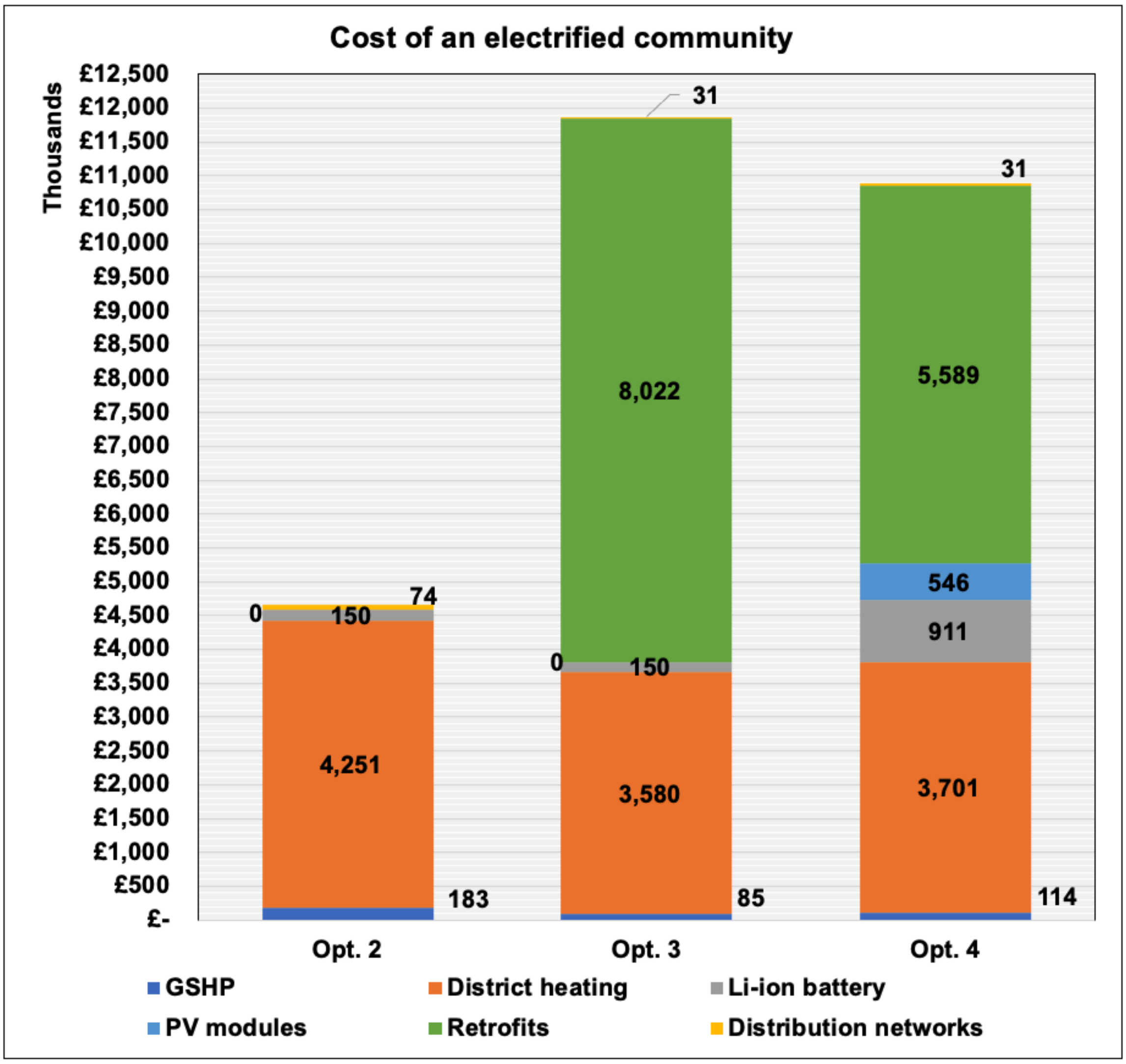

Figure 8-14: Screenshot of the modelling tool - The cost projection of an electrified community, including the community energy system, thermal efficiency improvement and distribution network.

In the Opt. 3 of Figure 8-14, the highest cost up to £8 million is the housing retrofit (i.e., thermal efficiency improvement). The costs of the district heating and GSHP are decreased due to a lower SH demand brought by a greater level of thermal efficiency in buildings. In the Opt. 4, the greatest cost is still the housing retrofit, around £5.6 million. In comparison with the Opt. 3, a lower improvement level of thermal efficiency reduces the cost of the housing retrofit but gives rise to extra costs on the GSHP, district heating, Li-ion battery and PV modules.

8.6. Discussion and conclusion

This chapter illustrated a modelling tool based on multi-vector community energy systems. In this modelling tool, users can adjust parameters such as the energy demands, community scale, number of EVs, distribution network constraints, percentage of smart charging, level of housing thermal efficiency improvement, etc., to obtain customised results. This modelling tool also provided technical parameters for building a community energy system. For instance, a systematic modelling approach, by analysing the simulated models' heating consumptions and geographical conditions, indicated the optimum distribution temperature of a LTDH system. Moreover, the capacities of batteries placed in homes and the community substation were defined. With the suitable scales of batteries, steady electricity flows can be created by performing smart management.

In this chapter, the modelling tool was demonstrated using the data in average UK dwelling in 2018. The targeted maximum power in the distribution network was 0.4 MW, providing a 20% demand buffer to the typical secondary substation. The simulation results included four options attaining the 100% electrification in a 384-dwelling community. The Opt. 1 that directly converted heating consumptions into electricity indicated a maximum power of 2.13 MW on the greatest demand day. The application of a community energy system as the Opt. 2 could manage the power flows at a steady state throughout the highest consumption week. This showed an electric power of 0.53 MW. The Opt. 3 and 4 were designed to meet the target of 0.4 MW of an electrified community. The Opt. 3 employed a community energy system and 72% housing thermal efficiency improvement. The Opt. 4 enabled users to define the improvement level of thermal efficiency in buildings. When an improvement level was lower than the calculated 72%, extra PV/storage units were applied to support the system.

Finally, the investment costs of an electrified community were estimated. The Opt. 1, having the greatest cost on the distribution network reinforcement, induced a cost of £515 thousand. The total prices of establishing an electrified community in the Opt. 2, 3 and 4 were £4.7 million, £11.9 million and £10.9 million. In the three options, the highest cost was the housing retrofit for thermal efficiency improvement, followed by a community energy system and distribution network reinforcement. As a result, applying a community energy system with housing thermal efficiency improvement to establish an electrified community did not appear to financial benefit initially. Nevertheless, this approach successfully reduced the electricity demand, flattened the demand peaks and coordinated various renewable technologies. Therefore, a community energy system is recommended as a long-term solution to attain the net-zero carbon emission goal.

The modelling tool was established using the Visual Basic for Applications (VBA) language. The VBA code and the screenshot of each worksheet are presented in Appendix 5 and Appendix 6.

8.7. Validation of the modelling tool of multi-vector community energy systems

The hourly power consumptions indicated in the modelling tool were generated by the procedure shown in Figure 8-15. Monthly demands from national statistical data are utilised to illustrate the demand percentages of each month across a whole year. The annual demand set by users, then, is reflected in the monthly demands. For example, comparing with the statistical data, a 20% increase in annual consumption set by users results in a 20% increase in each month. On the other hand, by applying hourly demand loads from studies, weekly and daily demand percentages within a month can be gained. This data is connected to the monthly demand derived from the annual consumption set by users. Therefore, the weekly and daily demands that match the annual consumption are presented.

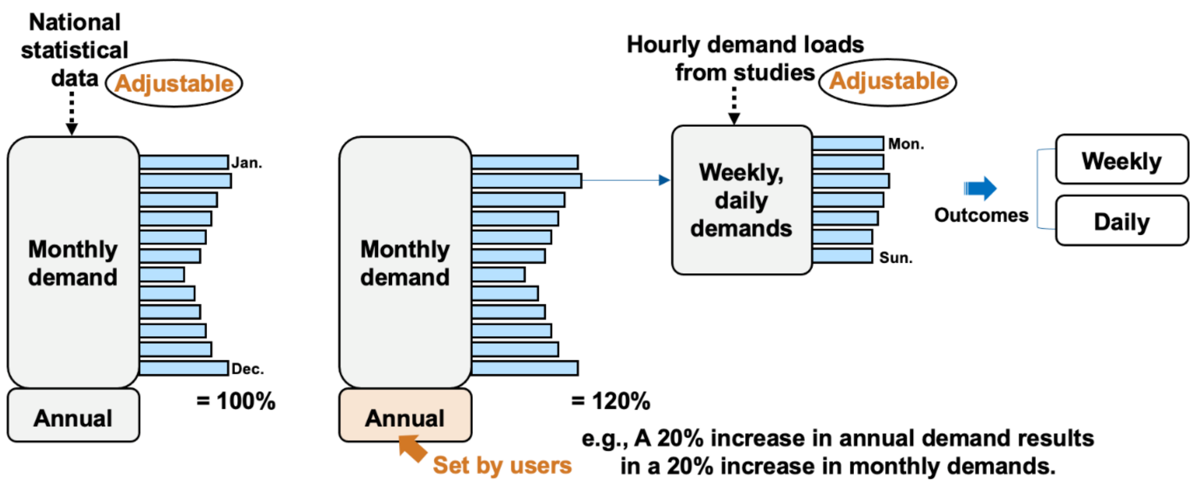

Figure 8-15: The procedure of generating hourly demand power.

The database of the modelling tool was obtained from studies that have been validated independently. By adopting the method of demand percentage, the correlation between hours remained the same. Only the amounts of demand were changed to meet the setting of annual consumption. Thus, the accuracy of the outcomes illustrated in the modelling tool was proved. This method can be applied to various conditions by adjusting the national statistical data and hourly demand loads in Figure 8-15. Comparisons between the modelling tool and data from studies are shown in Appendix 7.

Chapter 9

Discussion and Conclusion

This research suggested an electrification approach and developed a multi-vector community energy system for meeting the net-zero carbon emission goal. In an electrified community, the hourly electricity demands were investigated, including an electrified heating network, electric vehicles (EVs), lighting and appliances. This demand data was subsequently employed to define smart management measures in a community energy system. The capacity of the typical UK distribution network was considered in demonstration models for indicating the required improvement level of thermal performance in buildings. Ultimately, this research could illustrate the requirements of a community energy system and the investment costs of an electrified community. This chapter summarises the research procedures for developing a community energy system and an electrified community.

The following sections in this chapter are elaborated as: Section **9.1 Summary**: A summary of key messages from each chapter representing different development steps of a community energy system is elaborated. Section **9.2 Completion of research objectives**: The objectives presented in Chapter 1 are reviewed and illustrated. This includes the utilisation of a community energy system managing an electrified community and the modelling tool established to facilitate the 100% electrification. Section **9.3 Future works**: The flexibility and variety of a community energy system are depicted.

9.1. Summary

'Electrify everything' is identified to be an effective way for carbon emission reduction. The key to success in implementing this approach is the management of electric power supply and demand that was addressed throughout this thesis. Chapter 2, reviewing the future development of electricity supply systems, foresaw that the installed power production capacity would grow increase notably due to the utilisation of intermittent renewable power generations. This phenomenon will accompany a transformation of the power systems from centralised plants to decentralised small-scale wind and solar systems.

In Chapter 2 and Chapter 3, key technologies employed to increase energy distribution, conversion and generation efficiencies and manage power flows in an energy system were studied. In general, district heating systems are progressing in lower supply temperature for enabling the use of waste heat and high-efficiency heat pumps (HPs). To increase the efficiency of heat production, HPs are expected to dominate the residential heating supply. The review of electricity demand for EVs predicted that the home would be the main charging centre. Finally, because electrification induces considerable power consumption, battery storage (i.e., Li-ion battery) was an essential component to balance the supply and demand.

The reviewed technologies require a control system to ensure their coordination. For this purpose, a multi-vector community energy system was designed in Chapter 4. This community energy system was grouped into heating and electricity grids. The electrified heating network comprised a low-temperature district heating (LTDH) system, ground source heat pump (GSHP), electric heaters and thermal storage units. The electricity grid within a community energy system connected with EVs, battery storage, lighting and appliances, and heat generation units. Based on this system, smart control solutions such as the community-scale peak shaving, EV smart charging, and supply/demand data management could be able to perform.

Due to the application of a LTDH system, the distributed water temperature is necessary to be defined. This determines the electricity consumption of the heating network. In Chapter 5, a systematic modelling approach was established to measure the optimum distribution temperature with the least electricity consumption. The assessment showed that the utilisation rate of low-efficiency electric heaters for domestic hot water (DHW) production was varied significantly with the distribution temperature. The result indicated that the demand ratio of DHW to space heating (SH) is the critical factor defining the distribution temperature. This conclusion was applied to predict the supply temperature in a future world with greater thermal efficiency in buildings. As a result, a higher distribution temperature will be enabled to reduce electricity consumption.

The main goal of a community energy system was to manage an electrified community. Chapter 6 firstly investigated the electricity demands, including lighting and appliances, EVs, and residential heating. The community-scale was aligned to the number of households supplied by a typical low voltage (LV) substation in the UK. The result showed that the peak consumption power of an electrified community could be increased by over five times on the greatest demand day. Nevertheless, a community energy system utilising the electrified heating network, EV smart charging and community-scale peak shaving can possibly reduce the increased peak power to only a 33% increase. Along with this community energy system, this chapter presented that using a 70% thermal efficiency improvement in buildings, reducing the electricity demand for SH, allowed the typical UK distribution network to accommodate the consumptions of an electrified community. The improved percentage was compared with the 2018 level.

Apart from improving the thermal efficiency to meet the distribution network constraint, Chapter 7 illustrated that decentralised generation (DG) coupled with battery storage could be applied to support the system if the improvement level is lower than the 70%. This concept was demonstrated with 30%, 50% and 70% improvement scenarios and validated through a 12-week assessment in winter. The installed capacity of DG/storage units was increased with a decreasing level of thermal efficiency improvement. In the same chapter, to further decrease the electric power demand of an electrified heating network, an optimisation approach named distribution temperature management that supplies 40°C and 65°C water temperature separately to homes within a day was demonstrated. This reduced electricity consumption for heating by 11.1% annually.

A multi-vector community energy system was established and demonstrated from Chapter 4 to Chapter 7. The simulation models were then combined to build a modelling tool of community energy systems in Chapter 8. Using this modelling tool, a customised result for developing an electrified community could be obtained, providing four options for selection. Based on these options, the required capacities of each component of a community energy system and the electric load curves of the highest consumption period in a year were indicated. This detailed evaluation provided information on projecting investment costs of building an electrified community. The investment costs included the distribution network reinforcement, community energy system and housing thermal efficiency improvement.

9.2. Completion of research objectives

An electrified heating network model - Objective 1.

This research defined an electrified heating network through a GSHP, LTDH system, electric heaters and thermal storage units. A GSHP was selected as the primary heat production unit due to its great and stable COP. The LTDH system, distributing heat through flexible pipes, created the connection between homes. For DHW storage of each household, a 60°C water temperature was advisable to prevent the legionella issue. This temperature could be reached using electric heaters when the LTDH system cannot maintain this 60°C requirement. Apart from the thermal storage at home, a central thermal store was applied to mitigate peak demand and allow the system to utilise a GSHP with lower electric power.

After defining the heating network, a systematic modelling approach was developed to measure the optimum operating temperature. The evaluation at various supply temperatures included heating capacity, heating demands, GSHP capacity, thermal energy storage (TES), heat losses, and the utilisation rate of GSHP (high efficiency) and electric heaters (low efficiency). Briefly, this approach considered heat losses and the efficiency of heat production to define the distribution temperature. Furthermore, this research employed various demand ratios of DHW to SH to illustrate the tendency of the optimum distribution temperature with the growing thermal efficiency in buildings. Housing thermal efficiency determines the consumption of SH. Thus, by utilising various demand ratios of DHW to SH from 1:4.5 to 1:0.5, the optimum distribution temperature at different thermal efficiency levels was measured. The result indicated that buildings with higher thermal efficiency would enable a greater distribution temperature to reduce the electricity consumption of the electrified heating network.

An electrified community model - Objective 2.

In this research, hourly energy consumptions stemmed from evaluating annual and monthly demands from the national statistical data in 2018 with hourly consumption profiles from validated simulation tools or real-world physical studies. In an average UK dwelling, the annual energy consumptions of SH, DHW, EVs, and lighting and appliances were around 6.4 MWh, 1.6 MWh, 1.3 MWh, and 3.7 MWh, respectively. These were applied to produce the hourly consumption profile of a community. A LV substation in the typical UK distribution network provides 384 dwellings with electricity. Therefore, the scale of an electrified community was defined, which induced the maximum energy demand power of 2.1 MW on the coldest day.

Moreover, the maximum power supplied by a LV substation is 0.5 MW. To enable a 20% consumption buffer, the targeted maximum power was 0.4 MW in models, also matching the peak power before the electrification process. A community energy system that coordinates an electrified heating network, battery storage and decentralised generation was then employed to manage the power demands of this electrified community.

An electrified community model - Objective 3.

In comparison with the peak power demand without the 100% electrification on the coldest day, an electrified community increased the peak consumption by 5.4 times when energy demands were converted directly into electricity. This result was viewed as electric heating devices performing a COP of 1 for SH supply. The application of air source heat pumps (ASHPs) was assumed to have a COP of 3, which increased the peak power by 2.9 times.

Smart management measures conducted by a community energy system included the EV smart charging, community-scale peak shaving and ideal heating supply. For a demonstration model, the percentage of EV smart charging was assumed to be 50%. The capacity of a community battery that implemented peak shaving in a 384-dwelling community was 1.27 MWh, with a 15% demand buffer. Moreover, the ideal heating supply was to operate heat generation units at a constant power in the greatest consumption week. The result showed that the peak demand was increased by only 60% and could be potentially constrained at around 33% increase with better control of the battery system, comparing with the condition without the electrification on the coldest day.

An electrified community model - Objective 4.

In this research, the targeted maximum power was 0.4 MW in the typical UK distribution network. A community energy system was able to constrain the increased power demand brought by the electrification process at around a 33% increase, comparing with the target. This demand could be decreased by improving housing thermal efficiency that reduces SH consumption. The result showed that a community energy system with a 70% improvement in housing thermal efficiency met the target power. Thus, the existing distribution network could accommodate the electricity demands of an electrified community.

A decentralised generation (DG) model - Objective 5.

Photovoltaic (PV) generation was determined to supply electrified communities with clean energy. In this research, PV/storage was functioned to compensate for the demand exceeding the targeted power (0.4MW), thereby ensuring this distribution network operated at safe conditions. A lower level of housing thermal efficiency improvement gave rise to the need for a greater capacity of PV/storage units. For instance, comparing with the 2018 level, a 30% housing thermal efficiency improvement in a 384-dwelling community required PV modules with 647 kWp and battery storage with 14.4 MWh. The required peak production power of PV modules and the storage capacity of batteries were reduced to 304 kWp and 6.8 MWh, respectively, when the thermal efficiency was improved by 50%.

In the housing thermal efficiency improvement scenarios, the reliability of a community energy system was evaluated by illustrating the electric power demand of an electrified community in 12 weeks in winter. Some of these weekly power demands exceeded the targeted maximum power in the distribution network. On this occasion, the PV production within a community energy system could offset the exceeding power demands in most of the weeks. The battery storage met the consumptions that could not be compensated by PV generation. The reliability of a community energy system, then, was demonstrated.

Furthermore, based on the results, this research suggested approaches to improve the ability of community energy systems. First, the current home-based charging behaviour of most EVs should be changed, whereby EVs can be used to store PV generation for later domestic consumptions. A community energy system applying PV generation/EV storage can be the best practice in vehicle-to-grid (V2G) technology. Second, the distribution temperature management optimising an electrified heating network by supplying 40°C and 65°C water temperatures separately to homes within a day was recommended, which decreased the electricity consumption for heating by 11.1% annually.

A modelling tool of community energy systems - Objective 6.

A modelling tool based on the community energy system was established on an Excel workbook, enabling a broad range of adjustable parameters covering distribution network constraints, energy demands, community scale, ambient temperature, etc. The modelling result present the capacities of each instrument in the community energy system and the average investment cost of an electrified community. Using this modelling tool, the government or planner can select an approach that aligns with the electricity grid, geographical location and financial condition to develop an electrified community.

9.3. Future works

This research focused on the supply and demand management of residential consumptions, including heating, EVs, lighting and appliances, by utilising a multi-vector community energy system. A community energy system is flexible, variable, and expandable. For example, hydrogen expected to play an essential and complementary role in a highly electrified world [20] can be an energy fuel in the electrified heating network. The utilisation of hydrogen will not increase electricity demand; however, hydrogen production induces energy losses, which currently has a conversion efficiency of around 70% for electrolysis [20]. This does not consider the combustion efficiency of a hydrogen boiler. Therefore, a GSHP as the primary heat generation unit is a better choice for an area suitable for its installation.

Moreover, applying a GSHP within a community energy system has the likelihood to deliver a cooling solution with ultra-low carbon emissions; hence, this system will maintain the indoor temperature at a comfort level across a whole year. A community energy system could also extend to operate with waste heat recovery from factories and address consumptions in the commercial sector. Besides, this research has illustrated the models of an electrified community with a community energy system, which can indicate the required improvement level of thermal performance in buildings. This result can be used to create a model of building insulation, showing heat losses in different parts of a building. Therefore, the most cost-effective way to achieve the desired housing thermal efficiency can be obtained.

The applications mentioned above will be factored into the modelling tool of community energy systems. As a result, the modelling tool will be able to indicate the requirements of establishing an electrified community covering residential and commercial buildings, illustrate electricity demands of heating and cooling, and propose an efficient method for housing retrofit. Ultimately, electricity flow management between multiple communities will be enabled.

A community energy system has been depicted through demonstration models and validated by energyPRO. Therefore, obtaining funding for establishing an actual system is essential for system optimisation. This will consequently facilitate the development of electrified communities to attain the net-zero carbon emission goal.

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Appendix 1. Hydraulic layouts of the central thermal store and David Wilson House at the University of Nottingham

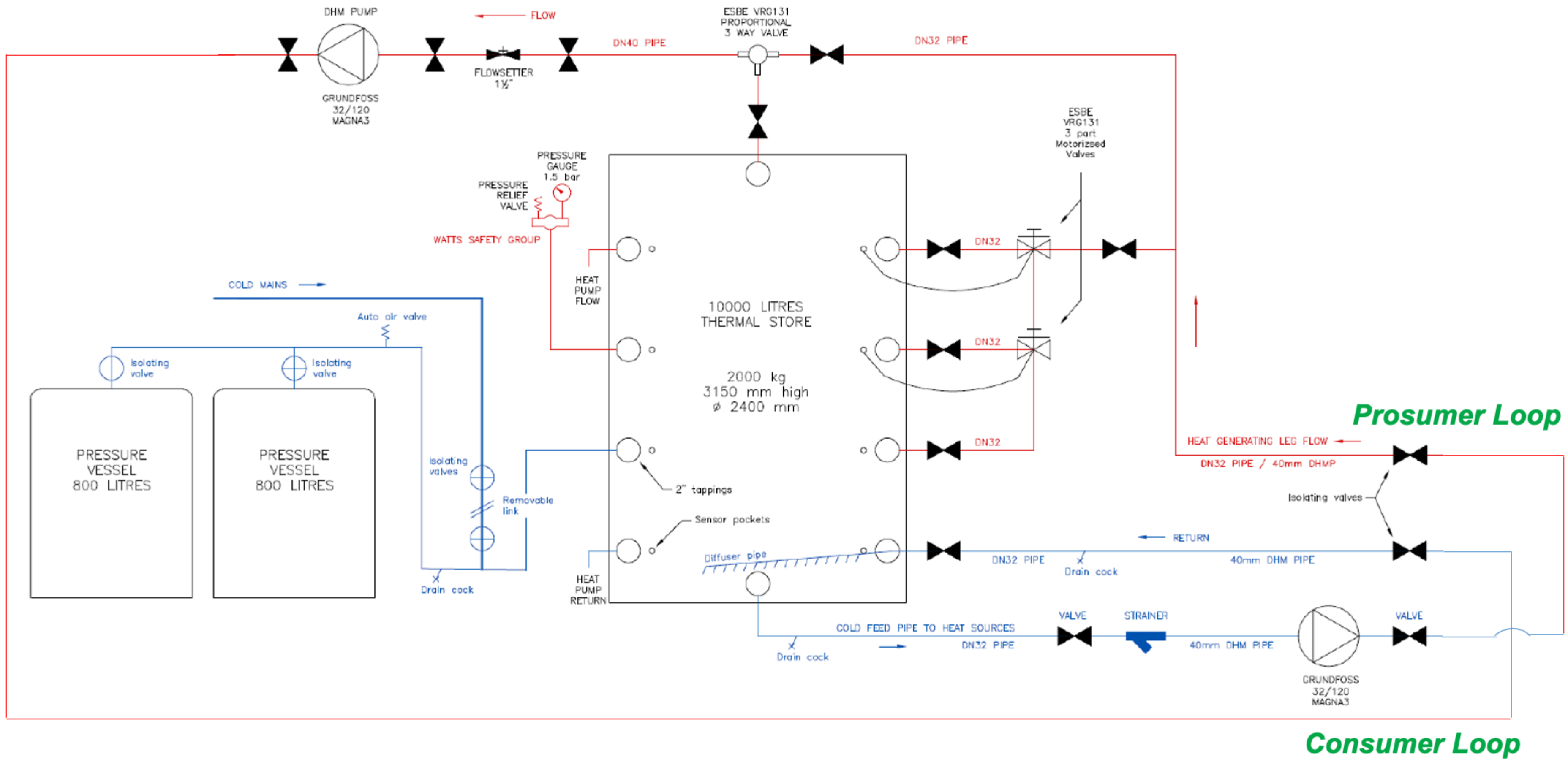


Figure A-1: The schematic hydraulic layout of the central thermal store [170].

VALVE POSITIONS - HEAT MAIN MODE	
VW1	CLOSED
VW2	OPEN
VW3	OPEN
VH1	OPEN
VH2	OPEN
VH3	CLOSED
VPRO1	OPEN
VPRO2	CLOSED
VPRO3	OPEN
VPRO4	OPEN

HIU VALVE POSITIONS - HEAT MAIN MODE	
VCW1	OPEN
VCW2	OPEN
VCH1	OPEN
VCH2	OPEN
VCPRO1	OPEN
VCPRO2	OPEN

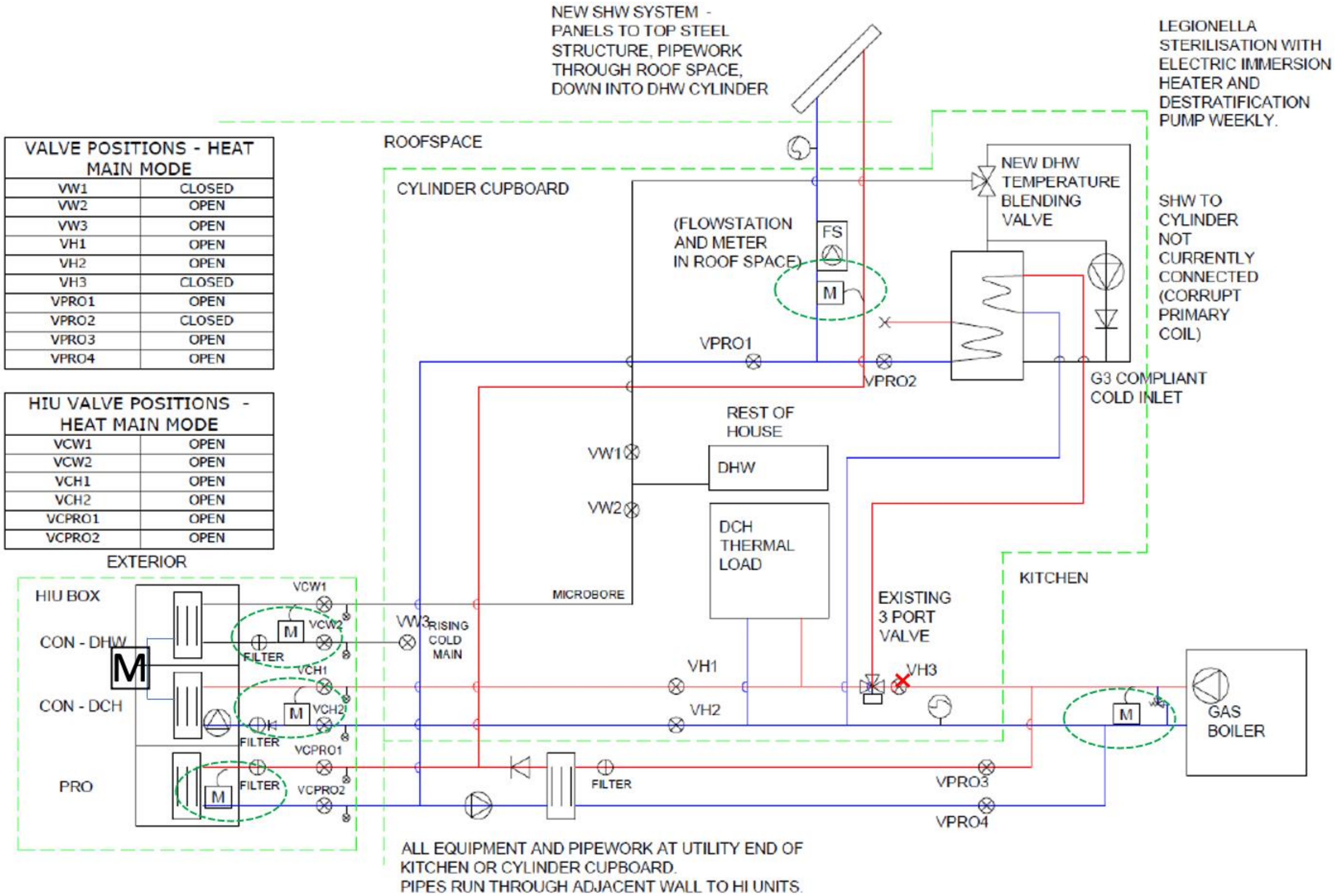


Figure A-2: The schematic hydraulic layout of the David Wilson House [170].

Appendix 2. Peak sun-hours and solar radiation

Peak sun-hours and solar radiation are the parameters for evaluating both the PV modules and solar collectors. The definition of peak sun hours is the hours in the day when the intensity of the sunlight reaches an average of 1 kW/m^2. For instance, if a location has 7 peak sun hours, the location receives 7 kWh/m^2 solar radiation in a day [171]. Figure A-3 is the average daily peak sun hours in the UK each month from 2010 to 2018. The month having the shortest peak sun-hours is December; with an average of 1.6 hours per day. In contrast, the month that has the longest peak sun-hours is July attaining an average of 6.6 hours per day.

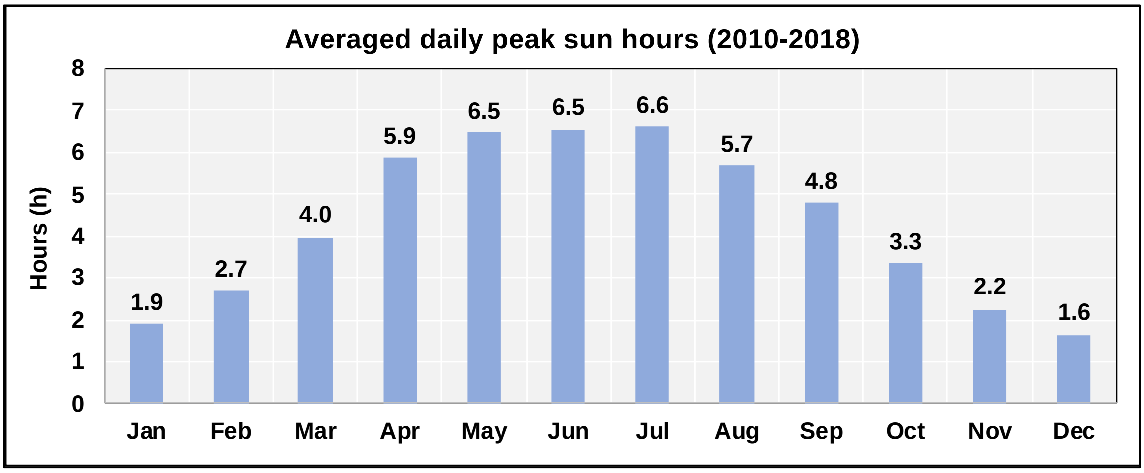


Figure A-3: The average daily peak sun hours in the UK each month from 2010 to 2018 [172].

Solar radiation is defined as the amount of sunlight reaching a horizontal area of the earth in a time period. The unit is expressed in joules per square metre (J/m^2). In the models, the unit is converted to watts per square meter (W/m^2), which is the value of the solar radiation divided by the time period expressed in second [173]. The solar radiation data from ERA5; an online dataset covering the climate variables on the planet since 1979 [121], is used in this research. By utilising energyPRO, solar radiation can be factored into the models. The evaluated location is assumed in Nottingham in the UK.

Appendix 3. A multi-vector community energy system with the 30% thermal efficiency improvement and decentralised generation coupled with battery storage

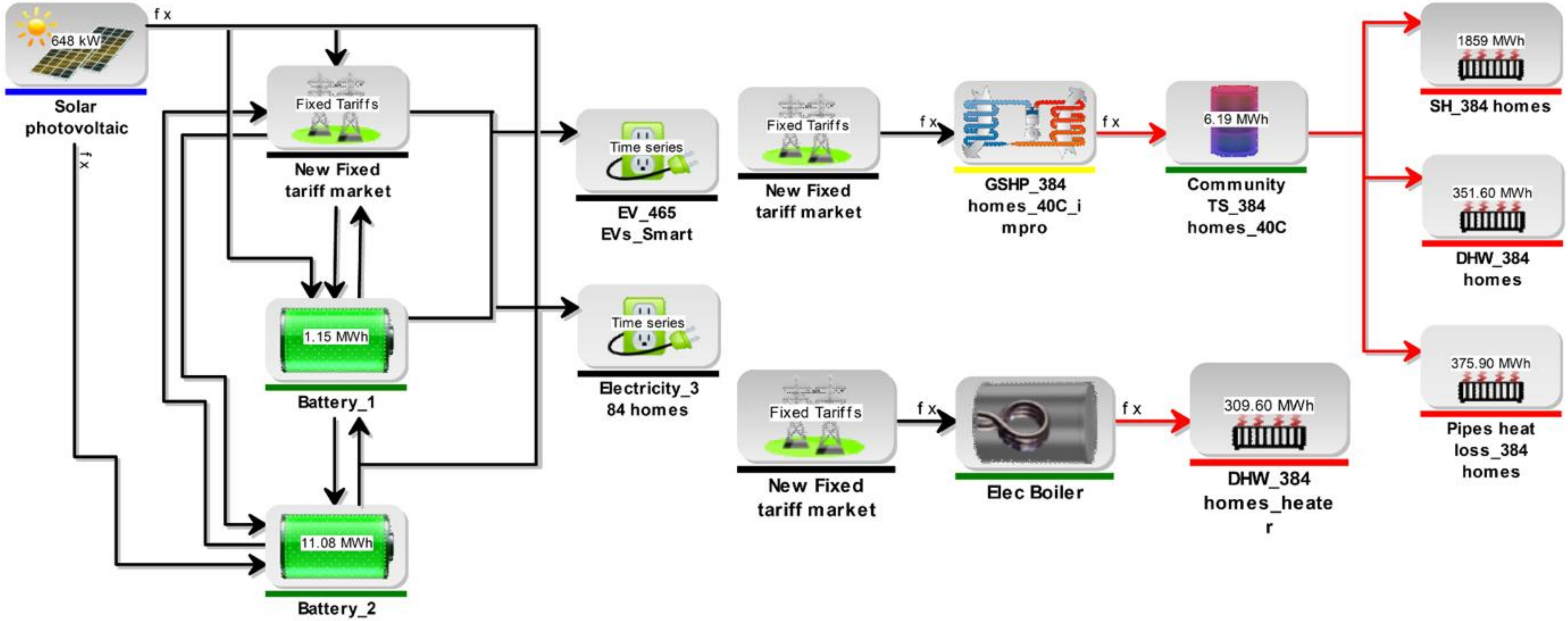


Figure A-4: The modelling configuration of the multi-vector community energy system with the 30% thermal efficiency improvement and decentralised generation.

Appendix 4. The UK electricity grid

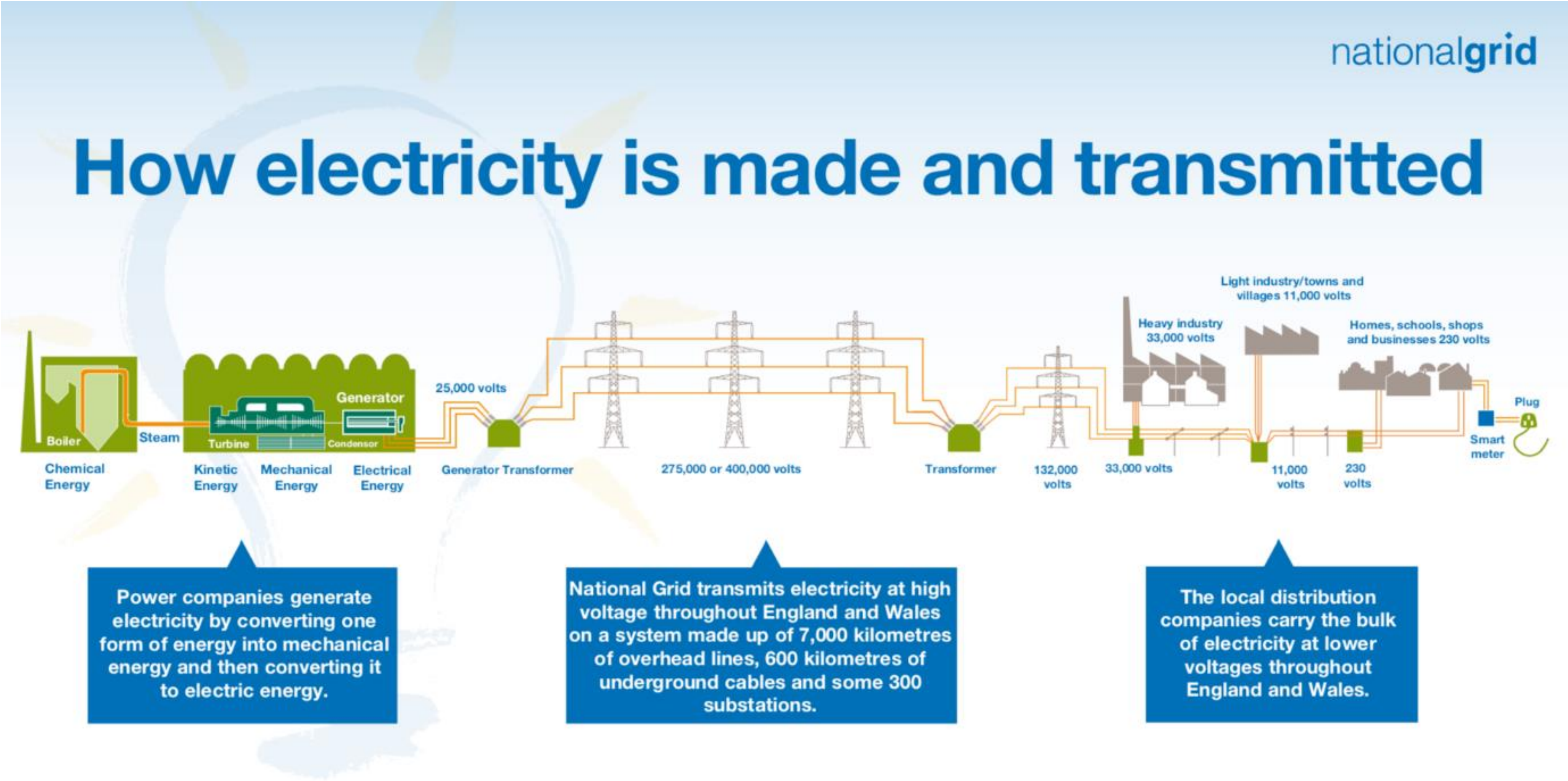


Figure A-5: An illustration of electricity generation, transmission and distribution [164].

Appendix 5. The VBA code of the modelling tool of multi-vector community energy systems

```
Public Sub Community_Energy_System()

'Multi-vector community energy system

'H3_dema
   Call AmbientT_HeatingDemand
'H2_T sele
   Call HeatingGrid_Opt2
'E2_EVs
   Call Edemand_EVs
'E3_elec
   Call Edemand_Electricity
'Demand Setting sheet
   Call ThermalEfficiency_Improvement
'H2_T sele
   Call HeatingGrid_Opt3
   Call HeatingGrid_Opt4
'H1_para
   Call Heating_Parameter
'E1_para
   Call Electricity_Parameter
'C1_E network
   Call Cost_E_Network_Opt1
   Call Cost_E_Network_Opt2
   Call Cost_E_Network_Opt3
   Call Cost_E_Network_Opt4
'C2_system
   Call Cost_Energy_System
'C3_retrofit
   Call Cost_Housing_Retrofit

Sheets("Summary").Select
Range("A1").Select

End Sub


Public Sub AmbientT_HeatingDemand()

Sheets("H1_para").Select

'Ambient temperature
      'T means temperature
   Dim Daily_T As Variant              'G91 to G113

      Dim j As Integer
      For j = 1 To 28

         Cells(j + 90, 7).Value = Cells((90 + 24 * j), 4).Value
         Daily_T = Cells(j + 90, 7).Value
         Cells(j + 90, 7).Select
         Selection.Font.Bold = True

      Next j

      Dim k As Integer
```

```
    For k = 1 To 10

        Cells(k + 123, 7).Value = Cells((762 + 24 * k), 4).Value
        Daily_T = Cells(k + 123, 7).Value
        Cells(k + 123, 7).Select
        Selection.Font.Bold = True

    Next k

    'F1 means 1st week of Feb., M1 means 1st week of Mar.
Dim Weekly_T_F1 As Variant        'H97
Dim Weekly_T_F2 As Variant        'H104
Dim Weekly_T_F3 As Variant        'H111
Dim Weekly_T_F4 As Variant        'H118
Dim Weekly_T_M1 As Variant        'H130

        Cells(97, 8).Value = "=AVERAGE(G91:G97)"
        Weekly_T_F1 = Cells(97, 8).Value
        Cells(97, 8).Select
        Selection.Font.Bold = True

        Cells(104, 8).Value = "=AVERAGE(G98:G104)"
        Weekly_T_F2 = Cells(104, 8).Value
        Cells(104, 8).Select
        Selection.Font.Bold = True

        Cells(111, 8).Value = "=AVERAGE(G105:G111)"
        Weekly_T_F3 = Cells(111, 8).Value
        Cells(111, 8).Select
        Selection.Font.Bold = True

        Cells(118, 8).Value = "=AVERAGE(G112:G118)"
        Weekly_T_F4 = Cells(118, 8).Value
        Cells(118, 8).Select
        Selection.Font.Bold = True

        Cells(130, 8).Value = "=AVERAGE(G124:G130)"
        Weekly_T_M1 = Cells(130, 8).Value
        Cells(130, 8).Select
        Selection.Font.Bold = True

Dim SettingT_forSH As Variant        'K121
    'Req means required
Dim Weekly_ReqSH_T_F1 As Variant        'I97
Dim Weekly_ReqSH_T_F2 As Variant        'I104
Dim Weekly_ReqSH_T_F3 As Variant        'I111
Dim Weekly_ReqSH_T_F4 As Variant        'I118
Dim Weekly_ReqSH_T_M1 As Variant        'I130

        SettingT_forSH = Cells(121, 11).Value
    'add - before weekly temp for changing direction
        Cells(97, 9).Value = -Weekly_T_F1 + SettingT_forSH
        Weekly_ReqSH_T_F1 = Cells(97, 9).Value
        Cells(97, 9).Select
        Selection.Font.Bold = True
```

```
        Cells(104, 9).Value = -Weekly_T_F2 + SettingT_forSH
        Weekly_ReqSH_T_F2 = Cells(104, 9).Value
        Cells(104, 9).Select
        Selection.Font.Bold = True

        Cells(111, 9).Value = -Weekly_T_F3 + SettingT_forSH
        Weekly_ReqSH_T_F3 = Cells(111, 9).Value
        Cells(111, 9).Select
        Selection.Font.Bold = True

        Cells(118, 9).Value = -Weekly_T_F4 + SettingT_forSH
        Weekly_ReqSH_T_F4 = Cells(118, 9).Value
        Cells(118, 9).Select
        Selection.Font.Bold = True

        Cells(130, 9).Value = -Weekly_T_M1 + SettingT_forSH
        Weekly_ReqSH_T_M1 = Cells(130, 9).Value
        Cells(130, 9).Select
        Selection.Font.Bold = True

    Dim Total_Weekly_ReqSH_T As Variant         'I119

        Cells(119, 9).Value = "=Sum(I97, I104, I111, I118)"
        Total_Weekly_ReqSH_T = Cells(119, 9).Value
        Cells(119, 9).Select
        Selection.Font.Bold = True

      'Req means required, D means demand, Pcent means percentage
    Dim Weekly_ReqSH_D_Pcent_F1 As Variant         'J97
    Dim Weekly_ReqSH_D_Pcent_F2 As Variant         'J104
    Dim Weekly_ReqSH_D_Pcent_F3 As Variant         'J111
    Dim Weekly_ReqSH_D_Pcent_F4 As Variant         'J118

        Cells(97, 10).Value = Weekly_ReqSH_T_F1 / Total_Weekly_ReqSH_T
        Weekly_ReqSH_D_Pcent_F1 = Cells(97, 10).Value
        Cells(97, 10).Select
        Selection.Font.Bold = True

        Cells(104, 10).Value = Weekly_ReqSH_T_F2 / Total_Weekly_ReqSH_T
        Weekly_ReqSH_D_Pcent_F2 = Cells(104, 10).Value
        Cells(104, 10).Select
        Selection.Font.Bold = True

        Cells(111, 10).Value = Weekly_ReqSH_T_F3 / Total_Weekly_ReqSH_T
        Weekly_ReqSH_D_Pcent_F3 = Cells(111, 10).Value
        Cells(111, 10).Select
        Selection.Font.Bold = True

        Cells(118, 10).Value = Weekly_ReqSH_T_F4 / Total_Weekly_ReqSH_T
        Weekly_ReqSH_D_Pcent_F4 = Cells(118, 10).Value
        Cells(118, 10).Select
        Selection.Font.Bold = True


    Dim Daily_ReqSH_T As Variant             'L91 to L118
```

```
    Dim m As Integer
    For m = 91 To 118

    'add - for changing direction
      Cells(m, 12).Value = -Cells(m, 7).Value + SettingT_forSH
      Daily_ReqSH_T = Cells(m, 12).Value
      Cells(m, 12).Select
      Selection.Font.Bold = True

    Next m

    Dim n As Integer
    For n = 124 To 127

    'add - for changing direction
      Cells(n, 12).Value = -Cells(n, 7).Value + SettingT_forSH
      Daily_ReqSH_T = Cells(n, 12).Value
      Cells(n, 12).Select
      Selection.Font.Bold = True

    Next n

  Dim Total_Daily_ReqSH_T As Variant        'S120
  'Req means required, D means demand, Pcent means percentage
  Dim Daily_ReqSH_D_Pcent As Variant        'S91 to S118

      Cells(120, 19).Value = "=SUM(L91:L118)"
      Total_Daily_ReqSH_T = Cells(120, 19).Value
      Cells(120, 19).Select
      Selection.Font.Bold = True

    For m = 91 To 118

      Cells(m, 19).Value = Cells(m, 12).Value / Total_Daily_ReqSH_T
      Daily_ReqSH_D_Pcent = Cells(m, 19).Value
      Cells(m, 19).Select
      Selection.Font.Bold = True

    Next m

  Dim Max_D_Week_Pcent As Variant        'U115
  Dim Max_D_Day_Pcent As Variant         'U116

      Cells(115, 21).Value = "=MAX(J97,J104,J111,J118)"
      Max_D_Week_Pcent = Cells(115, 21).Value
      Cells(115, 21).Select
      Selection.Font.Bold = True

      Cells(116, 21).Value = "=MAX(S91:S118)"
      Max_D_Day_Pcent = Cells(116, 21).Value
      Cells(116, 21).Select
      Selection.Font.Bold = True


Sheets("H3_dema").Select
```

```
    'D means demand
  Dim AvgDaily_HeatD As Variant   'J5 to J16

    Dim x As Integer
    For x = 5 To 16

      AvgDaily_HeatD = (Cells(x, 6).Value + Cells(x, 7).Value) / Cells(x, 9).Value
      Cells(x, 10).Value = AvgDaily_HeatD
      Cells(x, 10).Select
      Selection.Font.Bold = True

    Next x

    'D means demand
  Dim MaxD_month As Variant         'J19
    'M means month
  Dim MaxD_M_Daily As Variant       'K19
  Dim MaxD_M_DHW As Variant         'K21
  Dim MaxD_M_SH As Variant          'K23

      MaxD_month = "=XLOOKUP(MAX(J5:J16),J5:J16,E5:E16)"
      Cells(19, 10).Value = MaxD_month
      Cells(19, 10).Select
      Selection.Font.Bold = True

      MaxD_M_Daily = "=XLOOKUP(J19,E5:E16,J5:J16)"
      Cells(19, 11).Value = MaxD_M_Daily
      Cells(19, 11).Select
      Selection.Font.Bold = True

      Cells(21, 11).Value = "=XLOOKUP($J$19,$P$5:$P$16,$U$5:$U$16)"
      MaxD_M_DHW = Cells(21, 11).Value
      Cells(21, 11).Select
      Selection.Font.Bold = True

      Cells(23, 11).Value = "=XLOOKUP($J$19,$AC$5:$AC$16,$AH$5:$AH$16)"
      MaxD_M_SH = Cells(23, 11).Value
      Cells(23, 11).Select
      Selection.Font.Bold = True

'DHW
  'DHW energy demand

    'D means demand
  Dim Monthly_DHW_D As Variant        'Q5 to Q16
  Dim TotalD_Months As Variant        'Q17
  Dim Unit_Change As Integer          '1000

    Unit_Change = 1000

    Dim y As Integer
    For y = 5 To 16

      Monthly_DHW_D = Cells(y, 6).Value / Unit_Change
      Cells(y, 17).Value = Monthly_DHW_D
      Cells(y, 17).Select
```

```
        Selection.Font.Bold = True

    Next y

        Cells(17, 17).Value = "=SUM(Q5:Q16)"
        Cells(17, 17).Select
        Selection.Font.Bold = True

        TotalD_Months = Cells(17, 17).Value


Dim Ratio_M_DHW As Variant        'S5 to S16
Dim Total_Percentage As Variant  'S17

    Dim z As Integer
    For z = 5 To 16

        Ratio_M_DHW = Cells(z, 17).Value / TotalD_Months * 100
        Cells(z, 19).Value = Ratio_M_DHW
        Cells(z, 19).Select
        Selection.Font.Bold = True

    Next z

        Cells(17, 19).Value = "=SUM(S5:S16)"
        Cells(17, 19).Select
        Selection.Font.Bold = True

        Total_Percentage = Cells(17, 19).Value


Dim Annual_DHW_DoUser As Variant               'T4
    'DoUser means demand of user
Dim Monthly_DHW_DoUser As Variant             'T5 to T16
Dim Monthly_DHW_DoUser_kWh As Variant    'U5 to U16

        Annual_DHW_DoUser = Cells(4, 20).Value

    Dim a As Integer
    For a = 5 To 16

        Monthly_DHW_DoUser = Annual_DHW_DoUser * Cells(a, 19).Value / Total_Percentage
        Cells(a, 20).Value = Monthly_DHW_DoUser
        Cells(a, 20).Select
        Selection.Font.Bold = True

        Monthly_DHW_DoUser_kWh = Cells(a, 20).Value * Unit_Change
        Cells(a, 21).Value = Monthly_DHW_DoUser_kWh
        Cells(a, 21).Select
        Selection.Font.Bold = True

    Next a

'DHW weight in household tank

Dim Monthly_DHW_DoUser_kJ As Variant     'R27 to R38
```

```
Dim Unit_Change2 As Integer                    '3600
   'ToUser means temperature of User
Dim Tank_ToUser As Variant              'W25
Dim Water_Cp As Variant                 'N28

      Unit_Change2 = 3600
      Tank_ToUser = Cells(25, 23)
      Water_Cp = Cells(28, 14).Value

   Dim b As Integer
   For b = 27 To 38

      Monthly_DHW_DoUser_kJ = Cells(b, 17).Value * Unit_Change2
      Cells(b, 18).Value = Monthly_DHW_DoUser_kJ
      Cells(b, 18).Select
      Selection.Font.Bold = True

Dim Cold_In_T As Variant                'T27 to T38
Dim Hot_Out_T As Variant                'U27 to U38
Dim Monthly_DHW_kg As Variant           'W27 to W38
Dim Total_Months_DHW_kg As Variant      'W39

      Cold_In_T = Cells(b, 20).Value
      Cells(b, 20).Select
      Selection.Font.Bold = True

      Hot_Out_T = Cells(b, 21).Value
      Cells(b, 21).Select
      Selection.Font.Bold = True

      Monthly_DHW_kg = Monthly_DHW_DoUser_kJ / ((Tank_ToUser - Cold_In_T) * Water_Cp)
      Cells(b, 23).Value = Monthly_DHW_kg
      Cells(b, 23).Select
      Selection.Font.Bold = True

   Next b

      Cells(39, 23).Value = "=SUM(W27:W38)"
      Cells(39, 23).Select
      Selection.Font.Bold = True

      Total_Months_DHW_kg = Cells(39, 23).Value

Dim Feb_Month_DHW_kg As Variant         'W28
Dim Feb_Days As Integer                 'X28
Dim Feb_Week_DHW_kg As Variant          'Y28
Dim Week_Days As Integer                '7 days

      Feb_Month_DHW_kg = Cells(28, 23).Value
      Feb_Days = Cells(6, 9).Value
      Week_Days = 7

      Cells(28, 24).Value = Feb_Days
      Cells(28, 24).Select
      Selection.Font.Bold = True
```

```
        Feb_Week_DHW_kg = (Feb_Month_DHW_kg / Feb_Days) * Week_Days
        Cells(28, 25).Value = Feb_Week_DHW_kg
        Cells(28, 25).Select
        Selection.Font.Bold = True

'DHW hourly demand profile

    'EachDay means ex., Monday, Tuesday, etc.
Dim DemandEachDay As Variant                 'E44 to E50
    'N means number. ex., number of Mondays in a month
Dim EachDayN_Month As Integer                'F44 to F50
    'DemandEachDay_Month means ex., all Mondays demand of a month
Dim DemandEachDay_Month As Variant           'G44 to G50

    Dim c As Integer
    For c = 44 To 50

        DemandEachDay = Cells(c, 5).Value
        EachDayN_Month = Cells(c, 6).Value

        DemandEachDay_Month = DemandEachDay * EachDayN_Month
        Cells(c, 7).Value = DemandEachDay_Month
        Cells(c, 7).Select
        Selection.Font.Bold = True

    Next c

    'M means month, D means demand,EachDay means ex., Monday, Tuesday, etc.
Dim Total_M_D_DHW_fromEachDays As Variant          'G51

        Cells(51, 7).Value = "=SUM(G44:G50)"
        Cells(51, 7).Select
        Selection.Font.Bold = True

        Total_M_D_DHW_fromEachDays = Cells(51, 7).Value

Dim DHW_EachDay_Percentage As Variant           'H44 to H50

    Dim d As Integer
    For d = 44 To 50

        DHW_EachDay_Percentage = Cells(d, 7).Value / Total_M_D_DHW_fromEachDays
        Cells(d, 8).Value = DHW_EachDay_Percentage
        Cells(d, 8).Select
        Selection.Font.Bold = True

    'D means demand, M means month,OneEachDay means ex., one Monday, one Tuesday, etc.
Dim Max_D_M_OneEachDay As Variant            'I44 to I50

        'Max_D_M_OneEachDay = MaxD_M_DHW * Cells(d, 8).Value / Cells(d, 6).Value
        Max_D_M_OneEachDay = Range("K21").Value * Cells(d, 8).Value / Cells(d, 6).Value
        'MaxD_M_DHW*DHW_EachDay_Percentage/EachDayN_Month
        Cells(d, 9).Value = Max_D_M_OneEachDay
        Cells(d, 9).Select
        Selection.Font.Bold = True
```

```
    Next d

    'Ratio_toMatchUser means using database and input value of users to find ratio
  Dim DHW_Ratio_toMatchUser As Variant          'K44

      'DHW_Ratio_toMatchUser = MaxD_M_DHW / Total_M_D_DHW_fromEachDays
      DHW_Ratio_toMatchUser = Range("K21").Value / Total_M_D_DHW_fromEachDays
      Cells(44, 11).Value = DHW_Ratio_toMatchUser
      Cells(44, 11).Select
      Selection.Font.Bold = True

  Dim DHW_Hourly_Database As Variant      'N44 to N67
  Dim DHW_Hourly_MatchUser As Variant     'O44 to O67

    Dim e As Integer
    For e = 44 To 67

      DHW_Hourly_Database = Cells(e, 14).Value
      DHW_Hourly_MatchUser = DHW_Hourly_Database * DHW_Ratio_toMatchUser
      Cells(e, 15).Value = DHW_Hourly_MatchUser
      Cells(e, 15).Select
      Selection.Font.Bold = True

    'N means number
  Dim HouseholdN As Integer          'Q43
  Dim DHW_Hourly_MatchUser_HouseN     'Q44 to Q67

      HouseholdN = Cells(43, 17).Value
      DHW_Hourly_MatchUser_HouseN = DHW_Hourly_MatchUser * HouseholdN / Unit_Change
      Cells(e, 17).Value = DHW_Hourly_MatchUser_HouseN
      Cells(e, 17).Select
      Selection.Font.Bold = True

    Next e

    'D means demand, M means month. One week demand in the max. demand month
  Dim DHW_Max_D_M_Weekly As Variant       'V20

      Cells(20, 22).Value = "=SUM(I44:I50)/1000"
      DHW_Max_D_M_Weekly = Cells(20, 22).Value
      Cells(20, 22).Select
      Selection.Font.Bold = True

'SH
  'SH energy demand

    'D means demand
  Dim Monthly_SH_D As Variant          'AD5 to AD16
  Dim SH_TotalD_Months As Variant     'AD17

    Dim f As Integer
    For f = 5 To 16

      Monthly_SH_D = Cells(f, 7).Value / Unit_Change
      Cells(f, 30).Value = Monthly_SH_D
      Cells(f, 30).Select
```

```
        Selection.Font.Bold = True

    Next f

        Cells(17, 30).Value = "=SUM(AD5:AD16)"
        Cells(17, 30).Select
        Selection.Font.Bold = True

        SH_TotalD_Months = Cells(17, 30).Value

Dim Ratio_M_SH As Variant           'AF5 to AF16
Dim SH_Total_Percentage As Variant  'AF17

    Dim g As Integer
    For g = 5 To 16

        Ratio_M_SH = Cells(g, 30).Value / SH_TotalD_Months * 100
        Cells(g, 32).Value = Ratio_M_SH
        Cells(g, 32).Select
        Selection.Font.Bold = True

    Next g

        Cells(17, 32).Value = "=SUM(AF5:AF16)"
        Cells(17, 32).Select
        Selection.Font.Bold = True
        SH_Total_Percentage = Cells(17, 32).Value


Dim Annual_SH_DoUser As Variant         'AG4
    'DoUser means demand of user
Dim Monthly_SH_DoUser As Variant        'AG5 to AG16
Dim Monthly_SH_DoUser_kWh As Variant    'AH5 to AH16

        Annual_SH_DoUser = Cells(4, 33).Value

    Dim h As Integer
    For h = 5 To 16

        Monthly_SH_DoUser = Annual_SH_DoUser * Cells(h, 32).Value / SH_Total_Percentage
        Cells(h, 33).Value = Monthly_SH_DoUser
        Cells(h, 33).Select
        Selection.Font.Bold = True

        Monthly_SH_DoUser_kWh = Cells(h, 33).Value * Unit_Change
        Cells(h, 34).Value = Monthly_SH_DoUser_kWh
        Cells(h, 34).Select
        Selection.Font.Bold = True

    Next h

    'D means demand, M means month, Co means the coldest
    'The coldest week demand in the max. demand month
Dim Max_D_M_Co_Week As Variant          'AI20
    'The coldest day demand in the max. demand month
Dim Max_D_M_Co_Day As Variant           'AK20
```

```
Dim SH_Percentage_Co_Week As Variant   'AI24
Dim SH_Percentage_Co_Day As Variant    'AI26

    SH_Percentage_Co_Week = Cells(24, 35).Value
    SH_Percentage_Co_Day = Cells(26, 35).Value

    'Max_D_M_Co_Week = (MaxD_M_SH / Unit_Change) * SH_Percentage_Co_Week
    Max_D_M_Co_Week = (Range("K23").Value / Unit_Change) * SH_Percentage_Co_Week
    Cells(20, 35).Value = Max_D_M_Co_Week
    Cells(20, 35).Select
    Selection.Font.Bold = True

    'Max_D_M_Co_Day = (MaxD_M_SH / Unit_Change) * SH_Percentage_Co_Day
    Max_D_M_Co_Day = (Range("K23").Value / Unit_Change) * SH_Percentage_Co_Day
    Cells(20, 37).Value = Max_D_M_Co_Day
    Cells(20, 37).Select
    Selection.Font.Bold = True

Dim Max_D_M_Co_Day_kWh As Variant        'AD46

    Max_D_M_Co_Day_kWh = Max_D_M_Co_Day * Unit_Change
    Cells(46, 30).Value = Max_D_M_Co_Day_kWh
    Cells(46, 30).Select
    Selection.Font.Bold = True

  'D means demand. One Workday demand from database
Dim SH_Day_D_database As Variant             'AJ68
'Ratio_toMatchUser means using database and input value of users to find the ratio
Dim SH_Ratio_toMatchUser As Variant          'AG50

    Cells(68, 36).Value = "=SUM(AJ44:AJ67)"
    Cells(68, 36).Select
    Selection.Font.Bold = True
    SH_Day_D_database = Cells(68, 36).Value

    SH_Ratio_toMatchUser = Max_D_M_Co_Day_kWh / SH_Day_D_database
    Cells(50, 33).Value = SH_Ratio_toMatchUser
    Cells(50, 33).Select
    Selection.Font.Bold = True

Dim SH_Hourly_Database As Variant     'AK44 to AK67
Dim SH_Hourly_MatchUser As Variant    'AM44 to AM67

  Dim i As Integer
  For i = 44 To 67

    SH_Hourly_Database = Cells(i, 36).Value
    SH_Hourly_MatchUser = SH_Hourly_Database * SH_Ratio_toMatchUser
    Cells(i, 37).Value = DHW_Hourly_MatchUser
    Cells(i, 37).Select
    Selection.Font.Bold = True

  'N means number
Dim SH_Hourly_MatchUser_HouseN    'AM44 to AM67

    HouseholdN = Cells(43, 39).Value
```

```
        SH_Hourly_MatchUser_HouseN = SH_Hourly_MatchUser * HouseholdN / Unit_Change
        Cells(i, 39).Value = SH_Hourly_MatchUser_HouseN
        Cells(i, 39).Select
        Selection.Font.Bold = True

      Next i

 End Sub

Public Sub HeatingGrid_Opt2()

'H1_para
  Sheets("H1_para").Select

  'GSHP
    'COP
    'Power trendline y = ax^b
    Dim a_COP As Variant              'M9
    Dim b_COP As Variant              'M10

        Cells(9, 13).Value = "=EXP(INDEX(LINEST(LN(J5:J11),LN(I5:I11),,),1,2))"
        a_COP = Cells(9, 13).Value
        Cells(9, 13).Select
        Selection.Font.Bold = True

        Cells(10, 13).Value = "=INDEX(LINEST(LN(J5:J11),LN(I5:I11),,),1)"
        b_COP = Cells(10, 13).Value
        Cells(10, 13).Select
        Selection.Font.Bold = True


'H2_Tsele
  Sheets("H2_T sele").Select

'Pipe
  'PiHeatLoss_TempDiff
  Dim DistriT As Variant         'S6
  Dim ReturnT As Variant         'E29
  Dim SoilT As Variant           'S7
  Dim TempDiff As Variant        'S8

    Cells(6, 19).Value = Cells(26, 5).Value
    Cells(6, 20).Value = Cells(26, 6).Value
    Cells(6, 21).Value = Cells(26, 7).Value
    Cells(6, 22).Value = Cells(26, 8).Value
    Cells(6, 23).Value = Cells(26, 9).Value
    Cells(6, 24).Value = Cells(26, 10).Value

  Dim x As Integer
  For x = 19 To 24

    DistriT = Cells(6, x).Value
    ReturnT = Cells(29, 5).Value

    Cells(7, x).Value = Cells(36, 5).Value
    SoilT = Cells(7, x).Value
```

```
    Cells(8, x).Value = (DistriT + ReturnT) / 2 - SoilT
    TempDiff = Cells(8, x).Value

    Cells(8, x).Select
    Selection.Font.Bold = True

'PiBranch_U
    'B means branch
Dim PiB_LowFlowT As Variant        'B8
Dim PiB_ReturnT As Variant         'B9
    'Bu means a building
Dim Bu_HeatFlow As Variant         'B6
Dim WaterCp As Variant             'B7
Dim WaterDen As Variant            'B10
Dim PiB_FlowRate As Variant        'B5
Dim PiB_Uvalue As Variant          'S10

    PiB_LowFlowT = Cells(8, 2).Value
    PiB_ReturnT = Cells(9, 2).Value
    Bu_HeatFlow = Cells(6, 2).Value
    WaterCp = Cells(7, 2).Value
    WaterDen = Cells(10, 2).Value

    Cells(5, 2).Value = Bu_HeatFlow / (WaterCp * (PiB_LowFlowT - PiB_ReturnT) * WaterDen)
    PiB_FlowRate = Cells(5, 2).Value

    'column E is flow rate, colume G is U value
    Select Case Cells(5, 2).Value
        Case Is <= Cells(6, 5).Value
            PiB_Uvalue = Cells(6, 7).Value
        Case Is <= Cells(7, 5).Value
            PiB_Uvalue = Cells(7, 7).Value
        Case Is <= Cells(8, 5).Value
            PiB_Uvalue = Cells(8, 7).Value
        Case Is <= Cells(9, 5).Value
            PiB_Uvalue = Cells(9, 7).Value
        Case Is <= Cells(11, 5).Value
            PiB_Uvalue = Cells(11, 7).Value
        Case Is <= Cells(12, 5).Value
            PiB_Uvalue = Cells(12, 7).Value
    End Select

    Cells(10, 9).Value = PiB_Uvalue
    Cells(10, x).Value = Cells(10, 9).Value
    Cells(10, x).Select
    Selection.Font.Bold = True

'PiMain_U
    'M means Main
Dim PiM_Uvalue As Variant 'S12

    'distribution pipes: column E is flow rate, column G is U value
    'household number*flow rate
    'if pipe flow rate exceeds the max. pipe condition, then use the max. pipe
    Select Case Cells(5, x).Value * Cells(5, 2).Value
```

```
        Case Is <= Cells(6, 5).Value
          PiM_Uvalue = Cells(6, 7).Value
        Case Is <= Cells(7, 5).Value
          PiM_Uvalue = Cells(7, 7).Value
        Case Is <= Cells(8, 5).Value
          PiM_Uvalue = Cells(8, 7).Value
        Case Is <= Cells(9, 5).Value
          PiM_Uvalue = Cells(9, 7).Value
        Case Is <= Cells(11, 5).Value
          PiM_Uvalue = Cells(11, 7).Value
        Case Is <= Cells(12, 5).Value
          PiM_Uvalue = Cells(12, 7).Value
        Case Is <= Cells(14, 5).Value
          PiM_Uvalue = Cells(14, 7).Value
        Case Is <= Cells(15, 5).Value
          PiM_Uvalue = Cells(15, 7).Value
        Case Is <= Cells(16, 5).Value
          PiM_Uvalue = Cells(16, 7).Value
        Case Is > Cells(16, 5).Value
          PiM_Uvalue = Cells(16, 7).Value
    End Select

    Cells(12, x).Value = PiM_Uvalue
    Cells(12, x).Select
    Selection.Font.Bold = True

'PiNumber
    'N means number
Dim HouseholdN As Variant       'S5
Dim PiB_Number As Variant       'S13
Dim PiM_Number As Variant       'S14

    Cells(5, x).Value = Cells(44, 16).Value
    HouseholdN = Cells(5, x).Value
    'branch pipe number equals to household number
    Cells(13, x).Value = HouseholdN
    PiB_Number = Cells(13, x).Value

    'main pipe number equals to household number divided by 2
    Cells(14, x).Value = WorksheetFunction.RoundUp(HouseholdN / 2, 0)
    PiM_Number = Cells(14, x).Value

    Cells(13, x).Select
    Selection.Font.Bold = True
    Cells(14, x).Select
    Selection.Font.Bold = True

'PiHeatLoss
Dim TwinPiMax As Variant        'E12
Dim PiB_Length As Variant       'S9
Dim PiM_Length As Variant       'S11
Dim Oper_Hours As Variant       'S15
'StoB means small unit to big unit
Dim Unit_StoB As Variant        'S16
Dim PiHeatLoss_annual As Variant        'S18
```

```
        PiB_FlowRate = Cells(5, 2).Value
        TwinPiMax = Cells(12, 5).Value

        Cells(9, x).Value = Cells(33, 5).Value
        PiB_Length = Cells(9, x).Value

        Cells(11, x).Value = Cells(34, 5).Value
        PiM_Length = Cells(11, x).Value

        Cells(15, x).Value = 8760
        Oper_Hours = Cells(15, x).Value

        Cells(16, x).Value = 1000
        Unit_StoB = Cells(16, x).Value

        'household number*flow rate
        If HouseholdN * PiB_FlowRate <= TwinPiMax Then
        PiHeatLoss_annual = ((PiB_Uvalue * TempDiff * PiB_Length * PiB_Number) _
        + (PiM_Uvalue * TempDiff * PiM_Length * PiM_Number)) * Oper_Hours / Unit_StoB
        Else: PiHeatLoss_annual = 2 * ((PiB_Uvalue * TempDiff * PiB_Length * PiB_Number) _
        + (PiM_Uvalue * TempDiff * PiM_Length * PiM_Number)) * Oper_Hours / Unit_StoB
        End If

        Cells(18, x).Value = PiHeatLoss_annual
        Cells(18, x).Select
        Selection.Font.Bold = True

'DHW
    'DHW_Energy_Heater
    Dim TankT As Variant            'E28
    Dim TankWeight_kg As Variant      'S3
    Dim DHW_Energy_Heater As Variant    'S21

        TankT = Cells(28, 5).Value

        Cells(3, x).Value = Cells(46, 16).Value
        TankWeight_kg = Cells(3, x).Value

        'Temp. after HIU, y=0.9659x-0.5982, x: distribution T
        If DistriT <= TankT Then
        DHW_Energy_Heater = (TankT - (0.9659 * DistriT - 0.5982)) _
                    * WaterCp * TankWeight_kg / 3600 * HouseholdN
        Else: DHW_Energy_Heater = 0
        End If
        Cells(21, x).Value = DHW_Energy_Heater
        Cells(21, x).Select
        Selection.Font.Bold = True

    'DHW_Energy_LTDH
        'perH means per household
    Dim DHW_Energy_perH As Variant  'S2
    Dim DHW_Energy_LTDH As Variant  'S22

        Cells(2, x).Value = Cells(42, 16).Value
        DHW_Energy_perH = Cells(2, x).Value
```

```
        DHW_Energy_LTDH = DHW_Energy_perH * HouseholdN - DHW_Energy_Heater
        Cells(22, x).Value = DHW_Energy_LTDH
        Cells(22, x).Select
        Selection.Font.Bold = True

    'HIU efficiency
        'Eff means efficiency
    Dim DHW_HIU_Eff As Variant      'S24

        'HIU, y= -0.016x + 92.673, x:distribution T
        DHW_HIU_Eff = -0.016 * DistriT + 92.673
        Cells(24, x).Value = DHW_HIU_Eff
        Cells(24, x).Select
        Selection.Font.Bold = True

    'DHW_Energy_LTDH_HIU_Eff
    Dim DHW_Energy_LTDH_HIU_Eff As Variant      'S25

        DHW_Energy_LTDH_HIU_Eff = DHW_Energy_LTDH / (DHW_HIU_Eff / 100)
        Cells(25, x).Value = DHW_Energy_LTDH_HIU_Eff
        Cells(25, x).Select
        Selection.Font.Bold = True

'SH
    'SH_Energy_LTDH
    Dim SH_Energy_perH As Variant      'S4
    Dim SH_Energy_LTDH As Variant      'S28

        Cells(4, x).Value = Cells(42, 17).Value
        SH_Energy_perH = Cells(4, x).Value

        SH_Energy_LTDH = SH_Energy_perH * HouseholdN
        Cells(28, x).Value = SH_Energy_LTDH
        Cells(28, x).Select
        Selection.Font.Bold = True

    'HIU efficiency
        'Eff means efficiency
    Dim SH_HIU_Eff As Variant      'S30

        'HIU, y= -0.016x + 92.673, x:distribution T
        SH_HIU_Eff = -0.016 * DistriT + 92.673
        Cells(30, x).Value = SH_HIU_Eff
        Cells(30, x).Select
        Selection.Font.Bold = True

    'SH_Energy_LTDH_HIU_Eff
    Dim SH_Energy_LTDH_HIU_Eff As Variant      'S31

        SH_Energy_LTDH_HIU_Eff = SH_Energy_LTDH / (SH_HIU_Eff / 100)
        Cells(31, x).Value = SH_Energy_LTDH_HIU_Eff
        Cells(31, x).Select
        Selection.Font.Bold = True

'Electricity demand
    'COP of a GSHP
```

```
    Dim COP_GSHP As Variant             'S33

    Dim GSHP_COP_a As Variant            'E40
    Dim GSHP_COP_b As Variant            'E41

        GSHP_COP_a = Cells(40, 5).Value
        GSHP_COP_b = Cells(41, 5).Value
        COP_GSHP = GSHP_COP_a * (DistriT ^ GSHP_COP_b)
        Cells(33, x).Value = COP_GSHP
        Cells(33, x).Select
        Selection.Font.Bold = True

    'Electricity demand of a GSHP
        'Edemand means electricity demand
    Dim Edemand_GSHP As Variant            'S35

        Edemand_GSHP = (DHW_Energy_LTDH_HIU_Eff + SH_Energy_LTDH_HIU_Eff _
                + PiHeatLoss_annual) / COP_GSHP
        Cells(35, x).Value = Edemand_GSHP
        Cells(35, x).Select
        Selection.Font.Bold = True

    'Total electricity (electric heater + GSHP)
    Dim Edemand_Heater_GSHP_kW As Variant    'S36
    Dim Edemand_Heater_GSHP_MW As Variant    'S37

        Edemand_Heater_GSHP_kW = DHW_Energy_Heater + Edemand_GSHP
        Cells(36, x).Value = Edemand_Heater_GSHP_kW
        Cells(36, x).Select
        Selection.Font.Bold = True

        Edemand_Heater_GSHP_MW = Edemand_Heater_GSHP_kW / Unit_StoB
        Cells(37, x).Value = Edemand_Heater_GSHP_MW
        Cells(37, x).Select
        Selection.Font.Bold = True

    Next x


'Select the optimum temperature; the lowest electricity demand temperature
    Dim OptimumT As Variant                  'U46
    Dim OptimumT_Edemand_Heater As Variant        'U48
    Dim OptimumT_Edemand_GSHP As Variant          'U49
    Dim OptimumT_Edemand_Heater_GSHP As Variant    'U50

    'The optimum temp.
        'Applying XLookUp function, XLOOKUP(lookup_value,lookup_array,return_array)
        OptimumT = "=XLOOKUP(MIN(S37: X37),S37 :X37,S6:X6)"
        Cells(46, 21).Value = OptimumT
        Cells(46, 21).Select
        Selection.Font.Bold = True

    'The electricity demand of electric heater of the optimum temp.
        'U46 is the OptimumT, row 6 contains distribution temperature conditions
        OptimumT_Edemand_Heater = "=XLOOKUP(U46,S6:X6,S21:X21)" & "/1000"
        Cells(48, 21).Value = OptimumT_Edemand_Heater
```

```
    Cells(48, 21).Select
    Selection.Font.Bold = True

  'The electricity demand of GSHP of the optimum temp.
    'U46 is the OptimumT, row 6 contains distribution temperature conditions
    OptimumT_Edemand_GSHP = "=XLOOKUP(U46,S6:X6,S35:X35)" & "/1000"
    Cells(49, 21).Value = OptimumT_Edemand_GSHP
    Cells(49, 21).Select
    Selection.Font.Bold = True

  'The electricity demand of electric heater and GSHP of the optimum temp.
    OptimumT_Edemand_Heater_GSHP = Cells(48, 21).Value + Cells(49, 21).Value
    Cells(50, 21).Value = OptimumT_Edemand_Heater_GSHP
    Cells(50, 21).Select
    Selection.Font.Bold = True

'For generating the data of the coldest week

'Pipe
  'PiHeatLoss_TempDiff
  'W means week, for generating the data of the coldest day
  Dim W_DistriT As Variant              'AB6
  Dim W_ReturnT As Variant              'E29
  Dim W_SoilT As Variant                'AB7
  Dim W_TempDiff As Variant             'AB8

    W_DistriT = Cells(46, 21).Value
    Cells(6, 28).Value = W_DistriT

    W_ReturnT = Cells(29, 5).Value

    Cells(7, 28).Value = Cells(36, 5).Value
    W_SoilT = Cells(7, 28).Value

    Cells(8, 28).Value = (W_DistriT + W_ReturnT) / 2 - W_SoilT
    W_TempDiff = Cells(8, 28).Value

    Cells(8, 28).Select
    Selection.Font.Bold = True

  'PiBranch_U
    'B means branch
  Dim W_PiB_LowFlowT As Variant     'B8
  Dim W_PiB_ReturnT As Variant      'B9
    'Bu means a building
  Dim W_Bu_HeatFlow As Variant      'B6
  Dim W_WaterCp As Variant          'B7
  Dim W_WaterDen As Variant         'B10
  Dim W_PiB_FlowRate As Variant     'B5
  Dim W_PiB_Uvalue As Variant       'AB10

    W_PiB_LowFlowT = Cells(8, 2).Value
    W_PiB_ReturnT = Cells(9, 2).Value
    W_Bu_HeatFlow = Cells(6, 2).Value
    W_WaterCp = Cells(7, 2).Value
    W_WaterDen = Cells(10, 2).Value
```

```
    Cells(5, 2).Value = W_Bu_HeatFlow / (W_WaterCp * (W_PiB_LowFlowT - W_PiB_ReturnT) * W_WaterDen)
    W_PiB_FlowRate = Cells(5, 2).Value

    'column E is flow rate, column G is U value
    Select Case Cells(5, 2).Value
      Case Is <= Cells(6, 5).Value
        W_PiB_Uvalue = Cells(6, 7).Value
      Case Is <= Cells(7, 5).Value
        W_PiB_Uvalue = Cells(7, 7).Value
      Case Is <= Cells(8, 5).Value
        W_PiB_Uvalue = Cells(8, 7).Value
      Case Is <= Cells(9, 5).Value
        W_PiB_Uvalue = Cells(9, 7).Value
      Case Is <= Cells(11, 5).Value
        W_PiB_Uvalue = Cells(11, 7).Value
      Case Is <= Cells(12, 5).Value
        W_PiB_Uvalue = Cells(12, 7).Value
    End Select

    Cells(10, 9).Value = W_PiB_Uvalue
    Cells(10, 28).Value = Cells(10, 9).Value
    Cells(10, 28).Select
    Selection.Font.Bold = True

  'PiMain_U
    'M means Main
  Dim W_PiM_Uvalue As Variant 'AB12

    'distribution pipes: column E is flow rate, column G is U value
    'household number*flow rate
    'if pipe flow rate exceeds the max. pipe condition, then use the max. pipe
    Select Case Cells(5, 28).Value * Cells(5, 2).Value
      Case Is <= Cells(6, 5).Value
        W_PiM_Uvalue = Cells(6, 7).Value
      Case Is <= Cells(7, 5).Value
        W_PiM_Uvalue = Cells(7, 7).Value
      Case Is <= Cells(8, 5).Value
        W_PiM_Uvalue = Cells(8, 7).Value
      Case Is <= Cells(9, 5).Value
        W_PiM_Uvalue = Cells(9, 7).Value
      Case Is <= Cells(11, 5).Value
        W_PiM_Uvalue = Cells(11, 7).Value
      Case Is <= Cells(12, 5).Value
        W_PiM_Uvalue = Cells(12, 7).Value
      Case Is <= Cells(14, 5).Value
        W_PiM_Uvalue = Cells(14, 7).Value
      Case Is <= Cells(15, 5).Value
        W_PiM_Uvalue = Cells(15, 7).Value
      Case Is <= Cells(16, 5).Value
        W_PiM_Uvalue = Cells(16, 7).Value
      Case Is > Cells(16, 5).Value
        W_PiM_Uvalue = Cells(16, 7).Value
    End Select

    Cells(12, 28).Value = W_PiM_Uvalue
```

```
    Cells(12, 28).Select
    Selection.Font.Bold = True

'PiNumber
    'N means number
Dim W_HouseholdN As Variant         'AB5
Dim W_PiB_Number As Variant         'AB13
Dim W_PiM_Number As Variant         'AB14

    Cells(5, 28).Value = Cells(44, 16).Value
    W_HouseholdN = Cells(5, 28).Value
    'branch pipe number equals to household number
    Cells(13, 28).Value = W_HouseholdN
    W_PiB_Number = Cells(13, 28).Value

    'main pipe number equals to household number divided by 2
    Cells(14, 28).Value = WorksheetFunction.RoundUp(W_HouseholdN / 2, 0)
    W_PiM_Number = Cells(14, 28).Value

    Cells(13, 28).Select
    Selection.Font.Bold = True
    Cells(14, 28).Select
    Selection.Font.Bold = True

'PiHeatLoss
Dim W_TwinPiMax As Variant          'E12
Dim W_PiB_Length As Variant         'AB9
Dim W_PiM_Length As Variant         'AB11
Dim W_Oper_Hours As Variant         'AB15
Dim W_Unit_StoB As Variant          'AB16
Dim W_PiHeatLoss_annual As Variant      'AB18

    W_PiB_FlowRate = Cells(5, 2).Value
    W_TwinPiMax = Cells(12, 5).Value

    Cells(9, 28).Value = Cells(33, 5).Value
    W_PiB_Length = Cells(9, 28).Value

    Cells(11, 28).Value = Cells(34, 5).Value
    W_PiM_Length = Cells(11, 28).Value

    Cells(15, 28).Value = 168
    W_Oper_Hours = Cells(15, 28).Value
    Cells(16, 28).Value = 1000
    W_Unit_StoB = Cells(16, 28).Value

    'household number*flow rate
    If W_HouseholdN * W_PiB_FlowRate <= W_TwinPiMax Then
    W_PiHeatLoss_annual = ((W_PiB_Uvalue * W_TempDiff * W_PiB_Length * W_PiB_Number) _
    + (W_PiM_Uvalue * W_TempDiff * W_PiM_Length * W_PiM_Number)) * W_Oper_Hours / W_Unit_StoB
    Else: W_PiHeatLoss_annual = 2 * ((W_PiB_Uvalue * W_TempDiff * W_PiB_Length * W_PiB_Number) _
    + (W_PiM_Uvalue * W_TempDiff * W_PiM_Length * W_PiM_Number)) * W_Oper_Hours / W_Unit_StoB
    End If

    Cells(18, 28).Value = W_PiHeatLoss_annual
    Cells(18, 28).Select
```

```
    Selection.Font.Bold = True

'DHW
  'DHW_Energy_Heater
  Dim W_TankT As Variant                    'E28
  Dim W_TankWeight_kg As Variant        'AB3
  Dim W_DHW_Energy_Heater As Variant        'AB21

    W_TankT = Cells(28, 5).Value
    W_TankWeight_kg = Cells(3, 28).Value

    'Temp. after HIU, y=0.9659x-0.5982, x: distribution T
    If W_DistriT <= W_TankT Then
    W_DHW_Energy_Heater = (W_TankT - (0.9659 * W_DistriT - 0.5982)) _
                 * W_WaterCp * W_TankWeight_kg / 3600 * W_HouseholdN
    Else: W_DHW_Energy_Heater = 0
    End If
    Cells(21, 28).Value = W_DHW_Energy_Heater
    Cells(21, 28).Select
    Selection.Font.Bold = True

  'DHW_Energy_LTDH
    'perH means per household
  Dim W_DHW_Energy_perH As Variant        'AB2
  Dim W_DHW_Energy_LTDH As Variant       'AB22

    W_DHW_Energy_perH = Cells(2, 28).Value

    W_DHW_Energy_LTDH = W_DHW_Energy_perH * W_HouseholdN - W_DHW_Energy_Heater
    Cells(22, 28).Value = W_DHW_Energy_LTDH
    Cells(22, 28).Select
    Selection.Font.Bold = True

  'HIU efficiency
    'Eff means efficiency
  Dim W_DHW_HIU_Eff As Variant      'AB24

    'HIU, y= -0.016x + 92.673, x:distribution T
    W_DHW_HIU_Eff = -0.016 * W_DistriT + 92.673
    Cells(24, 28).Value = W_DHW_HIU_Eff
    Cells(24, 28).Select
    Selection.Font.Bold = True

  'DHW_Energy_LTDH_HIU_Eff
  Dim W_DHW_Energy_LTDH_HIU_Eff As Variant       'AB25

    W_DHW_Energy_LTDH_HIU_Eff = W_DHW_Energy_LTDH / (W_DHW_HIU_Eff / 100)
    Cells(25, 28).Value = W_DHW_Energy_LTDH_HIU_Eff
    Cells(25, 28).Select
    Selection.Font.Bold = True

'SH
  'SH_Energy_LTDH
  Dim W_SH_Energy_perH As Variant       'AB4
  Dim W_SH_Energy_LTDH As Variant       'AB28
```

```
    W_SH_Energy_perH = Cells(4, 28).Value

    W_SH_Energy_LTDH = W_SH_Energy_perH * W_HouseholdN
    Cells(28, 28).Value = W_SH_Energy_LTDH
    Cells(28, 28).Select
    Selection.Font.Bold = True

  'HIU efficiency
    'Eff means efficiency
  Dim W_SH_HIU_Eff As Variant      'AB30

    'HIU, y= -0.016x + 92.673, x:distribution T
    W_SH_HIU_Eff = -0.016 * W_DistriT + 92.673
    Cells(30, 28).Value = W_SH_HIU_Eff
    Cells(30, 28).Select
    Selection.Font.Bold = True

  'SH_Energy_LTDH_HIU_Eff
  Dim W_SH_Energy_LTDH_HIU_Eff As Variant        'AB31

    W_SH_Energy_LTDH_HIU_Eff = W_SH_Energy_LTDH / (W_SH_HIU_Eff / 100)
    Cells(31, 28).Value = W_SH_Energy_LTDH_HIU_Eff
    Cells(31, 28).Select
    Selection.Font.Bold = True

'Electricity demand
  'COP of a GSHP
  Dim W_COP_GSHP As Variant              'AB33

    'y=60.499*(x ^ (-0.695)), x:distribution T
    W_COP_GSHP = 60.499 * (W_DistriT ^ (-0.695))
    Cells(33, 28).Value = W_COP_GSHP
    Cells(33, 28).Select
    Selection.Font.Bold = True

  'Electricity demand of a GSHP
    'Edemand means electricity demand
  Dim W_Edemand_GSHP As Variant           'AB35

    W_Edemand_GSHP = (W_DHW_Energy_LTDH_HIU_Eff + W_SH_Energy_LTDH_HIU_Eff _
            + W_PiHeatLoss_annual) / W_COP_GSHP
    Cells(35, 28).Value = W_Edemand_GSHP
    Cells(35, 28).Select
    Selection.Font.Bold = True

  'Total electricity (electric heater + GSHP)
  Dim W_Edemand_Heater_GSHP_kW As Variant    'AB36
  Dim W_Edemand_Heater_GSHP_MW As Variant    'AB37

    W_Edemand_Heater_GSHP_kW = W_DHW_Energy_Heater + W_Edemand_GSHP
    Cells(36, 28).Value = W_Edemand_Heater_GSHP_kW
    Cells(36, 28).Select
    Selection.Font.Bold = True

    W_Edemand_Heater_GSHP_MW = W_Edemand_Heater_GSHP_kW / Unit_StoB
    Cells(37, 28).Value = W_Edemand_Heater_GSHP_MW
```

```
    Cells(37, 28).Select
    Selection.Font.Bold = True

  'For DHW + heat loss, SH demands in the coldest week
  Dim W_Edemand_DHW_GSHP As Variant       'AC35
  Dim W_DHW_GSHP_DHW_Heater As Variant    'AC36
  Dim W_Edemand_SH_GSHP As Variant        'AD35
  Dim W_Edemand_Loss_GSHP As Variant      'AE35

    W_Edemand_DHW_GSHP = W_DHW_Energy_LTDH_HIU_Eff / W_COP_GSHP
    Cells(35, 29).Value = W_Edemand_DHW_GSHP
    Cells(35, 29).Select
    Selection.Font.Bold = True

    W_DHW_GSHP_DHW_Heater = W_Edemand_DHW_GSHP + W_DHW_Energy_Heater
    Cells(36, 29).Value = W_DHW_GSHP_DHW_Heater
    Cells(36, 29).Select
    Selection.Font.Bold = True

    W_Edemand_SH_GSHP = W_SH_Energy_LTDH_HIU_Eff / W_COP_GSHP
    Cells(35, 30).Value = W_Edemand_SH_GSHP
    Cells(35, 30).Select
    Selection.Font.Bold = True

    W_Edemand_Loss_GSHP = W_PiHeatLoss_annual / W_COP_GSHP
    Cells(35, 31).Value = W_Edemand_Loss_GSHP
    Cells(35, 31).Select
    Selection.Font.Bold = True

  'hourly weekly demand
  Dim W_Edemand_hourlyTotal As Variant            'AB38
  Dim W_hourly_DHW_GSHP_DHW_Heater As Variant     'AC38
  Dim W_hourly_SH_GSHP As Variant                 'AD38
  Dim W_hourly_Loss_GSHP As Variant               'AE38

    W_Edemand_hourlyTotal = W_Edemand_Heater_GSHP_MW / W_Oper_Hours
    Cells(38, 28).Value = W_Edemand_hourlyTotal
    Cells(38, 28).Select
    Selection.Font.Bold = True

    W_hourly_DHW_GSHP_DHW_Heater = W_DHW_GSHP_DHW_Heater / Unit_StoB / W_Oper_Hours
    Cells(38, 29).Value = W_hourly_DHW_GSHP_DHW_Heater
    Cells(38, 29).Select
    Selection.Font.Bold = True

    W_hourly_SH_GSHP = W_Edemand_SH_GSHP / Unit_StoB / W_Oper_Hours
    Cells(38, 30).Value = W_hourly_SH_GSHP
    Cells(38, 30).Select
    Selection.Font.Bold = True

    W_hourly_Loss_GSHP = W_Edemand_Loss_GSHP / Unit_StoB / W_Oper_Hours
    Cells(38, 31).Value = W_hourly_Loss_GSHP
    Cells(38, 31).Select
    Selection.Font.Bold = True

End Sub
```

```
Public Sub Edemand_EVs()

Sheets("E2_EVs").Select

'per EV
  'D means demand, M means month. Average daily electricity demand in each month.
Dim EV_DailyD_EachM As Variant            'O3 to O14
Dim Days_EachM As Integer                 'P3 to P14
Dim EV_MonthlyD_EachM_kWh As Variant       'Q3 to Q14
Dim EV_MonthlyD_EachM_MWh As Variant       'R3 to R14
Dim Unit_Change As Integer                '1000

    Unit_Change = 1000

  Dim a_EV As Integer
  For a_EV = 3 To 14

    EV_DailyD_EachM = Cells(a_EV, 15).Value
    Days_EachM = Cells(a_EV, 16).Value

    EV_MonthlyD_EachM_kWh = EV_DailyD_EachM * Days_EachM
    Cells(a_EV, 17).Value = EV_MonthlyD_EachM_kWh
    Cells(a_EV, 17).Select
    Selection.Font.Bold = True

    EV_MonthlyD_EachM_MWh = EV_MonthlyD_EachM_kWh / Unit_Change
    Cells(a_EV, 18).Value = EV_MonthlyD_EachM_MWh
    Cells(a_EV, 18).Select
    Selection.Font.Bold = True

  Next a_EV

  'D means demand
Dim EV_AnnualD_MWh As Variant           'R15

    Cells(15, 18).Value = "=SUM(R3:R14)"
    EV_AnnualD_MWh = Cells(15, 18).Value
    Cells(15, 18).Select
    Selection.Font.Bold = True

  'M means month, D means demand
Dim EV_EachM_D_Ratio As Variant          'U3 to U14

  Dim b_EV As Integer
  For b_EV = 3 To 14

    'times 100 to be 100%
    Cells(b_EV, 21).Value = Cells(b_EV, 18).Value / EV_AnnualD_MWh * 100
    EV_EachM_D_Ratio = Cells(b_EV, 21).Value
    Cells(b_EV, 21).Select
    Selection.Font.Bold = True

  'M means month, D means demand.
  'Using ratio(demand percentage) and input annual demand to obtain each month demand
Dim EV_EachM_D_MatchUser As Variant            'V3 to V14
```

```
Dim EV_AnnualD_MatchUser As Variant              'V2

        EV_AnnualD_MatchUser = Cells(2, 22).Value
        'divided by 100 due to percentage
        EV_EachM_D_MatchUser = EV_AnnualD_MatchUser * EV_EachM_D_Ratio / 100
        Cells(b_EV, 22) = EV_EachM_D_MatchUser
        Cells(b_EV, 22).Select
        Selection.Font.Bold = True

Dim EV_EachM_D_MatchUser_kWh As Variant          'W3 to W14

        Cells(b_EV, 23).Value = EV_EachM_D_MatchUser * Unit_Change
        EV_EachM_D_MatchUser_kWh = Cells(b_EV, 23).Value
        Cells(b_EV, 23).Select
        Selection.Font.Bold = True

    Next b_EV

    'the demand of the max. demand month
Dim EV_Max_D_M_D As Variant                      'J4

        'XLOOKUP =(lookup value, lookup array, return array)
        Cells(4, 10).Value = "=XLOOKUP($I$4,$N$3:$N$14,$W$3:$W$14)"
        EV_Max_D_M_D = Cells(4, 10).Value
        Cells(4, 10).Select
        Selection.Font.Bold = True

    'EachDay means ex., each Monday in a month
Dim EV_DemandEachDay As Variant                  'L28 to L34
    'N means number. ex., number of Mondays in a month
Dim EV_EachDayN_Month As Integer                 'M28 to M34
    'DemandEachDay_Month means ex., all Mondays demand of a month
Dim EV_DemandEachDay_Month As Variant            'N28 to N34
Dim Total_EV_DemandEachDay_Month As Variant      'N35

    Dim c_EV As Integer
    For c_EV = 28 To 34

        EV_DemandEachDay = Cells(c_EV, 12).Value
        EV_EachDayN_Month = Cells(c_EV, 13).Value
        EV_DemandEachDay_Month = EV_DemandEachDay * EV_EachDayN_Month
        Cells(c_EV, 14).Value = EV_DemandEachDay_Month
        Cells(c_EV, 14).Select
        Selection.Font.Bold = True

    Next c_EV

        Cells(35, 14).Value = "=SUM(N28:N34)"
        Total_EV_DemandEachDay_Month = Cells(35, 14).Value
        Cells(35, 14).Select
        Selection.Font.Bold = True

    'EachDay_Percentage means ex., all Mondays demand percentage of a month
Dim EV_EachDay_Percentage As Variant             'O28 to O34
    'D means demand, M means month,OneEachDay means ex., one Monday, one Tuesday, etc.
Dim Max_D_M_OneEachDay_D As Variant              'P28 to P34
```

```
    For c_EV = 28 To 34

        EV_DemandEachDay_Month = Cells(c_EV, 14).Value
        Cells(c_EV, 15).Value = EV_DemandEachDay_Month / Total_EV_DemandEachDay_Month
        EV_EachDay_Percentage = Cells(c_EV, 15).Value
        Cells(c_EV, 15).Select
        Selection.Font.Bold = True

        EV_EachDayN_Month = Cells(c_EV, 13).Value
        Cells(c_EV, 16).Value = EV_Max_D_M_D * EV_EachDay_Percentage / EV_EachDayN_Month
        Max_D_M_OneEachDay_D = Cells(c_EV, 16).Value
        Cells(c_EV, 16).Select
        Selection.Font.Bold = True

    Next c_EV

    'D means demand, M means month. One week demand in the max. demand month
Dim EV_Max_D_M_Weekly As Variant            'X18

        Cells(18, 24).Value = "=SUM(P28:P34)/1000"
        EV_Max_D_M_Weekly = Cells(18, 24).Value
        Cells(18, 24).Select
        Selection.Font.Bold = True

    'Ratio_toMatchUser means using database and input value of users to find ratio
Dim EV_Ratio_toMatchUser As Variant          'R28

        Cells(28, 18).Value = EV_Max_D_M_D / Total_EV_DemandEachDay_Month
        EV_Ratio_toMatchUser = Cells(28, 18).Value
        Cells(28, 18).Select
        Selection.Font.Bold = True

    'Dprofile means demand profile
Dim EV_Hourly_Dprofile_Database As Variant         'U28 to U99
Dim EV_Hourly_Dprofile_User As Variant             'V28 to V99

    Dim d_EV As Integer
    For d_EV = 28 To 99

        EV_Hourly_Dprofile_Database = Cells(d_EV, 21).Value
        Cells(d_EV, 22).Value = EV_Hourly_Dprofile_Database * EV_Ratio_toMatchUser
        EV_Hourly_Dprofile_User = Cells(d_EV, 22).Value
        Cells(d_EV, 22).Select
        Selection.Font.Bold = True

    Next d_EV

    'Smart means smart charging
Dim EV_Smart_Percentage As Variant            'W27
Dim EV_Dprofile_User_Smart As Variant          'W45 to W50
Dim Smart_SumV45V50 As Variant          'for EV smart charging calculation
Dim Smart_SumV69V74 As Variant          'for EV smart charging calculation

        EV_Smart_Percentage = Cells(27, 23).Value
```

```
Dim e_EV As Integer
For e_EV = 45 To 50

   EV_Hourly_Dprofile_User = Cells(e_EV, 22).Value
   Cells(e_EV, 23).Value = EV_Hourly_Dprofile_User * (1 - EV_Smart_Percentage)
   EV_Dprofile_User_Smart = Cells(e_EV, 23).Value
   Cells(e_EV, 23).Select
   Selection.Font.Bold = True

Next e_EV


   Smart_SumV45V50 = Application.WorksheetFunction.Sum(Range("V45:V50"))

   If EV_Smart_Percentage <= 0.5 Then
      Cells(51, 23).Value = Smart_SumV45V50 * EV_Smart_Percentage / 8 _
      + Cells(51, 22).Value
      'divided by 8 because of sharing to 8 hours.
      'Cells(51, 22).Value is the original demand
   Else: Cells(51, 23).Value = Cells(51, 22).Value
   End If
      Cells(51, 23).Select
      Selection.Font.Bold = True


Dim f_EV As Integer
For f_EV = 52 To 58

   If EV_Smart_Percentage <= 0.5 Then
      Cells(f_EV, 23).Value = Smart_SumV45V50 * EV_Smart_Percentage / 8 _
      + Cells(f_EV, 22).Value
   Else: Cells(f_EV, 23).Value = Smart_SumV45V50 * EV_Smart_Percentage / 7 _
      + Cells(f_EV, 22).Value
   End If
      Cells(f_EV, 23).Select
      Selection.Font.Bold = True

Next f_EV


Dim g_EV As Integer
For g_EV = 59 To 68

   Cells(g_EV, 23).Value = Cells(g_EV, 22).Value
   Cells(g_EV, 23).Select
   Selection.Font.Bold = True

Next g_EV


Dim h_EV As Integer
For h_EV = 69 To 74

   Cells(h_EV, 23).Value = Cells(h_EV, 22).Value * (1 - EV_Smart_Percentage)
   Cells(h_EV, 23).Select
   Selection.Font.Bold = True
```

```
   Next h_EV


     Smart_SumV69V74 = Application.WorksheetFunction.Sum(Range("V69:V74"))

     If EV_Smart_Percentage <= 0.5 Then
        Cells(75, 23).Value = Smart_SumV69V74 * EV_Smart_Percentage / 8 _
        + Cells(75, 22).Value
        'divided by 8 because of sharing to 8 hours.
        'Cells(75, 22).Value is the original demand
     Else: Cells(75, 23).Value = Cells(75, 22).Value
     End If
        Cells(75, 23).Select
        Selection.Font.Bold = True


   Dim i_EV As Integer
   For i_EV = 76 To 82

     If EV_Smart_Percentage <= 0.5 Then
        Cells(i_EV, 23).Value = Smart_SumV69V74 * EV_Smart_Percentage / 8 _
        + Cells(i_EV, 22).Value
     Else: Cells(i_EV, 23).Value = Smart_SumV69V74 * EV_Smart_Percentage / 7 _
        + Cells(i_EV, 22).Value
     End If
        Cells(i_EV, 23).Select
        Selection.Font.Bold = True

   Next i_EV

   Dim EV_Number As Integer                    'Z27
     'N means number. With EV number.
   Dim EV_Hourly_Dprofile_User_N As Variant          'Y45 to Y82
   Dim EV_Dprofile_User_Smart_N As Variant           'Z45 to Z82

        EV_Number = Cells(27, 26).Value

     Dim j_EV As Integer
     For j_EV = 45 To 82

        Cells(j_EV, 25).Value = Cells(j_EV, 22).Value * EV_Number / Unit_Change
        EV_Hourly_Dprofile_User_N = Cells(j_EV, 25).Value
        Cells(j_EV, 25).Select
        Selection.Font.Bold = True

        Cells(j_EV, 26).Value = Cells(j_EV, 23).Value * EV_Number / Unit_Change
        EV_Dprofile_User_Smart_N = Cells(j_EV, 26).Value
        Cells(j_EV, 26).Select
        Selection.Font.Bold = True

     Next j_EV
End Sub

Public Sub Edemand_Electricity()
```

```
Sheets("E3_elec").Select

'per household
  'Res means residential, Ele means basic electricity demand
  'monthly electricity demand in each month
Dim Res_MonthlyEle_EachM As Variant                'I6 to I17
Dim Unit_Change As Integer                         '1000

    Unit_Change = 1000

  Dim a_EL As Integer
  For a_EL = 6 To 17

    Res_MonthlyEle_EachM = Cells(a_EL, 8).Value * Unit_Change * Unit_Change
    Cells(a_EL, 9).Value = Res_MonthlyEle_EachM
    Cells(a_EL, 9).Select
    Selection.Font.Bold = True


  'N means number. Household number in a nation
Dim HouseholdN_Nation As Variant                   'J6
  'M means month. Residential monthly electricity demand per household
Dim Res_M_Ele_PerHouse As Variant                  'I6 to I17

    HouseholdN_Nation = Cells(6, 10).Value

    Res_M_Ele_PerHouse = Res_MonthlyEle_EachM / HouseholdN_Nation
    Cells(a_EL, 11).Value = Res_M_Ele_PerHouse
    Cells(a_EL, 11).Select
    Selection.Font.Bold = True

  Next a_EL

  'EL means basic electricity demand, D means demand
Dim EL_AnnualD_MWh As Variant                      'K18

    Cells(18, 11).Value = "=SUM(K6:K17)"
    EL_AnnualD_MWh = Cells(18, 11).Value
    Cells(18, 11).Select
    Selection.Font.Bold = True

  'EL means basic electricity demand, M means month, D means demand
Dim EL_EachM_D_Ratio As Variant                    'P6 to P17

  Dim b_EL As Integer
  For b_EL = 6 To 17

    'times 100 to be 100%
    Cells(b_EL, 16).Value = Cells(b_EL, 11).Value / EL_AnnualD_MWh * 100
    EL_EachM_D_Ratio = Cells(b_EL, 16).Value
    Cells(b_EL, 16).Select
    Selection.Font.Bold = True

  'M means month, D means demand.
  'Using ratio(demand percentage) and input annual demand to obtain each month demand
Dim EL_EachM_D_MatchUser As Variant                'Q6 to Q17
```

```
Dim EL_AnnualD_MatchUser As Variant              'Q5

      EL_AnnualD_MatchUser = Cells(5, 17).Value

      'divided by 100 due to percentage
      EL_EachM_D_MatchUser = EL_AnnualD_MatchUser * EL_EachM_D_Ratio / 100
      Cells(b_EL, 17) = EL_EachM_D_MatchUser
      Cells(b_EL, 17).Select
      Selection.Font.Bold = True

Dim EL_EachM_D_MatchUser_kWh As Variant          'R6 to R17

      Cells(b_EL, 18).Value = EL_EachM_D_MatchUser * Unit_Change
      EL_EachM_D_MatchUser_kWh = Cells(b_EL, 18).Value
      Cells(b_EL, 18).Select
      Selection.Font.Bold = True

   Next b_EL

'the demand of the max. demand month
Dim EL_Max_D_M_D As Variant                      'C7

      'XLOOKUP =(lookup value, lookup array, return array)
      Cells(7, 3).Value = "=XLOOKUP($B$7,$G$6:$G$17,$R$6:$R$17)"
      EL_Max_D_M_D = Cells(7, 3).Value
      Cells(7, 3).Select
      Selection.Font.Bold = True

'EachDay means ex., each Monday in a month
Dim EL_DemandEachDay As Variant                  'L29 to L35
   'N means number. ex., number of Mondays in a month
Dim EL_EachDayN_Month As Integer                 'M29 to M35
   'DemandEachDay_Month means ex., all Mondays demand of a month
Dim EL_DemandEachDay_Month As Variant            'N29 to N35
Dim Total_EL_DemandEachDay_Month As Variant      'N36

   Dim c_EL As Integer
   For c_EL = 29 To 35

      EL_DemandEachDay = Cells(c_EL, 12).Value
      EL_EachDayN_Month = Cells(c_EL, 13).Value
      EL_DemandEachDay_Month = EL_DemandEachDay * EL_EachDayN_Month
      Cells(c_EL, 14).Value = EL_DemandEachDay_Month
      Cells(c_EL, 14).Select
      Selection.Font.Bold = True

   Next c_EL

      Cells(36, 14).Value = "=SUM(N29:N35)"
      Total_EL_DemandEachDay_Month = Cells(36, 14).Value
      Cells(36, 14).Select
      Selection.Font.Bold = True

   'EachDay_Percentage means ex., all Mondays demand percentage of a month
Dim EL_EachDay_Percentage As Variant             'O29 to O35
   'D means demand, M means month,OneEachDay means ex., one Monday, one Tuesday, etc.
```

```
Dim EL_Max_D_M_OneEachDay_D As Variant         'P29 to P35

  For c_EL = 29 To 35

    EL_DemandEachDay_Month = Cells(c_EL, 14).Value
    Cells(c_EL, 15).Value = EL_DemandEachDay_Month / Total_EL_DemandEachDay_Month
    EL_EachDay_Percentage = Cells(c_EL, 15).Value
    Cells(c_EL, 15).Select
    Selection.Font.Bold = True

    EL_EachDayN_Month = Cells(c_EL, 13).Value
    Cells(c_EL, 16).Value = EL_Max_D_M_D * EL_EachDay_Percentage / EL_EachDayN_Month
    EL_Max_D_M_OneEachDay_D = Cells(c_EL, 16).Value
    Cells(c_EL, 16).Select
    Selection.Font.Bold = True

  Next c_EL

  'D means demand, M means month. One week demand in the max. demand month
Dim EL_Max_D_M_Weekly As Variant           'S21

    Cells(21, 19).Value = "=SUM(P29:P35)/1000"
    EL_Max_D_M_Weekly = Cells(21, 19).Value
    Cells(21, 19).Select
    Selection.Font.Bold = True

  'Ratio_toMatchUser means using database and input value of users to find ratio
Dim EL_Ratio_toMatchUser As Variant         'R29

    Cells(29, 18).Value = EL_Max_D_M_D / Total_EL_DemandEachDay_Month
    EL_Ratio_toMatchUser = Cells(29, 18).Value
    Cells(29, 18).Select
    Selection.Font.Bold = True

  'Dprofile means demand profile
Dim EL_Hourly_Dprofile_Database As Variant         'U29 to U52
Dim EL_Hourly_Dprofile_User As Variant            'V29 to V52

  Dim d_EL As Integer
  For d_EL = 29 To 52

    EL_Hourly_Dprofile_Database = Cells(d_EL, 21).Value
    Cells(d_EL, 22).Value = EL_Hourly_Dprofile_Database * EL_Ratio_toMatchUser
    EL_Hourly_Dprofile_User = Cells(d_EL, 22).Value
    Cells(d_EL, 22).Select
    Selection.Font.Bold = True

Dim HouseholdN As Integer                     'X27
  'N means number. With household number in a community.
Dim EL_Hourly_Dprofile_User_N As Variant         'X29 to X52

    HouseholdN = Cells(27, 24).Value
    Cells(d_EL, 24).Value = EL_Hourly_Dprofile_User * HouseholdN / Unit_Change
    EL_Hourly_Dprofile_User_N = Cells(d_EL, 24).Value
    Cells(d_EL, 24).Select
    Selection.Font.Bold = True
```

```
   Next d_EL

End Sub

Public Sub ThermalEfficiency_Improvement()

Sheets("Demand Setting").Select

'Find required improvement percentage

   'targeted max. power on LV substation, set by user
   'M means maximum
Dim Target_MPower As Variant                'D8
   'P means power
Dim EL_ColdestWeek_P As Variant             'D60
Dim EV_ColdestWeek_P As Variant             'D61
Dim DHW_ColdestWeek_P As Variant            'D62
Dim SH_ColdestWeek_P As Variant             'D63
Dim DHW_SH_ColdestWeek_P As Variant         'D64
Dim HeatLoss_ColdestWeek_P As Variant       'D65

      Target_MPower = Cells(8, 4).Value
   'D9 is household number, set by user
      Cells(60, 4).Value = "=D9*E3_elec!S21/168"
      EL_ColdestWeek_P = Cells(60, 4).Value
      Cells(60, 4).Select
      Selection.Font.Bold = True

   'D10 is EV number, set by user
      Cells(61, 4).Value = "=D10*E2_EVs!X18/168"
      EV_ColdestWeek_P = Cells(61, 4).Value
      Cells(61, 4).Select
      Selection.Font.Bold = True

      Cells(62, 4).Value = "='H2_T sele'!AC38"
      DHW_ColdestWeek_P = Cells(62, 4).Value
      Cells(62, 4).Select
      Selection.Font.Bold = True

      Cells(63, 4).Value = "='H2_T sele'!AD38"
      SH_ColdestWeek_P = Cells(63, 4).Value
      Cells(63, 4).Select
      Selection.Font.Bold = True

      Cells(64, 4).Value = Target_MPower - EL_ColdestWeek_P _
      - EV_ColdestWeek_P
      DHW_SH_ColdestWeek_P = Cells(64, 4).Value
      Cells(64, 4).Select
      Selection.Font.Bold = True

      Cells(65, 4).Value = "='H2_T sele'!AE38"
      HeatLoss_ColdestWeek_P = Cells(65, 4).Value
      Cells(65, 4).Select
      Selection.Font.Bold = True
```

```
   'ImproPcent means improved percentage
Dim Opt3_ImproPcent As Variant            'D123

   If (1 - (Target_MPower - EL_ColdestWeek_P - EV_ColdestWeek_P _
   - DHW_ColdestWeek_P - HeatLoss_ColdestWeek_P) / SH_ColdestWeek_P) > 1 Then
      Cells(123, 4).Value = 1
   Else: Cells(123, 4).Value = (1 - (Target_MPower - EL_ColdestWeek_P - _
   EV_ColdestWeek_P - DHW_ColdestWeek_P - HeatLoss_ColdestWeek_P) / SH_ColdestWeek_P)
   End If
      Opt3_ImproPcent = Cells(123, 4).Value
      Cells(123, 4).Select
      Selection.Font.Bold = True

   'ImproPcent means improved percentage
   'Opt4 set by user
Dim Opt4_ImproPcent As Variant             'D149
Dim Opt4_PlanToImproPcent As Variant        'D17

      Opt4_PlanToImproPcent = Cells(17, 4).Value
   'divided by 100 to obtain percentage
      Cells(149, 4).Value = Opt4_PlanToImproPcent / 100
      Opt4_ImproPcent = Cells(149, 4).Value
      Cells(149, 4).Select
      Selection.Font.Bold = True

      Cells(26, 4).Select

Sheets("Efficiency impro").Select

      'Opt3 required thermal efficiency improvement level
   Range("E8").Value = Opt3_ImproPcent
      Range("E8").Select
      Selection.Font.Bold = True
   Range("E9").Value = Opt4_ImproPcent
      Range("E9").Select
      Selection.Font.Bold = True

End Sub

Public Sub HeatingGrid_Opt3()

  Sheets("H1_para").Select

'Opt3 demand
      'RedPercentage means reduced percentage
   Dim SH_RedPercentage As Variant              'R35
      'D means demand, ARed means after reduction
   Dim SH_D_AReduced As Variant                'R36 to R47

         Cells(35, 18).Value = "='Demand Setting'!D123"
         SH_RedPercentage = Cells(35, 18).Value

      For c = 36 To 47

         'HD_SH = Cells(c, 7).Value
         Cells(c, 18).Value = Cells(c, 7).Value * (1 - SH_RedPercentage)
```

```
      SH_D_AReduced = Cells(c, 18).Value
      Cells(c, 18).Select
      Selection.Font.Bold = True

    Next c

    Range("R48").Value = "=SUM(R36:R47)"
    Range("R48").Select
    Selection.Font.Bold = True

  Sheets("H2_T sele").Select

'Pipe
  'PiHeatLoss_TempDiff
  Dim DistriT As Variant      'AJ6
  Dim ReturnT As Variant      'E29
  Dim SoilT As Variant        'AJ7
  Dim TempDiff As Variant     'AJ8

    Cells(6, 36).Value = Cells(26, 5).Value
    Cells(6, 37).Value = Cells(26, 6).Value
    Cells(6, 38).Value = Cells(26, 7).Value
    Cells(6, 39).Value = Cells(26, 8).Value
    Cells(6, 40).Value = Cells(26, 9).Value
    Cells(6, 41).Value = Cells(26, 10).Value

  Dim x As Integer
  For x = 36 To 41

    DistriT = Cells(6, x).Value
    ReturnT = Cells(29, 5).Value

    Cells(7, x).Value = Cells(36, 5).Value
    SoilT = Cells(7, x).Value

    Cells(8, x).Value = (DistriT + ReturnT) / 2 - SoilT
    TempDiff = Cells(8, x).Value

    Cells(8, x).Select
    Selection.Font.Bold = True

  'PiBranch_U
    'B means branch
  Dim PiB_LowFlowT As Variant       'B8
  Dim PiB_ReturnT As Variant        'B9
    'Bu means a building
  Dim Bu_HeatFlow As Variant        'B6
  Dim WaterCp As Variant            'B7
  Dim WaterDen As Variant           'B10
  Dim PiB_FlowRate As Variant       'B5
  Dim PiB_Uvalue As Variant         'AJ10

    PiB_LowFlowT = Cells(8, 2).Value
    PiB_ReturnT = Cells(9, 2).Value
    Bu_HeatFlow = Cells(6, 2).Value
    WaterCp = Cells(7, 2).Value
```

```
    WaterDen = Cells(10, 2).Value

    Cells(5, 2).Value = Bu_HeatFlow / (WaterCp * (PiB_LowFlowT - PiB_ReturnT) * WaterDen)
    PiB_FlowRate = Cells(5, 2).Value

    'column E is flow rate, column G is U value
    Select Case Cells(5, 2).Value
        Case Is <= Cells(6, 5).Value
            PiB_Uvalue = Cells(6, 7).Value
        Case Is <= Cells(7, 5).Value
            PiB_Uvalue = Cells(7, 7).Value
        Case Is <= Cells(8, 5).Value
            PiB_Uvalue = Cells(8, 7).Value
        Case Is <= Cells(9, 5).Value
            PiB_Uvalue = Cells(9, 7).Value
        Case Is <= Cells(11, 5).Value
            PiB_Uvalue = Cells(11, 7).Value
        Case Is <= Cells(12, 5).Value
            PiB_Uvalue = Cells(12, 7).Value
    End Select

    Cells(10, 9).Value = PiB_Uvalue
    Cells(10, x).Value = Cells(10, 9).Value
    Cells(10, x).Select
    Selection.Font.Bold = True

'PiMain_U
    'M means Main
Dim PiM_Uvalue As Variant          'AJ12

    'distribution pipes: column E is flow rate, column G is U value
    'household number*flow rate
    'if pipe flow rate exceeds the max. pipe condition, then use the max. pipe
    Select Case Cells(5, x).Value * Cells(5, 2).Value
        Case Is <= Cells(6, 5).Value
            PiM_Uvalue = Cells(6, 7).Value
        Case Is <= Cells(7, 5).Value
            PiM_Uvalue = Cells(7, 7).Value
        Case Is <= Cells(8, 5).Value
            PiM_Uvalue = Cells(8, 7).Value
        Case Is <= Cells(9, 5).Value
            PiM_Uvalue = Cells(9, 7).Value
        Case Is <= Cells(11, 5).Value
            PiM_Uvalue = Cells(11, 7).Value
        Case Is <= Cells(12, 5).Value
            PiM_Uvalue = Cells(12, 7).Value
        Case Is <= Cells(14, 5).Value
            PiM_Uvalue = Cells(14, 7).Value
        Case Is <= Cells(15, 5).Value
            PiM_Uvalue = Cells(15, 7).Value
        Case Is <= Cells(16, 5).Value
            PiM_Uvalue = Cells(16, 7).Value
        Case Is > Cells(16, 5).Value
            PiM_Uvalue = Cells(16, 7).Value
    End Select
```

```
    Cells(12, x).Value = PiM_Uvalue
    Cells(12, x).Select
    Selection.Font.Bold = True

'PiNumber
    'N means number
Dim HouseholdN As Variant          'AJ5
Dim PiB_Number As Variant          'AJ13
Dim PiM_Number As Variant          'AJ14

    Cells(5, x).Value = Cells(44, 16).Value
    HouseholdN = Cells(5, x).Value
    'branch pipe number equals to household number
    Cells(13, x).Value = HouseholdN
    PiB_Number = Cells(13, x).Value

    'main pipe number equals to household number divided by 2
    Cells(14, x).Value = WorksheetFunction.RoundUp(HouseholdN / 2, 0)
    PiM_Number = Cells(14, x).Value

    Cells(13, x).Select
    Selection.Font.Bold = True
    Cells(14, x).Select
    Selection.Font.Bold = True

'PiHeatLoss
Dim TwinPiMax As Variant                 'E12
Dim PiB_Length As Variant                'AJ9
Dim PiM_Length As Variant                'AJ11
Dim Oper_Hours As Variant                'AJ15
'StoB means small unit to big unit
Dim Unit_StoB As Variant                 'AJ16
Dim PiHeatLoss_annual As Variant         'AJ18

    PiB_FlowRate = Cells(5, 2).Value
    TwinPiMax = Cells(12, 5).Value
    Cells(9, x).Value = Cells(33, 5).Value
    PiB_Length = Cells(9, x).Value
    Cells(11, x).Value = Cells(34, 5).Value
    PiM_Length = Cells(11, x).Value
    Cells(15, x).Value = 8760
    Oper_Hours = Cells(15, x).Value
    Cells(16, x).Value = 1000
    Unit_StoB = Cells(16, x).Value

    'household number*flow rate
    If HouseholdN * PiB_FlowRate <= TwinPiMax Then
    PiHeatLoss_annual = ((PiB_Uvalue * TempDiff * PiB_Length * PiB_Number) _
    + (PiM_Uvalue * TempDiff * PiM_Length * PiM_Number)) * Oper_Hours / Unit_StoB
    Else: PiHeatLoss_annual = 2 * ((PiB_Uvalue * TempDiff * PiB_Length * PiB_Number) _
    + (PiM_Uvalue * TempDiff * PiM_Length * PiM_Number)) * Oper_Hours / Unit_StoB
    End If

    Cells(18, x).Value = PiHeatLoss_annual
    Cells(18, x).Select
    Selection.Font.Bold = True
```

```
'DHW
  'DHW_Energy_Heater
  Dim TankT As Variant                    'E28
  Dim TankWeight_kg As Variant            'AJ3
  Dim DHW_Energy_Heater As Variant        'AJ21

    TankT = Cells(28, 5).Value

    Cells(3, x).Value = Cells(46, 16).Value
    TankWeight_kg = Cells(3, x).Value

    'Temp. after HIU, y=0.9659x-0.5982, x: distribution T
    If DistriT <= TankT Then
    DHW_Energy_Heater = (TankT - (0.9659 * DistriT - 0.5982)) _
                * WaterCp * TankWeight_kg / 3600 * HouseholdN
    Else: DHW_Energy_Heater = 0
    End If
    Cells(21, x).Value = DHW_Energy_Heater
    Cells(21, x).Select
    Selection.Font.Bold = True

  'DHW_Energy_LTDH
    'perH means per household
  Dim DHW_Energy_perH As Variant          'AJ2
  Dim DHW_Energy_LTDH As Variant          'AJ22

    Cells(2, x).Value = Cells(42, 16).Value
    DHW_Energy_perH = Cells(2, x).Value

    DHW_Energy_LTDH = DHW_Energy_perH * HouseholdN - DHW_Energy_Heater
    Cells(22, x).Value = DHW_Energy_LTDH
    Cells(22, x).Select
    Selection.Font.Bold = True

  'HIU efficiency
    'Eff means efficiency
  Dim DHW_HIU_Eff As Variant      'AJ24

    'HIU, y= -0.016x + 92.673, x:distribution T
    DHW_HIU_Eff = -0.016 * DistriT + 92.673
    Cells(24, x).Value = DHW_HIU_Eff
    Cells(24, x).Select
    Selection.Font.Bold = True

  'DHW_Energy_LTDH_HIU_Eff
  Dim DHW_Energy_LTDH_HIU_Eff As Variant          'AJ25

    DHW_Energy_LTDH_HIU_Eff = DHW_Energy_LTDH / (DHW_HIU_Eff / 100)
    Cells(25, x).Value = DHW_Energy_LTDH_HIU_Eff
    Cells(25, x).Select
    Selection.Font.Bold = True

'SH
  'SH_Energy_LTDH
  Dim SH_Energy_perH As Variant       'AJ4
```

```
    Dim SH_Energy_LTDH As Variant      'AJ28

        Cells(4, x).Value = Cells(41, 38).Value
        SH_Energy_perH = Cells(4, x).Value

        SH_Energy_LTDH = SH_Energy_perH * HouseholdN
        Cells(28, x).Value = SH_Energy_LTDH
        Cells(28, x).Select
        Selection.Font.Bold = True

    'HIU efficiency
        'Eff means efficiency
    Dim SH_HIU_Eff As Variant      'AJ30

        'HIU, y= -0.016x + 92.673, x:distribution T
        SH_HIU_Eff = -0.016 * DistriT + 92.673
        Cells(30, x).Value = SH_HIU_Eff
        Cells(30, x).Select
        Selection.Font.Bold = True

    'SH_Energy_LTDH_HIU_Eff
    Dim SH_Energy_LTDH_HIU_Eff As Variant      'AJ31

        SH_Energy_LTDH_HIU_Eff = SH_Energy_LTDH / (SH_HIU_Eff / 100)
        Cells(31, x).Value = SH_Energy_LTDH_HIU_Eff
        Cells(31, x).Select
        Selection.Font.Bold = True

'Electricity demand
    'COP of a GSHP
    Dim COP_GSHP As Variant              'AJ33

        'y=60.499*(x ^ (-0.695)), x:distribution T
        COP_GSHP = 60.499 * (DistriT ^ (-0.695))
        Cells(33, x).Value = COP_GSHP
        Cells(33, x).Select
        Selection.Font.Bold = True

    'Electricity demand of a GSHP
        'Edemand means electricity demand
    Dim Edemand_GSHP As Variant            'AJ35

        Edemand_GSHP = (DHW_Energy_LTDH_HIU_Eff + SH_Energy_LTDH_HIU_Eff _
                + PiHeatLoss_annual) / COP_GSHP
        Cells(35, x).Value = Edemand_GSHP
        Cells(35, x).Select
        Selection.Font.Bold = True

    'Total electricity (electric heater + GSHP)
    Dim Edemand_Heater_GSHP_kW As Variant    'AJ36
    Dim Edemand_Heater_GSHP_MW As Variant    'AJ37

        Edemand_Heater_GSHP_kW = DHW_Energy_Heater + Edemand_GSHP
        Cells(36, x).Value = Edemand_Heater_GSHP_kW
        Cells(36, x).Select
        Selection.Font.Bold = True
```

```
      Edemand_Heater_GSHP_MW = Edemand_Heater_GSHP_kW / Unit_StoB
      Cells(37, x).Value = Edemand_Heater_GSHP_MW
      Cells(37, x).Select
      Selection.Font.Bold = True

   Next x

'Select the optimum temperature; the lowest electricity demand temperature
   Dim OptimumT As Variant                    'U46
   Dim OptimumT_Edemand_Heater As Variant         'U48
   Dim OptimumT_Edemand_GSHP As Variant          'U49
   Dim OptimumT_Edemand_Heater_GSHP As Variant    'U50

   'The optimum temp.
      'Applying XLookUp function, XLOOKUP(lookup_value,lookup_array,return_array)
      OptimumT = "=XLOOKUP(MIN(AJ37: AO37),AJ37 :AO37,AJ6:AO6)"
      Cells(46, 38).Value = OptimumT
      Cells(46, 38).Select
      Selection.Font.Bold = True

   'The electricity demand of electric heater of the optimum temp.
      'U46 is the OptimumT, row 6 contains distribution temperature conditions
      OptimumT_Edemand_Heater = "=XLOOKUP(AL46,AJ6:AO6,AJ21:AO21)" & "/1000"
      Cells(48, 38).Value = OptimumT_Edemand_Heater
      Cells(48, 38).Select
      Selection.Font.Bold = True

   'The electricity demand of GSHP of the optimum temp.
      'U46 is the OptimumT, row 6 contains distribution temperature conditions
      OptimumT_Edemand_GSHP = "=XLOOKUP(AL46,AJ6:AO6,AJ35:AO35)" & "/1000"
      Cells(49, 38).Value = OptimumT_Edemand_GSHP
      Cells(49, 38).Select
      Selection.Font.Bold = True

   'The electricity demand of electric heater and GSHP of the optimum temp.
      OptimumT_Edemand_Heater_GSHP = Cells(48, 38).Value + Cells(49, 38).Value
      Cells(50, 38).Value = OptimumT_Edemand_Heater_GSHP
      Cells(50, 38).Select
      Selection.Font.Bold = True

End Sub

Public Sub HeatingGrid_Opt4()

   Sheets("H1_para").Select
'Opt4
      'RedPercentage means reduced percentage
   Dim Opt4_SH_RedPercentage As Variant           'AA35
      'D means demand, ARed means after reduction
   Dim Opt4_SH_D_AReduced As Variant              'AA36 to AA47

         Opt4_SH_RedPercentage = Cells(35, 27).Value

      For c = 36 To 47
```

```
        'HD_SH = Cells(c, 7).Value
        Cells(c, 27).Value = Cells(c, 7).Value * (1 - Opt4_SH_RedPercentage)
        Opt4_SH_D_AReduced = Cells(c, 27).Value
        Cells(c, 27).Select
        Selection.Font.Bold = True

      Next c

      Range("AA48").Value = "=SUM(AA36:AA47)"
      Range("AA48").Select
      Selection.Font.Bold = True

  Sheets("H2_T sele").Select

'Pipe
  'PiHeatLoss_TempDiff
  Dim DistriT As Variant       'AU6
  Dim ReturnT As Variant       'E29
  Dim SoilT As Variant         'AU7
  Dim TempDiff As Variant      'AU8

      Cells(6, 47).Value = Cells(26, 5).Value
      Cells(6, 48).Value = Cells(26, 6).Value
      Cells(6, 49).Value = Cells(26, 7).Value
      Cells(6, 50).Value = Cells(26, 8).Value
      Cells(6, 51).Value = Cells(26, 9).Value
      Cells(6, 52).Value = Cells(26, 10).Value

  Dim x As Integer
  For x = 47 To 52

      DistriT = Cells(6, x).Value
      ReturnT = Cells(29, 5).Value
      Cells(7, x).Value = Cells(36, 5).Value
      SoilT = Cells(7, x).Value
      Cells(8, x).Value = (DistriT + ReturnT) / 2 - SoilT
      TempDiff = Cells(8, x).Value
      Cells(8, x).Select
      Selection.Font.Bold = True

  'PiBranch_U
      'B means branch
  Dim PiB_LowFlowT As Variant        'B8
  Dim PiB_ReturnT As Variant         'B9
      'Bu means a building
  Dim Bu_HeatFlow As Variant         'B6
  Dim WaterCp As Variant             'B7
  Dim WaterDen As Variant            'B10
  Dim PiB_FlowRate As Variant        'B5
  Dim PiB_Uvalue As Variant          'AU10

      PiB_LowFlowT = Cells(8, 2).Value
      PiB_ReturnT = Cells(9, 2).Value
      Bu_HeatFlow = Cells(6, 2).Value
      WaterCp = Cells(7, 2).Value
      WaterDen = Cells(10, 2).Value
```

```
    Cells(5, 2).Value = Bu_HeatFlow / (WaterCp * (PiB_LowFlowT - PiB_ReturnT) * WaterDen)
    PiB_FlowRate = Cells(5, 2).Value

    'column E is flow rate, column G is U value
    Select Case Cells(5, 2).Value
        Case Is <= Cells(6, 5).Value
            PiB_Uvalue = Cells(6, 7).Value
        Case Is <= Cells(7, 5).Value
            PiB_Uvalue = Cells(7, 7).Value
        Case Is <= Cells(8, 5).Value
            PiB_Uvalue = Cells(8, 7).Value
        Case Is <= Cells(9, 5).Value
            PiB_Uvalue = Cells(9, 7).Value
        Case Is <= Cells(11, 5).Value
            PiB_Uvalue = Cells(11, 7).Value
        Case Is <= Cells(12, 5).Value
            PiB_Uvalue = Cells(12, 7).Value
    End Select

    Cells(10, 9).Value = PiB_Uvalue
    Cells(10, x).Value = Cells(10, 9).Value
    Cells(10, x).Select
    Selection.Font.Bold = True

'PiMain_U
    'M means Main
Dim PiM_Uvalue As Variant       'AU12

    'distribution pipes: column E is flow rate, column G is U value
    'household number*flow rate
    'if pipe flow rate exceeds the max. pipe condition, then use the max. pipe
    Select Case Cells(5, x).Value * Cells(5, 2).Value
        Case Is <= Cells(6, 5).Value
            PiM_Uvalue = Cells(6, 7).Value
        Case Is <= Cells(7, 5).Value
            PiM_Uvalue = Cells(7, 7).Value
        Case Is <= Cells(8, 5).Value
            PiM_Uvalue = Cells(8, 7).Value
        Case Is <= Cells(9, 5).Value
            PiM_Uvalue = Cells(9, 7).Value
        Case Is <= Cells(11, 5).Value
            PiM_Uvalue = Cells(11, 7).Value
        Case Is <= Cells(12, 5).Value
            PiM_Uvalue = Cells(12, 7).Value
        Case Is <= Cells(14, 5).Value
            PiM_Uvalue = Cells(14, 7).Value
        Case Is <= Cells(15, 5).Value
            PiM_Uvalue = Cells(15, 7).Value
        Case Is <= Cells(16, 5).Value
            PiM_Uvalue = Cells(16, 7).Value
        Case Is > Cells(16, 5).Value
            PiM_Uvalue = Cells(16, 7).Value
    End Select

    Cells(12, x).Value = PiM_Uvalue
```

```
    Cells(12, x).Select
    Selection.Font.Bold = True

'PiNumber
    'N means number
Dim HouseholdN As Variant        'AU5
Dim PiB_Number As Variant        'AU13
Dim PiM_Number As Variant        'AU14

    Cells(5, x).Value = Cells(44, 16).Value
    HouseholdN = Cells(5, x).Value
    'branch pipe number equals to household number
    Cells(13, x).Value = HouseholdN
    PiB_Number = Cells(13, x).Value

    'main pipe number equals to household number divided by 2
    Cells(14, x).Value = WorksheetFunction.RoundUp(HouseholdN / 2, 0)
    PiM_Number = Cells(14, x).Value

    Cells(13, x).Select
    Selection.Font.Bold = True
    Cells(14, x).Select
    Selection.Font.Bold = True

'PiHeatLoss
Dim TwinPiMax As Variant        'E12
Dim PiB_Length As Variant       'AU9
Dim PiM_Length As Variant       'AU11
Dim Oper_Hours As Variant       'AU15
'StoB means small unit to big unit
Dim Unit_StoB As Variant                'AU16
Dim PiHeatLoss_annual As Variant        'AU18

    PiB_FlowRate = Cells(5, 2).Value
    TwinPiMax = Cells(12, 5).Value
    Cells(9, x).Value = Cells(33, 5).Value
    PiB_Length = Cells(9, x).Value
    Cells(11, x).Value = Cells(34, 5).Value
    PiM_Length = Cells(11, x).Value
    Cells(15, x).Value = 8760
    Oper_Hours = Cells(15, x).Value
    Cells(16, x).Value = 1000
    Unit_StoB = Cells(16, x).Value

    'household number*flow rate
    If HouseholdN * PiB_FlowRate <= TwinPiMax Then
    PiHeatLoss_annual = ((PiB_Uvalue * TempDiff * PiB_Length * PiB_Number) _
    + (PiM_Uvalue * TempDiff * PiM_Length * PiM_Number)) * Oper_Hours / Unit_StoB
    Else: PiHeatLoss_annual = 2 * ((PiB_Uvalue * TempDiff * PiB_Length * PiB_Number) _
    + (PiM_Uvalue * TempDiff * PiM_Length * PiM_Number)) * Oper_Hours / Unit_StoB
    End If

    Cells(18, x).Value = PiHeatLoss_annual
    Cells(18, x).Select
    Selection.Font.Bold = True
```

```
'DHW
  'DHW_Energy_Heater
  Dim TankT As Variant            'E28
  Dim TankWeight_kg As Variant     'AU3
  Dim DHW_Energy_Heater As Variant    'AU21

    TankT = Cells(28, 5).Value
    Cells(3, x).Value = Cells(46, 16).Value
    TankWeight_kg = Cells(3, x).Value

    'Temp. after HIU, y=0.9659x-0.5982, x: distribution T
    If DistriT <= TankT Then
    DHW_Energy_Heater = (TankT - (0.9659 * DistriT - 0.5982)) _
              * WaterCp * TankWeight_kg / 3600 * HouseholdN
    Else: DHW_Energy_Heater = 0
    End If
    Cells(21, x).Value = DHW_Energy_Heater
    Cells(21, x).Select
    Selection.Font.Bold = True

  'DHW_Energy_LTDH
    'perH means per household
  Dim DHW_Energy_perH As Variant     'AU2
  Dim DHW_Energy_LTDH As Variant    'AU22

    Cells(2, x).Value = Cells(42, 16).Value
    DHW_Energy_perH = Cells(2, x).Value

    DHW_Energy_LTDH = DHW_Energy_perH * HouseholdN - DHW_Energy_Heater
    Cells(22, x).Value = DHW_Energy_LTDH
    Cells(22, x).Select
    Selection.Font.Bold = True

  'HIU efficiency
    'Eff means efficiency
  Dim DHW_HIU_Eff As Variant      'AU24

    'HIU, y= -0.016x + 92.673, x:distribution T
    DHW_HIU_Eff = -0.016 * DistriT + 92.673
    Cells(24, x).Value = DHW_HIU_Eff
    Cells(24, x).Select
    Selection.Font.Bold = True

  'DHW_Energy_LTDH_HIU_Eff
  Dim DHW_Energy_LTDH_HIU_Eff As Variant     'AU25

    DHW_Energy_LTDH_HIU_Eff = DHW_Energy_LTDH / (DHW_HIU_Eff / 100)
    Cells(25, x).Value = DHW_Energy_LTDH_HIU_Eff
    Cells(25, x).Select
    Selection.Font.Bold = True

'SH
  'SH_Energy_LTDH
  Dim SH_Energy_perH As Variant     'AU4
  Dim SH_Energy_LTDH As Variant    'AU28
```

```
        Cells(4, x).Value = Cells(41, 49).Value
        SH_Energy_perH = Cells(4, x).Value

        SH_Energy_LTDH = SH_Energy_perH * HouseholdN
        Cells(28, x).Value = SH_Energy_LTDH
        Cells(28, x).Select
        Selection.Font.Bold = True

    'HIU efficiency
        'Eff means efficiency
    Dim SH_HIU_Eff As Variant      'AU30

        'HIU, y= -0.016x + 92.673, x:distribution T
        SH_HIU_Eff = -0.016 * DistriT + 92.673
        Cells(30, x).Value = SH_HIU_Eff
        Cells(30, x).Select
        Selection.Font.Bold = True

    'SH_Energy_LTDH_HIU_Eff
    Dim SH_Energy_LTDH_HIU_Eff As Variant  'AU31

        SH_Energy_LTDH_HIU_Eff = SH_Energy_LTDH / (SH_HIU_Eff / 100)
        Cells(31, x).Value = SH_Energy_LTDH_HIU_Eff
        Cells(31, x).Select
        Selection.Font.Bold = True

'Electricity demand
    'COP of a GSHP
    Dim COP_GSHP As Variant                'AU33

        'y=60.499*(x ^ (-0.695)), x:distribution T
        COP_GSHP = 60.499 * (DistriT ^ (-0.695))
        Cells(33, x).Value = COP_GSHP
        Cells(33, x).Select
        Selection.Font.Bold = True

    'Electricity demand of a GSHP
        'Edemand means electricity demand
    Dim Edemand_GSHP As Variant            'AU35

        Edemand_GSHP = (DHW_Energy_LTDH_HIU_Eff + SH_Energy_LTDH_HIU_Eff _
                + PiHeatLoss_annual) / COP_GSHP
        Cells(35, x).Value = Edemand_GSHP
        Cells(35, x).Select
        Selection.Font.Bold = True

    'Total electricity(electric heater + GSHP)
    Dim Edemand_Heater_GSHP_kW As Variant    'AU36
    Dim Edemand_Heater_GSHP_MW As Variant    'AU37

        Edemand_Heater_GSHP_kW = DHW_Energy_Heater + Edemand_GSHP
        Cells(36, x).Value = Edemand_Heater_GSHP_kW
        Cells(36, x).Select
        Selection.Font.Bold = True

        Edemand_Heater_GSHP_MW = Edemand_Heater_GSHP_kW / Unit_StoB
```

```
        Cells(37, x).Value = Edemand_Heater_GSHP_MW
        Cells(37, x).Select
        Selection.Font.Bold = True

    Next x

'Select the optimum temperature; the lowest electricity demand temperature
    Dim OptimumT As Variant                     'U46
    Dim OptimumT_Edemand_Heater As Variant        'U48
    Dim OptimumT_Edemand_GSHP As Variant          'U49
    Dim OptimumT_Edemand_Heater_GSHP As Variant   'U50

    'The optimum temp.
        'Applying XLookUp function, XLOOKUP(lookup_value,lookup_array,return_array)
        OptimumT = "=XLOOKUP(MIN(AU37: AZ37),AU37 :AZ37,AU6:AZ6)"
        Cells(46, 49).Value = OptimumT
        Cells(46, 49).Select
        Selection.Font.Bold = True

    'The electricity demand of electric heater of the optimum temp.
        'U46 is the OptimumT, row 6 contains distribution temperature conditions
        OptimumT_Edemand_Heater = "=XLOOKUP(AW46,AU6:AZ6,AU21:AZ21)" & "/1000"
        Cells(48, 49).Value = OptimumT_Edemand_Heater
        Cells(48, 49).Select
        Selection.Font.Bold = True

    'The electricity demand of GSHP of the optimum temp.
        'U46 is the OptimumT, row 6 contains distribution temperature conditions
        OptimumT_Edemand_GSHP = "=XLOOKUP(AW46,AU6:AZ6,AU35:AZ35)" & "/1000"
        Cells(49, 49).Value = OptimumT_Edemand_GSHP
        Cells(49, 49).Select
        Selection.Font.Bold = True

    'The electricity demand of electric heater and GSHP of the optimum temp.
        OptimumT_Edemand_Heater_GSHP = Cells(48, 49).Value + Cells(49, 49).Value
        Cells(50, 49).Value = OptimumT_Edemand_Heater_GSHP
        Cells(50, 49).Select
        Selection.Font.Bold = True

End Sub


Public Sub Heating_Parameter()


Sheets("H1_para").Select

'GSHP
    'COP
    'Power trendline y = ax^b
    Dim a As Variant            'M9
    Dim b As Variant            'M10

            Cells(9, 13).Value = "=EXP(INDEX(LINEST(LN(J5:J11),LN(I5:I11),,),1,2))"
            a = Cells(9, 13).Value
            Cells(9, 13).Select
```

```
        Selection.Font.Bold = True

        Cells(10, 13).Value = "=INDEX(LINEST(LN(J5:J11),LN(I5:I11),,),1)"
        b = Cells(10, 13).Value
        Cells(10, 13).Select
        Selection.Font.Bold = True

    Dim GSHP_Opt2_SupplyT As Variant        'N5, J34
    Dim GSHP_Opt2_COP As Variant            'O5
    Dim GSHP_Opt3_SupplyT As Variant        'R5, S34
    Dim GSHP_Opt3_COP As Variant            'S5
    Dim GSHP_Opt4_SupplyT As Variant        'V5, AB34
    Dim GSHP_Opt4_COP As Variant            'W5

        GSHP_Opt2_SupplyT = Cells(5, 14).Value
        GSHP_Opt3_SupplyT = Cells(5, 18).Value
        GSHP_Opt4_SupplyT = Cells(5, 22).Value

        GSHP_Opt2_COP = a * (GSHP_Opt2_SupplyT ^ b)
        Cells(5, 15).Value = GSHP_Opt2_COP
        Cells(5, 15).Select
        Selection.Font.Bold = True

        GSHP_Opt3_COP = a * (GSHP_Opt3_SupplyT ^ b)
        Cells(5, 19).Value = GSHP_Opt3_COP
        Cells(5, 19).Select
        Selection.Font.Bold = True

        GSHP_Opt4_COP = a * (GSHP_Opt4_SupplyT ^ b)
        Cells(5, 23).Value = GSHP_Opt4_COP
        Cells(5, 23).Select
        Selection.Font.Bold = True

'Thermal energy storage
      'HD means heat demand
    Dim HD_DHW As Variant           'F36 to F47
    Dim HD_SH As Variant            'G36 to G47
    Dim HD_Opt2 As Variant          'K36 to K47

      Dim c As Integer
      For c = 36 To 47

        HD_DHW = Cells(c, 6).Value
        HD_SH = Cells(c, 7).Value
        HD_Opt2 = HD_DHW + HD_SH
        Cells(c, 11).Value = HD_Opt2
        Cells(c, 11).Select
        Selection.Font.Bold = True

      Next c

      'D means demand, M means month. Number of days in the Max demand month
    Dim Max_D_M_Days As Integer         'I49, G55
      'D means demand, M means month. Demand in the Max demand month
    Dim Max_D_M_D As Variant            'L49
```

```
        Cells(49, 9).Value = "=XLOOKUP(MAX(K36:K47),K36:K47,H36:H47)"
        Max_D_M_Days = Cells(49, 9).Value
        Cells(49, 9).Select
        Selection.Font.Bold = True

        Cells(49, 12).Value = "=MAX(K36:K47)"
        Max_D_M_D = Cells(49, 12).Value
        Cells(49, 12).Select
        Selection.Font.Bold = True

Dim Max_D_M_Daily As Variant        'M37

        Max_D_M_Daily = Max_D_M_D / Max_D_M_Days
        Cells(37, 13).Value = Max_D_M_Daily
        Cells(37, 13).Select
        Selection.Font.Bold = True

    'ES means energy storage, Vol means volume
Dim Opt2_ES_HalfDay_Vol As Variant        'O37
    'Cap means capacity
Dim Opt2_ES_HalfDay_Cap As Variant        'P37
Dim Unit_Change As Integer              '1000
Dim Unit_Change2 As Integer             '3600
Dim Water_Cp As Variant                 'C39
    'N means number
Dim HouseholdN As Variant               'C36, I54
Dim LTDH_ReturnT As Variant             'C37
    'UtiRate means utilisation rate
Dim ES_UtiRate As Variant               'C38

        Unit_Change = 1000
        Unit_Change2 = 3600
        HouseholdN = Cells(36, 3).Value
        LTDH_ReturnT = Cells(37, 3).Value
        ES_UtiRate = Cells(38, 3).Value
        Water_Cp = Cells(39, 3).Value

        'divided by 2, because half day
        Opt2_ES_HalfDay_Vol = (Max_D_M_Daily * Unit_Change2 / 2) / _
        (Water_Cp * (GSHP_Opt2_SupplyT - LTDH_ReturnT)) / Unit_Change * HouseholdN _
        / ES_UtiRate
        Cells(37, 15).Value = Opt2_ES_HalfDay_Vol
        Cells(37, 15).Select
        Selection.Font.Bold = True

        Opt2_ES_HalfDay_Cap = Opt2_ES_HalfDay_Vol * Unit_Change * Water_Cp * _
        (GSHP_Opt2_SupplyT - LTDH_ReturnT) / Unit_Change2 / Unit_Change
        Cells(37, 16).Value = Opt2_ES_HalfDay_Cap
        Cells(37, 16).Select
        Selection.Font.Bold = True

'Opt3
    'RedPercentage means reduced percentage
Dim SH_RedPercentage As Variant             'R35
    'D means demand, ARed means after reduction
Dim SH_D_AReduced As Variant                'R36 to R47
```

```
Dim HD_Opt3 As Variant                    'T36 to T47

    Cells(35, 18).Value = "='Demand Setting'!D123"
    SH_RedPercentage = Cells(35, 18).Value

  For c = 36 To 47

    'HD_SH = Cells(c, 7).Value
    Cells(c, 18).Value = Cells(c, 7).Value * (1 - SH_RedPercentage)
    SH_D_AReduced = Cells(c, 18).Value
    Cells(c, 18).Select
    Selection.Font.Bold = True

    HD_DHW = Cells(c, 6).Value
    HD_Opt3 = HD_DHW + SH_D_AReduced
    Cells(c, 20).Value = HD_Opt3
    Cells(c, 20).Select
    Selection.Font.Bold = True


  Next c

Dim Opt3_Max_D_M_Daily As Variant          'V37
  'Demand in th max. demand month
Dim Opt3_Max_D_M_D As Variant              'U37

    Cells(37, 21).Value = "=XLOOKUP(E55,E36:E47,T36:T47)"
    Opt3_Max_D_M_D = Cells(37, 21).Value
    Cells(37, 21).Select
    Selection.Font.Bold = True

    Opt3_Max_D_M_Daily = Opt3_Max_D_M_D / Max_D_M_Days
    Cells(37, 22).Value = Opt3_Max_D_M_Daily
    Cells(37, 22).Select
    Selection.Font.Bold = True

'ES means energy storage, Vol means volume
Dim Opt3_ES_HalfDay_Vol As Variant       'X37
  'Cap means capacity
Dim Opt3_ES_HalfDay_Cap As Variant       'Y37

     'divided by 2, because half day
    Opt3_ES_HalfDay_Vol = (Opt3_Max_D_M_Daily * Unit_Change2 / 2) / _
    (Water_Cp * (GSHP_Opt3_SupplyT - LTDH_ReturnT)) / Unit_Change * HouseholdN _
    / ES_UtiRate
    Cells(37, 24).Value = Opt3_ES_HalfDay_Vol
    Cells(37, 24).Select
    Selection.Font.Bold = True

    Opt3_ES_HalfDay_Cap = Opt3_ES_HalfDay_Vol * Unit_Change * Water_Cp * _
    (GSHP_Opt3_SupplyT - LTDH_ReturnT) / Unit_Change2 / Unit_Change
    Cells(37, 25).Value = Opt3_ES_HalfDay_Cap
    Cells(37, 25).Select
    Selection.Font.Bold = True

'Opt4
```

```
  'RedPercentage means reduced percentage
Dim Opt4_SH_RedPercentage As Variant             'AA35
  'D means demand, ARed means after reduction
Dim Opt4_SH_D_AReduced As Variant                'AA36 to AA47
  'HD means heat demand
Dim HD_Opt4 As Variant                           'AC36 to AC47

    Opt4_SH_RedPercentage = Cells(35, 27).Value

  For c = 36 To 47

    HD_SH = Cells(c, 7).Value
    Cells(c, 27).Value = HD_SH * (1 - Opt4_SH_RedPercentage)
    Opt4_SH_D_AReduced = Cells(c, 27).Value
    Cells(c, 27).Select
    Selection.Font.Bold = True

    HD_DHW = Cells(c, 6).Value
    HD_Opt4 = HD_DHW + Opt4_SH_D_AReduced
    Cells(c, 29).Value = HD_Opt4
    Cells(c, 29).Select
    Selection.Font.Bold = True

  Next c

Dim Opt4_Max_D_M_Daily As Variant                'AE37
  'Demand in the max. demand month
Dim Opt4_Max_D_M_D As Variant                    'AD37

    Cells(37, 30).Value = "=XLOOKUP(E55,E36:E47,AC36:AC47)"
    Opt4_Max_D_M_D = Cells(37, 30).Value
    Cells(37, 30).Select
    Selection.Font.Bold = True

    Opt4_Max_D_M_Daily = Opt4_Max_D_M_D / Max_D_M_Days
    Cells(37, 31).Value = Opt4_Max_D_M_Daily
    Cells(37, 31).Select
    Selection.Font.Bold = True

  'ES means energy storage, Vol means volume
Dim Opt4_ES_HalfDay_Vol As Variant       'AG37
  'Cap means capacity
Dim Opt4_ES_HalfDay_Cap As Variant       'AH37

     'divided by 2, because half day
    Opt4_ES_HalfDay_Vol = (Opt4_Max_D_M_Daily * Unit_Change2 / 2) / _
    (Water_Cp * (GSHP_Opt4_SupplyT - LTDH_ReturnT)) / Unit_Change * HouseholdN _
    / ES_UtiRate
    Cells(37, 33).Value = Opt4_ES_HalfDay_Vol
    Cells(37, 33).Select
    Selection.Font.Bold = True

    Opt4_ES_HalfDay_Cap = Opt4_ES_HalfDay_Vol * Unit_Change * Water_Cp * _
    (GSHP_Opt4_SupplyT - LTDH_ReturnT) / Unit_Change2 / Unit_Change
    Cells(37, 34).Value = Opt4_ES_HalfDay_Cap
    Cells(37, 34).Select
```

```
        Selection.Font.Bold = True

'Household tanks
    'D means demand, M means month. The max demand month
  Dim Max_D_M As Variant              'E55
    'the DHW demand of the max demand month
  Dim Max_D_M_DHW As Variant          'F55

        Cells(55, 5).Value = "=XLOOKUP(MAX(K36:K47),K36:K47,E36:E47)"
        Max_D_M = Cells(55, 5).Value
        Cells(55, 5).Select
        Selection.Font.Bold = True

        Cells(55, 6).Value = "=XLOOKUP(MAX(K36:K47),K36:K47,F36:F47)"
        Max_D_M_DHW = Cells(55, 6).Value
        Cells(55, 6).Select
        Selection.Font.Bold = True

    'D means demand. Daily DHW demand per household
  Dim DHW_Daily_D_PerHouse As Variant          'H55
  Dim DHW_Daily_D_Community As Variant          'I55

        Cells(55, 8).Value = Max_D_M_DHW / Max_D_M_Days
        DHW_Daily_D_PerHouse = Cells(55, 8).Value
        Cells(55, 8).Select
        Selection.Font.Bold = True

        Cells(55, 9).Value = DHW_Daily_D_PerHouse * HouseholdN
        DHW_Daily_D_Community = Cells(55, 9).Value
        Cells(55, 9).Select
        Selection.Font.Bold = True

    'Vol means volume
  Dim HouseTank_Vol_kg As Variant          'J58
  Dim HouseTank_Vol_m3 As Variant          'K58
    'UtiRate means utilisation rate
  Dim HouseTank_Vol_m3_UtiRate As Variant      'L58
  Dim HouseTank_T As Variant               'H58
    'Household tank cold inlet temperature
  Dim ColdIn_T As Variant                  'I58

        HouseTank_T = Cells(58, 8).Value
        ColdIn_T = Cells(58, 9).Value
        Cells(58, 10).Value = (DHW_Daily_D_PerHouse * Unit_Change2) / _
        (Water_Cp * (HouseTank_T - ColdIn_T))
        HouseTank_Vol_kg = Cells(58, 10).Value
        Cells(58, 10).Select
        Selection.Font.Bold = True

        HouseTank_Vol_m3 = HouseTank_Vol_kg / Unit_Change
        Cells(58, 11).Value = HouseTank_Vol_m3
        Cells(58, 11).Select
        Selection.Font.Bold = True

        HouseTank_Vol_m3_UtiRate = HouseTank_Vol_m3 / ES_UtiRate
        Cells(58, 12).Value = HouseTank_Vol_m3_UtiRate
```

```
        Cells(58, 12).Select
        Selection.Font.Bold = True

End Sub

Public Sub Electricity_Parameter()

Sheets("E1_para").Select

'Electricity storage
  'D meand demand, N means number of EVs
Dim EV_HourlyD_N As Variant                   'I4 to I27
Dim EL_HourlyD_N As Variant                   'J4 to J27
Dim EV_EL_HourlyD_N As Variant                'K4 to K27
  'Avg means average, also mean data, average power demand throughout a day
Dim Avg_EV_EL_HourlyD_N As Variant            'H4 to H27
Dim Demand_VS_Mean As Variant                 'L4 to L27
  'E means Electricity
Dim E_Storage As Variant                      'M4 to M27
Dim Total_E_Storage As Variant                'M29
'UtiRate means utilisation rate
Dim Total_E_Storage_UtiRate As Variant        'N29
Dim UtiRate_Battery As Variant                'C10

  Dim a_EV_EL As Integer
  For a_EV_EL = 4 To 27

    EV_HourlyD_N = Cells(a_EV_EL, 9).Value
    EL_HourlyD_N = Cells(a_EV_EL, 10).Value
    EV_EL_HourlyD_N = EV_HourlyD_N + EL_HourlyD_N
    Cells(a_EV_EL, 11).Value = EV_EL_HourlyD_N
    Cells(a_EV_EL, 11).Select
    Selection.Font.Bold = True

    Avg_EV_EL_HourlyD_N = Cells(a_EV_EL, 8).Value
    Demand_VS_Mean = EV_EL_HourlyD_N - Avg_EV_EL_HourlyD_N
    Cells(a_EV_EL, 12).Value = Demand_VS_Mean
    Cells(a_EV_EL, 12).Select
    Selection.Font.Bold = True

    If Demand_VS_Mean > 0 Then
      Cells(a_EV_EL, 13).Value = Demand_VS_Mean
    Else: Cells(a_EV_EL, 13).Value = 0
    End If

      E_Storage = Cells(a_EV_EL, 13).Value
      Cells(a_EV_EL, 13).Select
      Selection.Font.Bold = True

  Next a_EV_EL

    Cells(29, 13).Value = Application.WorksheetFunction.Sum(Range("M4:M27"))
    Total_E_Storage = Cells(29, 13).Value
    Cells(29, 13).Select
    Selection.Font.Bold = True
```

```
        UtiRate_Battery = Cells(10, 3).Value
        Total_E_Storage_UtiRate = Total_E_Storage / UtiRate_Battery
        Cells(29, 14).Value = Total_E_Storage_UtiRate
        Cells(29, 14).Select
        Selection.Font.Bold = True


'For community-scale peak shaving
        'targeted max. power in a distribution network
    Dim TargetedMaxPower As Variant                'O4 to O27
    Dim D_Over_TargetedMaxPower As Variant            'P4 to P27
    Dim E_Storage_OverTarget As Variant             'Q4 to Q27
    Dim Total_E_Storage_OverTarget As Variant        'Q29
    'UtiRate means utilisation rate
    Dim Total_E_Storage_OverTarget_UtiRate As Variant   'R29

        For a_EV_EL = 4 To 27

            TargetedMaxPower = Cells(a_EV_EL, 15).Value
            EV_EL_HourlyD_N = Cells(a_EV_EL, 11).Value
            D_Over_TargetedMaxPower = EV_EL_HourlyD_N - TargetedMaxPower
            Cells(a_EV_EL, 16).Value = D_Over_TargetedMaxPower
            Cells(a_EV_EL, 16).Select
            Selection.Font.Bold = True

            If D_Over_TargetedMaxPower > 0 Then
                Cells(a_EV_EL, 17).Value = D_Over_TargetedMaxPower
            Else: Cells(a_EV_EL, 17).Value = 0
            End If

                E_Storage_OverTarget = Cells(a_EV_EL, 17).Value
                Cells(a_EV_EL, 17).Select
                Selection.Font.Bold = True

        Next a_EV_EL

        Cells(29, 17).Value = Application.WorksheetFunction.Sum(Range("Q4:Q27"))
        Total_E_Storage_OverTarget = Cells(29, 17).Value
        Cells(29, 17).Select
        Selection.Font.Bold = True

        Total_E_Storage_OverTarget_UtiRate = Total_E_Storage_OverTarget _
        / UtiRate_Battery
        Cells(29, 18).Value = Total_E_Storage_OverTarget_UtiRate
        Cells(29, 18).Select
        Selection.Font.Bold = True

        'E means Electricity
    Dim Total_E_Storage_UtiRate_Substation As Variant   'T29

        Total_E_Storage_UtiRate_Substation = Total_E_Storage_UtiRate _
        - Total_E_Storage_OverTarget_UtiRate
        Cells(29, 20).Value = Total_E_Storage_UtiRate_Substation
        Cells(29, 20).Select
        Selection.Font.Bold = True
```

```
 Sheets("Efficiency impro").Select

'PV modules
    'Max demand month
Dim Max_D_Month As Variant           'F12
Dim Max_D_Month_SunHours As Variant     'F14

  Range("F12").Value = "=H3_dema!J19"
  Max_D_Month = Range("F12").Value

    'lookup the peak sun hours of the max demand month
  Range("F14").Value = "=XLOOKUP(F12,E1_para!F36:F47,E1_para!G36:G47)"
  Max_D_Month_SunHours = Range("F14").Value

Dim Opt4_MaxWeekPower_PV_Storage As Variant        'P9
Dim Opt4_MaxWeek_Storage As Variant              'E15
Dim Opt4_MaxWeek_PV As Variant                  'G15

    'average demand power of the PV,Storage in the max. demnad week
  Range("P9").Value = Range("K9").Value - Range("O9").Value - Range("N9").Value
  Opt4_MaxWeekPower_PV_Storage = Range("P9").Value

    '24 is hours of a day, 7 is days of a week
  Opt4_MaxWeek_Storage = Opt4_MaxWeekPower_PV_Storage * 24 * 7
  Range("E15").Value = Opt4_MaxWeek_Storage
    Range("E15").Select
    Selection.Font.Bold = True

  Opt4_MaxWeek_PV = Opt4_MaxWeekPower_PV_Storage * 24 / Max_D_Month_SunHours
  Range("G15").Value = Opt4_MaxWeek_PV
    Range("G15").Select
    Selection.Font.Bold = True

  'UtiRate means utilisation rate
Dim Opt4_MaxWeek_Storage_UtiRate As Variant       'E20
  'B1 means battery 1
Dim Opt4_MaxWeek_Storage_UtiRate_B1 As Variant     'E21
Dim Opt4_MaxWeek_Storage_UtiRate_B2 As Variant     'E22
Dim Opt4_MaxWeek_PV_kW As Variant               'H20

  'UtiRate_Battery = Range("D24").Value
  Opt4_MaxWeek_Storage_UtiRate = Opt4_MaxWeek_Storage / Range("D24").Value
  Range("E20").Value = Opt4_MaxWeek_Storage_UtiRate

  Range("E21").Value = "=E1_para!N29"
  Opt4_MaxWeek_Storage_UtiRate_B1 = Range("E21").Value

  Opt4_MaxWeek_Storage_UtiRate_B2 = Opt4_MaxWeek_Storage_UtiRate _
  - Opt4_MaxWeek_Storage_UtiRate_B1
  Range("E22").Value = Opt4_MaxWeek_Storage_UtiRate_B2
    Range("E22").Select
    Selection.Font.Bold = True

    'times 1000 to be kW
  Opt4_MaxWeek_PV_kW = Opt4_MaxWeek_PV * 1000
```

```
  Range("H20").Value = Opt4_MaxWeek_PV_kW
    Range("H20").Select
    Selection.Font.Bold = True

End Sub

Public Sub Cost_E_Network_Opt1()
```

Opt2, 3, 4 utilise the same code; hence, it is not shown.

```
Sheets("C1_E network").Select

'Distribution network

'Secondary substation
  'Transformer
    'SS means subsation. The max hourly power demand in a community
  Dim Opt1_SS_Demand As Variant              'U59
  Dim Transformer_kVA As Variant             'W63
  Dim Transformer_Cost As Variant            'W64
  Dim Demand_buffer As Variant               'U75

      Demand_buffer = Range("U75").Value

      Range("U59").Value = "='Demand Setting'!D73*1000"
      Opt1_SS_Demand = Range("U59").Value

    Select Case Range("U59").Value
      Case Is <= Range("O63").Value * Demand_buffer
        Transformer_kVA = 0
      Case Is <= Range("F63").Value * Demand_buffer
        Transformer_kVA = Range("F63").Value
      Case Is > Range("F63").Value * Demand_buffer
        Transformer_kVA = Range("G63").Value
    End Select

      Range("W63").Value = Transformer_kVA
      Range("W63").Select
      Selection.Font.Bold = True

    Select Case Range("W63").Value
      Case Is = 0
        Transformer_Cost = 0
      Case Is = Range("F63").Value
        Transformer_Cost = Range("F64").Value
      Case Is = Range("G63").Value
        Transformer_Cost = Range("G64").Value
    End Select

      Range("W64").Value = Transformer_Cost
      Range("W64").Select
      Selection.Font.Bold = True

  'New SS
    If Range("W63").Value = 0 Then
      Range("W67").Value = 0
    ElseIf Range("U59").Value <= Range("W63") * Demand_buffer Then
```

```
   Range("W67").Value = 0
ElseIf Range("U59").Value > Range("W63").Value * Demand_buffer Then
   Range("W67").Value = Range("U59").Value - (Range("W63").Value * Demand_buffer)
End If
      Range("W67").Select
      Selection.Font.Bold = True

If Range("W67").Value > Range("W63").Value * Demand_buffer Then
   Range("X67").Value = Range("W67").Value - (Range("W63").Value * Demand_buffer)
Else: Range("X67").Value = 0
End If
      Range("X67").Select
      Selection.Font.Bold = True

If Range("X67").Value > Range("W63").Value * Demand_buffer Then
   Range("Y67").Value = Range("X67").Value - (Range("W63").Value * Demand_buffer)
Else: Range("Y67").Value = 0
End If
      Range("Y67").Select
      Selection.Font.Bold = True

If Range("Y67").Value > Range("W63").Value * Demand_buffer Then
   Range("Z67").Value = Range("Y67").Value - (Range("W63").Value * Demand_buffer)
Else: Range("Z67").Value = 0
End If
      Range("Z67").Select
      Selection.Font.Bold = True

If Range("Z67").Value > Range("W63").Value * Demand_buffer Then
   Range("AA67").Value = Range("Z67").Value - (Range("W63").Value * Demand_buffer)
Else: Range("AA67").Value = 0
End If
      Range("AA67").Select
      Selection.Font.Bold = True

If Range("AA67").Value > Range("W63").Value * Demand_buffer Then
   Range("AB67").Value = Range("AA67").Value - (Range("W63").Value * Demand_buffer)
Else: Range("AB67").Value = 0
End If
      Range("AB67").Select
      Selection.Font.Bold = True

   'New SS kVA
Dim a_Cost As Integer
For a_Cost = 23 To 28

   If Cells(67, a_Cost).Value = 0 Then
      Cells(69, a_Cost).Value = 0
   ElseIf Cells(67, a_Cost).Value <= Range("E69").Value * Demand_buffer Then
      Cells(69, a_Cost).Value = Range("E69").Value
   ElseIf Cells(67, a_Cost).Value <= Range("F69").Value * Demand_buffer Then
      Cells(69, a_Cost).Value = Range("F69").Value
   ElseIf Cells(67, a_Cost).Value <= Range("G69").Value * Demand_buffer Then
      Cells(69, a_Cost).Value = Range("G69").Value
   ElseIf Cells(67, a_Cost).Value <= Range("H69").Value * Demand_buffer Then
      Cells(69, a_Cost).Value = Range("H69").Value
```

```
      ElseIf Cells(67, a_Cost).Value > Range("H69").Value * Demand_buffer Then
         Cells(69, a_Cost).Value = Range("H69").Value
      End If
            Cells(69, a_Cost).Select
            Selection.Font.Bold = True

   Next a_Cost

   For a_Cost = 23 To 28

      If Cells(69, a_Cost).Value = 0 Then
         Cells(70, a_Cost).Value = 0
      ElseIf Cells(69, a_Cost).Value = Range("E69").Value Then
         Cells(70, a_Cost).Value = Range("E70").Value
      ElseIf Cells(69, a_Cost).Value = Range("F69").Value Then
         Cells(70, a_Cost).Value = Range("F70").Value
      ElseIf Cells(69, a_Cost).Value = Range("G69").Value Then
         Cells(70, a_Cost).Value = Range("G70").Value
      ElseIf Cells(69, a_Cost).Value = Range("H69").Value Then
         Cells(70, a_Cost).Value = Range("H70").Value
      End If
            Cells(70, a_Cost).Select
            Selection.Font.Bold = True

   Next a_Cost

'11kV feeder

  'Feeder
  Dim Opt1_OneFeeder_Demand As Variant                    'U44
     'N means number
  Dim Opt1_N_Feeders As Integer                       'W47
  Dim Opt1_Cost_Feeders As Variant                     'W49
     'N means number. The number of secondary SS connected with a feeder
  Dim N_Secondary_SS As Integer                        'O59
     'Cost shares to each SS
  Dim Opt1_Cost_Feeders_SS As Variant                    'W50

     N_Secondary_SS = Range("O59").Value
     Range("U44").Value = Opt1_SS_Demand * N_Secondary_SS
     Opt1_OneFeeder_Demand = Range("U44").Value
            Range("U44").Select
            Selection.Font.Bold = True

     Range("W47").Value = WorksheetFunction.RoundUp(Opt1_OneFeeder_Demand _
     / (Range("O46").Value * Demand_buffer), 0)
            Opt1_N_Feeders = Range("W47").Value
            Range("W47").Select
            Selection.Font.Bold = True

        'Range("O49").Value is the length of a feeder
        'Range("O47").Value is the cost per m
     Range("W49").Value = (Opt1_N_Feeders - 1) * Range("O49").Value _
     * Range("O47").Value
            Opt1_Cost_Feeders = Range("W49").Value
            Range("W49").Select
```

```
            Selection.Font.Bold = True


      Range("W50").Value = Opt1_Cost_Feeders / N_Secondary_SS
            Opt1_Cost_Feeders_SS = Range("W50").Value
            Range("W50").Select
            Selection.Font.Bold = True

   'Circuit breaker
   Dim Opt1_Cost_CircuitBreaker As Variant              'W53
      'Cost shares to each SS
   Dim Opt1_Cost_CircuitBreaker_SS As Variant            'W54

        'Range("E51").Value is the cost of a circuit breaker
      Range("W53").Value = (Opt1_N_Feeders - 1) * Range("E51").Value
            Opt1_Cost_CircuitBreaker = Range("W53").Value
            Range("W53").Select
            Selection.Font.Bold = True

       Range("W54").Value = Opt1_Cost_CircuitBreaker / N_Secondary_SS
            Opt1_Cost_CircuitBreaker_SS = Range("W54").Value
            Range("W54").Select
            Selection.Font.Bold = True

'Primary substation
   'Transformer
      'P means primary, SS means substation. The max hourly power demand
   Dim Opt1_PSS_Demand As Variant                  'U26
   Dim PSS_Transformer_kVA As Variant              'W29
   Dim PSS_Transformer_Cost As Variant             'W30
      'number of feeders connected to a PSS
   Dim PSS_N_Feeders As Integer                 'O44
      'Std means standard
   Dim PSS_Std_Transformer_kVA As Variant          'O28

        PSS_N_Feeders = Range("O44").Value
        Range("U26").Value = Opt1_OneFeeder_Demand * PSS_N_Feeders
        Opt1_PSS_Demand = Range("U26").Value
        Range("U26").Select
        Selection.Font.Bold = True


        PSS_Std_Transformer_kVA = Range("O28").Value
      If Opt1_PSS_Demand <= PSS_Std_Transformer_kVA * Demand_buffer Then
        PSS_Transformer_kVA = 0
      ElseIf Opt1_PSS_Demand > PSS_Std_Transformer_kVA * Demand_buffer Then
        PSS_Transformer_kVA = Range("E29").Value
      End If
        Range("W29").Value = PSS_Transformer_kVA
        Range("W29").Select
        Selection.Font.Bold = True

      If PSS_Transformer_kVA = Range("E29").Value Then
        PSS_Transformer_Cost = Range("E32").Value
      Else: PSS_Transformer_Cost = 0
      End If
```

```
    Range("W30").Value = PSS_Transformer_Cost
    Range("W30").Select
    Selection.Font.Bold = True

  'PSS transformer cost shared to each SS
Dim PSS_Transformer_Cost_PerSS As Variant            'W31

      'number of SSs is feeders times SS per feeder
    PSS_Transformer_Cost_PerSS = PSS_Transformer_Cost _
    / (PSS_N_Feeders * N_Secondary_SS)
    Range("W31").Value = PSS_Transformer_Cost_PerSS
    Range("W31").Select
    Selection.Font.Bold = True

'New PSS
  If PSS_Transformer_kVA = 0 Then
    Range("W34").Value = 0
  ElseIf Range("U26").Value <= PSS_Transformer_kVA * Demand_buffer Then
    Range("W34").Value = 0
  ElseIf Range("U26").Value > PSS_Transformer_kVA * Demand_buffer Then
    Range("W34").Value = Range("U26").Value - (PSS_Transformer_kVA * Demand_buffer)
  End If
      Range("W34").Select
      Selection.Font.Bold = True

  Dim b_Cost As Integer
  For b_Cost = 23 To 29

    If Cells(34, b_Cost).Value > PSS_Transformer_kVA * Demand_buffer Then
      Cells(34, b_Cost + 1).Value = Cells(34, b_Cost).Value _
      - (PSS_Transformer_kVA * Demand_buffer)
    Else: Cells(34, b_Cost + 1).Value = 0
    End If
        Cells(34, b_Cost + 1).Select
        Selection.Font.Bold = True
  Next b_Cost


  'New SS kVA
  Dim c_Cost As Integer
  For c_Cost = 23 To 30

    If Cells(34, c_Cost).Value = 0 Then
      Cells(36, c_Cost).Value = 0
    ElseIf Cells(34, c_Cost).Value <= Range("E34").Value * Demand_buffer Then
      Cells(36, c_Cost).Value = Range("E34").Value
    ElseIf Cells(34, c_Cost).Value > Range("E34").Value * Demand_buffer Then
      Cells(36, c_Cost).Value = Range("F34").Value
    End If
        Cells(36, c_Cost).Select
        Selection.Font.Bold = True

  Next c_Cost

  For c_Cost = 23 To 30
```

```
        If Cells(36, c_Cost).Value = 0 Then
          Cells(37, c_Cost).Value = 0
        ElseIf Cells(36, c_Cost).Value = Range("E34").Value Then
          Cells(37, c_Cost).Value = Range("E35").Value
        ElseIf Cells(36, c_Cost).Value = Range("F34").Value Then
          Cells(37, c_Cost).Value = Range("F35").Value
        End If
            Cells(37, c_Cost).Select
            Selection.Font.Bold = True

          'number of SSs under a PSS is feeders times SS per feeder
        Cells(38, c_Cost).Value = Cells(37, c_Cost).Value _
        / (PSS_N_Feeders * N_Secondary_SS)
            Cells(38, c_Cost).Select
            Selection.Font.Bold = True

      Next c_Cost

'33kV feeder
  'Feeder
      Dim Opt1_33kVFeeder_Demand As Variant               'U15
        'N means number
      Dim Opt1_N_33kVFeeders As Integer                   'W18
      Dim Opt1_Cost_33kVFeeders As Variant                'W19
        'N means number. Number of PSS connected to a 33kV feeder
      Dim N_PSS_33kVFeeder As Integer                     'O26
      Dim Std_33kVFeeder_kVA As Variant                   'O17
      Dim Std_33kVFeeder_Cost As Variant                  'O18
      Dim Opt1_Cost_33kVFeeders_PerSS As Variant          'W20

        N_PSS_33kVFeeder = Range("O26").Value
        Opt1_33kVFeeder_Demand = Opt1_PSS_Demand * N_PSS_33kVFeeder
        Range("U15").Value = Opt1_33kVFeeder_Demand
              Range("U15").Select
              Selection.Font.Bold = True

        Std_33kVFeeder_kVA = Range("O17").Value
        Opt1_N_33kVFeeders = WorksheetFunction.RoundUp(Opt1_33kVFeeder_Demand _
        / (Std_33kVFeeder_kVA * Demand_buffer), 0)
              Range("W18").Value = Opt1_N_33kVFeeders
              Range("W18").Select
              Selection.Font.Bold = True

        Std_33kVFeeder_Cost = Range("O18").Value
        Range("W19").Value = (Opt1_N_33kVFeeders - 1) * Std_33kVFeeder_Cost
              Opt1_Cost_33kVFeeders = Range("W19").Value
              Range("W19").Select
              Selection.Font.Bold = True

        Range("W20").Value = Opt1_Cost_33kVFeeders / (PSS_N_Feeders * N_Secondary_SS)
              Opt1_Cost_33kVFeeders_PerSS = Range("W20").Value
              Range("W20").Select
              Selection.Font.Bold = True

'132/33kV substation
      'SS means substation
```

```
Dim Opt1_132_33kV_SS_Demand As Variant                'U8

        'one 33kV feeder connecting with one 132/33kV substation
    Opt1_132_33kV_SS_Demand = Opt1_33kVFeeder_Demand
          Range("U8").Value = Opt1_132_33kV_SS_Demand
          Range("U8").Select
          Selection.Font.Bold = True

'Transformer
Dim SS_132_33kV_Transformer_kVA As Variant             'W11
Dim SS_132_33kV_Transformer_Cost As Variant            'W12
  'number of feeders connected to a PSS
Dim SS_132_33kV_Transformer_Cost_PerSS As Integer        'W13

  If Opt1_132_33kV_SS_Demand <= Range("E9").Value * Demand_buffer Then
    Range("W11").Value = 0
  Else: Range("W11").Value = Range("F9").Value
  End If
        SS_132_33kV_Transformer_kVA = Range("W11").Value
        Range("W11").Select
        Selection.Font.Bold = True

  If SS_132_33kV_Transformer_kVA = 0 Then
    SS_132_33kV_Transformer_Cost = 0
  ElseIf SS_132_33kV_Transformer_kVA = Range("F9").Value Then
    SS_132_33kV_Transformer_Cost = Range("F12").Value
  End If
        Range("W12").Value = SS_132_33kV_Transformer_Cost
        Range("W12").Select
        Selection.Font.Bold = True

  SS_132_33kV_Transformer_Cost_PerSS = SS_132_33kV_Transformer_Cost _
  / (PSS_N_Feeders * N_Secondary_SS)
        Range("W13").Value = SS_132_33kV_Transformer_Cost_PerSS
        Range("W13").Select
        Selection.Font.Bold = True

Dim Opt1_TotalCost_PerSS As Variant           'W4

    Opt1_TotalCost_PerSS = Opt1_Cost_Feeders_SS + Opt1_Cost_CircuitBreaker_SS _
    + Transformer_Cost + Range("W70").Value + Range("X70").Value + Range("Y70").Value _
    + Range("Z70").Value + Range("AA70").Value + Range("AB70").Value _
    + PSS_Transformer_Cost_PerSS + Range("W38").Value + Range("X38").Value _
    + Range("Y38").Value + Range("Z38").Value + Range("AA38").Value _
    + Range("AB38").Value + Range("AC38").Value + Range("AD38").Value _
    + Opt1_Cost_33kVFeeders_PerSS + SS_132_33kV_Transformer_Cost_PerSS
      Range("W4").Value = Opt1_TotalCost_PerSS
      Range("W4").Select
      Selection.Font.Bold = True

End Sub

Public Sub Cost_Energy_System()

Sheets("C2_system").Select
```

```
'GSHP cost
    'Linear trendline
  Dim Linear_a As Variant          'D16
  Dim Linear_b As Variant          'D17

    Linear_a = _
    Application.WorksheetFunction.Slope(Range("D8:U8"), Range("D7:U7"))
    Range("D16").Value = Linear_a
      Range("D16").Select
      Selection.Font.Bold = True

    Linear_b = _
    Application.WorksheetFunction.Intercept(Range("D8:U8"), Range("D7:U7"))
    Range("D17").Value = Linear_b
      Range("D17").Select
      Selection.Font.Bold = True

    'Cap means capacity, inSys means in a system
  Dim Opt2_GSHP_Cap_inSys As Variant        'G12
  Dim Opt2_Cost_GSHP As Variant            'G13
  Dim Opt3_GSHP_Cap_inSys As Variant        'H12
  Dim Opt3_Cost_GSHP As Variant            'H13
  Dim Opt4_GSHP_Cap_inSys As Variant        'I12
  Dim Opt4_Cost_GSHP As Variant            'I13

    Range("G12").Value = "=Summary!C18*1000"
    Opt2_GSHP_Cap_inSys = Range("G12").Value
    Range("H12").Value = "=Summary!C19*1000"
    Opt3_GSHP_Cap_inSys = Range("H12").Value
    Range("I12").Value = "=Summary!C20*1000"
    Opt4_GSHP_Cap_inSys = Range("I12").Value

    Opt2_Cost_GSHP = Linear_a * Opt2_GSHP_Cap_inSys + Linear_b
    Range("G13").Value = Opt2_Cost_GSHP
      Range("G13").Select
      Selection.Font.Bold = True
    Opt3_Cost_GSHP = Linear_a * Opt3_GSHP_Cap_inSys + Linear_b
    Range("H13").Value = Opt3_Cost_GSHP
      Range("H13").Select
      Selection.Font.Bold = True
    Opt4_Cost_GSHP = Linear_a * Opt4_GSHP_Cap_inSys + Linear_b
    Range("I13").Value = Opt4_Cost_GSHP
      Range("I13").Select
      Selection.Font.Bold = True

'District heating system
  Dim Total_Length_Pipe As Variant            'D29
  Dim Cost_Per_m_Pipe As Variant              'D30
  Dim Total_Cost_Pipe As Variant              'D31
  Dim HouseholdN As Integer                  'D34
  Dim InternalPipe_length As Variant          'D35
  Dim Cost_Per_m_InternalPipe As Variant        'D36
  Dim Total_Cost_InternalPipe As Variant        'D37
  Dim HeatingSS_Cap_kW As Variant             'D40
  Dim Cost_HeatingSS_PerkW As Variant          'D41
  Dim Total_Cost_HeatingSS As Variant          'D42
```

```
    Range("D29").Value _
    = "=('H2_T sele'!E33*'H2_T sele'!S13)+('H2_T sele'!E34*'H2_T sele'!S14)"
    Total_Length_Pipe = Range("D29").Value
    Cost_Per_m_Pipe = Range("D30").Value

    Total_Cost_Pipe = Total_Length_Pipe * Cost_Per_m_Pipe
    Range("D31").Value = Total_Cost_Pipe
        Range("D31").Select
        Selection.Font.Bold = True

    Range("D34").Value = "='Demand Setting'!D9"
    HouseholdN = Range("D34").Value
    InternalPipe_length = Range("D35").Value
    Cost_Per_m_InternalPipe = Range("D36").Value
    Total_Cost_InternalPipe = HouseholdN * InternalPipe_length * Cost_Per_m_InternalPipe
    Range("D37").Value = Total_Cost_InternalPipe
        Range("D37").Select
        Selection.Font.Bold = True

    Range("D40").Value = "='H2_T sele'!B6*'Demand Setting'!D9"
    HeatingSS_Cap_kW = Range("D40").Value
    Cost_HeatingSS_PerkW = Range("D41").Value
    Total_Cost_HeatingSS = HeatingSS_Cap_kW * Cost_HeatingSS_PerkW
    Range("D42").Value = Total_Cost_HeatingSS
        Range("D42").Select
        Selection.Font.Bold = True

    'HIU means heat interface unit
Dim Cost_HIU_PerHouse As Variant                'D46
Dim Total_Cost_HIU As Variant                 'D47
Dim Cost_HeatMeter_PerHouse As Variant             'D51
Dim Total_Cost_HeatMeter As Variant              'D52
    'TS means thermal store
Dim Cost_TS_Per_m3 As Variant                 'D56

    Cost_HIU_PerHouse = Range("D46").Value
    Total_Cost_HIU = HouseholdN * Cost_HIU_PerHouse
    Range("D47").Value = Total_Cost_HIU
        Range("D47").Select
        Selection.Font.Bold = True

    Cost_HeatMeter_PerHouse = Range("D51").Value
    Total_Cost_HeatMeter = HouseholdN * Cost_HeatMeter_PerHouse
    Range("D52").Value = Total_Cost_HeatMeter
        Range("D52").Select
        Selection.Font.Bold = True

Dim Opt2_TS_m3 As Variant                    'G55
Dim Opt3_TS_m3 As Variant                    'H55
Dim Opt4_TS_m3 As Variant                    'I55
Dim Opt2_Total_Cost_TS As Variant                'G57
Dim Opt3_Total_Cost_TS As Variant                'H57
Dim Opt4_Total_Cost_TS As Variant                'I57

    Cost_TS_Per_m3 = Range("D56").Value
```

```
    Range("G55").Value = "=Summary!F18"
    Opt2_TS_m3 = Range("G55").Value
    Range("H55").Value = "=Summary!F19"
    Opt3_TS_m3 = Range("H55").Value
    Range("I55").Value = "=Summary!F20"
    Opt4_TS_m3 = Range("I55").Value

    Opt2_Total_Cost_TS = Opt2_TS_m3 * Cost_TS_Per_m3
    Range("G57").Value = Opt2_Total_Cost_TS
      Range("G57").Select
      Selection.Font.Bold = True
    Opt3_Total_Cost_TS = Opt3_TS_m3 * Cost_TS_Per_m3
    Range("H57").Value = Opt3_Total_Cost_TS
      Range("H57").Select
      Selection.Font.Bold = True
    Opt4_Total_Cost_TS = Opt4_TS_m3 * Cost_TS_Per_m3
    Range("I57").Value = Opt4_Total_Cost_TS
      Range("I57").Select
      Selection.Font.Bold = True

    'DHS means district heating system
  Dim Opt2_Total_Cost_DHS As Variant                    'G59
  Dim Opt3_Total_Cost_DHS As Variant                    'H59
  Dim Opt4_Total_Cost_DHS As Variant                    'I59

    Opt2_Total_Cost_DHS = Total_Cost_Pipe + Total_Cost_InternalPipe + Total_Cost_HeatingSS _
    + Total_Cost_HIU + Total_Cost_HeatMeter + Opt2_Total_Cost_TS
    Range("G59").Value = Opt2_Total_Cost_DHS
      Range("G59").Select
      Selection.Font.Bold = True
    Opt3_Total_Cost_DHS = Total_Cost_Pipe + Total_Cost_InternalPipe + Total_Cost_HeatingSS _
    + Total_Cost_HIU + Total_Cost_HeatMeter + Opt3_Total_Cost_TS
    Range("H59").Value = Opt3_Total_Cost_DHS
      Range("H59").Select
      Selection.Font.Bold = True
    Opt4_Total_Cost_DHS = Total_Cost_Pipe + Total_Cost_InternalPipe + Total_Cost_HeatingSS _
    + Total_Cost_HIU + Total_Cost_HeatMeter + Opt4_Total_Cost_TS
    Range("I59").Value = Opt4_Total_Cost_DHS
      Range("I59").Select
      Selection.Font.Bold = True

'Li-ion battery
  Dim Cost_LiBattery_PerMWh As Variant          'E66
  Dim Opt2_Battery1_MWh As Variant              'G67
  Dim Opt3_Battery1_MWh As Variant              'H67
  Dim Opt4_Battery1_MWh As Variant              'I67
  Dim Opt2_Battery2_MWh As Variant              'G68
  Dim Opt3_Battery2_MWh As Variant              'H68
  Dim Opt4_Battery2_MWh As Variant              'I68
  Dim Opt2_Cost_LiBattery As Variant            'G69
  Dim Opt3_Cost_LiBattery As Variant            'H69
  Dim Opt4_Cost_LiBattery As Variant            'I69

    Cost_LiBattery_PerMWh = Range("E66").Value
```

```
    Range("G67").Value = "=Summary!J18"
    Opt2_Battery1_MWh = Range("G67").Value
    Range("H67").Value = "=Summary!J19"
    Opt3_Battery1_MWh = Range("H67").Value
    Range("I67").Value = "=Summary!J20"
    Opt4_Battery1_MWh = Range("I67").Value

    Range("G68").Value = "=Summary!M18"
    Opt2_Battery2_MWh = Range("G68").Value
    Range("H68").Value = "=Summary!M19"
    Opt3_Battery2_MWh = Range("H68").Value
    Range("I68").Value = "=Summary!M20"
    Opt4_Battery2_MWh = Range("I68").Value

    Opt2_Cost_LiBattery = Opt2_Battery1_MWh * Cost_LiBattery_PerMWh _
      + Opt2_Battery2_MWh * Cost_LiBattery_PerMWh
    Range("G69").Value = Opt2_Cost_LiBattery
      Range("G69").Select
      Selection.Font.Bold = True

    Opt3_Cost_LiBattery = Opt3_Battery1_MWh * Cost_LiBattery_PerMWh _
      + Opt3_Battery2_MWh * Cost_LiBattery_PerMWh
    Range("H69").Value = Opt3_Cost_LiBattery
      Range("H69").Select
      Selection.Font.Bold = True

    Opt4_Cost_LiBattery = Opt4_Battery1_MWh * Cost_LiBattery_PerMWh _
      + Opt4_Battery2_MWh * Cost_LiBattery_PerMWh
    Range("I69").Value = Opt4_Cost_LiBattery
      Range("I69").Select
      Selection.Font.Bold = True

'PV modules
  Dim Cost_PV_PerkW As Variant                'D81
  Dim Opt4_PV_required_kW As Variant            'I82
  Dim Opt4_Total_Cost_PV As Variant             'I83

    Cost_PV_PerkW = Range("D81").Value
    Range("I82").Value = "=Summary!I20"
    Opt4_PV_required_kW = Range("I82").Value
    Opt4_Total_Cost_PV = Cost_PV_PerkW * Opt4_PV_required_kW
    Range("I83").Value = Opt4_Total_Cost_PV
      Range("I83").Select
      Selection.Font.Bold = True

'Solar Thermal
  Dim Cost_SThermal_Per_m2 As Variant               'D101
  Dim Opt4_SThermal_required_m2 As Variant            'I100
  Dim Opt4_Total_Cost_SThermal As Variant             'I102

    Cost_SThermal_Per_m2 = Range("D101").Value
    Range("I100").Value = "='Demand Setting'!D162"
    Opt4_SThermal_required_m2 = Range("I100").Value
    Opt4_Total_Cost_SThermal = Cost_SThermal_Per_m2 * Opt4_SThermal_required_m2
    Range("I102").Value = Opt4_Total_Cost_SThermal
      Range("I102").Select
```

```
        Selection.Font.Bold = True

End Sub

Public Sub Cost_Housing_Retrofit()

Sheets("C3_retrofit").Select

Dim Cost_Retrofit_Per_House As Variant         'O55
   'D means demand
Dim SH_EnergyD_PerHouse As Variant             'Q49
   'N means number
Dim HouseholdN As Integer                  'R49
   'Pcent means percentage
Dim Opt3_Thermal_Improved_Pcent As Variant      'R50
Dim Opt3_Related_HouseholdN As Variant         'S49
   'the reduced SH demand percentage after retrofit
Dim Retrofit_Reduced_Pcent As Variant          'S50
Dim Opt3_Total_Cost_Retrofit As Variant        'R54

      'SUM(I55:N55) is the costs of each retrofit item
   Range("O55").Value = "=SUM(I55:N55)"
   Cost_Retrofit_Per_House = Range("O55").Value

   Range("Q49").Value = "='Demand Setting'!D16"
   SH_EnergyD_PerHouse = Range("Q49").Value

   Range("R49").Value = "='Demand Setting'!D9"
   HouseholdN = Range("R49").Value

   Range("R50").Value = "=Summary!F6"
   Opt3_Thermal_Improved_Pcent = Range("R50").Value

   Retrofit_Reduced_Pcent = Range("S50").Value

   Opt3_Related_HouseholdN = Opt3_Thermal_Improved_Pcent * HouseholdN _
   / Retrofit_Reduced_Pcent
   Range("S49").Value = Opt3_Related_HouseholdN
      Range("S49").Select
      Selection.Font.Bold = True

   Opt3_Total_Cost_Retrofit = Opt3_Related_HouseholdN * Cost_Retrofit_Per_House
   Range("R54").Value = Opt3_Total_Cost_Retrofit
      Range("R54").Select
      Selection.Font.Bold = True

   'Pcent means percentage
Dim Opt4_Thermal_Improved_Pcent As Variant            'V50
Dim Opt4_Related_HouseholdN As Variant               'W49
Dim Opt4_Total_Cost_Retrofit As Variant              'V54

   Range("V50").Value = "=Summary!F7"
   Opt4_Thermal_Improved_Pcent = Range("V50").Value
```

```
    Opt4_Related_HouseholdN = Opt4_Thermal_Improved_Pcent * HouseholdN _
    / Retrofit_Reduced_Pcent
    Range("W49").Value = Opt4_Related_HouseholdN
        Range("W49").Select
        Selection.Font.Bold = True

    Opt4_Total_Cost_Retrofit = Opt4_Related_HouseholdN * Cost_Retrofit_Per_House
    Range("V54").Value = Opt4_Total_Cost_Retrofit
        Range("V54").Select
        Selection.Font.Bold = True

End Sub
```

Appendix 6. Screenshot of each worksheet of the modelling tool of multi-vector community energy systems

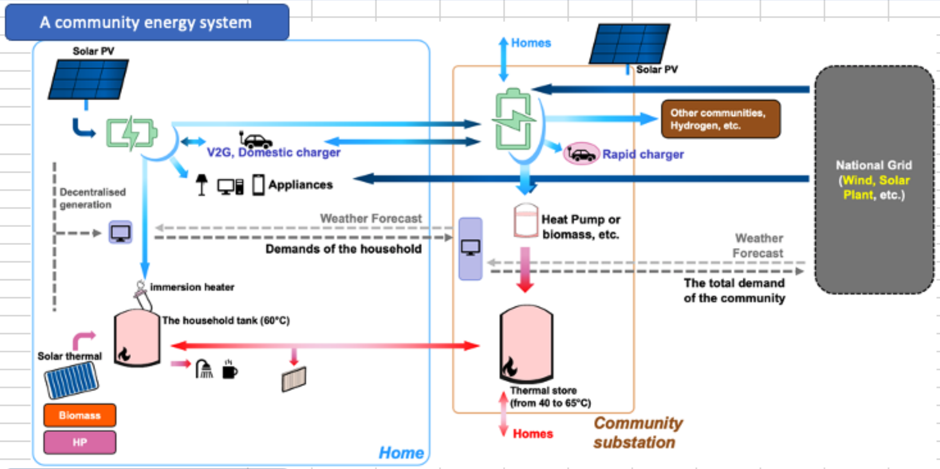
	Variables
	outcome

Settings

Community	LV substation	0.5	MW	
	Targeted power on LV substation	0.4	MW	the maximum power on the distribution network
	Homes	384	numbers	
	EVs	465	numbers	
	Smart charging	50	%	
District heating	Return temperature	30	°C	
	Soil temperature	10	°C	to GSHP calculation, soil temp. is only 10°C
	Length branch pipe	5	m	
	Length main pipe	10	m	
Annual demands per unit	Space heating	6.365	MWh	consumption decided by people'behavior', therby don't consider the heat loss in buildings, 260 W/°C in 2018
	Plan to improve	50	%	Opt.4, assigned improvement level
	COP (efficiency)	1		Opt.1, an electric heater, ASHP, etc.
	Domestic hot water	1.649	MWh	
	Household tank temperature	60	°C	
	Lighting and appliances	3.749	MWh	
	EVs	1.321	MWh	

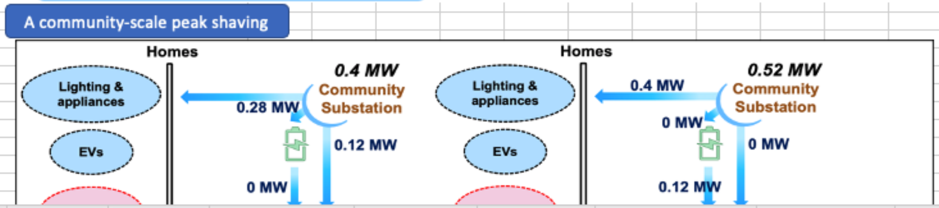
Run

Information



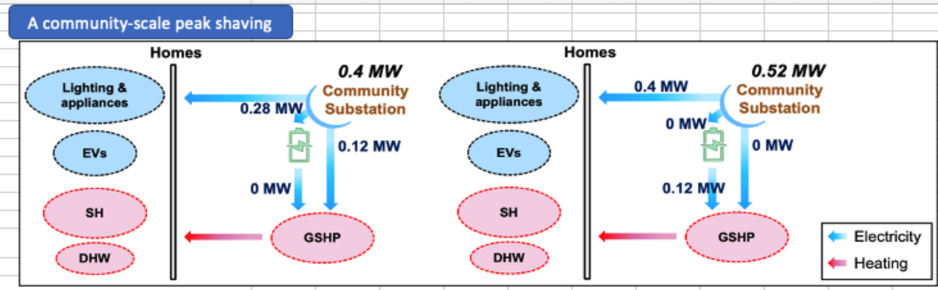
Demands

Annual Energy demand	**Space heating**	2444.3	MWh
	Domestic hot water	633.2	MWh
	Lighting and appliances	1439.6	MWh
	EVs	614.1	MWh
Annual Electricity demand	GSHP	725.3	MWh
	Ele heaters	309.6	MWh
	Lighting and appliances	1439.6	MWh
	EVs	614.1	MWh
Opt.2	**Total**	3088.6	MWh
	GSHP	548.2	MWh
	Ele heaters	37.3	MWh
Opt.3	**Total**	2639.2	MWh
	GSHP	571.1	MWh
	Ele heaters	173.4	MWh
Opt.4	**Total**	2798.3	MWh
Averaged base demand			
26/02-04/03 (coldest week)	Lighting and appliances	**0.215**	MW
	EVs	**0.077**	MW
	DHW	**0.049**	MW
	SH	**0.179**	MW
	DHW+SH (meet target)	**0.11**	MW
	Heat loss	**0.009**	MW



Demand Setting | Summary | H1_para | H2_T sele | H3_dema | H4_profile | E1_para | E2_EVs | E3_elec | C1_E network | C2_system | C3_retrofit | Efficiency impro | noSys profile

B	C	D	E	F
Opt.4	Total	2798.3	MWh	
Averaged base demand				
26/02-04/03 (coldest week)	Lighting and appliances	0.215	MW	
	EVs	0.077	MW	
	DHW	0.049	MW	
	SH	0.179	MW	
	DHW+SH (meet target)	0.11	MW	
	Heat loss	0.009	MW	

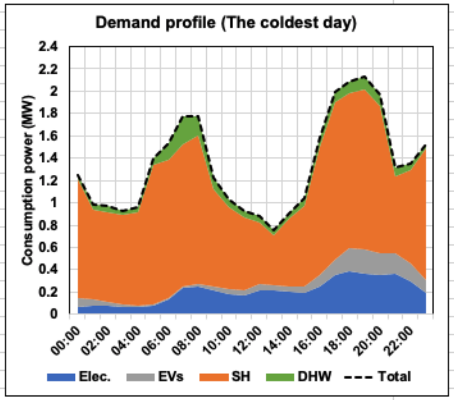


Parameters of energy system

Elextrified heating and transport

Opt. 1 — no smart charging and energy system

C	D	E
Max. power at peak hours	2.13	MW



District heating and Battery

B	C	D	E	F
Opt. 2	***Improvement***	0%		
	Heating			
	GSHP			
	Electrical power	0.26	MW	10% budget
	Supply temperature	40	°C	
	COP (efficiency)	4.67		
	Thermal storage			
	Water tank	907.02	m3	half day storage
	Water tank	10.5	MWh	100% storage capacity
	Household tank	0.116	m3	One dwelling
	Electricity generation			
	PV	0		
	Solar thermal	0		
	Electricity storage			
	Battery_1	1.27	MWh	Peak shaving, 100% storage capacity
	B1_Substation	0.93		
	B1_Homes	0.34		
	Battery_2	0		
	Max. power	0.520	MW	

Demand Setting | Summary | H1_para | H2_T sele | H3_dema | H4_profile | E1_para | E2_EVs | E3_elec | C1_E network | C2_system | C3_retrofit | Efficiency impro | noSys profile

A	B	C	D	E	F	G	H
UK housing							
	Opt. 3	***Improvement***	***72%***		no PV, electricity storage for daily peak shaving only		
		Heating					
		GSHP					
		Electrical power	0.12	MW	10% budget		
		Supply temperature	60	°C			
		COP (efficiency)	3.52				
		Thermal storage					
		Water tank	111.54	m3	half day storage		
		Water tank	3.9	MWh	100% storage capacity		
		Household tank	0.116	m3	One dwelling		
		Electricity generation					
		PV	0				
		Solar thermal	0				
		Electricity storage					
		Battery_1	1.27	MWh	Peak shaving, 100% storage capacity		
		B1_Substation	0.93				
		B1_Homes	0.34				
		Battery_2	0				
		Max. power; target	0.4	MW			
	Opt. 4	***Plan to improve***	***50%***				
		Heating					
		GSHP					
		Electrical power	0.16	MW	10% budget		
		Supply temperature	50	°C			
		COP (efficiency)	4.00				
		Thermal storage					
		Water tank	254.10	m3	half day storage		
		Water tank	5.9	MWh	100% storage capacity		
		Household tank	0.116	m3	One dwelling		
		Electricity generation					
		PV	349.4	kWp	storage power* 24 hrs/ sun hrs* 1000 reflect to 'Plan to improve' item	38	inclination angle
		Solar thermal	150.9	m2	daily demand of DHW in Jul./ conversion factor/ sun hrs/ 0.85	53	inclination angle
		Electricity storage					
		Battery_1	1.27	MWh	Peak shaving, 100% storage capacity, for the coldest week		
		B1_Substation	0.93				
		B1_Homes	0.34				
		Battery_2	6.45	MWh	storage for the coldest week		
		PV, storage	0.04				
		Max. power; target	0.4	MW			

Demand Setting | Summary | H1_para | H2_T sele | H3_dema | H4_profile | E1_para | E2_EVs | E3_elec | C1_E network | C2_system | C3_retrofit | Efficiency impro | noSys profile | +

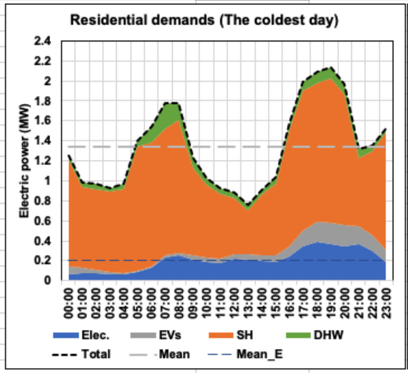
An electrified community	Energy system	District heating	Housing thermal efficiency	
Opt. 1	X	X	X	
Opt. 2	V	V	X	
Opt. 3	V	V	Condition 1	72%
Opt. 4	V	V	Condition 2	50%

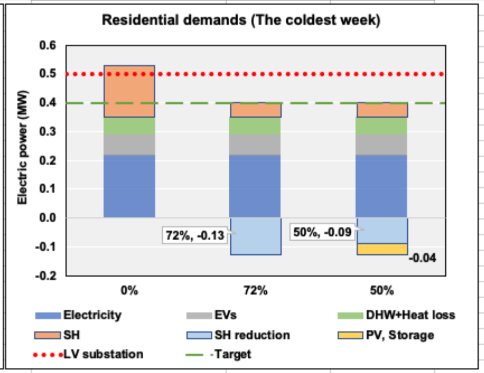
Parameters of a community energy system

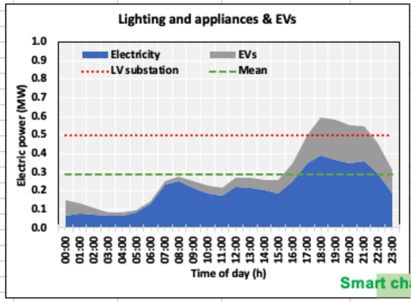
	Heating_GSHP			Thermal storage			DG	Electricity storage			
An electrified community	Electrical power	Supply temperature	COP (efficiency)	Tank	Tank	1 household tank	PV	Battery_1	B1_Substation	B1_Homes	Battery_2
Opt. 1	0	0	0	0	0	0	0	0	0	0	0
Opt. 2	0.26	40	4.67	907.02	10.53	0.116	0	1.27	0.93	0.34	0
Opt. 3	0.12	60	3.52	111.54	3.89	0.116	0	1.27	0.93	0.34	0
Opt. 4	0.16	50	4.00	254.10	5.90	0.116	349.37	1.27	0.93	0.34	6.45
	MW	°C		m3	MWh	m3 *One dwelling*	kWp	MWh			MWh

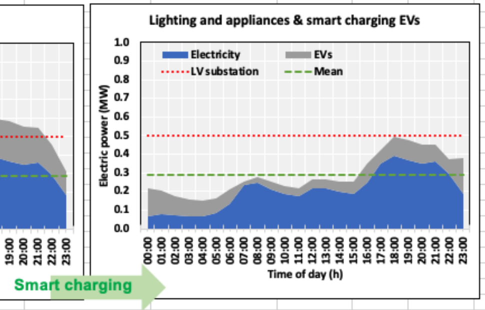
Opt. 1 | Opt. 2 | Opt. 3 | Opt. 4

Smart charging | 50 | %







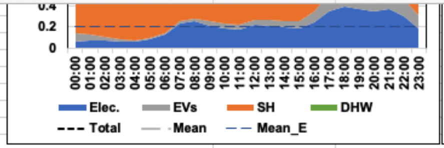


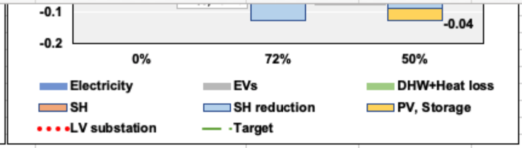
Cost assessment

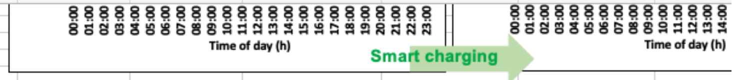
Cost (£)	*Distribution networks*		
Opt. 1	515,305	71875	substations — total dwellings/dwellings in a SS
Opt. 2	73,500	37,037,527,708	Total cost (all SS)
Opt. 3	31,250		
Opt. 4	31,250		

Cost (£)	*GSHP*	*District heating*	*Li-ion battery*	*PV modules*	*Retrofits*	Total	SS + Sys
Opt. 1	0	0	0	0			

Demand Setting | Summary | H1_para | H2_T sele | H3_dema | H4_profile | E1_para | E2_EVs | E3_elec | C1_E network | C2_system | C3_retrofit | Efficiency impro | noSys profile | +





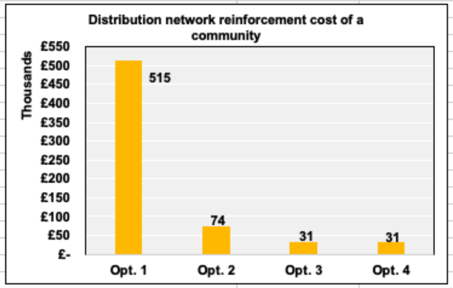


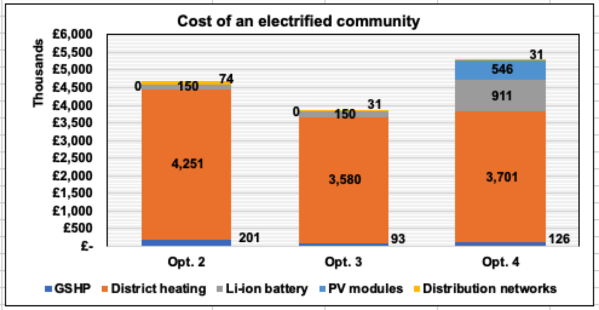
Cost assessment

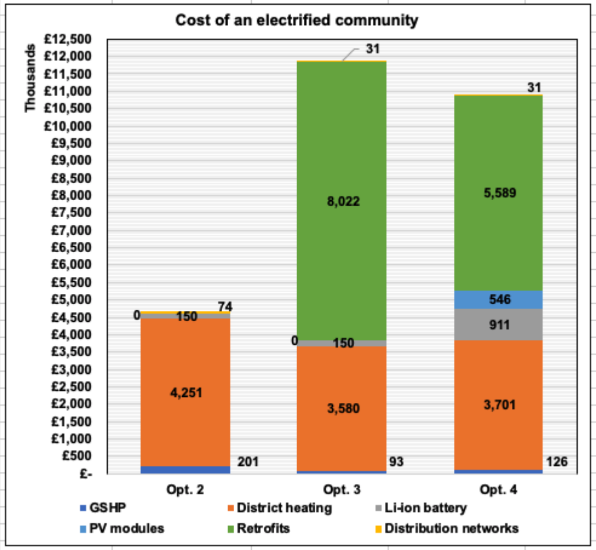
Cost (£)	Distribution networks
Opt. 1	515,305
Opt. 2	73,500
Opt. 3	31,250
Opt. 4	31,250

71875	substations	total dwellings/dwellings in a SS
37,037,527,708	Total cost (all SS)	

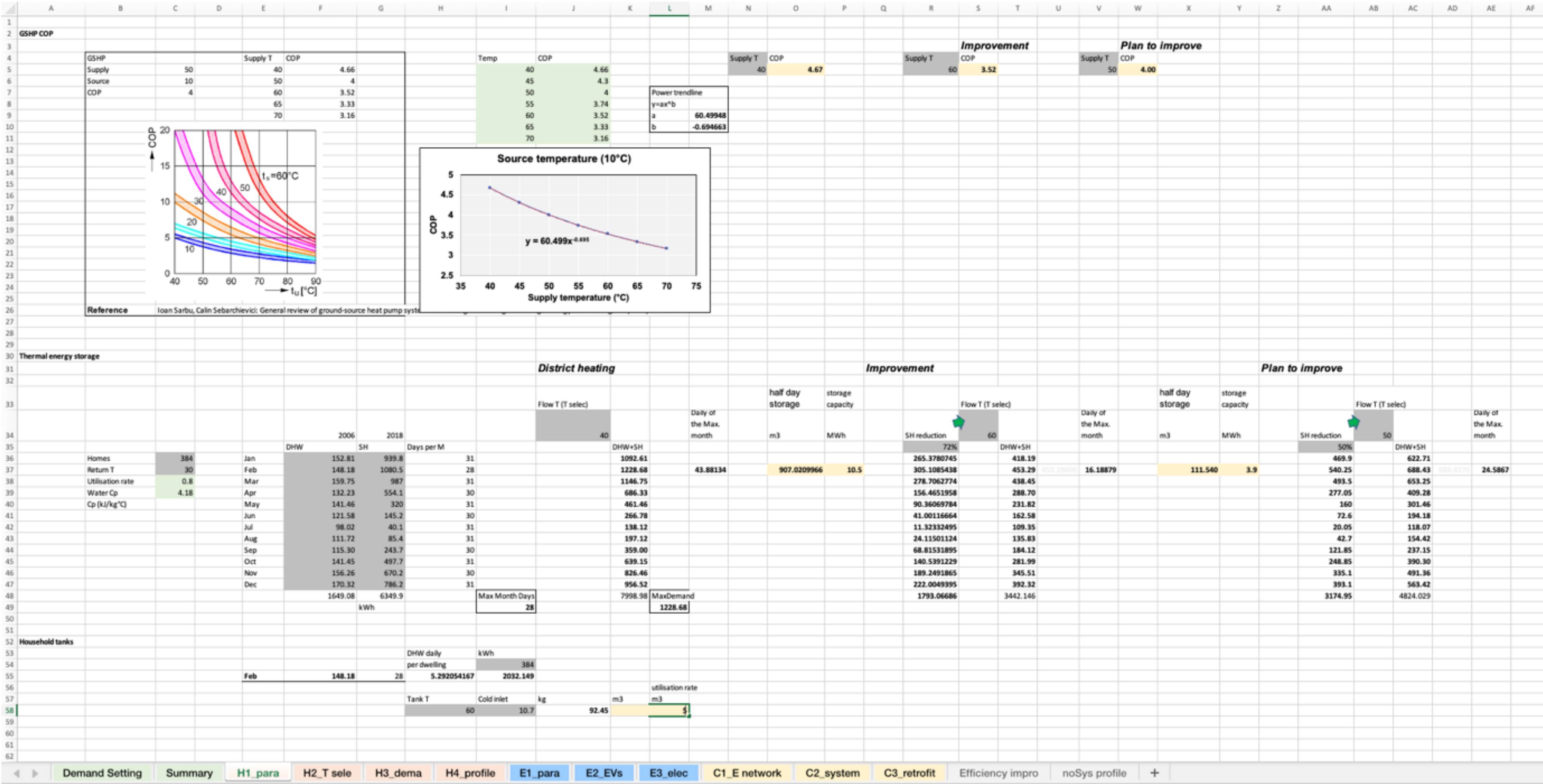
Cost (£)	GSHP	District heating	Li-ion battery	PV modules	Retrofits	Total	SS + Sys
Opt. 1	0	0	0	0			
Opt. 2	201,062	4,250,955	150,363	0		4,602,380	4,675,880
Opt. 3	92,824	3,580,364	150,363	0	8,022,066	11,845,618	11,876,868
Opt. 4	125,648	3,700,544	910,965	545,723	5,589,333	10,872,213	10,903,463







Demand Setting | Summary | H1_para | H2_T sele | H3_dema | H4_profile | E1_para | E2_EVs | E3_elec | C1_E network | C2_system | C3_retrofit | Efficiency impro | noSys profile



GSHP COP

GSHP		Supply T	COP
Supply	50	40	4.66
Source	10	50	4
COP	4	60	3.52
		65	3.33
		70	3.16

Reference: Ioan Sarbu, Calin Sebarchievici: General review of ground-source heat pump syste

Temp	COP
40	4.66
45	4.3
50	4
55	3.74
60	3.52
65	3.33
70	3.16

Power trendline	
y=ax^b	
a	60.49948
b	-0.694663

Supply T	COP
40	4.67

Improvement

Supply T	COP
60	3.52

Plan to improve

Supply T	COP
50	4.00

Thermal energy storage

			2006 DHW	2018 SH	Days per M
Homes	384	Jan	152.81	939.8	31
Return T	30	Feb	148.18	1080.5	28
Utilisation rate	0.8	Mar	159.75	987	31
Water Cp	4.18	Apr	132.23	554.1	30
Cp (kJ/kg°C)		May	141.46	320	31
		Jun	121.58	145.2	30
		Jul	98.02	40.1	31
		Aug	111.72	85.4	31
		Sep	115.30	243.7	30
		Oct	141.45	497.7	31
		Nov	156.26	670.2	30
		Dec	170.32	786.2	31
			1649.08	6349.9	
				kWh	

Max Month Days: 28

District heating

Flow T (T selec) 40	DHW+SH	Daily of the Max. month	half day storage m3	storage capacity MWh
	1092.61			
	1228.68	43.88134	907.0209966	10.5
	1146.75			
	686.33			
	461.46			
	266.78			
	138.12			
	197.12			
	359.00			
	639.15			
	826.46			
	956.52			
	7998.98			

MaxDemand: 1228.68

Improvement

SH reduction 72%	Flow T (T selec) 60 DHW+SH	Daily of the Max. month	half day storage m3	storage capacity MWh
265.3780745	418.19			
305.1085438	453.29	16.18879	111.540	3.9
278.7062774	438.45			
156.4651958	288.70			
90.36069784	231.82			
41.00116664	162.58			
11.32332495	109.35			
24.11501124	135.83			
68.81531895	184.12			
140.5391229	281.99			
189.2491865	345.51			
222.0049395	392.32			
1793.06686	3442.146			

Plan to improve

SH reduction 50%	Flow T (T selec) 50 DHW+SH	Daily of the Max. month
469.9	622.71	
540.25	688.43	24.5867
493.5	653.25	
277.05	409.28	
160	301.46	
72.6	194.18	
20.05	118.07	
42.7	154.42	
121.85	237.15	
248.85	390.30	
335.1	491.36	
393.1	563.42	
3174.95	4824.029	

Household tanks

			DHW daily per dwelling	kWh 384
Feb	148.18	28	5.292054167	2032.149

Tank T	Cold inlet	kg	m3	utilisation rate m3
60	10.7	92.45		5

Demand Setting | Summary | H1_para | H2_T sele | H3_dema | H4_profile | E1_para | E2_EVs | E3_elec | C1_E network | C2_system | C3_retrofit | Efficiency impro | noSys profile

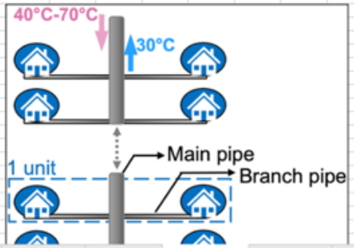
	A	B	D	E	F	G	I	J	K	L
4				flow rate	pipe size					
5	V (heat medium flow rate (l/s)	0.144991		<		U		U		
6	Q (heat flow, kW)	6		0.1	20x1.9	0.116			40C	
7	Cp (kJ/kg°C)	4.18		0.19	25x2.3	0.139	flow rate	number of households	flow rate	
8	θV (flow temp., °C)	40		0.38	32x2.9	0.183	0.144991	1	0.144991	Branch pipe
9	θR (return temp., °C)	30		0.68	40x3.7	0.211	U	5	0.724953	
10	ρ (density of water, kg/l)	0.99		1.25	50x4.6	0.195	0.139	10	1.449906	
11				2.35	63x5.8	0.238		12	1.739887	
12			DUO	3.6	75x6.8	0.28		20	2.899812	
13				5.9	90x8.2	0.206		24	3.479774	
14				10	110x10	0.296		50	7.249529	
15				14	125x11.4	0.303		100	14.49906	Main pipe
16				18	140x12.7	0.308				
17			UNO x2	29	160x14.6	0.303				

	C–D	E	F	G	H	I	J
26	evaluated distribution T	40	45	50	55	60	65
28	tank T	60					
29	lower return T	30					
30	return T	30					
33	length branch pipe, m	5					
34	length main pipe, m	10					
36	Soil T	10					
38	GSHP COP						
39	y=ax^b						
40	a	60.49948					
41	b	-0.694663					

	Q	R	S	T	U	V	W	X	AB	AC
1			40C	45C	50C	55C	60C	65C	for generating the data of t	
2		DHW consumption	1649.079	1649.079	1649.0788	1649.079	1649.079	1649.079	37.04438	
3	Per household	water in tank (kg)	31618.24	31618.24	31618.239	31618.24	31618.24	31618.24	647.145	
4		SH consumption	6365.444	6365.444	6365.444	6365.444	6365.444	6365.444	336.715	
5		households	384	384	384	384	384	384	384	
6		distribution T	40	45	50	55	60	65	40	
7		soil T	10	10	10	10	10	10	10	
8		T(return 30C, soil 10C)	25	27.5	30	32.5	35	37.5	25	
9		length branch pipe, m	5	5	5	5	5	5	5	
10		branch U	0.139	0.139	0.139	0.139	0.139	0.139	0.139	
11		length main pipe, m	10	10	10	10	10	10	10	
12		main U	0.308	0.308	0.308	0.308	0.308	0.308	0.308	
13		branch number	384	384	384	384	384	384	384	
14		main number	192	192	192	192	192	192	192	
15		hours	8760	8760	8760	8760	8760	8760	168	
16		W to kW	1000	1000	1000	1000	1000	1000	1000	
17		annual heat loss	annual hea	annual hea	annual heat	annual hea	annual hea	annual heat loss	weekly heat loss	
18			375909.1	413500	451090.94	488681.9	526272.8	563863.7	7209.216	
20		DHW								
21		Energy (from Elec. Boiler)	309612.5	241528.6	173444.59	105360.6	37276.66	0	6336.982	
22		Energy (from LTDH) kWh	323633.7	391717.7	459801.66	527885.6	595969.6	633246.3	7888.06	
23		Energy demand before HIU								
24		HIU efficiency	92.033	91.953	91.873	91.793	91.713	91.633	92.033	
25		DHW, Energy (from LTDH) kWh	351649.7	425997.7	500475.29	575082.7	649820.2	691067.9	8570.904	
27		SH								
28		Energy (from LTDH) kWh	2444331	2444331	2444330.5	2444331	2444331	2444331	129298.7	
29		Energy demand before HIU								
30		HIU efficiency	92.033	91.953	91.873	91.793	91.713	91.633	92.033	
31		SH, Energy (from LTDH) kWh	2655928	2658239	2660553.7	2662872	2665195	2667522	140491.6	
33		COP	4.67	4.30	4.00	3.74	3.52	3.33	4.66	
34		DHW + SH								DHW
35		Enerygy consumption of GSHP	725279.6	813695.4	904113.51	996625.2	1091295	1178069	33540.07	1839.543689
36		**Total Electricity (Elec. Boiler + GSHP)**	1034892	1055224	1077558.1	1101986	1128571	1178069	39877.06	8176.525608
37		**MWh**	1034.892	1055.224	1077.5581	1101.986	1128.571	1178.069	39.87706	
38									0.237363	0.048669795
39										To Demand Se

	P	Q	S	T	U	V
39	**Energy demand per household**					
40	DHW	SH	DHW	ratio	SH	
41	1.649078784	6.365444105	1649.079	3.86	6365.444	
42	1649.078784	6365.444105				
43	**Households**					
44	384					
45	**Water in tank (kg) per household**		DHW:SH		384	
46	31618.23904			3.86	40	°C
48				Ele heaters	309.61253	MWh
49				GSHP	725.27962	MWh
50				Total	1034.8921	MWh

Layout of an heating network



Demand Setting | Summary | H1_para | H2_T sele | H3_dema | H4_profile | E1_para | E2_EVs | E3_elec | C1_E network | C2_system | C3_retrofit | Efficiency impro | noSys profile | +

	W	X	AB	AC	AD	AE
1	**60C**	**65C**	for generating the data of the coldest week			
2	1649.079	1649.079	37.04438			
3	31618.24	31618.24	647.145			
4	6365.444	6365.444	336.715			
5	384	384	384			
6	60	65	40			
7	10	10	10			
8	**35**	**37.5**	**25**			
9	5	5	5			
10	**0.139**	**0.139**	**0.139**			
11	10	10	10			
12	**0.308**	**0.308**	**0.308**			
13	**384**	**384**	**384**			
14	**192**	**192**	**192**			
15	8760	8760	168			
16	1000	1000	1000			
17	annual hea	annual heat loss	**weekly heat loss**			
18	**526272.8**	**563863.7**	**7209.216**			
21	**37276.66**	**0**	**6336.982**			
22	**595969.6**	**633246.3**	**7888.06**			
24	**91.713**	**91.633**	**92.033**			
25	**649820.2**	**691067.9**	**8570.904**			
28	**2444331**	**2444331**	**129298.7**			
30	**91.713**	**91.633**	**92.033**			
31	**2665195**	**2667522**	**140491.6**			
33	**3.52**	**3.33**	**4.66**			
34				DHW	SH	Heat loss
35	**1091295**	**1178069**	**33540.07**	**1839.543689**	**30153.24**	**1547.289**
36	**1128571**	**1178069**	**39877.06**	**8176.525608**		
37	**1128.571**	**1178.069**	**39.87706**			
38			**0.237363**	**0.048669795**	**0.179484**	**0.00921**
39				To Demand Setting, D62, D63		

	AG	AI	AJ	AK	AL	AM	AN	AO
1	***Improvement***		**40C**	**45C**	**50C**	**55C**	**60C**	**65C**
2	72%	DHW consumption	1649.079	1649.079	1649.079	1649.079	1649.079	1649.079
3		water in tank (kg)	31618.239	31618.24	31618.239	31618.24	31618.24	31618.24
4		SH consumption	1793.067	1793.067	1793.067	1793.067	1793.067	1793.067
5		households	384	384	384	384	384	384
6		distribution T	40	45	50	55	60	65
7		soil T	10	10	10	10	10	10
8		T(return 30C, soil 10C)	**25**	**27.5**	**30**	**32.5**	**35**	**37.5**
9		length branch pipe, m	5	5	5	5	5	5
10		branch U	**0.139**	**0.139**	**0.139**	**0.139**	**0.139**	**0.139**
11		length main pipe, m	10	10	10	10	10	10
12		main U	**0.308**	**0.308**	**0.308**	**0.308**	**0.308**	**0.308**
13		branch number	**384**	**384**	**384**	**384**	**384**	**384**
14		main number	**192**	**192**	**192**	**192**	**192**	**192**
15		hours	8760	8760	8760	8760	8760	8760
16		W to kW	1000	1000	1000	1000	1000	1000
17			annual heat l	annual hea	annual heat	annual hea	annual hea	annual heat loss
18			**375909.12**	**413500**	**451090.94**	**488681.9**	**526272.8**	**563863.7**
20		DHW						
21		Energy (from Elec. Boiler)	**309612.528**	**241528.6**	**173444.59**	**105360.6**	**37276.66**	**0**
22		Energy (from LTDH) kWh	**323633.725**	**391717.7**	**459801.66**	**527885.6**	**595969.6**	**633246.3**
23		Energy demand before HIU						
24		HIU efficiency	**92.033**	**91.953**	**91.873**	**91.793**	**91.713**	**91.633**
25		DHW, Energy (from LTDH) kWh	**351649.652**	**425997.7**	**500475.29**	**575082.7**	**649820.2**	**691067.9**
27		SH						
28		Energy (from LTDH) kWh	**688537.674**	**688537.7**	**688537.67**	**688537.7**	**688537.7**	**688537.7**
29		Energy demand before HIU						
30		HIU efficiency	**92.033**	**91.953**	**91.873**	**91.793**	**91.713**	**91.633**
31		SH, Energy (from LTDH) kWh	**748142.16**	**748793.1**	**749445.08**	**750098.2**	**750752.5**	**751408**
33		COP	**4.66**	**4.29**	**3.99**	**3.73**	**3.52**	**3.32**
34		DHW + SH						
35		Enerygy consumption of GSHP	**316724.639**	**369968.3**	**426327.31**	**485745**	**548168.2**	**603435.7**
36		**Total Electricity (Elec. Boiler + GSHP)**	**626337.167**	**611496.9**	**599771.91**	**591105.6**	**585444.8**	**603435.7**
37		**MWh**	**626.337167**	**611.4969**	**599.77191**	**591.1056**	**585.4448**	**603.4357**
40			DHW	ratio	SH			
41			1649.079	1.09	1793.067			
45			DHW:SH		384			
46				1.087314	**60**	°C		
48			Ele heaters	37276.66	**37.276659**	MWh		
49			GSHP	548168.2	**548.16817**	MWh		
50			Total		**585.44483**	MWh		

	AR	AT	AU	AV	AW	AX	AY	AZ
1	***Plan to improve***		**40C**	**45C**	**50C**	**55C**	**60C**	**65C**
2	50%	DHW consumption	1649.079	1649.079	1649.079	1649.079	1649.079	1649.079
3		water in tank (kg)	31618.239	31618.24	31618.239	31618.24	31618.24	31618.24
4		SH consumption	3174.950	3174.950	3174.950	3174.950	3174.950	3174.950
5		households	384	384	384	384	384	384
6		distribution T	40	45	50	55	60	65
7		soil T	10	10	10	10	10	10
8		T(return 30C, soil 10C)	**25**	**27.5**	**30**	**32.5**	**35**	**37.5**
9		length branch pipe, m	5	5	5	5	5	5
10		branch U	**0.139**	**0.139**	**0.139**	**0.139**	**0.139**	**0.139**
11		length main pipe, m	10	10	10	10	10	10
12		main U	**0.308**	**0.308**	**0.308**	**0.308**	**0.308**	**0.308**
13		branch number	**384**	**384**	**384**	**384**	**384**	**384**
14		main number	**192**	**192**	**192**	**192**	**192**	**192**
15		hours	8760	8760	8760	8760	8760	8760
16		W to kW	1000	1000	1000	1000	1000	1000
17			annual heat	annual hea	annual heat	annual hea	annual hea	annual heat loss
18			**375909.12**	**413500**	**451090.94**	**488681.9**	**526272.8**	**563863.7**
20		DHW						
21		Energy (from Elec. Boiler)	**309612.53**	**241528.6**	**173444.59**	**105360.6**	**37276.66**	**0**
22		Energy (from LTDH) kWh	**323633.72**	**391717.7**	**459801.66**	**527885.6**	**595969.6**	**633246.3**
23		Energy demand before HIU						
24		HIU efficiency	**92.033**	**91.953**	**91.873**	**91.793**	**91.713**	**91.633**
25		DHW, Energy (from LTDH) kWh	**351649.65**	**425997.7**	**500475.29**	**575082.7**	**649820.2**	**691067.9**
27		SH						
28		Energy (from LTDH) kWh	**1219180.8**	**1219181**	**1219180.8**	**1219181**	**1219181**	**1219181**
29		Energy demand before HIU						
30		HIU efficiency	**92.033**	**91.953**	**91.873**	**91.793**	**91.713**	**91.633**
31		SH, Energy (from LTDH) kWh	**1324721.3**	**1325874**	**1327028.4**	**1328185**	**1329343**	**1330504**
33		COP	**4.66**	**4.29**	**3.99**	**3.73**	**3.52**	**3.32**
34		DHW + SH						
35		Enerygy consumption of GSHP	**440473.86**	**504390.6**	**571087.99**	**640554.2**	**712771.5**	**777607.3**
36		**Total Electricity (Elec. Boiler + GSHP)**	**750086.38**	**745919.1**	**744532.58**	**745914.8**	**750048.1**	**777607.3**
37		**MWh**	**750.08638**	**745.9191**	**744.53258**	**745.9148**	**750.0481**	**777.6073**
40			DHW	ratio	SH			
41			1649.079	1.925287	3174.950			
45			DHW:SH		384			
46				1.925287	**50**	°C		
48			Ele heaters	173444.6	**173.44459**	MWh		
49			GSHP	571088	**571.08799**	MWh		
50			Total		4	MWh		

Demand Setting | Summary | H1_para | H2_T sele | H3_dema | H4_profile | E1_para | E2_EVs | E3_elec | C1_E network | C2_system | C3_retrofit | Efficiency impro | noSys profile | +

	2006	2018		DHW+SH
	DHW	SH	Days per M	Averaged Daily
Jan	152.81	939.8	31	35.25
Feb	148.18	1080.5	28	43.88
Mar	159.75	987	31	36.99
Apr	132.23	554.1	30	22.88
May	141.46	320	31	14.89
Jun	121.58	145.2	30	8.89
Jul	98.02	40.1	31	4.46
Aug	111.72	85.4	31	6.36
Sep	115.30	243.7	30	11.97
Oct	141.45	497.7	31	20.62
Nov	156.26	670.2	30	27.55
Dec	170.32	786.2	31	30.86
	1649.08	6349.9 kWh		
Note		monthly load generated		

Max demand month	Max. Average Daily	
Feb	43.88133988	Database
	DHW monthly	Aligns to User's annual
	148.1775167	
	SH monthly	
	1083.145	

	MWh	Ratio	Monthly	
			1.649	Obtained annual data from sheet 1
Jan	0.15281	9.26632	0.15281	152.81
Feb	0.14818	8.98547	0.14818	148.18
Mar	0.15975	9.68704	0.15975	159.75
Apr	0.13223	8.01869	0.13223	132.23
May	0.14146	8.57825	0.14146	141.46
Jun	0.12158	7.37282	0.12158	121.58
Jul	0.09802	5.9442	0.09802	98.02
Aug	0.11172	6.77444	0.11172	111.72
Sep	0.1153	6.99203	0.1153	115.30
Oct	0.14145	8.57728	0.14145	141.45
Nov	0.15626	9.4755	0.15626	156.26
Dec	0.17032	10.328	0.17032	170.32
	1.64908	100	MWh	kWh

Max demand month
Weekly
0.03704
MWh

	MWh	Ratio	Monthly	
			6.365	Obtained annual data from
Jan	0.9398	14.8002	0.94210056	942.101
Feb	1.0805	17.016	1.08314499	1083.145
Mar	0.987	15.5436	0.98941611	989.416
Apr	0.5541	8.72612	0.5554564	555.456
May	0.32	5.03945	0.32078334	320.783
Jun	0.1452	2.28665	0.14555544	145.555
Jul	0.0401	0.63151	0.04019816	40.1982
Aug	0.0854	1.3449	0.08560905	85.6091
Sep	0.2437	3.83786	0.24429656	244.297
Oct	0.4977	7.83792	0.49891833	498.918
Nov	0.6702	10.5545	0.6718406	671.841
Dec	0.7862	12.3813	0.78812456	788.125
	6.3499	100	MWh	kWh

Max demand month	Max demand month
coldest week	**coldest day**
0.33672	0.06086
MWh	MWh

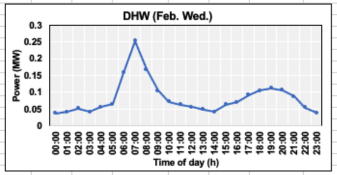
Consumed the most energy week
31.1%
Consumed the most energy day
5.6%

Water Cp		kWh	kJ	Temperature		Tank T	Monthly	Days of month	Weekly
Cp (kJ/kg°C)				Cold water	Hot water		60		
4.18	Jan	152.81	550112	11.1	52.1		2691.32		
	Feb	148.18	533439	10.7	51.9		2588.58	28	647.145
	Mar	159.75	575089	12	51.8		2866.27		
	Apr	132.23	476044	14.8	52.1		2519.61		
	May	141.46	509263	16	52.4		2768.94		
	Jun	121.58	437701	18.5	52.5		2523.21		
	Jul	98.02	352888	20.5	51.9		2137.29		
	Aug	111.72	402177	19.5	52.9		2375.67		
	Sep	115.30	415095	19	52.1		2422.07		
	Oct	141.45	509206	16.3	52.4		2787.63		
	Nov	156.26	562530	13.3	52.9		2881.73		
	Dec	170.32	613139	12	51.9		3055.92		
							31618.2		
							kg		

DHW

		Days of mo	demand	%	Max demand month One day	Max demand month Ratio to match
Mo	1.06260	4	4.2504	14%	5.16728679	4.862871061
Tu	1.06260	4	4.2504	14%	5.16728679	
We	1.06260	4	4.2504	14%	5.16728679	
Th	1.06260	4	4.2504	14%	5.16728679	
Fr	1.06260	4	4.2504	14%	5.16728679	
Sa	1.15240	4	4.6096	15%	5.60397261	
Su	1.15240	4	4.6096	15%	5.60397261	
	kW		30.4712			

		kW	with N
		Feb	MW
Workdays	DHW	Wed	384
00:00	0.020	0.09726	0.03735
01:00	0.022	0.10698	0.04108
02:00	0.028	0.13616	0.05229
03:00	0.022	0.10844	0.04164
04:00	0.030	0.1454	0.05583
05:00	0.035	0.16923	0.06498
06:00	0.084	0.40945	0.15723
07:00	0.135	0.65649	0.25209
08:00	0.090	0.43766	0.16806
09:00	0.056	0.27232	0.10457
10:00	0.039	0.18722	0.07189
11:00	0.034	0.16437	0.06312
12:00	0.030	0.14589	0.05602
13:00	0.026	0.12643	0.04855
14:00	0.022	0.10844	0.04164
15:00	0.034	0.16437	0.06312
16:00	0.038	0.18236	0.07003
17:00	0.049	0.23731	0.09113
18:00	0.056	0.27135	0.1042
19:00	0.060	0.29274	0.11241
20:00	0.057	0.27475	0.1055
21:00	0.047	0.22855	0.08777
22:00	0.029	0.142	0.05453
23:00	0.021	0.10212	0.03921

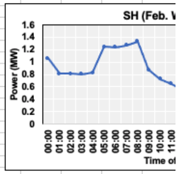


SH

Consumed the most energy day 60.8557 Coldest demand (kWh)

Ratio to match
13.758909

		kW	with N
		Feb	MW
Workdays	SH	Wed	384
00:00	0.201	0.10212	1.06197
01:00	0.153	0.10212	0.80836
02:00	0.154	0.10212	0.81365
03:00	0.152	0.10212	0.80308
04:00	0.157	0.10212	0.8295
05:00	0.235	0.10212	1.2416
06:00	0.234	0.10212	1.23632
07:00	0.24	0.10212	1.26802
08:00	0.252	0.10212	1.33142
09:00	0.165	0.10212	0.87176
10:00	0.138	0.10212	0.72911
11:00	0.123	0.10212	0.64986
12:00	0.106	0.10212	0.56004
13:00	0.083	0.10212	0.43852
14:00	0.115	0.10212	0.60759
15:00	0.136	0.10212	0.71855
16:00	0.219	0.10212	1.15707
17:00	0.266	0.10212	1.40539
18:00	0.263	0.10212	1.38954
19:00	0.272	0.10212	1.43709
20:00	0.248	0.10212	1.31029
21:00	0.13	0.10212	0.68684
22:00	0.159	0.10212	0.84006
23:00	0.222	0.10212	1.17292
	4.423		



Demand Setting | Summary | H1_para | H2_T sele | H3_dema | H4_profile | E1_para | E2_EVs | E3_elec | C1_E network | C2_system | C3_retrofit | Efficiency impro | noSys profile | +

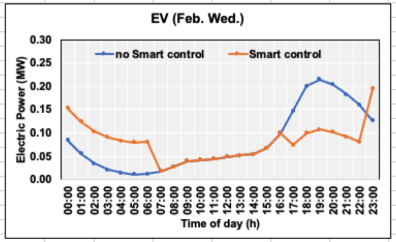
	C	D	E	F
1	per EV	kW		
2	Hour	Residential	ratio	
3	00:00	0.11	11.0	
4	01:00	0.08	7.6	
5	02:00	0.05	4.8	
6	03:00	0.03	3.1	
7	04:00	0.02	2.2	
8	05:00	0.02	1.9	
9	06:00	0.02	2.1	
10	07:00	0.03	3.2	
11	08:00	0.05	5.1	
12	09:00	0.08	7.8	
13	10:00	0.08	8.2	
14	11:00	0.09	8.9	
15	12:00	0.10	9.8	
16	13:00	0.10	10.5	
17	14:00	0.11	10.8	
18	15:00	0.13	13.2	
19	16:00	0.20	19.6	
20	17:00	0.29	28.9	
21	18:00	0.39	39.2	
22	19:00	0.41	41.5	
23	20:00	0.38	38.1	
24	21:00	0.33	33.4	
25	22:00	0.28	28.3	
26	23:00	0.21	21.4	3.6
27	00:00	0.15	14.5	
28	01:00	0.09	9.5	
29	02:00	0.06	5.8	
30	03:00	0.04	3.7	
31	04:00	0.03	2.5	
32	05:00	0.02	2.0	
33	06:00	0.02	2.3	
34	07:00	0.03	3.4	
35	08:00	0.05	5.3	
36	09:00	0.08	7.7	
37	10:00	0.08	8.0	
38	11:00	0.09	8.6	
39	12:00	0.09	9.4	
40	13:00	0.10	9.9	
41	14:00	0.10	10.4	
42	15:00	0.13	13.0	
43	16:00	0.19	19.4	
44	17:00	0.29	29.1	
45	18:00	0.40	39.7	
46	19:00	0.42	42.4	
47	20:00	0.40	39.6	
48	21:00	0.35	35.2	
49	22:00	0.31	30.6	
50	23:00	0.24	23.8	3.8
51	00:00	0.17	16.5	
52	01:00	0.11	10.8	
53	02:00	0.07	6.6	
54	03:00	0.04	4.2	
55	04:00	0.03	2.8	
56	05:00	0.02	2.2	
57	06:00	0.02	2.4	
58	07:00	0.04	3.5	
59	08:00	0.05	5.4	
60	09:00	0.08	7.8	
61	10:00	0.08	8.2	
62	11:00	0.09	8.8	
63	12:00	0.10	9.6	

	I	J
3	Max demand month	Monthly
4	Feb	110.6

	M	N	O	P	Q	R	U	V	W	X
1	per EV		per day			monthly	Ratio	Monthly		
2		months	kWh		kWh	MWh		1.32075	Obtained annual data from sheet 1	
3		Jan	4.2	31	130.2	0.1302	9.858035	0.130	130.2	
4		Feb	3.95	28	110.6	0.1106	8.37403	0.111	110.6	
5		Mar	3.75	31	116.25	0.11625	8.801817	0.116	116.25	
6		Apr	3.4	30	102	0.102	7.722885	0.102	102	
7		May	3.4	31	105.4	0.1054	7.980314	0.105	105.4	
8		Jun	3.3	30	99	0.099	7.495741	0.099	99	
9		Jul	3.25	31	100.75	0.10075	7.628242	0.101	100.75	
10		Aug	2.85	31	88.35	0.08835	6.689381	0.088	88.35	
11		Sep	3.4	30	102	0.102	7.722885	0.102	102	
12		Oct	3.7	31	114.7	0.1147	8.68446	0.115	114.7	
13		Nov	4.25	30	127.5	0.1275	9.653606	0.128	127.5	
14		Dec	4	31	124	0.124	9.388605	0.124	124	
15					1320.75	1.32075	100	MWh	kWh	
16										Max demand month
17										Weekly
18										0.02765
19										MWh

	K	L	M	N	O	P	R
26		kW					
27			Days of month	demand	%	One day	Ratio to match
28	Mo	3.6	4	14.4221229	14%	3.938086	1.092235
29	Tu	3.8	4	15.0262033	15%	4.103036	
30	We	3.9	4	15.42142	15%	4.210953	
31	Th	3.9	4	15.6485116	15%	4.272962	
32	Fr	3.7	4	14.842866	15%	4.052974	
33	Sa	3.2	4	12.85378	13%	3.509837	
34	Su	3.3	4	13.0453701	13%	3.562152	
35		kW		101.260274			

	T	U	V	W	Y	Z
24						with N
25			kW	kW		MW
26			Feb	Smart	no Smart co	Smart control
27	Tu		Tu	0.5		465
28	00:00	0.15	0.15863			
29	01:00	0.09	0.103292			
30	02:00	0.06	0.06374			
31	03:00	0.04	0.040443			
32	04:00	0.03	0.027509			
33	05:00	0.02	0.02214			
34	06:00	0.02	0.024997			
35	07:00	0.03	0.036849			
36	08:00	0.05	0.057613			
37	09:00	0.08	0.083651			
38	10:00	0.08	0.086988			
39	11:00	0.09	0.093938			
40	12:00	0.09	0.102903			
41	13:00	0.10	0.108315			
42	14:00	0.10	0.113344			
43	15:00	0.13	0.14145			
44	16:00	0.19	0.211548			
45	17:00	0.29	0.317389	0.15869427	0.148	0.074
46	18:00	0.40	0.433451	0.21672552	0.202	0.101
47	19:00	0.42	0.463225	0.23161263	0.215	0.108
48	20:00	0.40	0.432921	0.21646068	0.201	0.101
49	21:00	0.35	0.384778	0.19238901	0.179	0.089
50	22:00	0.31	0.334363	0.16718171	0.155	0.078
51	23:00	0.24	0.259556	0.40743947	0.121	0.189
52	00:00	0.17	0.180495	0.32837795	0.084	0.153
53	01:00	0.11	0.117499	0.26538221	0.055	0.123
54	02:00	0.07	0.072509	0.22039176	0.034	0.102
55	03:00	0.04	0.045792	0.19367513	0.021	0.090
56	04:00	0.03	0.030748	0.17863108	0.014	0.083
57	05:00	0.02	0.023931	0.17181403	0.011	0.080
58	06:00	0.02	0.026426	0.17430914	0.012	0.081
59	07:00	0.04	0.038599	0.03859915	0.018	0.018
60	08:00	0.05	0.059034	0.05903362	0.027	0.027
61	09:00	0.08	0.085243	0.08524269	0.040	0.040
62	10:00	0.08	0.089472	0.0894719	0.042	0.042
63	11:00	0.09	0.095575	0.09557539	0.044	0.044



Demand Setting | Summary | H1_para | H2_T sele | H3_dema | H4_profile | E1_para | E2_EVs | E3_elec | C1_E network | C2_system | C3_retrofit | Efficiency impro | noSys profile

Max demand month	Monthly
Feb	376.087

months	TWh	MWh	households	per dwelling MWh		Ratio	Monthly 3.748913	Obtained annual data from sheet 1
Jan	10.86	10860000	27600000	0.393		10.4958	0.393	393.478
Feb	10.38	10380000		0.376		10.03189	0.376	376.087
Mar	10.85	10850000		0.393		10.48613	0.393	393.116
Apr	8.67	8670000		0.314		8.37924	0.314	314.130
May	7.18	7180000		0.260		6.939209	0.260	260.145
Jun	6.75	6750000		0.245		6.52363	0.245	244.565
Jul	6.45	6450000		0.234		6.233691	0.234	233.696
Aug	6.49	6490000		0.235		6.272349	0.235	235.145
Sep	7.17	7170000		0.260		6.929545	0.260	259.783
Oct	8.41	8410000		0.305		8.12796	0.305	304.710
Nov	9.69	9690000		0.351		9.365033	0.351	351.087
Dec	10.57	10570000		0.383		10.21552	0.383	382.971
				3.749	homes	100	MWh	kWh

Max demand month

Weekly

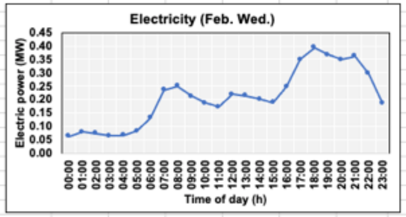
0.094021739

MWh

	100 homes		1 home	
	Q1 weekda	Q1 weeken	Q1 weekda	Q1 weekend
0	14.023	15.448	0.140	0.15448375
1	17.374	17.956	0.174	0.179557917
2	16.097	16.303	0.161	0.163030556
3	14.256	13.921	0.143	0.13921375
4	14.618	14.681	0.146	0.14681375
5	18.165	17.360	0.182	0.173598333
6	28.922	22.317	0.289	0.2231675
7	51.914	37.226	0.519	0.3722575
8	54.708	50.370	0.547	0.503703889
9	46.774	68.440	0.468	0.684396111
10	40.920	61.433	0.409	0.614331944
11	38.014	58.961	0.380	0.589609444
12	48.143	60.886	0.481	0.608857917
13	47.147	61.341	0.471	0.613407361
14	44.060	58.308	0.441	0.583079167
15	41.308	63.234	0.413	0.632339861
16	54.627	75.519	0.546	0.755185694
17	76.549	83.682	0.765	0.836824167
18	86.242	81.610	0.862	0.816102778
19	80.527	84.559	0.805	0.845590694
20	76.500	80.515	0.765	0.805151667
21	79.297	73.946	0.793	0.739455139
22	64.960	59.289	0.650	0.592894583
23	41.127	43.826	0.411	0.438260833

	1 home						
		Days of month	demand	%	One day		Ratio to match
Mo	10.963	4	43.85093	14%	13.00837		1.187
Tu	10.963	4	43.85093	14%	13.00837		
We	10.963	4	43.85093	14%	13.00837		
Th	10.963	4	43.85093	14%	13.00837		
Fr	10.963	4	43.85093	14%	13.00837		
Sa	12.211	4	48.84526	15%	14.48994		
Su	12.211	4	48.84526	15%	14.48994		
			316.9452		kWh		

		kW	with N MW
		Feb	384
	Q1 weekdays	Wed	
00:00	0.140	0.166	0.064
01:00	0.174	0.206	0.079
02:00	0.161	0.191	0.073
03:00	0.143	0.169	0.065
04:00	0.146	0.173	0.067
05:00	0.182	0.216	0.083
06:00	0.289	0.343	0.132
07:00	0.519	0.616	0.237
08:00	0.547	0.649	0.249
09:00	0.468	0.555	0.213
10:00	0.409	0.486	0.186
11:00	0.380	0.451	0.173
12:00	0.481	0.571	0.219
13:00	0.471	0.559	0.215
14:00	0.441	0.523	0.201
15:00	0.413	0.490	0.188
16:00	0.546	0.648	0.249
17:00	0.765	0.908	0.349
18:00	0.862	1.023	0.393
19:00	0.805	0.956	0.367
20:00	0.765	0.908	0.349
21:00	0.793	0.941	0.361
22:00	0.650	0.771	0.296
23:00	0.411	0.488	0.187



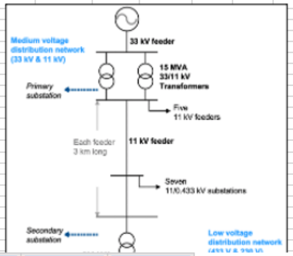
Demand Setting | Summary | H1_para | H2_T sele | H3_dema | H4_profile | E1_para | E2_EVs | E3_elec | C1_E network | C2_system | C3_retrofit | Efficiency impro | noSys profile | +

B	C	D	E	F	G	H
132/33 kV substation		Transformer	existing			
		kVA	60,000	90,000		
		units		2		
		cost per unit		750,000		
		cost total		1,500,000		
33kV feeder						
		kVA	24,000			
		cost	500,000			
Primary substation						
	33/11.5 kV					
		Transformer				
		kVA	24,000			
		units	2			
		cost per unit	750,000			
		cost total	1,500,000			
new HV substation	33/11.5 kV	kVA	10,000	24,000		
		cost	760,000	2,000,000		
11kV feeder						
		kVA	5,000	7,700	8,000	
		cost per m	50	100	100	
		type		underground cable	underground cable	
		Size		185mm2	300mm2	
		Circuit breaker				
		cost	50,000			
Secondary substation						
	11/0.433kV					
		existing 300 kVA SS				
		Replacement transformer				
		kVA	500	800	1000	
		cost total	10,000	16,000	20,000	
				assumed it's linear		
new LV substation						
	11/0.433kV					
		kVA	315	500	800	1000
		cost total	24,000	33,917	50,000	60,721
				assumed it's linear		*assumed it's linear*

Reference

https://www.westernpower.co.uk/connections-landing/connections-regulations-and-policy/connections-charging-statements

L	M	N	O
Standard conditions			
Grid supply			
	33 kV		
		kVA	500,000
33kV feeder		number	1
		kVA	24,000
		cost	500,000
Primary substation			
	33/11.5 kV	number	1
	Transformer		
		kVA	15,000
		units	2
11kV feeder			
		number	6
		kVA	8,000
		cost per m	100
		length, m	3,000
Secondary substation			
		number	8
	11/0.433kV		
	Transformer		
		kVA	500
	assumed the existing LV network can accommodate the demand		



T	U	V	W	X	Y	Z	AA	AB	AC	AD
		Opt. 1								
		Total cost per SS	**515,305**							
1 substation demanc	**102,290**									
132/33 kV		**Reinforcement**								
		Transformer								
		kVA	**90,000**							
		cost	**1500000**							
		per SS cost	**31,250**							
1 feeder demand	**102,290**									
		Reinforcement								
		Feeder								
		N	**6**							
		cost	**2,500,000**							
		per SS cost	**52,083**							
1 PSS Demand	**102,290**									
		Reinforcement								
		Transformer								
		kVA	**24,000**							
		cost	**1,500,000**							
		per SS cost	**31,250**							
		New PSS								
		Demand over 24,000*0.8	**83,090**	**63,890**	**44,690**	**25,490**	**6,290**	**0**	**0**	**0**
		kVA	**24000**	**24000**	**24000**	**24000**	**10000**	**0**	**0**	**0**
		cost	**2,000,000**	**2,000,000**	**2,000,000**	**2,000,000**	**760,000**	-	-	-
		per SS cost	**41,667**	**41,667**	**41,667**	**41,667**	**15,833**	-	-	-
1 feeder Demand	**17,048**									
		Reinforcement								
		Feeder								
		N	**3**							
		cost	**600,000**							
		per SS cost	**75,000**							
		Circuit breaker								
		cost	**100,000**							
		per SS cost	**12,500**							
1 SS Demand	2,131.0									
		Reinforcement					Note			
		Transformer					1. replacing transformer			
		kVA	**1,000**				2. building new SS			
		cost	**20,000**							
		New SS								
		Demand over 1000*0.8	**1331**	**531**	**0**	**0**	**0**	**0**		
		kVA	**1000**	**800**	**0**	**0**	**0**	**0**		
		cost	**60,721**	**50,000**	-	-	-	-		
Demand buffer										
20%	0.80									

Demand Setting | Summary | H1_para | H2_T sele | H3_dema | H4_profile | E1_para | E2_EVs | E3_elec | C1_E network | C2_system | C3_retrofit | Efficiency impro | noSys profile | +

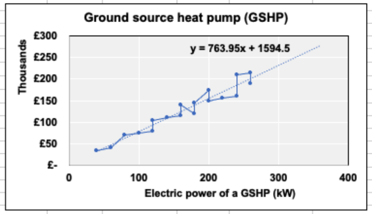
GSHP

	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U
			40+40	40+60	60+60	40+40+40	40+40+60	40+60+60	40+40+40+40	60+60+60	40+40+40+60	40*5	40+40+60+60	40+60+60+60	60+60+60+60	40*6	40*5+60	60+60+60+40+40
kW	40	60	80	100	120	120	140	160	160	180	180	200	200	220	240	240	260	260
cost	35,000	40,000	70,000	75,000	80,000	105,000	110,000	115,000	140,000	120,000	145,000	175,000	150,000	155,000	160,000	210,000	215,000	190,000

y=763.95x+1594.5

	Opt.1	Opt.2	Opt. 3	Opt. 4
		261	119	162
		201,062	**92,824**	**125,648**

Linear trendline	
y=ax+b	
a	**763.95**
b	**1,594.53**



Reference

https://www.trusted.energy/

Typically to achieve large outputs 40kW or 60kW heat pumps are cascaded together.

prices for supply and installation of the pumps, including the horizontal ground collector pipes required.

District heating system

		D	E	Opt.1	Opt.2	Opt. 3	Opt. 4
	Network capital costs (main network- buried)						
	m	3840					
	cost per m	468					
	total cost	**1,797,120**					
	Network capital costs (internal pipe)						
	dwellings	384					
assumed	m per dwelling	15					
	cost per m	169					
	total cost	**973,440**					
	Substations cost						
	kW	2,304					
	cost per kW	35					
	total cost	**80,640**					
	Domestic HIUs cost						
	dwellings	384					
	cost per dwelling	1,075					
	total cost	**412,800**					
	Heat meter cost						
	dwellings	384					
	cost per dwelling	579					
	total cost	**222,336**					
	Thermal store cost						
	m3			0	907.02	111.54	254.10
	cost per m3	843					
	total cost			0	**764,619**	**94,028**	**214,208**
	Total			0	**4,250,955**	**3,580,364**	**3,700,544**

Reference

https://www.gov.uk/government/publications/assessment-of-the-costs-performance-and-characteristics-of-uk-heat-networks

Li-ion battery

		D	E	F	G	H	I
		$	£				
	cost per MWh	156,000	118,000				
	Battery_1			0	1.27	1.27	1.27

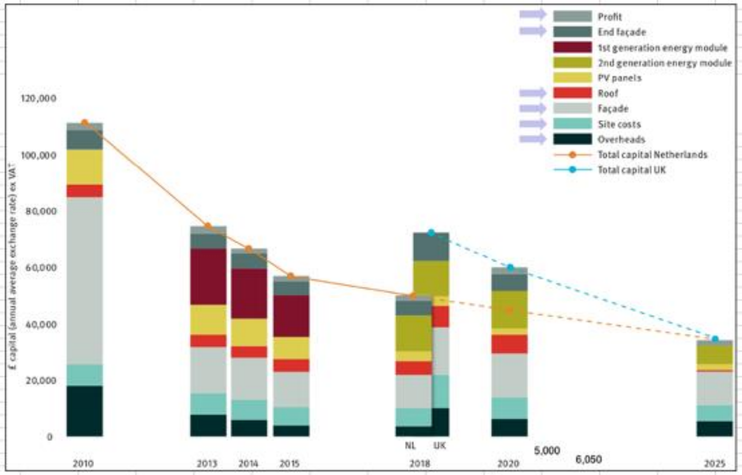
Reference

https://about.bnef.com/blog/battery-pack-prices-fall-as-market-ramps-up-with-market-average-at-156-kwh-in-2019/?sf113554299

Demand Setting | Summary | H1_para | H2_T sele | H3_dema | H4_profile | E1_para | E2_EVs | E3_elec | C1_E network | C2_system | C3_retrofit | Efficiency impro | noSys profile | +

Row	B	C	D	E	F	G	H	I	T
39		Substations cost							Reference
40		kW	2,304						https://www.gov.uk/government/publications/assessment-of-the-costs-performance-and-characteristics-of-uk-heat-networks
41		cost per kW	35						
42		total cost	**80,640**						
44		Domestic HIUs cost							
45		dwellings	384						
46		cost per dwelling	1,075						
47		total cost	**412,800**						
49		Heat meter cost							
50		dwellings	384						
51		cost per dwelling	579						
52		total cost	**222,336**						
54		Thermal store cost							
55		m3			0	907.02	111.54	254.10	
56		cost per m3	843						
57		total cost			0	**764,619**	**94,028**	**214,208**	
59		Total			0	**4,250,955**	**3,580,364**	**3,700,544**	
65	**Li-ion battery**		$	£					
66		cost per MWh	156,000	118,000					Reference
67		Battery_1			0	1.27	1.27	1.27	https://about.bnef.com/blog/battery-pack-prices-fall-as-market-ramps-up-with-market-average-at-156-kwh-in-2019/?sf113554299
68		Battery_2			0	0	0	6.45	
69					-	**150,363**	**150,363**	**910,965**	
77	**PV modules**								
79					**Opt.1**	**Opt.2**	**Opt. 3**	**Opt. 4**	Reference
80		0-4 kW							https://www.gov.uk/government/statistics/solar-pv-cost-data
81		cost per kW installed	1,562						
82		required kWp						349.37	
83		total cost						**545,723**	
93	**Solar thermal**	http://solarproject.co.uk/Panels.html							
94		20X47mm tubes (£)	375						Reference
95		Diameter of tubes	47						http://solarproject.co.uk/Panels.html
96		Length of tubes (mm	1500						
97		m2	1.41						
99					**Opt.1**	**Opt.2**	**Opt. 3**	**Opt. 4**	
100		required m2						150.89	
101		cost per m2	266						
102		total cost						**40,132**	

Demand Setting | Summary | H1_para | H2_T sele | H3_dema | H4_profile | E1_para | E2_EVs | E3_elec | C1_E network | C2_system | C3_retrofit | Efficiency impro | noSys profile | +

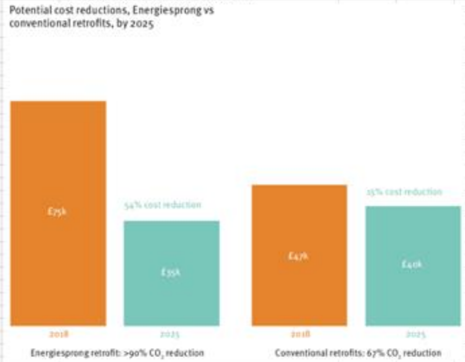


5,000

6,050

Reference https://www.green-alliance.org.uk/reinventing_retrofit.php

Energiesprong homes.Their excellent insulation lowers each home's heat demand by at least 90 per cent, and the use of heat pumps, which are four times as efficient as gas boilers, further reduces demand.



	UK				
	2020			2025	
	£			£	
Profit	62,000	2,400	Profit	35,000	2,000
End façade	59,600	6,200	End façade		
2nd	53,400	13,900	2nd	33,000	6,600
PV	39,500	2,500	PV	26,400	2,200
Roof	37,000	6,980	Roof	24,200	500
Façade	30,020	16,020	Façade	23,700	12,500
Site costs	14,000	7,950	Site costs	11,200	5,700
Overheads	6,050	6,050	Overheads	5,500	5,500

2025							
							90% reduction
	Overheads	Site costs	Façade	Roof	End façade	Profit	per dwelling
	5,500	5,700	12,500	500	-	2,000	26,200

Opt. 3		
SH per hom	homes	homes
6.365	384	306
	72%	90%

Opt. 4		
SH per hom	homes	homes
6.365	384	213
	50%	90%

Opt. 3	8,022,066

Opt. 4	5,589,333

Demand Setting | Summary | H1_para | H2_T sele | H3_dema | H4_profile | E1_para | E2_EVs | E3_elec | C1_E network | C2_system | C3_retrofit | Efficiency impro | noSys profile

Appendix 7. Validation of the electricity demand profiles

To validate the modelling tool of multi-vector community energy systems (Chapter 8), figures that compare the modelling tool and studies are illustrated. The electricity consumption of DHW in an average household is presented in Figure A-6. This includes the results from the modelling tool and a study named household electricity survey (HES) [163]. By utilising the method of demand percentage, the electric load curves show a great match. The power consumption from HES is relatively low because electric heaters are a supplement to water heating. Using gas to heat water is indicated to be the main choice in the survey.

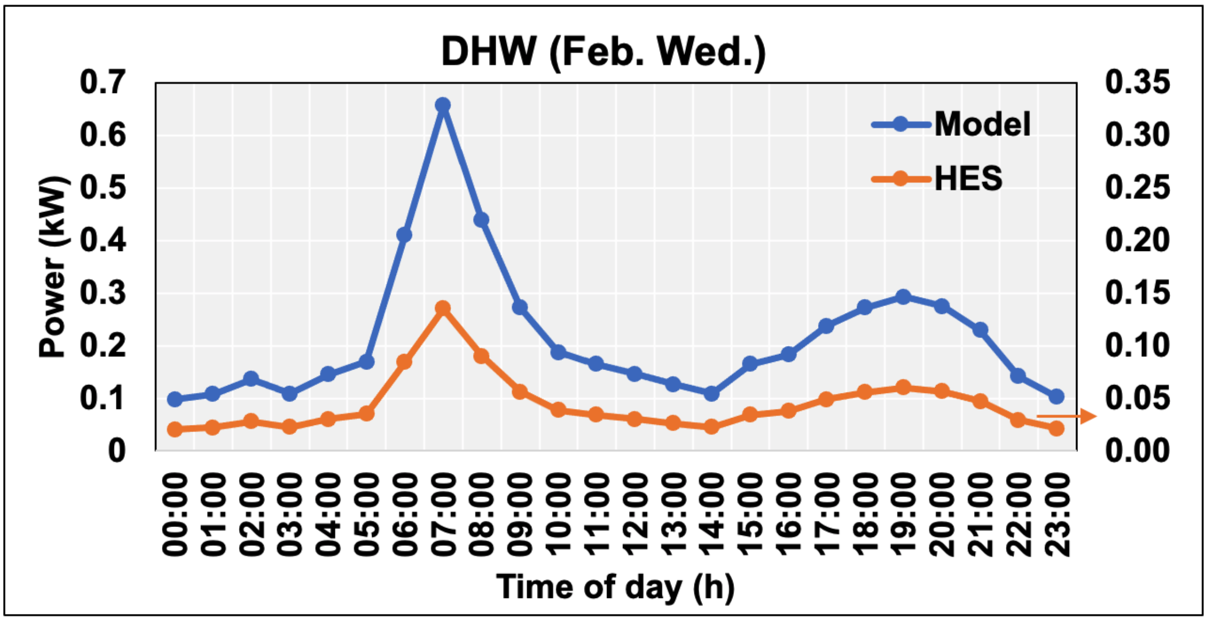


Figure A-6: The comparison between the modelling tool and household electricity survey (HES), showing DHW demand in an average UK dwelling [163].

For SH consumption, the same study HES reports that electric SH was supplied mostly by the individual or portable heaters and was used occasionally [163]. As a result, the electric power demand from HES is lower than from the modelling tool, illustrated in Figure A-7. Nonetheless, the load curves indicate a great match.

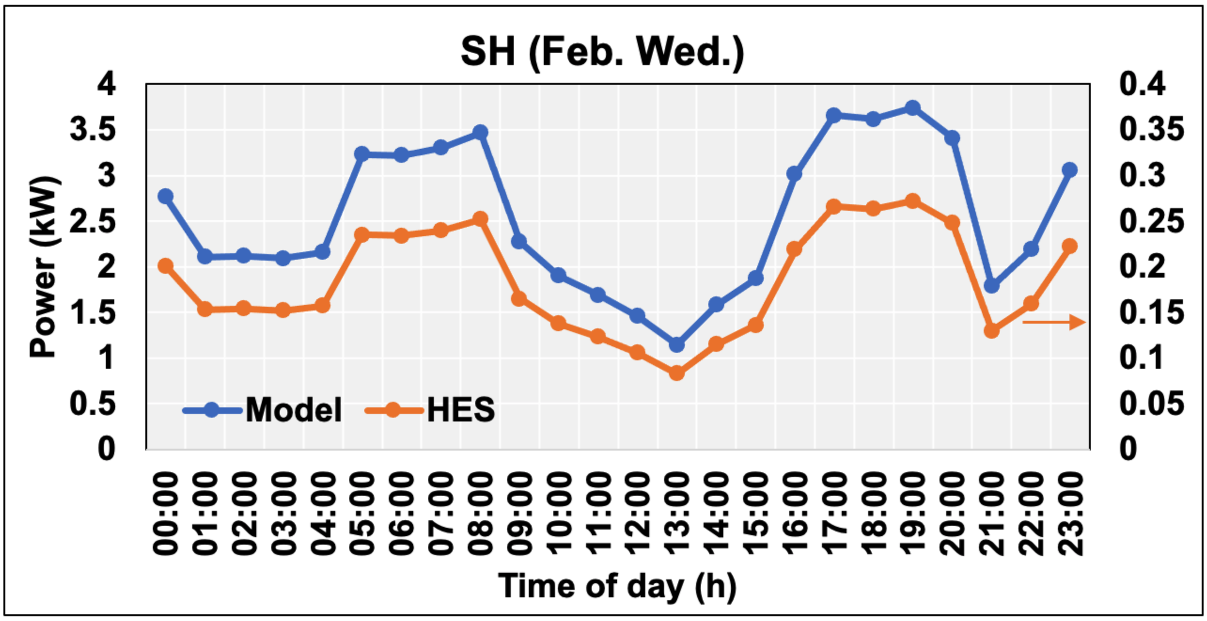


Figure A-7: The comparison between the modelling tool and household electricity survey (HES), showing SH demand in an average UK dwelling [163].

Figure A-8 illustrates the electricity demand of lighting and appliances, which is a comparison between the modelling tool and an open-source software named CREST [134]. The electric load curve from the modelling tool matches the profile from CREST due to the method of demand percentage. The power demand indicated by the modelling tool is aligned to national statistical data in 2018 and shows a slightly greater consumption than CREST.

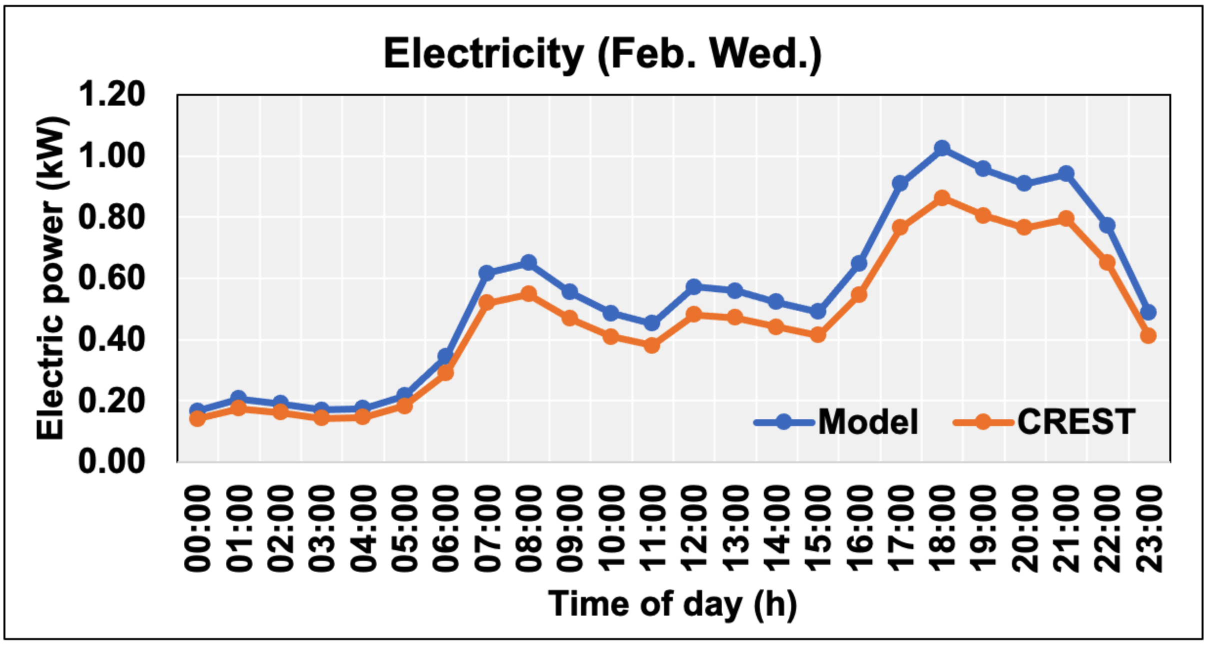


Figure A-8: The comparison between the modelling tool and CREST, showing demand of lighting and appliances in an average UK dwelling.