IRENA

International Renewable Energy Agency

SMART ELECTRIFICATION OF END-USE SECTORS

BENEFITS FOR DISTRIBUTION GRIDS

AN IRENA INNOVATION LANDSCAPE BRIEF

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CONTENTS

FIGURES

TABLES

ABBREVIATIONS

EUR	euro
EV	electric vehicle
GW	gigawatt
GWh	gigawatt hour
HP	heat pump
km	kilometre
kW	kilowatt
kW_{th}	kilowatt thermal
MVA	megavolt ampere
MVAr	megavolt ampere reactive
MW	megawatt
MWh	megawatt hour
PV	photovoltaic
USD	United States dollar
V1G	uni-directional smart charging
V2G	bi-directional smart charging; vehicle-to-grid
VR	voltage regulation

EXECUTIVE SUMMARY

This study aims to inform relevant stakeholders about the benefits that smart electrification strategies can bring to energy systems. The objective is to quantify these benefits for a distribution grid that serves electricity to a residential area. The analysis demonstrates how harnessing flexibility from distributed energy resources allow grids to be better prepared for a largely electrified future. This implies, on the one hand, the reduction of grid losses that are proportional to the electricity currents, and, on the other hand, the deferral of grid investments. These benefits require quantitative assessment to better assess such benefits for each context.

The study assumes a largely electrified energy system. This implies the roll-out of heat pumps, electric vehicles (EVs), in addition to decentralised rooftop solar photovoltaics (PV). These assets, if integrated under a smart strategy, can help operate distribution systems in a more effective way. The study assesses a specific distribution grid that covers the energy needs of around 25 000 users and compares different smart electrification strategies. Results show that benefits, in terms of grid loss reductions and the use of grid lines, are maximised if all the flexibility is harnessed from all assets combined. The reduced use of lines consequently implies that investments in grid reinforcement can be delayed, and grid investments can even be avoided.

Specifically, the minimisation of losses is estimated at 3% of the total energy delivered. Even more, smart electrification can reduce the use of lines by half and delay potential grid reinforcement needs. For the grid considered in this study, savings are estimated at around USD 13.3 (EUR 12 million), which is equivalent to USD 8.3 per megawatt hour (MWh) (EUR 7.5/MWh) delivered, assuming an investment lifetime of 40 years and a weighted average capital cost of 4%.

KEY FINDINGS

1 Countries with high electrification ambitions in their end-use sectors should enable diverse flexibility resources and adopt a smart electrification approach in order to safeguard grid reliance and avoid large investment costs in grids and generation capacity. This is even more important for countries with inherent grid constraints, such as a lack of interconnections or limited renewable energy potential compared to high electricity demand. However, flexibility sources should be strategically selected depending on the specific conditions.

2 Flexibility can be harnessed across all segments of the energy system – from power generation to transmission, distribution and demand – using energy storage assets and demand-side management. However, due to increased complexity in the operation of the system, increased digitalisation and automation are key.

3 End users can play a key role if they own assets that allow for flexible energy consumption. For residential users, flexibility may come from smart operation of all types of distributed energy resources, including power-to-heat and power-to-mobility assets (*e.g.* heat pumps or electric vehicles [EVs]) as well as decentralised power generation (*e.g.* rooftop photovoltaic [PV] or behind-the-meter batteries).

4 Given the increased amount of distributed energy resources connected to the grid, innovative operation of the distribution system and harnessing demand-side flexibility can result in tremendous savings by deferring investment in grid reinforcement. The present analysis shows that for a grid serving 12 000 households (25 000 users) with significant penetration of distributed energy resources (20% of households own an EV; more than 50% use a heat pump; 25% have a PV installation), investment needs on grid reinforcements of around USD 13.3 million (EUR 12 million) can be delayed. This represents energy bill savings of around USD 8.3/megawatt hour (MWh) (EUR 7.5/MWh) if grid investment should be repaid via bill taxes, assuming a grid lifetime of 40 years and a capital recovery factor of 5.8% (weighted average capital cost of 4%).

5 From an operation perspective, the present study shows that by harnessing flexible sources (EVs, heat pumps with thermal storage and PV), grid losses can be reduced by more than 3% if all three flexibility sources are in place.

6 Climate is an important factor in the prioritisation of, and strategy adopted for, flexibility options. In mild climates where heating requirements are limited, uni-directional charging (V1G) of EVs provides enough demand-side flexibility to peak-shave demand. However, when heat demand is significant (cold climates), the possibility of using energy from the battery of the EV – meaning using the battery bi-directionally (vehicle to grid, V2G) – helps cover heating peak loads directly from the EV battery and limits the impact on the grid. Note that cooling demands have not been considered in this analysis; however, similar conclusions can apply in the case of hot climates (*e.g.* the Middle East). Potential infrastructure or techno-economic constraints related to V1G or V2G are not addressed.

7 The SMART scenario that combines all possible flexibility options – including thermal storage, V2G charging for EVs and rooftop PV – provides the best results in terms of reduction of losses and use of the grid, according to the analysis. The addition of decentralised PV to the SMART scenario improves the results by decreasing the dependency on the grid (on-site electricity production and consumption).

8 The adoption of smart electrification strategies can limit the risk of grid congestion by reducing the level-of-use ratio of critical lines (the ratio of actual maximum power to the maximum rated capacity of the line) by 50%, according to the analysis. This means that only half of the line capacity is actually required, such that smart electrification can accommodate more electricity-based demand without investment needs and without compromising the operation of networks.

9 Total savings – including 1) avoided grid investments, 2) loss reductions in the operation of the grid and 3) a lower marginal cost of electricity due to the reduction of peak loads – are estimated to result in a 35% reduction of the unitary energy costs, from USD 77.2/MWh (EUR 69.4/MWh) in the BASE scenario down to USD 49.6/MWh (EUR 44.6/MWh) in the SMART scenario, according to the analysis. This represents economic savings of USD 2.9 (EUR 2.6 million) annually (more than USD 222 or EUR 200 per household).

10 This study aims to quantify the benefits of smart electrification. Importantly, users have their own preferences and patterns when consuming electricity. Therefore, to achieve flexible energy systems, it is crucial to have the right financial incentives in place, compensating consumers for reacting to signals, as well as increased digitalisation and automation infrastructure. Alternatively, a more regulated approach is based on granting distribution system operators the capacity to curtail loads for certain periods, as a very last option. Generally, commercial and industrial users may be better targets for demand side management, as they are more economically driven than residential users that have less rational profiles.

1

INTRODUCTION

The cost-competitiveness of wind and solar power paves the way for energy transition towards global climate goals, providing clean and affordable electricity. In combination with energy efficiency measures, electrification is expected to be the promising pathway to underpin the decarbonisation of energy systems globally. However, in general, the variability of wind and solar sources poses challenges to the system and may drive the design of effective strategies for the electrification of end-use sectors.

The electrification pathway requires a new paradigm from the supply side but also from the demand side. Demand-side transformation cannot rely only on the technological replacement of traditional fossil fuel-based technologies with electricity-based technologies (*i.e.* the replacement of gas boilers with heat pumps, or of engine-powered vehicles with electric ones). It also requires smart operation of these assets, to harness the flexibility from this new electricity demand sector. In addition, it requires supporting business models that help maximise the use of renewable energy sources, reduce investments and limit the strain on power system assets. For this to happen, the active participation of all actors across the energy value chain, and in particular of consumers, is key. New emerging business models, regulations, and innovations in system planning and operation need to complement the emerging technologies. This comprehensive approach is known as *smart electrification* (IRENA, 2023a).

Smart electrification brings a number of benefits. One of these benefits is more efficient operation of distribution networks. Managing distributed energy resources in a smart way, and harnessing their flexibility potential, can enable better use of the distribution infrastructure. In particular, the presence of sector coupling assets (such as electric vehicles (EVs) and heat pumps), combined with local renewable energy generation, allows optimising the operation of the distribution network in a way that minimises energy losses, improves security of supply and reduces peak loads; this in turn delays or minimises the need for grid reinforcement investments as well as maintenance and replacement costs. This aspect is of interest for energy systems that show a high utilisation rate of their grid infrastructure, which in some cases leads to congestion problems.

Missing out on the opportunities offered by sector coupling assets results in a less effective integration of variable renewable energy generation and increases curtailment. This applies to both centralised and decentralised renewable generation. Even more, it can create operational problems for distribution system operators, including increased technical and economical network losses, unbalanced voltage values in grid nodes due to the rapid fluctuation of renewable generation, grid congestion, etc. This can make the operation unsafe and unreliable, and lead to sub-optimal planning and operation, which may result in the need to over-invest in expanding and reinforcing the existing electricity grid and generation capacity.

To avoid over-investing, smart electrification of end-use sectors is essential. Among others, this should include incentives to develop supply- and demand-side flexibility in key sectors such as heating and transport.

2

THE IMPORTANCE OF SMART ELECTRIFICATION STRATEGIES IN JAPAN

Japan is an example of a national energy system with a high utilisation rate of its grid infrastructure. This stems from different factors related to geography (an island energy system) and the structure of end-use consumption (extensive use of electricity-based equipment). Climate conditions in the country are characterised by hot summers and cold winters, depending on the latitude.

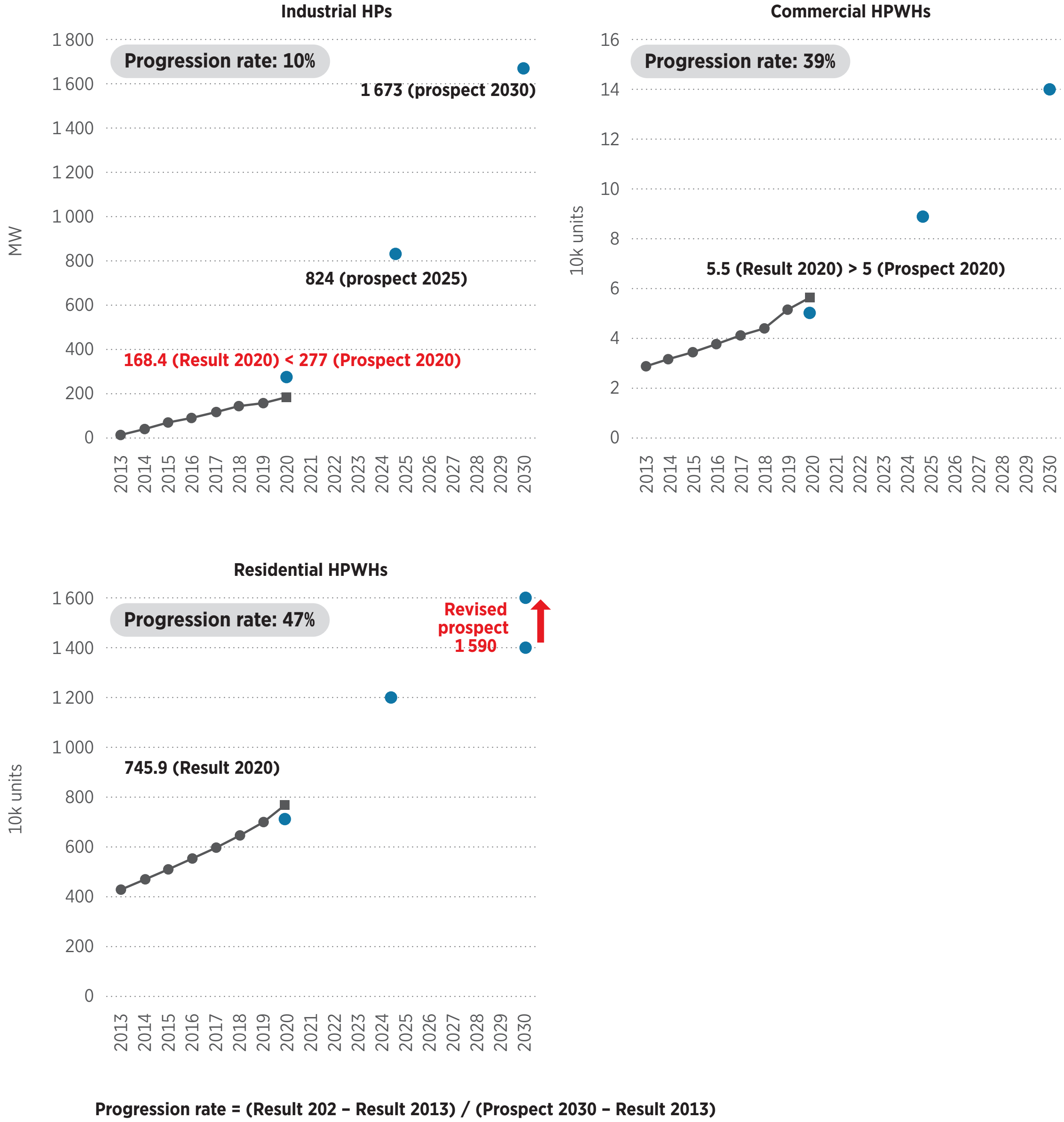
Japan is a densely populated country, with 331 people per square kilometre in a total land area of 378 000 square kilometres. It has large urban areas with a high density of energy demand. For example, the combined demand of Tokyo, Chubu and Kansai is around 100 gigawatts (GW) of peak load, which complicates the operation of distribution grids.

At the same time, Japan is committed to a target of carbon neutrality by 2050 (IRENA, 2022), which implies even larger targets for electrification of the country's energy sector beyond its current electrification rate. For example, Japan is expected to roll out heat pumps in all sectors including industry, commercial and residential (Figure 1). Japan aims to incorporate more than 1.7 GW of heat pumps in the industrial sector by 2030 (up from 0.3 GW today), 140 000 heat pump units in commercial buildings (up from 55 000 units today) and nearly 16 million units in the residential sector (up from 7.5 million units today) (Fujita, 2023). All of these measures should be accompanied by a reduction in net energy consumption through the implementation of energy efficiency measures and the integration of distributed generation, such as small-scale solar photovoltaic (PV) systems.

The electrification of the transport sector is also expected to grow significantly in the coming years in Japan. Under the "announced pledges scenarios", shares of battery electric vehicle sales are expected to grow by 30 percentage points, electric buses by 16 percentage points, and electric trucks by 3 percentage points, in comparison to the "stated policies scenarios" (IEA, 2023a). All these projections will add pressure to the grid infrastructure and in particular to the distribution grids in urban areas, where the energy demand density is already high.

Possible solutions to minimise grid congestion and to address the variability caused by high penetration of wind and solar generation are the use of flexible and dispatchable thermal power plants, grid reinforcement and pumped hydropower. A solution that could potentially minimise the investment needs is the adoption of demand response mechanisms, including the deployment of distributed energy resources such as stationary storage batteries, smart charging of EVs, deploying distributed solar PV closer to demand, smart operation of heat pumps, etc. The smart operation of these distributed resources can play a key role for the energy system.

FIGURE 1 | Japanese policy goals towards 2030 and progress until 2020 for the roll-out of heat pumps



Notes: HPs – heat pumps; HPWH – heat pump water heaters.
Source: Fujita, 2023.

Since 2014, when the first curtailment event occurred in Kyushu, the Agency for Natural Resources and Energy (ANRE) of Japan's Ministry of Economy, Trade and Industry (METI) has been working on measures to reduce curtailment of renewables. In 2022, 0.3% of the total renewable energy produced in Japan was curtailed (IEA, 2023b). The plan aims to target three main solutions: increasing demand-side flexibility, increasing supply-side flexibility and grid reinforcement (Shulman, 2023).

3

SCOPE AND LIMITATIONS OF THE STUDY

The case of Japan is not an isolated story, and many other energy systems are confronting similar challenges in the face of net zero emission targets and decarbonisation of end uses. This study aims to inform policy makers and relevant stakeholders of the benefits that can be unlocked by a smart and flexible operation of the distribution system in a context of significant electrification of end uses. This implies a large deployment of EVs and residential heat pumps, coupled with decentralised solar PV — pivotal components in the smart electrification pathway. The study aims to quantify the benefits for a grid layout under consumption patterns representative of countries located in intermediate latitudes with cold winters and mild summers (similar to Japan).

The study is conducted under certain assumptions, and results should be contextualised accordingly. First, it assumes that flexibility assets are already deployed and available to contribute to the effective operation of a distribution grid. Three distributed energy sources are considered: bi-directional electric vehicles, heat pumps and rooftop PV systems. PV systems are assumed to supply homes and buildings directly but not to exchange electricity with the grid.

In terms of consumption patterns, a synthetic demand is assumed. The demand shifts are driven based on the operation of the grid and according to the flexible capacity of the assets available for each case assessed. For example, in the case of heat pumps, the thermal demand of households should be satisfied over a week. According to this, the distribution system operator would accommodate the total weekly demand for each hour based on the use of the grid.

The study focuses on a distribution grid that supplies a residential area; therefore, other demand profiles such as those from commercial or tertiary buildings are out of the scope of the study. This assumption allows testing the impact of smart electrification, since the daily demand fluctuation of a single use is larger than in a scenario where different demand profiles that show certain complementarity are added up.

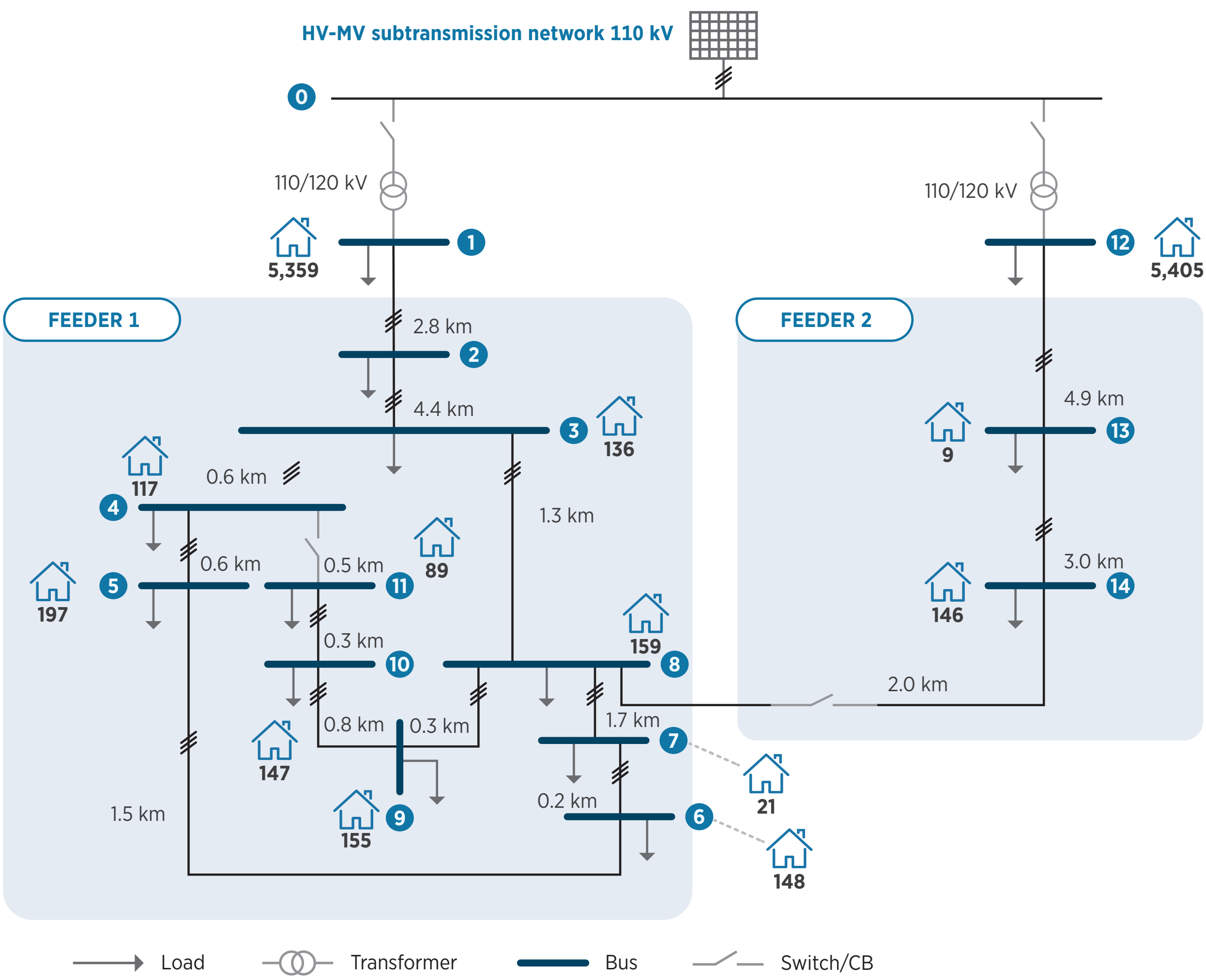
Other aspects related to the grid – such as dynamic stability issues, short-circuit calculations and reverse power occurrence – are outside the scope of the study. Additional conversion technologies such as fuel cells or co-generation units are not considered. More details are presented in the section dedicated to the description of the scenarios.

4

BASE SCENARIO

To quantify the benefits derived from the smart operation of a distribution network, the study has selected a specific network layout that provides electricity to a residential area (neither industrial nor tertiary consumption units are considered in the analysis). The layout of the distribution network selected is the CIGRE medium-voltage network (CIGRE, 2014), in which the additional elements (heat pumps, EV charging stations and decentralised PV installations) are incorporated across the consumption nodes in the grid. The grid is composed of two high- to medium-voltage transformers and two associated feeders; 14 nodes to which households are connected; and 13 lines that connect the nodes (Figure 2).

FIGURE 2 | CIGRE medium-voltage network



Notes: CB = circuit breaker ; km = kilometres; kV = kilovolts; HV = high voltage; MV = medium voltage.

Source: CIGRE, 2014.

The network supplies the electricity demand of roughly 12 000 households, which represents around 26 500 users assuming an average occupancy per household of 2.2 users, which is representative of regions such as Europe or Japan (Eurostat, 2023; Statista, 2023). The number of households connected to the grid per node is shown in Figure 2.

Based on the number of households, a level of penetration for heat pumps, EVs and distributed PV was determined. The number of units in each case is provided In Table 1.

TABLE 1 | Number of end users and low-carbon units per node

Node	Number of households	Number of EVs	Number of residential heat pumps	Number of locally installed PV systems
1	5 359	1 057	3 034	1 404
2	0	0	0	0
3	136	27	77	35
4	117	23	66	31
5	197	39	111	51
6	148	29	84	39
7	21	4	12	5
8	159	31	90	42
9	155	31	88	41
10	147	29	83	38
11	89	18	50	23
12	5 405	1 067	3 060	1 416
13	9	2	5	2
14	146	29	83	38
TOTAL	12 088	2 386	6 843	3 165
Number of users	26 594			
Installed capacity		kWh*	kW	kWp
		95 440	34 215	7 913
Number of units per				
100 households		20	57	26
100 users		9	26	12
Installed capacity per		kWh	kW	kWp
households		7.9	2.8	0.7
users		3.6	1.3	0.3

Notes: * EV battery capacity; EVs = electric vehicles; kWh = kilowatt hour; kWp = kilowatt 'peak' power ; PV = photovoltaic.

Assumptions for penetration of electric vehicles, heat pumps and solar PV systems

The REmap 1.5°C scenario[1] (IRENA, 2023b) projects 793 million heat pump units (of 20 kilowatts (kW) each) for the buildings sector by 2050, and 2 182 million electric and plug-in hybrid light passenger vehicles globally (1 811 for the G20 countries). Both assets can be found in the buildings sector, including commercial and residential segments.

Currently, the share of passenger electric cars is roughly just over one vehicle per 1 000 users in some regions of the world, such as Europe and Japan, although the figure is expected to grow (Eurostat, 2022; Statista, 2022). The present study considers 90 passenger electric cars per 1 000 users, or a 70-times increase. Looking at the current number of EVs in the market (26.2 million) and the global population (7.95 billion), as well as the projections for 2050 (2 182 million EVs and 9.7 billion people) (IRENA, 2023b; OECD, 2024), the value selected here reflects the estimated number of EVs per household in 10 years under the assumption of a linear evolution between 2023 and 2050.

Today, an estimated 16% of households and commercial buildings in Europe are equipped with heat pumps. This represents 6.4 heat pumps per 100 inhabitants, considering the same average members per household indicated earlier. In Japan, the heat pump share exceeds 90%; however, only 44% of Japanese households use the units for heating purposes (IIR, 2024). The study assumes a three-fold increase in heat pump penetration in Europe and a similar rate as currently for heat pumps providing heating and cooling in Japan (57%).

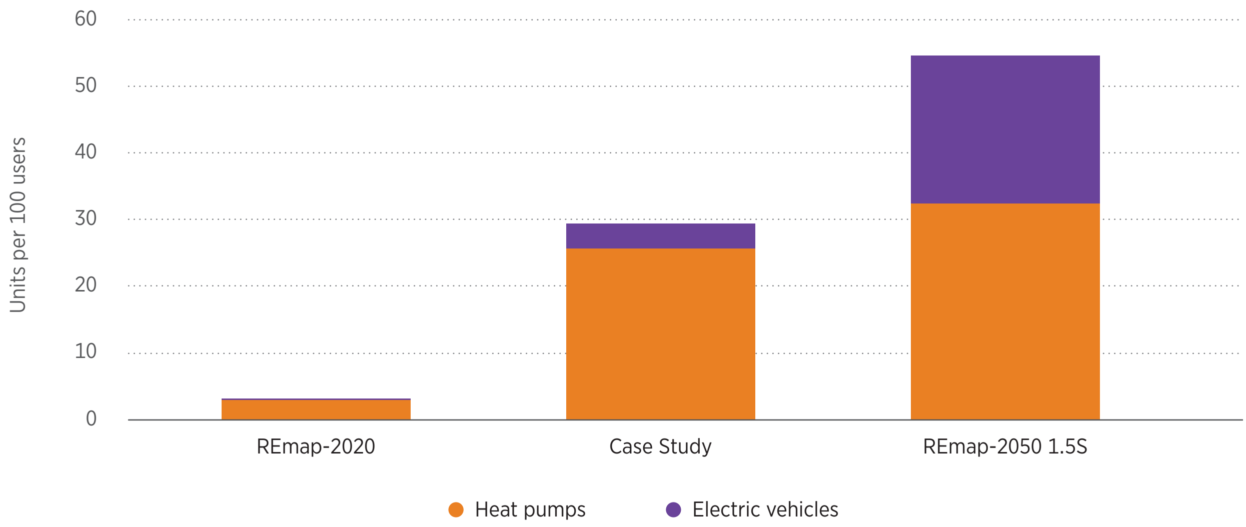
The assumption of 5 kW heat pump units is used to cover a peak heating demand of 15 kW per household, if the seasonal co-efficient of performance (the ratio between the amount of heat produced to the amount of electricity consumed during a period, typically a year) is assumed to be 3. This size can be considered large, since for a 100 square metre household, a heat pump with a capacity of 5 kilowatts thermal (kW_{th}) to 7.5 kW_{th} (depending on insulation levels and outdoor temperatures) is typically sufficient. However, due to uncertainty related to operation, a 15 kW_{th} size ensures that heating demand is covered.

Lastly, the study considers a PV deployment of 300 watts-peak (W_p) per person, which implies that, on average, each household has an installed capacity of 660 W_p. Contrary to the case of EVs and heat pumps, the growth of PV is not as subject to the energy needs per user but rather to the available surface and regulation and business models available in each region, such as net metering or virtual batteries.

As shown in Figure 3, the case study represents an intermediate scenario between the status in 2020 (REmap scenario) and the projections for 2050 under the REmap 1.5°C scenario in 2050, in terms of penetration of heat pumps and EVs. Examining each component separately, heat pumps are widely deployed in the model, which aims to represent a more mature market, as in the case of Japan. Overall, the case study presents a scenario that is anticipated to materialise around 2030.

[1] *1.5S = 1.5°C scenario.*

FIGURE 3 | Number of heat pumps and electric vehicle units for the base case scenario

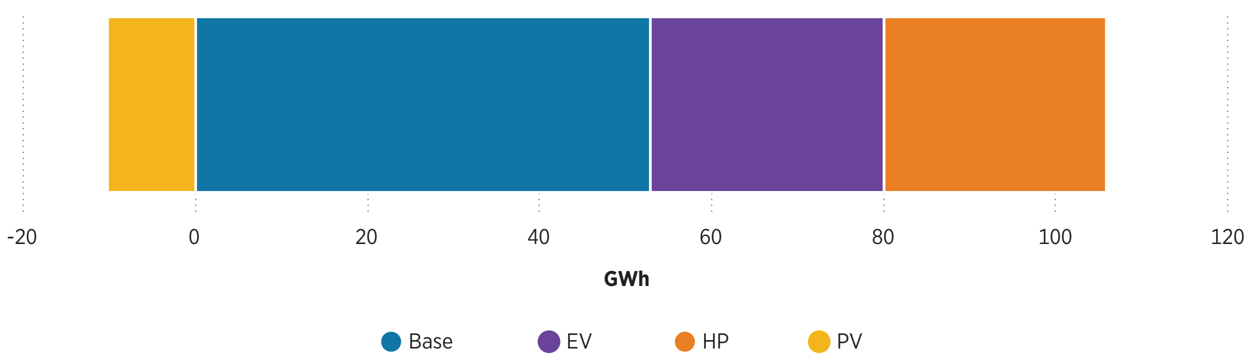


Case study energy demand

As explained in the scope of the study, a synthetic demand profile is assumed. This implies that the energy demand profile is not affected by dynamics related to price signals or user preferences. Only the operation of the grid is allowed to modify demand profiles based on the flexibility capabilities of the assets, with the condition that the total demand over a certain period is not changed. In the next section, the flexibility capabilities are introduced.

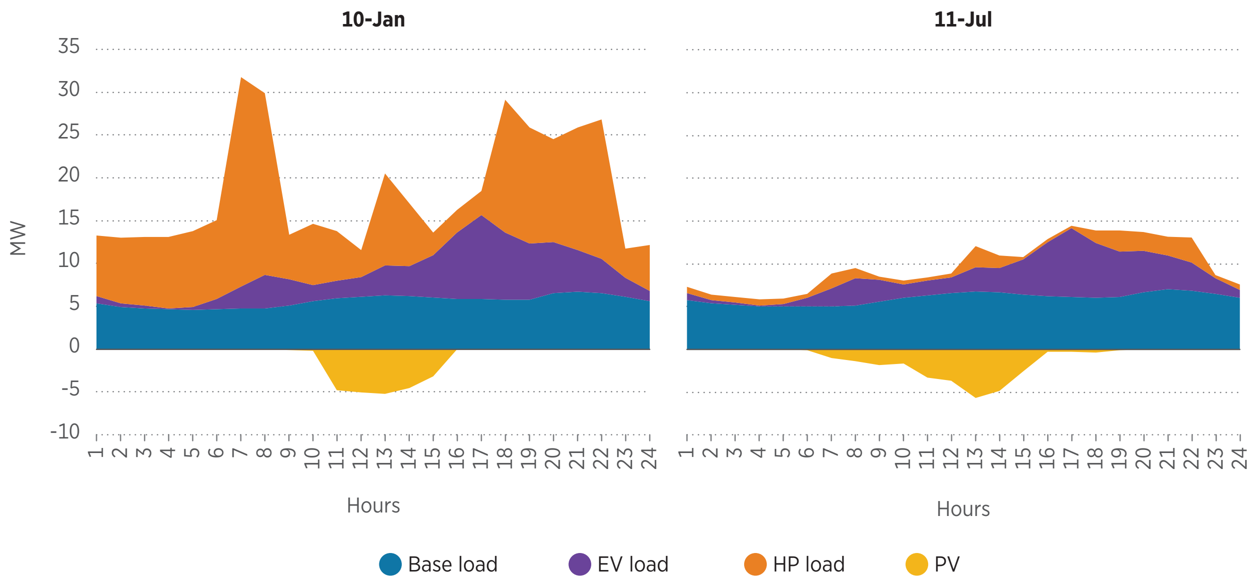
The total consumption of the system, presented in Figure 4, amounts to 105 gigawatt hours (GWh) per year, while the PV production amounts to roughly 10 GWh per year (15% capacity factor). The baseload demand represents 50% of the total demand, with EVs representing 26% of demand and heat pumps representing 24%. PV production is roughly 10% of the total electricity demand. In Figure 5, the daily demand profiles for the different uses, including PV production, are shown. The hourly demand profiles have been selected based on IEA (2020) and IRENA (2020).

FIGURE 4 | Total annual energy demand



Notes: PV production is represented as a negative value, as it decreases the net demand in the grid.
EV = electric vehicle; HP = heat pumps; PV = photovoltaic.

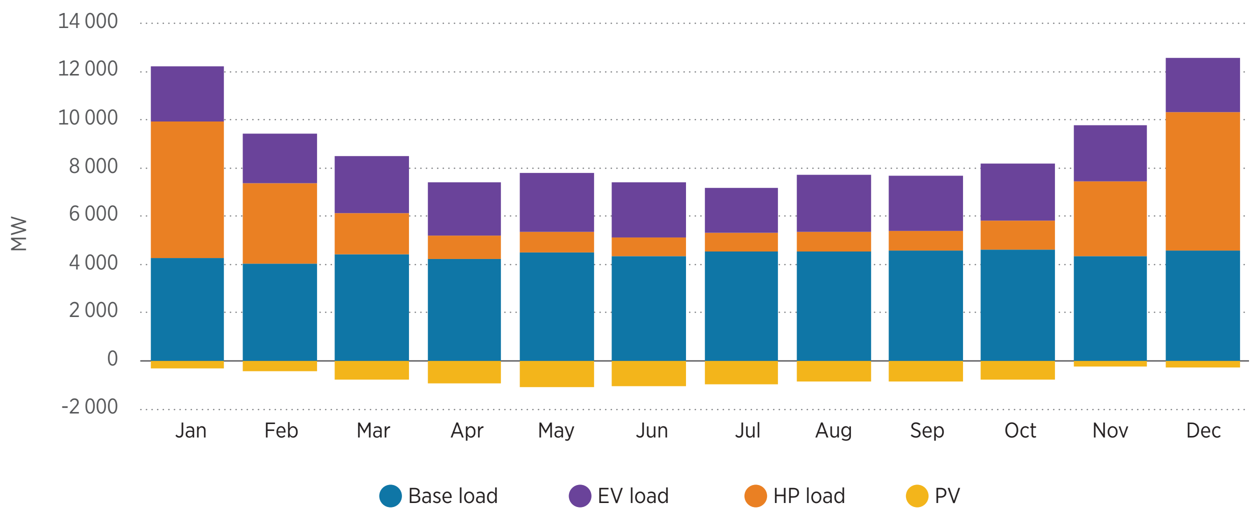
FIGURE 5 | Daily energy demand profile for a winter day (left) and summer day (right)



Notes: EV = electric vehicle; HP = heat pump; PV = photovoltaic.

Figure 6 displays the monthly aggregated demand. One important assumption in the analysis is the fact that cooling is not considered during the summer period. As a result, the minimal consumption of heat pumps during this period is attributed to temperatures below 21 degrees Celsius on summer nights.

FIGURE 6 | Aggregated monthly energy demand profiles



Notes: EV = electric vehicle; HP = heat pump; PV = photovoltaic.

As mentioned in the scope of the study, the residential scenario excludes other energy demand profiles such as those from tertiary buildings (*i.e.* offices) that could be complementary to the residential demand. This means that when end users leave homes, they continue consuming energy in offices, which may imply a flatter demand profile curve. Yet, in many national contexts, peak demands coincide with peaks in residential sectors.

5

SCENARIOS

In this analysis, different smart electrification strategies have been defined in different scenarios, and their benefits are assessed and compared. Seven scenarios are defined, considering different operation strategies for heat pumps, EVs, and whether or not rooftop PV systems are installed. The different smart electrification strategies assessed are summarised in Table 2.

TABLE 2 | Summary of flexibility assets enabled in each scenario

Scenario	Flexibility available				Distributed PV generation
	Heat pump flexibility (thermal storage)	Uni-directional smart charging of EVs (V1G)	Bi-directional smart charging of EVs (V2G)	V2G charging and voltage regulation	
1. BASE					
2. ThermalFlex	✓				
3. V1G		✓			
4. V2G			✓		
5. V2G&VR			✓	✓	
6. SMART	✓	✓	✓	✓	
7. SMART&PV	✓	✓	✓	✓	✓

Notes: V1G = uni-directional smart charging; V2G = bi-directional smart charging; vehicle-to-grid; VR = voltage regulation; EV = electric vehicle; PV = photovoltaic.

No flexibility available

1. **BASE:** This is the base scenario, with uncontrollable devices and no flexibility (presented in the previous section).

Flexibility provided by heat pumps only:

2. **ThermalFlex:** Heat pumps can ramp up and down up to 30% of their capacity for each timestep. This scenario, therefore, assumes that the extra heat produced can be stored and used later during periods when heat pumps produce below heat demand. From a physical point of view, it is equivalent to assume the existence of thermal storage; however, associated costs for thermal storage capacity are not considered. In addition, thermal losses are neglected. One important feature of this scenario is the number of consecutive hours that heat pumps can operate below or above demand. In the study, the total thermal demand across a week should be preserved. Therefore, in an extreme flexible operation, heat pumps could produce above 30% of the demand for 84 hours (half a week) and below 30% for another 84 hours, during which the extra energy produced in the prior period is used.

Flexibility provided by EVs only:

3. **V1G:** uni-directional smart charging. Analogous to the ThermalFlex scenario, daily consumption should be met. Thus, the EV battery can be operated accordingly.
4. **V2G:** bi-directional smart (dis)charging. Building on the previous scenario, the EV battery can also be used to peak-shave electric demand when the electricity stored is sufficient to do so.
5. **V2G&VR:** bi-directional smart (dis)charging with the possibility of voltage regulation – total daily consumption of EVs is the same as in the BASE scenario. The regulation of voltage aims to balance the loss of voltage from intermittent power generation at the cost of increasing the apparent power flowing across the lines.

Flexibility provided by both heat pumps and EVs:

6. **SMART:** Flexibility is provided by both heat pumps and EVs, including voltage regulation as well. This scenario combines the features of scenarios 2 (ThermalFlex) and 5 (V2G&VR)

Flexibility provided by both heat pumps and EVs, with rooftop solar PV also installed:

7. **SMART&PV:** The SMART scenario with the addition of locally installed solar PV. PV generation is placed close to the demand so that it reduces the net electricity demand from the grid. Decentralised local generation does not include behind-the-meter battery storage or net metering with the grid.

6

MODEL SET-UP

The model implemented to analyse the impact of smart electrification strategies on technical conditions in the distribution grid is based on the optimal power flow formulation. It consists of a set of technical constraints and mathematical equations that define the correlation between the input values such as active and re-active power and impedance of lines, and outputs such as nodal voltage magnitudes and line currents. The objective function of the given optimisation problem is the minimisation of energy losses in a distribution network.

The mathematical formulation of a distribution network includes high- and medium-voltage transformers, distribution lines and underground cables, medium-voltage nodes, aggregated loads that represent demand of residential end users, aggregated demand of heat pumps, aggregated demand caused by charging of EVs, and aggregated production of locally installed PV systems. To balance total production, the distribution grid is connected to a higher-level grid that provides energy requirements. The model has been developed by IRENA.

7

RESULTS

The main goal of the analysis is to determine the impact of various smart electrification scenarios on the distribution grid. To do so, the following parameters are evaluated for each scenario:

- Demand profile
- Network losses
- Voltage profiles (nodal voltage magnitude)
- Power flows and line uses.

DEMAND PROFILE

KEY FINDINGS

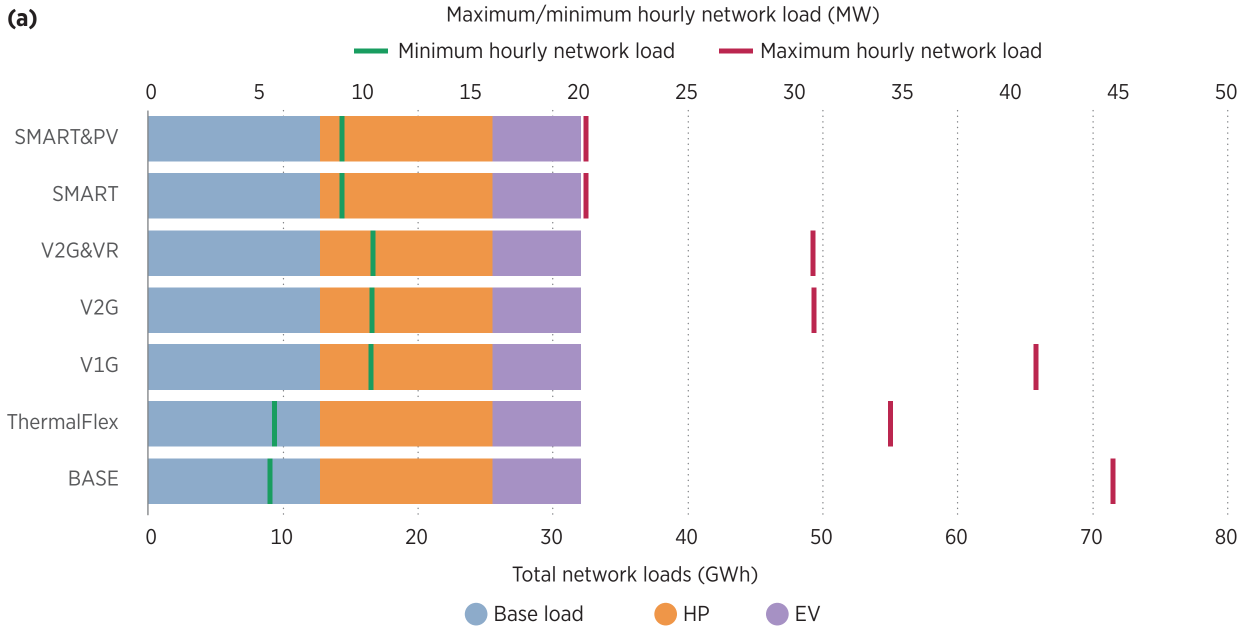
Smart electrification flattens the demand profile / decreases peak demand:

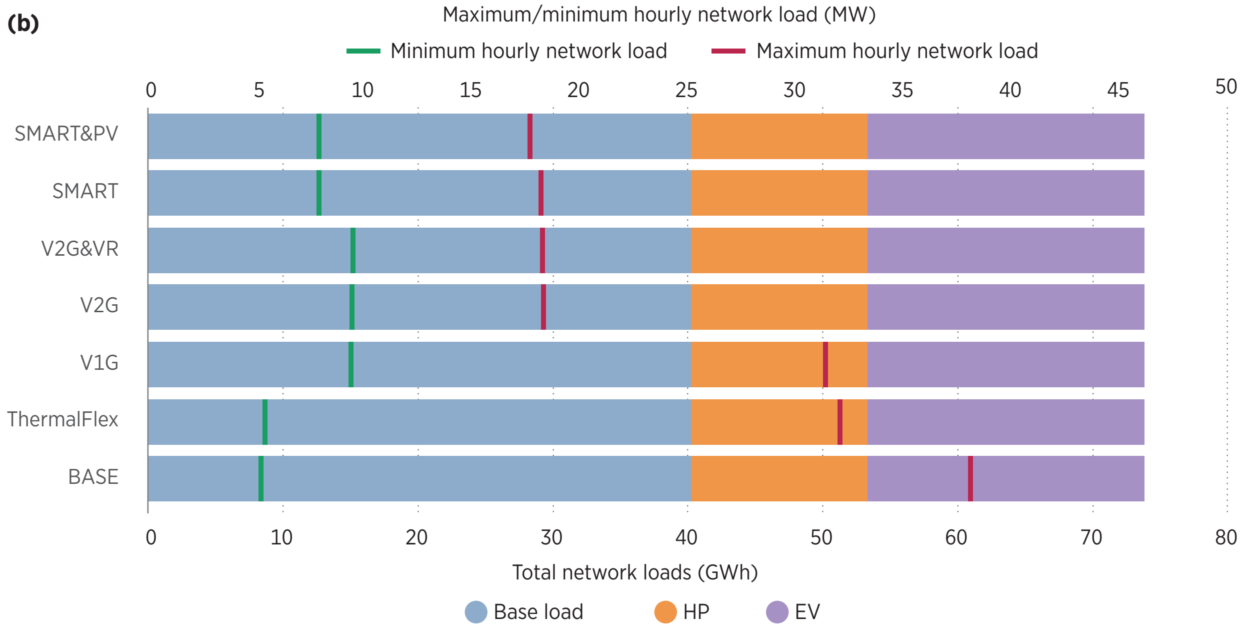
- Thermal storage capacity can shift the use of heat pumps from hours with high demand to hours with lower demand. Peak demand is reduced by almost one-fourth compared to the BASE scenario.
- V2G charging is more effective in reducing peak demand than V1G charging.
- There are great synergies between PV generation and EV charging load during summer months.
- Combining flexible operation of heat pumps with smart charging of EVs and local generation from PV yields the best results in decreasing the peak loads and flattening the demand profile.

The demand profiles for each timestep, set to one hour, are presented in Figure 7. Total active demand in each period is calculated as the sum of the demand load, from heat pumps, EV charging (and discharging), and PV generation, as well as the baseload demand. The hourly demand values will vary based on the optimal use of the available flexibility sources in each scenario. The baseline demand is the only inflexible demand across all scenarios.

Figure 7 shows the comparison of the total, maximum and minimum demand values for each scenario and for the winter and non-winter periods[2]. The total value of the demand remains constant across all scenarios for comparative reasons. The maximum and minimum hourly demands vary depending on the flexibility sources available.

FIGURE 7 | Total, maximum and minimum energy demand — winter (a) and non-winter (b)





Notes: GWh = gigawatt hours; MW = megawatt; V1G = uni-directional smart charging; V2G = vehicle-to-grid (bi-directional smart charging); VR = voltage regulation; EV = electric vehicle; HP= heat pump; PV = photovoltaic.

[2] *The winter period corresponds to the winter season, from 21 December to 21 March. The non-winter period includes the rest of the seasons.*

Winter period

During the winter period, it is observed that the BASE scenario provides the widest range of values: minimum values are slightly higher than 5 megawatts (MW), and maximum values go up to 45 MW. The high peak demand is the result of no flexibility sources available. However, most hours (50%) are in the range between 12.5 MW and 17.5 MW.

In the ThermalFlex scenario, minimum values are at the same level as in the BASE scenario, while maximum values are greatly reduced by more than 23% (10 MW). This means that the thermal storage capacity can shift the use of heat pumps from hours with high demand to hours with lower demand.

When harnessing the flexibility from EVs (V1G, V2G and V2G&VR scenarios), different results are observed. In the case of V1G, peak demand is reduced compared to the BASE scenario (8%), but not as much as in the ThermalFlex scenario. The peak demand is greatly reduced by enabling the flexibility from V2G (31% compared to the BASE scenario). V2G and V2G&VR show similar results.

Using thermal storage is more beneficial in reducing peak demands in the winter period, than only V1G smart charging of EVs. However, making full use of the EV battery in V2G scenarios has a greater impact than thermal storage flexibility alone. This result is subject to the penetration ratio between heat pumps and EVs in the system (see Figure 3). In all three cases (V1G, V2G and V2G&VR), the average demand increases compared to the BASE scenario, which indicates that a more stable use of the grid is achieved, with lower peaks and higher valleys.

Lastly, the SMART and SMART&PV scenarios completely shave outlier values, which means that they additionally flatten the demand profile curve by further removing peak demands. The impact of PV installations is limited in winter time due to limited sunny hours.

Non-winter period

Demand profiles during the non-winter period are vastly different, mainly because of lower heat demand during this period (Figure 7b). Therefore, peak demand is reduced by 15% in the BASE scenario; for the winter period, the BASE scenario shows a peak demand of 45 MW, whereas for the non-winter period it reaches 38 MW. The ThermalFlex scenario is therefore not relevant in this case since heat pumps and thermal storage are not used. In the non-winter period (including the period from March to December) the peak reduction provided by flexible heat is 16% (23% for winter).

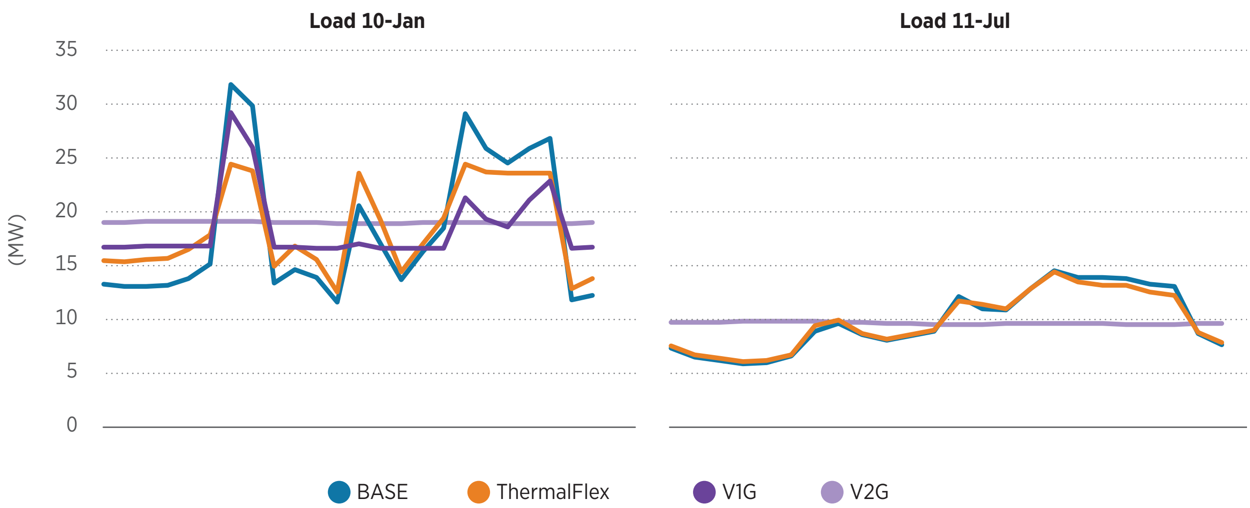
Regarding the EV scenarios, in contrast to the winter period, incorporating V1G results in a greater peak demand reduction of 18% (compared to 8% in winter) and further reduces the peak demand observed in the ThermalFlex scenario. This finding leads to an important conclusion: in regions with low heating demand (such as warm climates or non-winter periods) or where heating is not flexible or not widely electrified, prioritising V1G smart charging from EVs is recommended when devising smart electrification strategies.

Overall, for the bi-directional smart charging EV scenarios (V2G and V2G&VR), the minimum, maximum, and range of values are relatively similar – meaning that smart electrification in both scenarios is equally effective. Peak demand is reduced by half in both scenarios as well as in the SMART case. In summer, PV generation reduces peaks from the grid with an additional 3%. This reduction is due to reduction of the net demand, since PV provides on-site consumption in the grid nodes. The PV installed capacity represents 18% of the peak demand in the BASE scenario. In addition to this, in the non-winter period when PV production is higher, the demand is not as high as in winter (see Figure 7) and the peak demand does not occur in the central hours of the day, which means that a lot of energy produced by PV is wasted.

When there is electrified and flexible heat demand under the presence of thermal storage capacity, prioritising flexibility from heat pumps over V1G smart charging of EVs is the most effective approach. In all cases, V2G alone is more effective in reducing peak demands due to the capacity to use the EV battery to shift demand.

Figure 8 shows the demand profiles for four selected scenarios in the representative winter and summer day. As can be seen, the BASE, ThermalFlex and V1G scenarios are characterised by peaks in demand that occur early in the morning. The V1G and especially ThermalFlex scenarios decrease the maximum demand by more than 5 MW in some periods. Demand curves in the V2G SMART and SMART&PV scenarios are additionally flattened – *i.e.* smart electrification leads to values of consumption that are more equally distributed during a day. Even though the minimum demand increases in these scenarios, a decrease in the maximum demand has a value of more than 10 MW in some periods. Similar trends are observed for the summer case, but at lower levels of demand.

FIGURE 8 | Total energy demand in the representative winter day (left) and summer day (right)

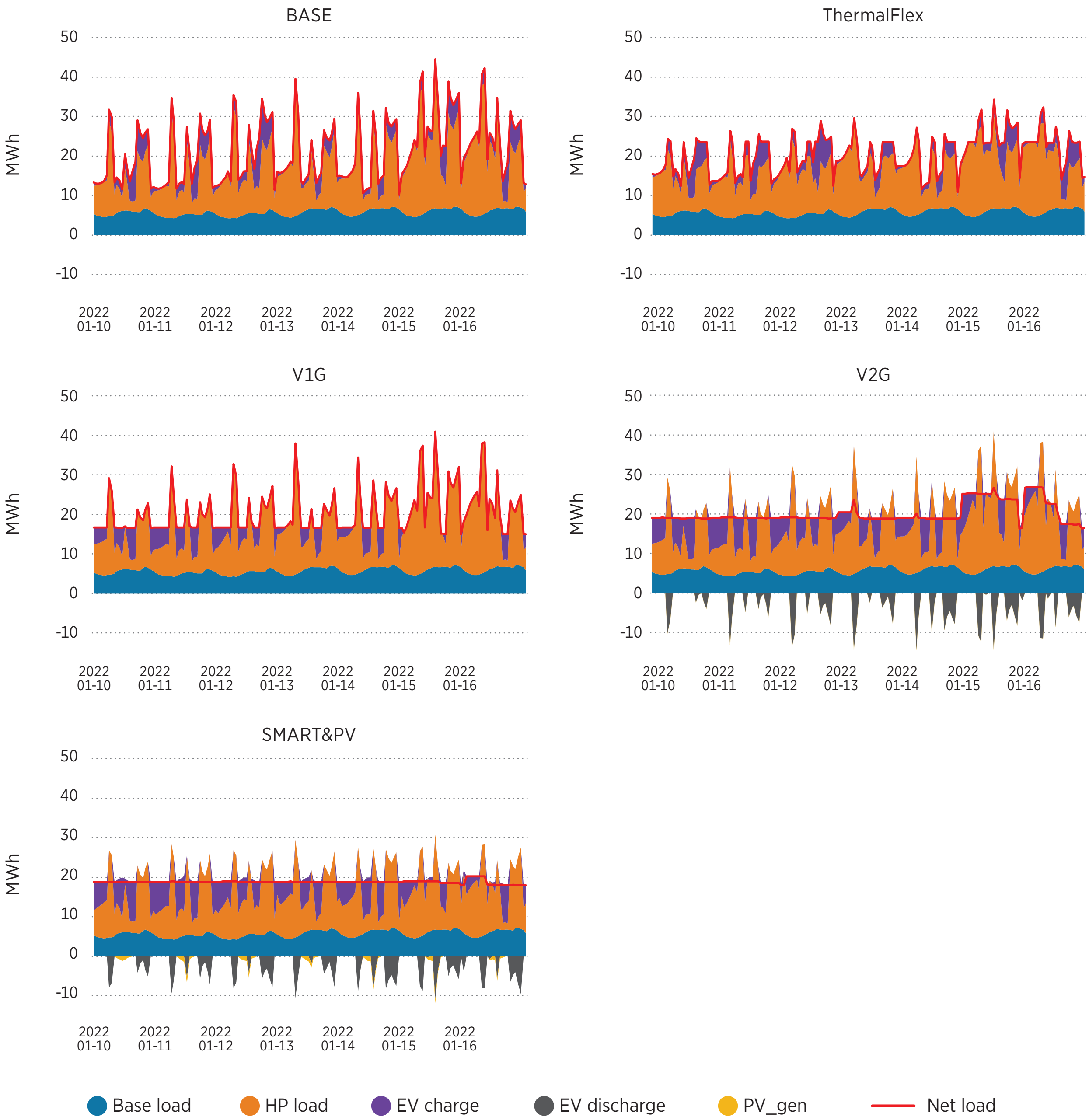


Notes: V1G = uni-directional smart charging; V2G = bi-directional smart charging; vehicle-to-grid; MW = megawatt.

Figures 9 and 10 present the hourly demand profiles for a week in winter and summer. It is observed that smart electrification flattens the demand curve by lowering the peak demand. Not all scenarios are equally efficient, and seasonality plays an important role in demand values and their potential rescheduling, which impacts the smart charging strategy that can be adopted. As mentioned, thermal storage has significant potential in shifting heating demand in winter, while it plays no role in the summer. Notably, heat pumps were observed only for the purpose of heating and not cooling. If cooling were also considered in the analyses, the benefit of the ThermalFlex scenario would be relevant in summer months too, and less of the energy produced by decentralised PV in the SMART&PV scenario would be curtailed.

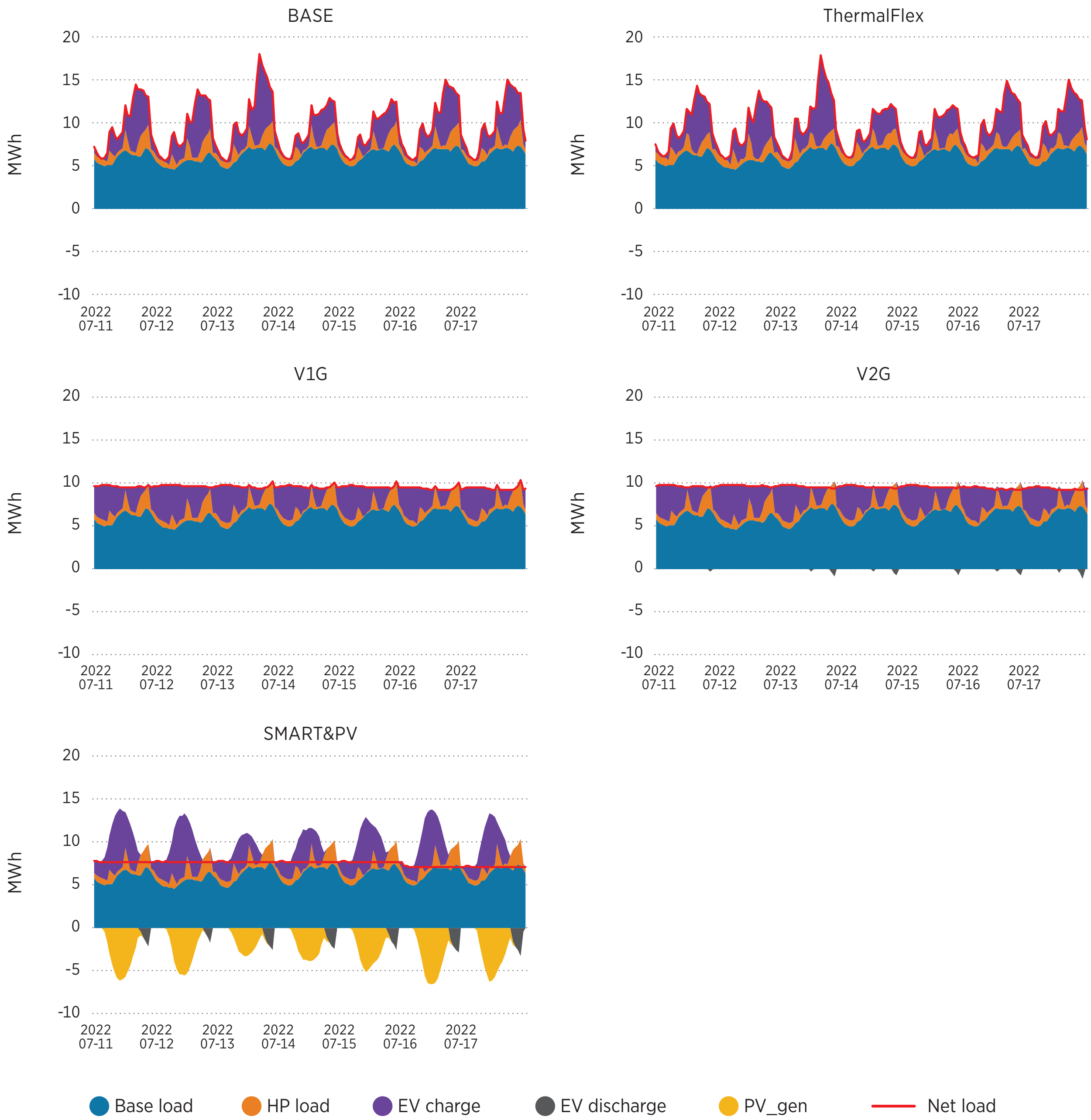
Even though the V1G scenario helps in reducing peak load, it is not always the most efficient option. In summer periods, all scenarios with defined local production (V2G – SMART&PV) achieve much better results in terms of the potential reduction of peak demand. This is because the net electricity demand decreases considerably due to on-site production that covers part of demand. In winter periods, peak demand caused by heating can be covered not only by thermal storage, but also by electricity generation from EV battery storage, via V2G charging.

FIGURE 9 | Weekly demand dispatch – winter



Notes: MWh = megawatt hour; V1G = uni-directional smart charging; V2G = bi-directional smart charging; vehicle-to-grid; EV = electric vehicle; HP= heat pump; PV_gen = photovoltaic generation.

FIGURE 10 | **Weekly demand dispatch – non-winter**



Notes: MWh = megawatt hour; V1G = uni-directional smart charging; V2G = bi-directional smart charging; vehicle-to-grid; EV = electric vehicle; HP= heat pump; PV_gen = photovoltaic generation.

NETWORK LOSSES

KEY MESSAGES

Smart electrification flattens the demand profile, which also contributes to decreased use of the grid and therefore to lower network losses.

- Due to the nature of electricity losses, they follow the pattern of electricity demand. Thus, reducing peak demand will reduce grid losses.
- The installation of PV systems locally contributes to a lower use of the grid and then to lower losses (18% reduction), since demand is covered with locally produced electricity.
- The introduction of heat pumps equipped with thermal storage helps to decrease total network losses by 27% and to reduce peak losses by 67%, when compared with the BASE scenario.
- The V2G smart charging of EVs largely flattens the curve, as it acts as distributed storage, which also contributes to lower use of the grid and to decreasing network losses.

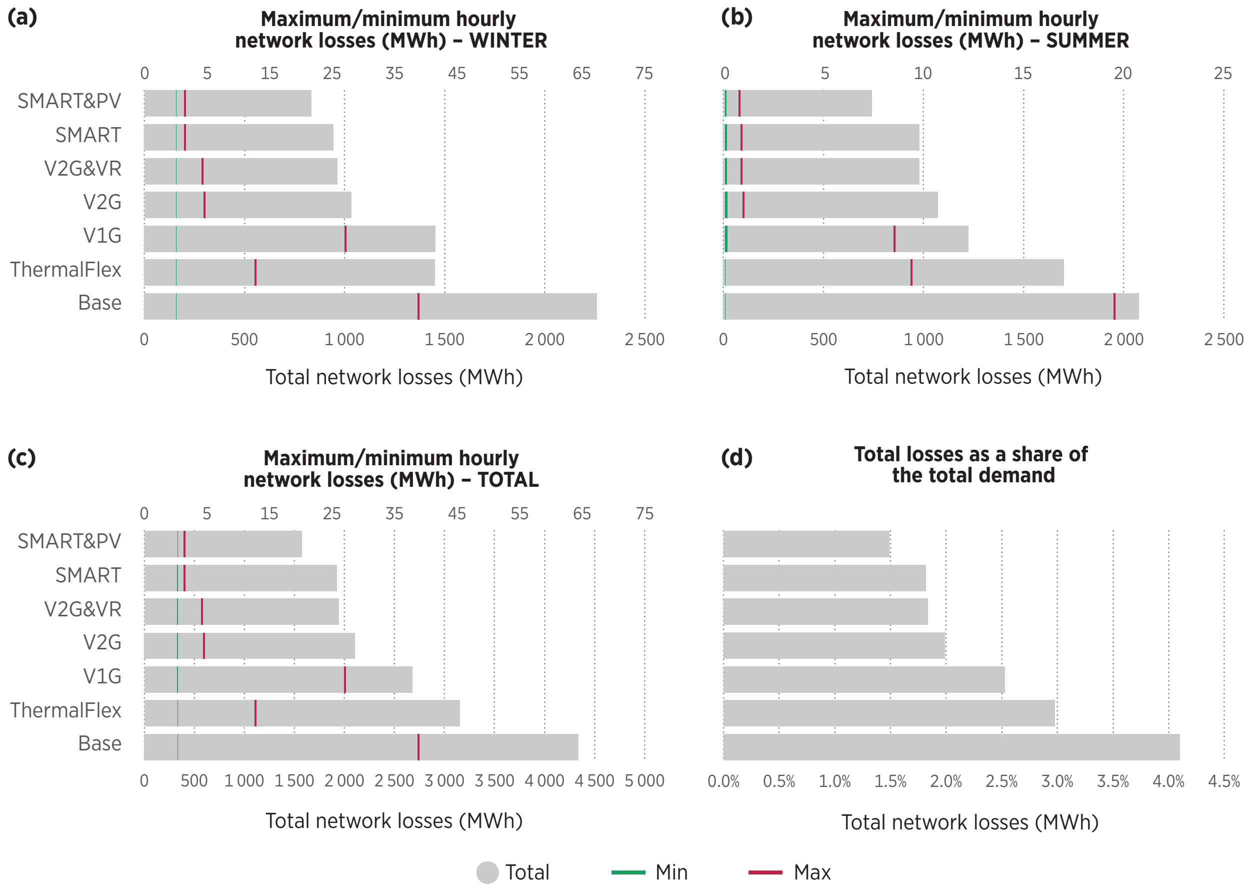
Minimising total active network losses was set as the objective function of the optimisation problem defined in this study. Physically, losses are proportional to the square of the current flowing across the grid lines. This means that the model reschedules the heating demand by using the flexibility of heat pumps and the charging and discharging curves of EVs to reduce those current flows across the network. Therefore, the model seeks to lower and flatten the demand curves over time and thus reduce high use rates in terms of maximum capacity of the grid. Results across scenarios follow the same pattern as those for the demand due to the relation between currents and losses. As for the discussion around demand profiles, the incorporation of PV systems locally contributes to a lower use of the grid and then to lower losses, since decentralised PV is produced and consumed on-site.

Network losses for the winter and non-winter seasons are shown in Figure 11. In winter, losses account for 4% of the total demand in the BASE scenario. The introduction of flexible heat pump operations helps decrease total network losses by more than 1 GWh (27% reduction), representing a one percentage point reduction compared to the base demand. In addition, flexibility provided by heat pumps reduces peak losses by 67%, from 38.7 MW to 12.6 MW. This result is in line with the peak demand reduction observed in the previous section (23% reduction). The minimum loss values remain at similar values.

As with the results for the demand profile, V1G flexibility does not contribute to a reduction in peak demand to the same extent as thermal storage does in winter. Overall, V1G reduces losses by 38%. However, when bi-directional charging is enabled, peak losses fall by two-thirds, from 38.7 MW to 4.4 MW. The combined flexibility scenarios (SMART and SMART&PV) reduce total losses even further, down to 1.9 GWh from 4.4 GWh. Decentralised PV results in additional reductions, bringing the total down to 1.5 GWh (18% reduction compared to the SMART scenario and 63% compared to the BASE scenario). Overall, the adoption of EV flexibility, either V1G or V2G, allows balancing the use of the grid, as this increases the use of the grid in periods when overall demand is low and reduces grid use when demand is high (in the chart, minimum values are in green and maximum values are in red).

Results for the summer period (or non-winter period) show similar trends across scenarios as the results in winter. The SMART&PV scenario greatly reduces grid losses compared to the SMART case (24% in summer versus 12% in winter) because of the increased generation of decentralised PV. For the V1G scenarios, loss profiles are stable. The difference between the maximum and minimum values is 4 MW.

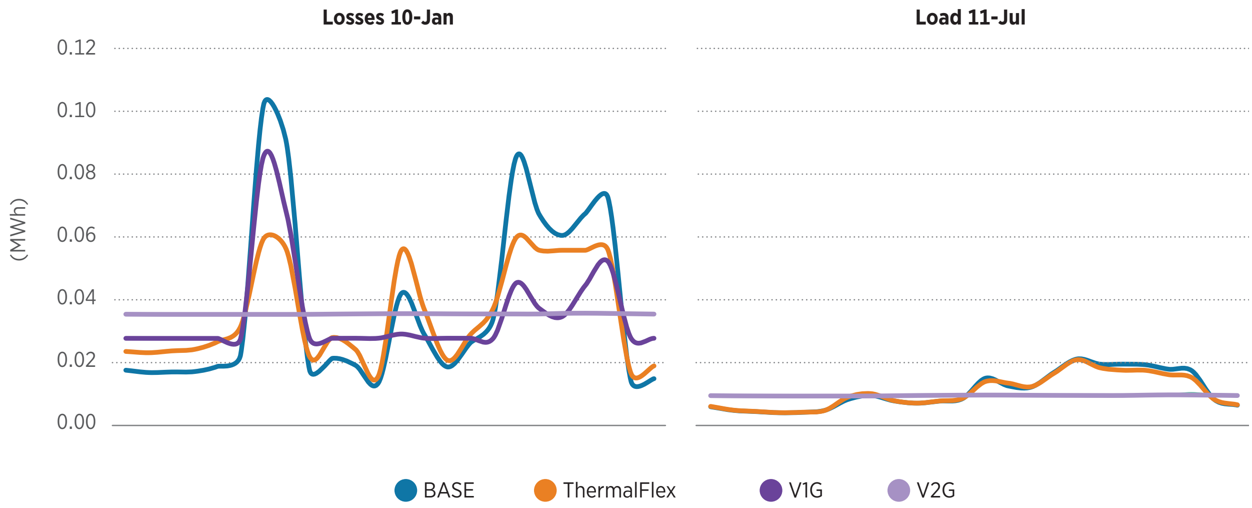
FIGURE 11 | Energy grid losses in (a) winter, (b) summer, (c) total and (d) total as a share of demand



Notes: MWh = megawatt hour; V1G = uni-directional smart charging; V2G = bi-directional smart charging; vehicle-to-grid; VR = voltage regulation; EV = electric vehicle; HP= heat pump; PV = photovoltaic.

The conclusions drawn from analyses of total network losses can also be identified in the daily performance of the network (Figure 12). It is observed how the peak demand in early hours of the winter day is reduced by the V1G, ThermalFlex, and V2G scenarios, in this order. The same applies for the peak demand in the evenings. The case of V2G flattens the curve to a large extent, as was already presented for the annual analysis where the maximum and minimum values were close to each other. Another important observation is the similarity of the daily patterns of the losses and the daily demand (Figure 12). In the case of summer, losses are much lower due to a lower utilisation of the grid as a result of a lower heating demand.

FIGURE 12 | Total energy losses in the representative winter day (left) and summer day (right)



Notes: MWh = megawatt hour; V1G = uni-directional smart charging; V2G = bi-directional smart charging; vehicle-to-grid.

VOLTAGE PROFILES

KEY MESSAGES

Even though there were no under-voltage problems in the network, the results clearly show that any possible problems caused by further increases in the share of wind and solar generation can be successfully resolved by implementing voltage regulation control using the capabilities of V2G assets.

- The ThermalFlex and V1G scenarios do not show great potential in the improvement of the voltage profile. They are effective in reducing some extreme values, but on average the voltage values are similar to the BASE scenario. In both scenarios, voltage values below 95% of the nominal value are greatly reduced, from 1.7% of the hours for the BASE scenario to 0.9% and 0.7% for each scenario respectively.

- If smart charging of EVs allows also voltage regulation (V2G&VR and SMART scenarios), average voltage values get closer to the nominal value, from 97.7% in the BASE scenario to 98.8% in the V2G&VR. In addition, the deviation of hourly voltage values decreases by almost 40% compared to the BASE scenario, in the present analysis.

- In the SMART&PV scenario, the presence of PV slightly increases voltage values, with the average value being 0.1% higher than in the SMART scenario for the non-winter period and 0.04% in the winter one, according to this analysis.

- Results show that under a co-ordinated integration, PV, EVs and heat pumps can mutually offset one another and achieve a balanced grid.

Electrification of the heating and transport sectors increases electricity consumption in the distribution grids and consequentially can alter the voltage magnitude below allowed values. An opposite effect is produced by the integration of solar PV, which potentially leads to over-voltage problems, particularly in periods of low consumption and high generation. The occurrence of reverse power flows can also impact voltage profiles in distribution grids. The negative effects of the integration of distributed energy sources can be prevented by using smart electrification strategies that take advantage of EV assets. To evaluate the effect of voltage, this analysis considers as acceptable voltage values between 90% and 110% of the nominal value.

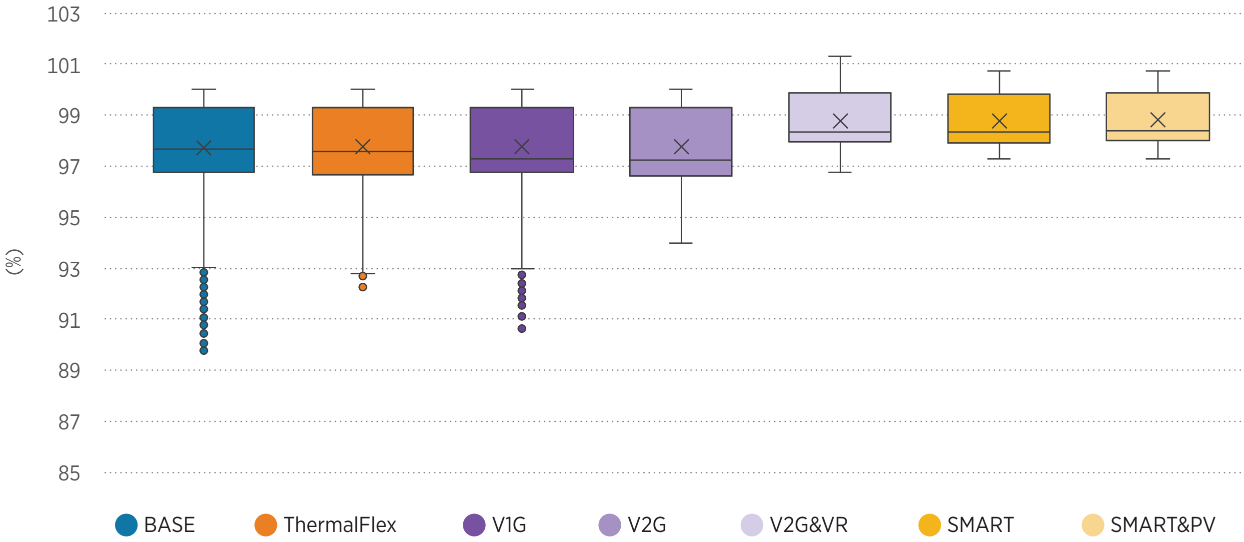
Figure 13 shows the boxplot graph with the hourly voltage values for the winter season. In the chart, points marked with *"o"* represent outliers and with *"x"* represent values of each scenario. The line splitting the box in two represents the median value. This shows that 50% of the data lies on the upper side of the median value and 50% lies on the lower side. The lower edge of the box represents the lower quartile; it shows the value at which the first 25% of the data falls up to. The upper edge of the box shows the upper quartile; it shows that 25% of the data lies to the right of the upper quartile value. The values at which the vertical lines stop (whiskers) are the values of the upper and lower values of the data. The single points on the diagram show the outliers.

As mentioned, the electricity demand is the highest in the winter period; therefore, the network is used at higher capacity during this period. Due to the impact of total load on the value of voltage magnitude, the lowest values are expected in this season, which is confirmed by the model. Even if peak demand is the largest in the BASE scenario and therefore the voltage magnitude is lowest, on average, differences are small across the scenarios without voltage regulation control.

The scenarios enabling bi-directional charging (V2G) allow shaving outliers' voltage values in the lower voltage range – just 0.2% of hours show values below 95%. Once voltage regulation strategies via EV batteries are enabled (V2G&VR, SMART and SMART&PV), average voltage values get closer to the nominal values. In average terms, the voltage value is 98.8% compared to the average 97.7% of the V2G scenario. In addition, the fluctuation of voltage values is much lower in those scenarios in which voltage regulation is enabled. To provide some values, the standard deviation of voltage values in the V2G&VR is 29% lower than in the case of V2G (1.38 versus 0.98). This reduction reaches 40% when compared to the BASE scenario (1.63 versus 0.98).

Even though there were not any under-voltage problems in the network, the results clearly show that any possible problems caused by the further increase in the share of variable wind and solar integration can be successfully resolved by implementing voltage regulation strategies using EV batteries.

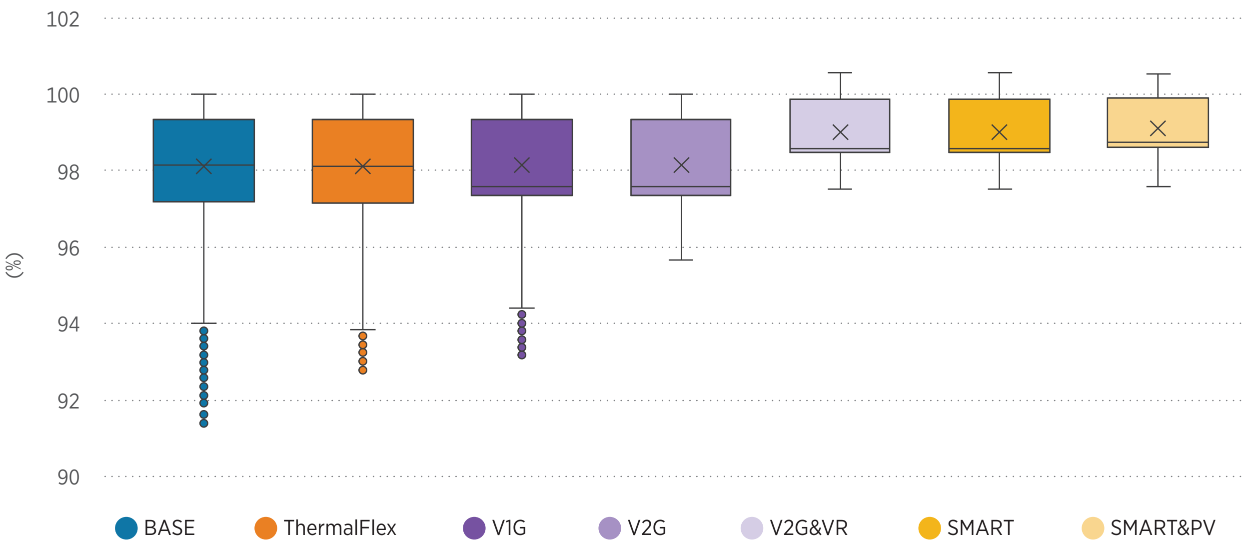
FIGURE 13 | Voltage magnitude – winter



Notes: V1G = uni-directional smart charging; V2G = bi-directional smart charging; vehicle-to-grid; VR = voltage regulation.

Figure 14 shows the values of voltage magnitude for the non-winter season. Qualitatively, results are almost identical to the ones obtained in the winter period. Once the voltage regulation is enabled by using EV batteries, the average voltage values increase up to an average value of 99%, which is as high as the average values for scenarios with no voltage regulation (98.1%). In addition, the deviation is greatly improved, reaching 39% reduction compared to the BASE scenario and 29% compared to the V2G scenario.

FIGURE 14 | Voltage magnitude – non-winter



Notes: V1G = uni-directional smart charging; V2G = bi-directional smart charging; vehicle-to-grid; VR = voltage regulation.

From the voltage analysis, it can be concluded that despite the lack of under-voltage or over-voltage problems, observed smart electrification strategies help in improving voltage profiles, in particular when V2G allows for voltage regulation. Voltage regulation provided by EVs additionally increases voltage magnitude values, which is important due to the continuous electrification since new loads in the system such as heat pumps or EVs would normally tend to reduce the voltage in grid nodes.

Lastly, in terms of PV adoption, the SMART&PV scenario shows slightly higher voltage values of 0.1% in the non-winter period and 0.04% in the winter period, compared to the SMART scenario. Therefore, by integrating PV, EVs and heat pumps in a co-ordinated manner, they can mutually offset one another and achieve a balanced system.

POWER FLOWS AND LINE USES

KEY MESSAGES

If the line does not have the capacity to accommodate the peak demand, brownouts or blackouts may occur. For this reason, it is of extreme importance to investigate the maximum use of lines. Smart electrification strategies allow for reducing the use of lines, defined as the maximum power values observed to the maximum capacity of the grid, below 50%, according to the present analysis.

- The presence of flexible heating demand (ThermalFlex scenario) enables the decrease in the use of line capacity. The V2G scenario and the possibility to meet a share of the demand on-site with PV generation greatly decreases the power flow of lines, as part of the demand is covered locally. Reductions are 40-50% in terms of peak power flows, including active and re-active power.

- The SMART&PV scenario reduces the average use of lines from 24.8 megavolts-ampere (MVA) in the BASE scenario down to 11 MVA in winter, almost a 50% reduction. This indicates that smart electrification enables a larger electrification rate using the same infrastructure.

- V2G achieves reductions in the use of lines of almost 40%. The combination of all enabling solutions achieves reductions of 50% in all critical lines.

Besides the analysis of the power (supply and demand) in every node, it is equally important to analyse power flows through transformers and lines in the grid. Each line is characterised by its thermal capacity, which determines its maximum power or current rating. Overloading a line by forcing larger currents than nominal for each line may shorten the line lifetime and endangers the safe and reliable operation of distribution networks. This analysis shows how smart electrification strategies can effectively decrease the load in the lines and prevent unreliable operation and the need for grid reinforcements.

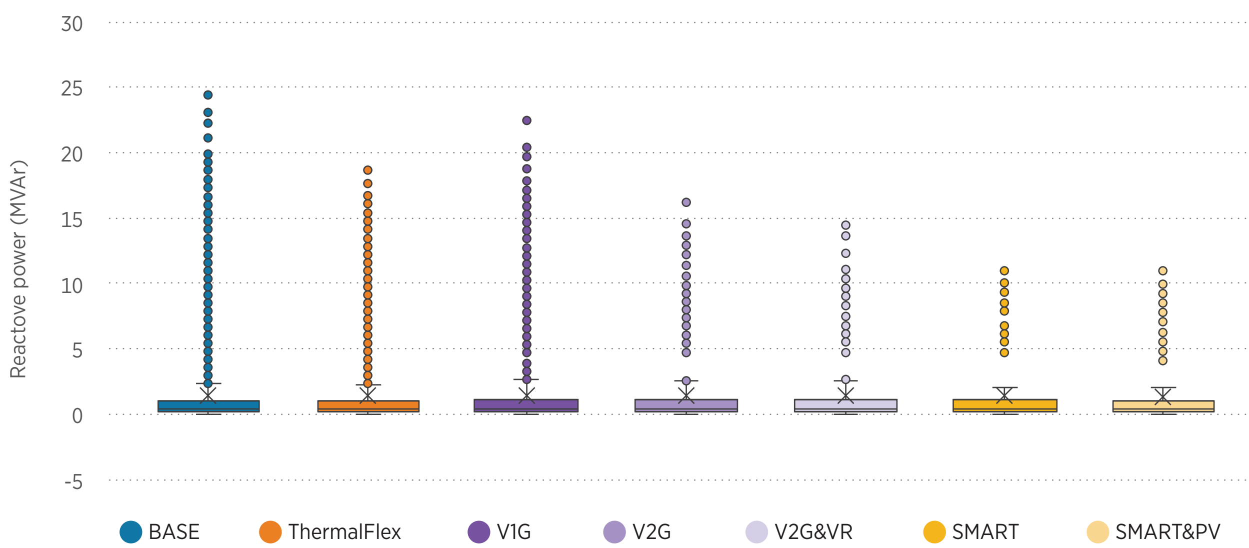
Figure 15 shows the power flow of lines in the winter season in terms of apparent power (MVA). Due to the peak of demand in winter, the power that flows through the lines is the highest for this season in the BASE scenario, when the maximum value registered of power through a line is 24.8 MVA. The presence of flexible heating demand (ThermalFlex scenario) enables the decrease in the use of lines. The maximum power for this scenario is 18.9 MVA (23.5% lower than in the BASE scenario). The V1G scenario also achieves reductions compared to the BASE scenario, but peak values are higher than in the ThermalFlex scenario. The maximum power registered in the grid is 22.8 MVA.

The presence of V2G – which allows the bi-directional charging of EVs and thus supplies certain demand on-site – reduces the use of the grid, reducing the maximum power in the grid by 40% (14.7 MVA). In the V2G&VR scenario, re-active power when EVs are being charged or discharged can differ from zero. Even though it helps decrease losses or improve voltage magnitude, as presented in the previous section, theoretically it could negatively affect the use of the line capacity due to an increase in the apparent power, which is the vectorial sum of active and re-active power, due to the larger amount of re-active power flowing across lines.

Results show that this is not the case. The V2G&VR scenario shows similar peak power values as in the V2G, which means that the re-active power potential negative effect from EV charging and discharging is levelled out by voltage regulation and lower current flowing across the lines. The combination of all flexibility assets under the SMART scenario further reduces the peak power in the grid by half, the largest reduction across scenarios. In winter, the presence of PV does not reduce peak flows since the hours of maximum solar production do not coincide in time with peak demands. Therefore, the SMART and SMART&PV scenarios show similar results in terms of power flows.

In addition to the peak flow observed, another interesting result in the power flows is the average values. All scenarios perform in a similar way, with differences in uses below 1%. Only when local PV is enabled (SMART&PV), a significant reduction of 4.2% is achieved.

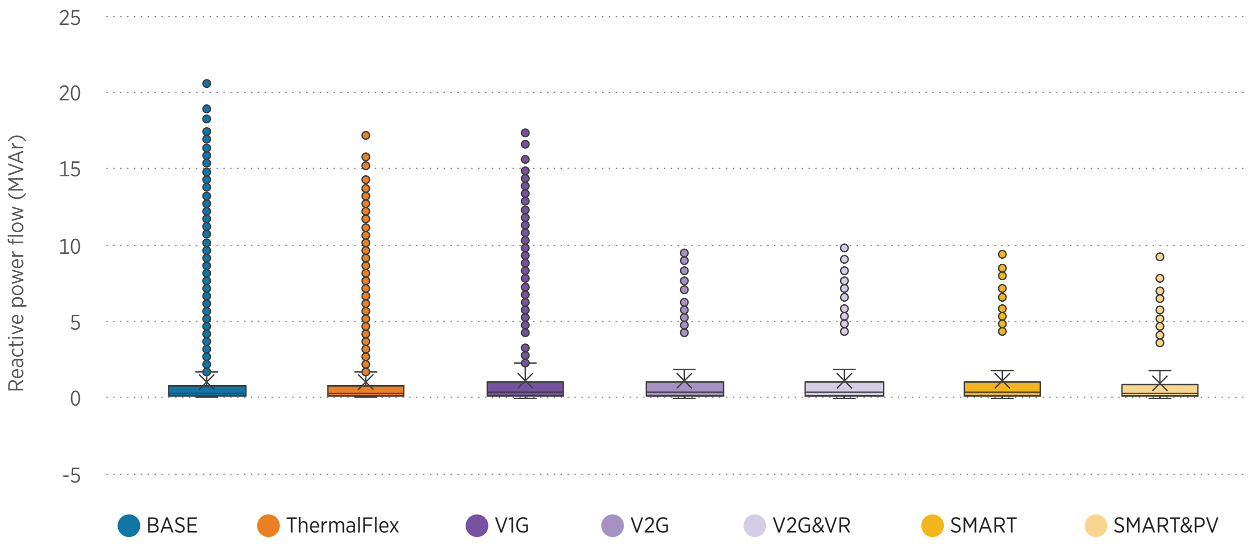
FIGURE 15 | Lines power flow – winter



Notes: V1G = uni-directional smart charging; V2G = bi-directional smart charging; vehicle-to-grid; VR = voltage regulation; PV = photovoltaic; MVAr = megavolt amperes reactive.

The results of the non-winter season are shown in Figure 16. Trends are similar to the results of the winter period. It is observed that V2G is the most effective asset to reduce peak power across lines. While the ThermalFlex and V1G scenarios achieve reductions in the maximum power flow of around 15%, the presence of V2G increases this reduction to above 50%. The major difference compared to results in winter is that the effect of PV is significant in terms of peak shaving. It contributes to a reduction in peak flows of 3% compared to the SMART scenario and in the average use of the grids by 10% due to a lower net demand that has to be supplied from the grid.

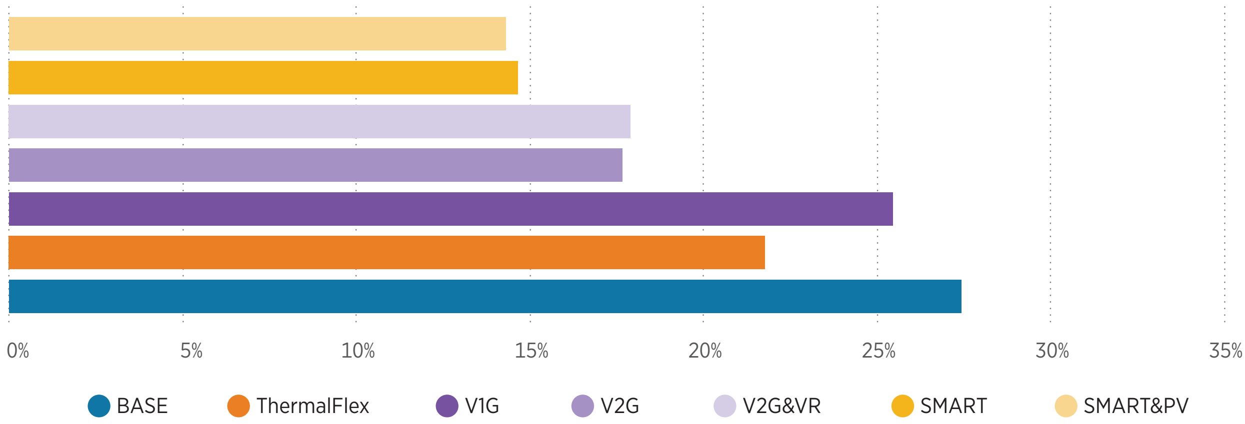
FIGURE 16 | **Lines power flow – non-winter**



Notes: V1G = uni-directional smart charging; V2G = bi-directional smart charging; vehicle-to-grid; VR = voltage regulation; PV = photovoltaic; MVAr = megavolt amperes reactive.

Another important aspect for network management is the use of the grid relative to the capacity of each line, which is referred to as the use of line. Looking into the average use of all lines for each scenario, it can be seen in Figure 17 how the adoption of flexibility measures reduces the use of lines. The SMART&PV scenario reduces the average use of lines from 27.4% in the BASE scenario down to 14.3%, almost a 50% reduction. This indicates that, contrary to what might be expected, the electrification of the energy system allows for more integration of electricity-based consuming units, such as EVs and heat pumps, as long as they provide flexibility to the grid.

FIGURE 17 | Average use of line per scenario

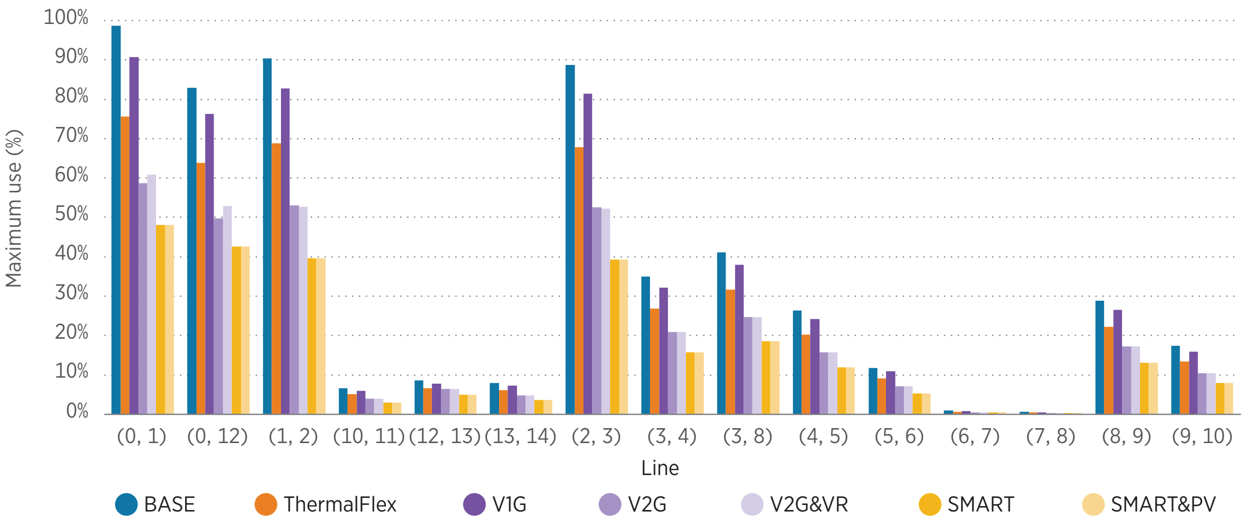


Notes: V1G = uni-directional smart charging; V2G = bi-directional smart charging; vehicle-to-grid; VR = voltage regulation; PV = photovoltaic; MVAr = megavolt amperes reactive.

Having said that, the bottleneck when discussing the capacity of grids to cope with a more electrified system is related to the peak hours when congestion may occur. If the line does not have the capacity to accommodate the peak demand, blackouts may occur. For this reason, it is extremely important to look into the maximum use of lines. Figure 18 shows the maximum use of lines for all lines and scenarios. Two observations can be made based on the results presented; first, flexibility greatly reduces the risk of potential congestion. Second, the use of lines is uneven across lines, which depends on the design of the grid. In our case study, lines (0,1), (0,12), (1,2) and (2,3) are those with higher utilisation. These lines are at the beginning of medium-voltage feeders, and the highest load flows through them. That is the reason for their high exploitation (see Figure 2).

Understanding the impact on these four lines of a smart electrification approach will give us an idea of how far the transformation of end uses can go.

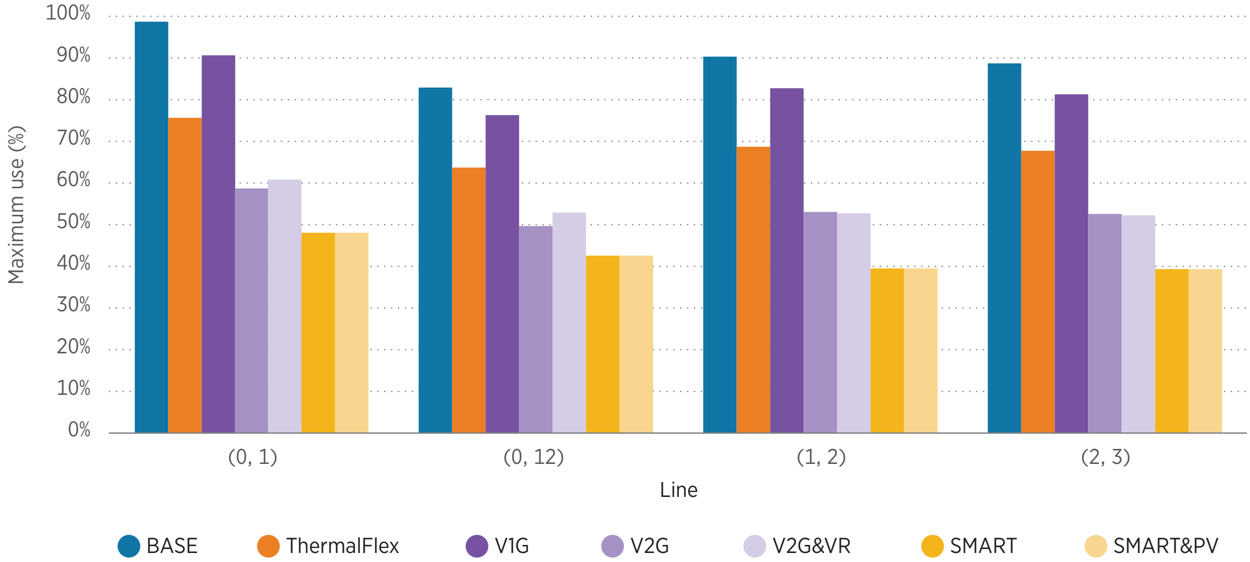
FIGURE 18 | Maximum use of lines capacity



Notes: V1G = uni-directional smart charging; V2G = bi-directional smart charging; vehicle-to-grid; VR = voltage regulation; PV = photovoltaic.

In Figure 19, the maximum use of critical lines is presented. As can be observed, enabling flexibility reduces the use of lines by 50%. Again, V1G does not contribute as much as thermal storage in reducing the maximum use of lines. Conversely, V2G achieves reductions of almost 40%. The combination of all enabling solutions achieves reductions of 50% in all critical lines. The adoption of PV does not provide additional reduction because the large production of PV does not coincide with the peaks in demand when the largest use of the lines occurs.

FIGURE 19 | Maximum use of lines for the most demanded lines



Notes: V1G = uni-directional smart charging; V2G = bi-directional smart charging; vehicle-to-grid; VR = voltage regulation; PV = photovoltaic.

The adoption of smart electrification strategies can limit the risk of grid congestion by reducing the use of critical lines by 50%, according to the present analysis. This means that smart electrification can accommodate more electricity-based demand without compromising the operation of the networks – thus delaying the need for investments.

ECONOMIC ANALYSIS

KEY MESSAGES

- In the selected case study, smart electrification strategies can defer the need of reinforcing the grid, which would require the addition of two transformers and around 7 kilometres of lines (the four lines presented in Figure 19). The total investment cost would amount up to USD 13.3 million (EUR 12 million).

- Assuming a capital recovery factor of 5.8%, which corresponds to a weighted average capital cost of 5% over a 40-year lifespan, the savings would reach USD 8.3/MWh (EUR 7.5 /MWh). This would have a significant impact on the energy bills of end users.

- Losses avoided represent up to 3% of the energy cost in the SMART&PV scenario.

- In the SMART scenario, the energy cost can be reduced by 35% under marginal whole electricity prices, from around USD 8 million (EUR 7.34 million) down to USD 5 million (EUR 4.72 million) annually.

Smart electrification brings three main economic advantages:

1) grid reinforcement deferrals due to lower line rates of uses – the grid-related capital expenditure (CAPEX)
2) savings provided by the reduction of losses in the grid operation – the grid-related operational expenditure (OPEX)
3) lower wholesale electricity prices, since peaker plants, the most expensive ones, are not dispatched.

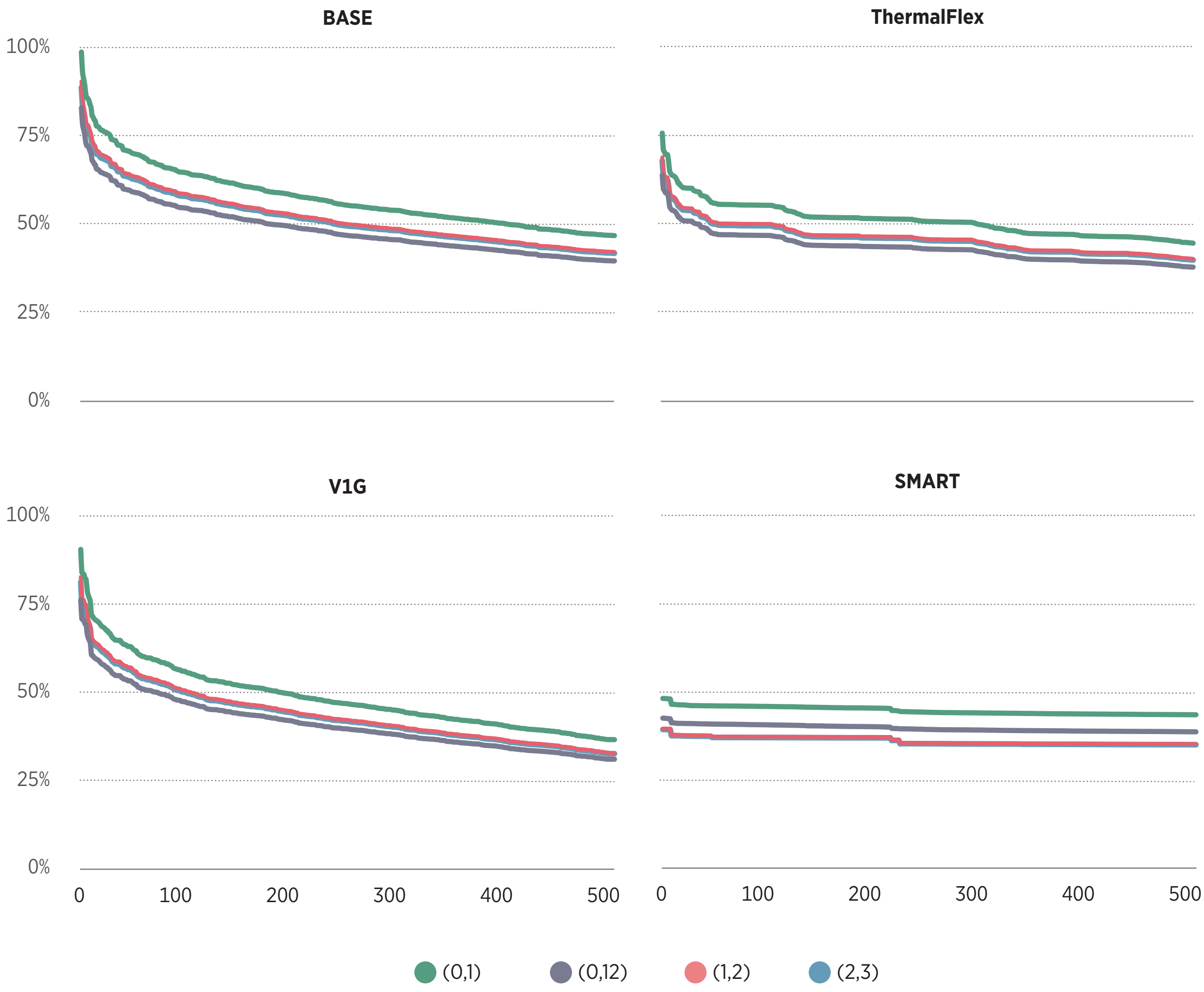
This last advantage does not relate directly to a distribution grid alone. Yet, if all distribution grids connected to a transmission grid were to enable flexibility assets, and were operated under a smart approach, wholesale electricity prices would drop due to flatter demand curves, assuming marginal price-based electricity markets.

The model implemented for this analysis focuses on the operation of the grid, and it seeks the minimisation of losses in the grid. Therefore, it solves the scenarios on the basis that enough grid capacity is in place. As a result, penalties for unserved loads. or strategies to address congestion such as rotational load shedding, are not reflected in the model.

It is assumed that lines with a use capacity of 80% or more would require medium-term investments, or at least a close examination in terms of grid planning. This would imply a certain budget allocation and grid reinforcement execution. As Figure 19 shows, this is the case of four lines in the present analysis.

In Figure 20, the load duration curves of the most used lines are presented for the 500 hours of the year when the use is higher. As can be observed, the use of the lines exceeds 80% of their capacity (the threshold considered for potential investment requirements) for around 20 hours per year, which would not lead to investment planning. Interestingly, in the SMART scenario, the use of lines does not exceed 50% of their capacity, highlighting the benefits of enabling flexibility sources through a smart approach. In other words, the SMART scenario would allow for further electrification without compromising the capacity of the lines.

FIGURE 20 | Load duration curves of the use of lines (ratio of actual capacity to nominal capacity) for the most demanded lines in the grid



Notes: V1G = uni-directional smart charging.

High power flows increase the thermal usage of a line, shorten its lifetime and increase the risk of failure. Table 3 displays the maximum capacity utilisation, nominal capacity, and length of lines (0,1), (0,12), (1,2) and (2,3). As shown, the capacity utilisation of these lines exceeds 80%, and the assumption is that these lines need to be reinforced in the near future.

TABLE 3 | Characteristics and investment cost of repowering critical lines

Line	Maximum use (%)	Length (km)	Capacity* (MVA)	New capacity (MVA)	Cost of addition for repowering (1 000 EUR)
0-1	98.71	/	25	50	4 729
0-12	82.98	/	25	50	4 729
1-2	90.37	2.82	5	10	1 157
2-3	88.67	4.42	5	10	1 686
				TOTAL (1 000 EUR)	12 303

Notes: * Capacity in apparent power; MVA = megavolt ampere.
Source: (ACER, 2023; Aleen, 2024; CLASP, 2013; CNMC, 2019; Federal Reserve Bank of St. Louis, 2024; PwC, 2023; T&D Europe, 2024)

The system operator should add two new transformers and around 7 kilometres of lines. The total investment cost would be up to USD 13.3 million (EUR 12 million). The decrease in the maximum use of line capacity after implementing smart electrification strategies would present significant savings and the postponement of investment. If a capital recovery factor of 5.8% is assumed, corresponding to a weighted average capital cost of 5% over a 40-year lifespan, the savings in the levelised cost of energy would amount to USD 8.2/MWh (EUR 7.4/MWh) over a 40-year period.

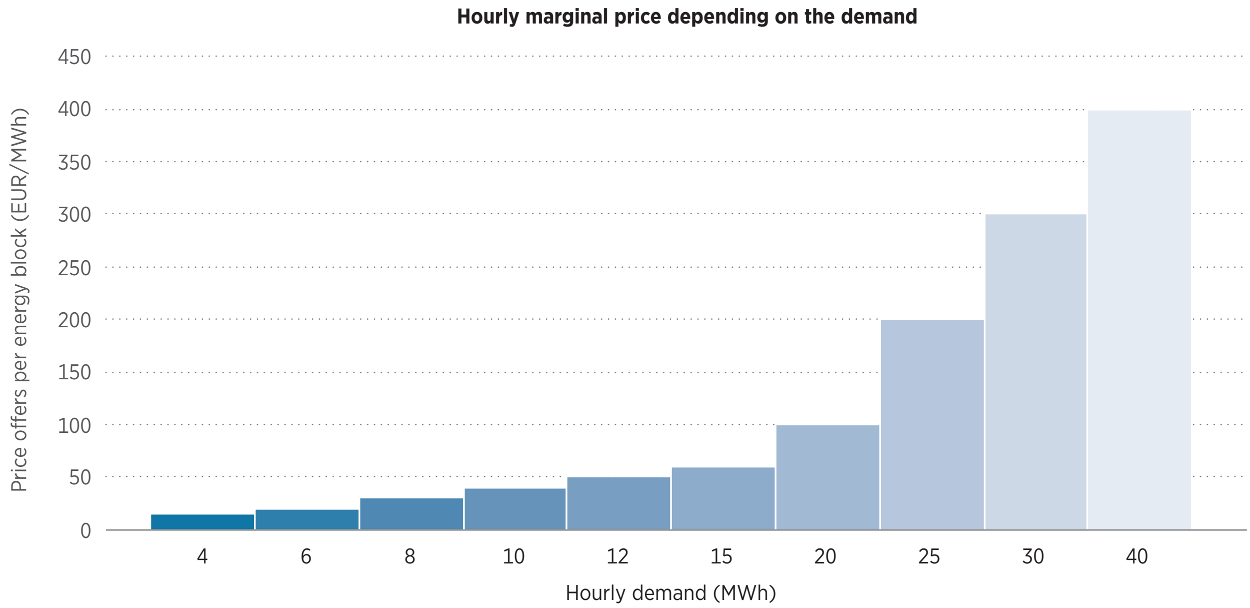
The savings achieved by reducing grid losses amount to 3% of the total energy delivered. If it is assumed that all these avoided costs are passed on directly to consumers, the savings amount to USD 5/MWh (EUR 4.5/MWh) on a yearly basis, based on a retail final price of USD 174/MWh (EUR 157/MWh). Unlike the analysis on grid reinforcement, this value is not dependant on investment decisions, as it relates solely to the operation of the existing grid considered in the analysis.

To conclude the analysis, an attempt to quantify the marginal cost reduction provided by a more flexible system is covered. As mentioned before, the model used in this study determines the optimal operation of the grid to minimise losses. This means that synthetic demand profiles were assumed that could be re-shaped based on the flexibility provided by the assets available in each scenario, with the goal of reducing losses in the lines. In other words, the model does not consider market dynamics triggered by pricing mechanisms such as price signal responses. Still, with the information provided by the model, an estimation of energy cost reductions can be quantified.

To do so, a distribution price based on the consumption level is defined. Here, it is important to highlight that in electricity markets, the price formation is a complex task that is subject to many aspects beyond the level of energy consumption. For example, in marginal pricing electricity markets, the marginal pricing (or "pay-as-cleared") that is defined by the last selected offer – this is a generating unit offer – may vary depending on the level of renewable generation available, as renewables are first in the order of merit. Similarly, the availability of peaker generators – those that run only when there is a high demand – can also affect the wholesale electricity price.

To avoid this complexity, here, prices for different levels of energy are assumed, as presented in Figure 21. The rationale behind this selection of prices is that the higher the demand, the more expensive generation technologies are required to meet the demand. Here the maximum and minimum prices are set at USD 445/MWh (EUR 400/MWh) and USD 16.6/MWh (EUR 15/MWh) respectively.

FIGURE 21 | Wholesale electricity price estimation

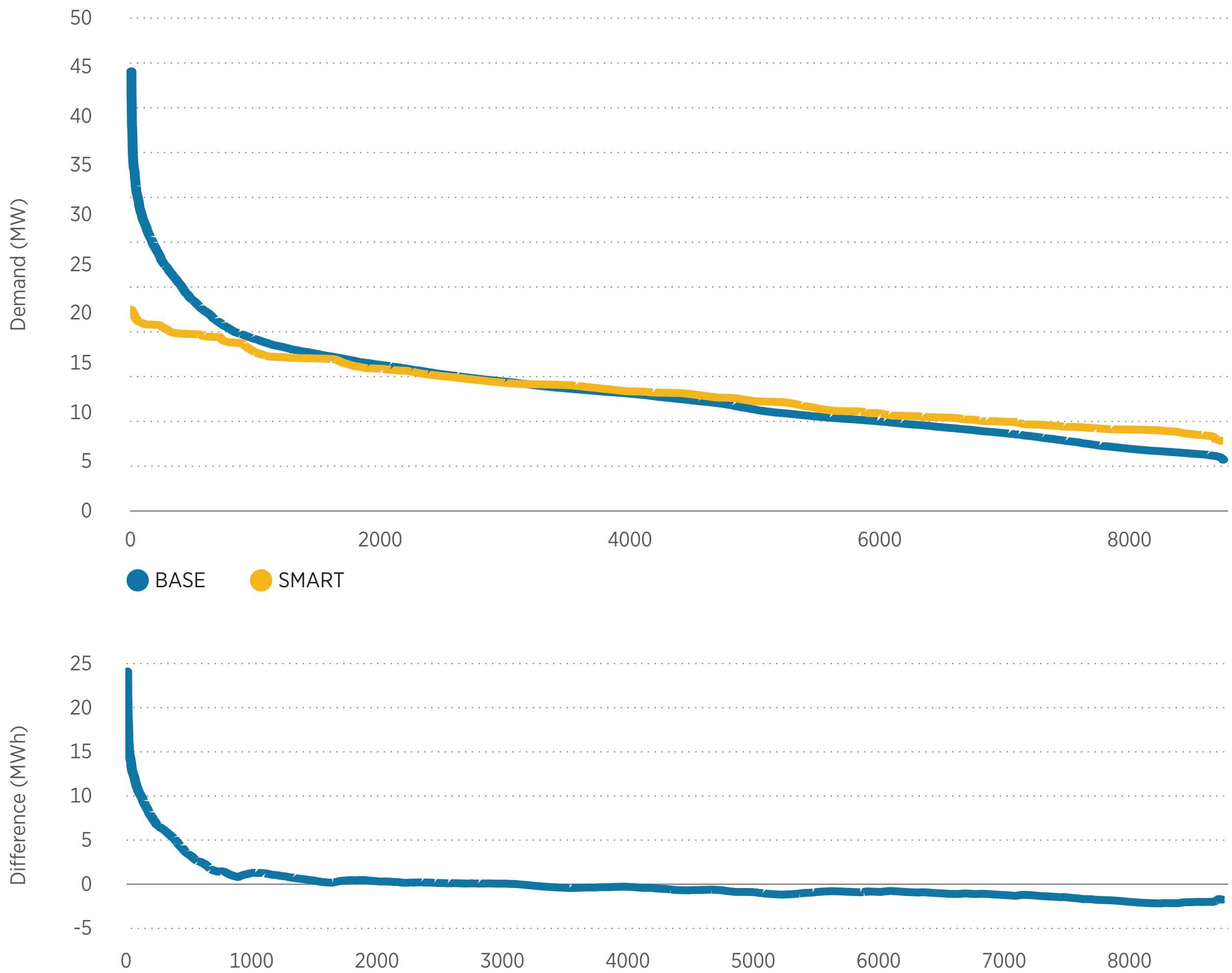


Example of generation technologies offer prices for energy blocks
Photovoltaics-Wind-Hydro-Other RES> Nuclear > CC > Coal > Gas (peaker)

Notes: MWh = megawatt hours; RES = renewable energy resources; CC = Combined cycle power plant

In this way, if smart electrification strategies help reduce peak demand and provide a more stable use of the grid, energy savings will come not only from the reduction of losses or grid reinforcement delays in the mid- to long-term, but also from a cheaper electricity price. Figure 22 shows the reduction of peak demand values due to the availability of flexible assets. This translates into significant savings. Applying the price distributions presented previously, the energy cost in the BASE scenario is USD 7.25 million (EUR 6.52 million) (USD 69/MWh or EUR 62/MWh), while in the SMART case this cost is reduced to USD 5.4 (EUR 4.88 million) (USD 51/MWh or EUR 46/MWh), which represents a 25% reduction. This benefit is to be added on top of those discussed before in the section.

FIGURE 22 | Load duration curve of the demand in the BASE and SMART scenarios (upper) and difference in demand between the two scenarios



Notes: MW = megawatt; MWh =megawatt hour.

Therefore, summing up all three components in both the BASE and SMART scenarios, unitary energy costs are USD 77/MWh (EUR 69.4/MWh) (including the marginal and the grid reinforcement costs) in the BASE scenario and USD 45/MWh (EUR 44.6/MWh) in the SMART scenario. The SMART scenario reduces total costs by 35%, from USD 8 million (EUR 7.35 million) down to USD 5.2 million (EUR 4.72 million) annually.

8

CONCLUSIONS

This study aims to quantify the benefits that flexibility sources can bring to the distribution grid management. The case study considered aims to reproduce typical conditions of residential urban areas, where energy demand is geographically dense and heating consumption is dominant.

In the context of a largely electrified energy system, the proposed case study assumes a large penetration of heat pumps that can operate in a flexible way by ramping up and down up to 30% of the nominal capacity, thanks to the presence of thermal storage. In addition, certain deployment of electric vehicles (passenger cars) is assumed. These vehicles can interact with the grid in one or two directions depending on the specific scenarios and can also offer their battery capacity for more efficient grid management. Together, heat pumps and EVs represent an additional demand of 50% compared to the existing baseload demand.

Results obtained across scenarios suggest that flexibility options complement each other, and benefits are maximised when they are combined. Specifically, the adoption of holistic smart electrification approaches can limit the risk of congestion by reducing the use of critical lines by 50%. This means that smart electrification can accommodate more electricity-based demand without compromising the operation of the networks – and thus delaying the need for investments. These results can be estimated in economic savings of around USD 27.3/MWh (EUR 24.6/MWh) – a 35% reduction – combining the effect of grid loss reduction and potential grid investment delays.

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