Australian National University

The opportunities to flex water heating and electric vehicle charging loads in the ACT

April 2025

Dr Bjorn Sturmberg

bjorn.sturmberg@anu.edu.au

A/Prof. Marnie Shaw

marnie.shaw@anu.edu.au

Dr Bin Lu

bin.lu@anu.edu.au

School of Engineering

The Australian National University

Canberra ACT 2600 Australia

www.anu.edu.au

Executive Summary

The Australian Capital Territory (ACT) serves as a useful case study of city-level decarbonisation, having already achieved 100% renewable electricity by 2020, and with an ambitious target for net-zero emissions by 2045. The transition presents both challenges and opportunities for managing electricity demand.

This research focuses on the opportunity to better utilise existing network infrastructure and reduce energy costs for ACT residents. Our analysis found that **significant population growth to 2045 and electrification can be accommodated within the capacity of existing distribution zone substations if, and only if, the timing of electric vehicle charging and water heating is shaped** to occur in times of otherwise low electricity demand. The inflexibility of current appliances comes at the major cost of peak demands and these will grow – even in the absence of electrification – with population growth.

Our analysis found:

- Electric vehicles (EVs) significantly contribute to projected demand increase; for instance, in areas like Gungahlin and South Canberra, EVs add 45% and 30% to the present demand respectively.
- The transition of households from gas to electric water heating will lead to a neutral change in electricity consumption, thanks to the efficiency of heat pumps.
- Without any load shifting, the combined effect of population growth and EV adoption could result in a 75% increase in peak electricity demand in some suburbs.
- Increasing the length of time that EVs are plugged in to their chargers, to facilitate a greater range of options for optimised charging, is greatly increases the flexibility of this demand – as shown in our previous research.
- The merits of sophisticated demand optimisation systems are counterbalanced by the imperative to move quickly – **simple, time-based approaches should not be delayed**.

In summary, simple strategic policies that shift loads into low demand periods would enable significant growth in total demand to be accommodated within existing zone substation capacity limits. For example, in the suburb of Gungahlin, such measures could limit peak demand increases to just 25%, while all private vehicles and domestic hot water are electrified, and the population grows by 30%.

This research was funded by the ActewAGL Endowment Fund, administered by the Australian National University. The findings and conclusions presented were developed independently and do not necessarily reflect the views of ActewAGL.

Background and Aims

Decarbonisation is transforming energy systems worldwide. The Australian Capital Territory (ACT) serves as a useful case study of city-level decarbonisation, having achieved 100% renewable electricity by 2020, having a high rate of rooftop solar installations (as of April 2025, 40.1% of houses have solar[1]) and having set an ambitious target for net-zero emissions by 2045. The ACT Government's Integrated Energy Plan[2] outlines a strategic vision where the electricity network will evolve from supplying approximately one-third of the territory's energy needs to nearly all, as gas and transport systems become electrified.

While the electrification of a city presents challenges for electricity infrastructure, it also offers opportunities for optimising and enhancing the existing grid. The International Energy Agency (IEA) has highlighted that the electrification of new sectors could potentially double global electricity consumption by 2050. Modelling commissioned by the ACT Government aligns with this projection, with the maximum electricity demand expected to increase from 650 to 1600 MW, alongside a more than doubling of grid infrastructure expenses, from $360M to $800M[3].

While this modelled scenario might eventuate, there is great potential to create a more efficient, lower-cost future in which the flexibility of customer energy resources (CER) — including electric hot water systems, household batteries, and electric vehicle batteries — is utilised to shift demand temporally to better utilise existing grid capacity and minimise infrastructure upgrades. This report aims to estimate the opportunities for flexible loads to reduce peak demand in the ACT, with the ultimate goal of lowering the costs associated with electrifying the territory.

Extensive research has examined various aspects of CER, including their roles in demand management, grid support functions such as frequency and voltage regulation, microgrid formation, and adoption drivers. However, there is a significant knowledge gap regarding the collective impact of customer resources and the feasibility of achieving simple coordination at the city scales.

This report addresses this research gap through high-resolution modelling of customer resources at a regional level, using the ACT as a case study. The focus on private vehicles and residential water heating is intended to capture the most significant and immediate impacts of electrification. While out of scope of our study, there are major additional loads to consider, including domestic space heaters, as well as commercial and industrial buildings and other vehicle types.

The research has two primary aims:

1. **to quantify the projected increase in ACT electricity demand** by 2045 resulting from the electrification of all private vehicles and residential water heating, as well as population growth; and
2. **to demonstrate opportunities to efficiently accommodate this demand** into the distribution network by optimising when electric vehicles and water heaters draw power.

For the avoidance of doubt, this second aim demonstrates what is *possible*, in the interest of motivating and guiding policy actions to create a *preferred* outcome; it does not necessarily represent the *probable* outcome of current policies or behaviours[4].

This report explores the potential of these technologies to facilitate a smarter and more cost-effective use of electricity infrastructure, supporting a people-centred and lower cost transition to a fully electrified and sustainable energy future.

1 https://pv-map.apvi.org.au/historical
2 https://www.climatechoices.act.gov.au/__data/assets/pdf_file/0006/2509458/integrated-energy-plan-2024-2030.pdf
3 Marsden Jacobs Evoenergy Net Zero Modelling Journey. Regulatory proposal for the ACT electricity distribution network 2024–29
4 https://thevoroscope.com/2017/02/24/the-futures-cone-use-and-history/

Method

Concept

Given the unknowability of the evolution of the energy system over the next two decades, we adopt a scenario analysis approach that models a range of potential futures. This requires that we prioritise a small number of variables whose influence on outcomes we can interrogate while holding all other variables fixed.

We chose to investigate two variables:

1. the future adoption of rooftop solar, and
2. the portion of EV charging that is done at home versus in public (including work) locations.

We consider two values for each variable, which yields a total of four variable combination scenarios.

We model population growth, technology adoption and technology use at a suburb level. For population growth we adopt ACT Government forecasts. For the number of private vehicles, we assume the per capita rate to remain fixed at 0.58. In all our scenarios we assume that, by 2045, 100% of passenger vehicles are electric and that 100% of residential water heating is done electrically, with 75% using heat pumps and 25% by resistive heaters.

These suburb-based forecasts are aggregated into their respective zone substations, with some suburbs being distributed between multiple zone substations. This is done because:

a. the impacts on electricity distribution network are determined by the location of loads, and
b. electric vehicle travel patterns place loads in different locations at different times of the day.

Evoenergy provides 15-minute load data for each zone substation. The base case for our scenarios is to apply the demand growth of each suburb to the latest year of substation data. The analysis over a year is crucial for capturing the natural variability of customer demand and solar generation and the resultant variability in substation loading – noting that substation investments are driven by (often short-lived) extrema in high and low loading.

We incorporate the impact of additional rooftop solar installations, noting again the variability of solar generation, by utilising the solar generation data (one year at 5-minute resolution) from 100 rooftop solar systems in the Nextgen data set[5]. For each suburb we scale this solar generation profile by the assumed capacity of new solar installations between 2024 and 2045. (The solar generation of existing solar systems is incorporated within the current zone substation data).

The method as described thus far enables the calculation of total electricity demand at zone substations in 2045 (research aim #1).

Pursuing research aim #2 requires the distribution of EV and water heating power consumption profiles to periods of time when substations (and typically electricity generators) are far from their maximum capacity. To model this, we sought an approach that does not overly idealise the responsiveness and foresight of 'smart systems' (such as clouds reducing solar generation). Furthermore, we sought to use a relatively simple approach that is explainable to all stakeholders. We therefore allot these EV and heating loads to occur across set time windows of each day at a constant rate. Such an approach would also be relatively practical to implement using timers.

There are typically two periods of the day when load is low on the distribution network: overnight and during sunlight (solar power producing) hours. To utilise the available network capacity at these times we chose to have resistive water heaters operate overnight, while heat pump water heaters operate during the middle of the day (where their efficiency is also boosted by higher ambient temperatures). EV charging demand is similarly distributed across fixed daytime and night-time windows. In this case, the precise allocation is dependent on the scenario (discussed below).

[5] https://zenodo.org/records/14885676, https://zenodo.org/records/14885589

Defining variables

We consider two values for rooftop solar additions:

1. a ***High solar*** scenario, and
2. a ***Low solar***.

The values for these are discussed in the ACT rooftop solar by 2045 subsection below. Similarly, we consider two values for EV charging:

1. a ***High home charging*** scenario, and
2. a ***Low home charging*** scenario.

The values for the ***High home charging*** scenario are the Step Change scenario in AEMO's 2024 ESOO (which in turn come from the CSIRO 2023 EV forecast). In the ***Low home charging*** scenario, 20% of charging is shifted from homes to work/public charging, which doubles the prevalence of work/public charging.

Table 1: Defining variables of solar and EV charging scenarios

Solar scenarios	***High solar***	***Low solar***
Rooftop solar additions by 2045	1500 MW	1000 MW
EV charging scenarios	***High home charging***	***Low home charging***
Home charging (L1, L2)	68%	48%
Work/public charging (L2)	20%	40%
Public fast charging (L3)	12%	12%

In all scenarios:

- Home charging is split evenly between daytime and nighttime charging. This value was chosen after performing sensitivity analysis on 30%, 50% and 70% daytime charging, discussed below.
- Half of workplace and public charging is assumed to occur within the inner city (Inner North and Inner South zone substations), with the other half assumed to occur in the outer suburbs (with a net zero flow of vehicles into and out of each suburb/substation).
- The base case ***High home charging*** scenario is roughly consistent with the current number of parking spots (13,000 City Centre, 8,000 Inner South). In this scenario has 20% of ACT vehicles (378,000 in 2045) charge at work/public. Half of these charge in the city (38,000 in 2045), with these equally distributed across the inner north and inner south.

These details are sufficient background to understand the study's key results. Readers looking for greater details can refer to Table 2, others may skip to the Results section.

The python code used in this study is publicly available at https://github.com/bjornsturmberg/ACT_flexible_loads

Table 2: Full list of model variables

Variable	Value	Comment
Current population	457,565	2022 ABS
2045 population	653,064	ACT Population Projections
Current rooftop solar capacity	448 MW	APVI
Current portion gas hot water	45%	Correspondence with ACT government
Current portion resistive hot water	49.5%	90% of electric hot water systems. Correspondence with ACT government
Current portion heat pump hot water	5.5%	10% of electric hot water systems. Correspondence with ACT government
2045 portion gas hot water	0%	Fully electric ACT 2045
2045 portion resistive hot water	25%	Study assumption
2045 portion heat pump hot water	75%	Study assumption
2045 resistive hot water operation times	22:00 to 6:00	Given they don't benefit from higher daytime temperatures
2045 heat pump hot water operation times	11:00 to 15:00	Assumes constant load, which in practice could be achieved with random start times (within this period) set upon install.
Vehicles (2021)	318,000	https://www.abs.gov.au/statistics/industry/tourism-and-transport/motor-vehicle-census-australia/latest-release
Vehicles (2045)	377,871	Assuming constant vehicles per capita rate of 0.58, based on the ABS Motor Vehicle Census 2021.
EV fleet share (2045)	100%	Fully electric ACT 2045
EV daily energy needs	6.6 kWh	For 12,000 km annual travel https://electricvehiclecouncil.com.au/docs/how-much-electricity-does-charging-an-electric-vehicle-consume-compared-to-typical-household-usage/
EV daytime charging period	9:00-16:00	Empirically chosen to match solar
EV nighttime charging period	22:00-6:00	Empirically chosen to avoid evening and morning peaks
EV fast charger charging period	6:00-24:00	Assume no overnight use

ACT rooftop solar by 2045

The ACT has a very high proportion of rooftop solar installations. At the end of the 2023-24 financial year, the total rooftop solar capacity in the ACT reached 448 MW, including 321 MW on residential dwellings and 127 MW on commercial buildings. This equates to nearly 1 kW of installed rooftop solar capacity per capita. According to the statistics from APVI[6], 40.1% of houses in the ACT are now equipped with solar photovoltaic systems (April 2025). Over the past decade from 2014-15 to 2023-2024, the installed rooftop solar capacity in the ACT has grown at an annual average rate of 28%, with the annual growth rate over the past five years even higher at 35%.

However, as rooftop solar installations approach saturation, the growth of rooftop solar capacity is expected to slow down. In fact, the increase in rooftop solar capacity for 2023-24 was 66 MW, with a growth rate of only 17% from 2022-23. This was the first decline in the annual addition of rooftop solar in the ACT since 2014-15, with both residential and commercial solar installations showing a slowing trend. The APVI's 2019 assessment[7] of the rooftop solar potential across Australia estimated that the ACT rooftops could accommodate a maximum solar capacity of 2000 MW, generating 3315 GWh annually. The APVI's 2024 assessment[8] further examined the potential for residential rooftop solar, including both residential houses and apartments. It concluded that the residential solar capacity potential in the ACT is 1000 MW (in the range of 820–1300 MW), capable of generating 1400 GWh annually. As suggested by the APVI's figures, the current rooftop solar capacity in the ACT represents about one-quarter of the total installation potential.

In the All-Electric ACT study, we can assume two future scenarios for rooftop solar capacity in the ACT by 2045:

1. a ***Low solar*** scenario assuming the total installed capacity will reach 1000 MW by 2045, effectively doubling the current capacity and reaching half of the total potential; and
2. a ***High solar*** scenario assuming the total installed capacity will reach 1500 MW by 2045, equivalent to three-quarters of the total installation potential.

Sensitivity analysis of portion of EV charging during daytime

When EVs charge has a strong impact on regional (and substation) load profiles. In our analysis we considered half of EV charging to occur during daytime hours and half to occur during the nighttime. Specifically, we concentrated the charging within these periods to the hours of 9:00-16:00 and 22:00-6:00 so as to avoid peaks in the underlying load profile.

This division between day and night times was informed by a sensitivity analysis that tested the divisions between day and night of 30-70%, 50-50% and 70-30%.

Increases in the proportion of charging occurring during the daytime reduced the peak demand. For example, in Belconnen:

- 30% day time charging: peak demand is 182.1 MW and the 90th centile is 162.1 MW
- 50% day time charging: peak demand is 175.1 MW and the 90th centile is 154.2 MW
- 70% day time charging: peak demand is 175.1 MW and the 90th centile is 150.1 MW

Based on this observation we selected the 50-50% split to create scenarios that captured the potential benefits of strategic EV charging without expecting overly ambitious behaviour shifts from current – nighttime heavy - charging patterns.

[6] https://pv-map.apvi.org.au/historical

[7] https://www.cefc.com.au/document?file=/media/rcalz41c/isf-rooftop-solar-potential-report-final_.pdf

[8] https://apvi.org.au/wp-content/uploads/2024/04/Solar-potential-of-Australian-housing-stock-published-16-4-24.pdf

Method visualisation

The method used to generate future load profiles is illustrated in Figs. 1-3. Figure 1 shows how we begin by taking the current zone substation load profile (shown in blue). From this, we estimate the load profile of all energy uses except for water heating (shown in red). This is done by estimating the number of electric water heaters in each region and their total daily energy consumption, and then subtracting this energy from the load profile assuming that electricity consumption occurs at a constant rate across the day. This assumption is certainly incorrect, but without any reliable data to inform a non-uniform profile this was considered the most reasonable approach.

Once this load profile in the absence of water heating has been calculated, we multiply it by the forecast population growth to 2045 in the region (shown in the green curve). This load profile serves as the underlying (inflexible) demand, onto which we then add water heating and vehicle charging according to the specific assumptions of a scenario, as well as additional rooftop solar generation. The influence of future solar installations is captured in the green curve of Fig. 1, while Fig. 2 illustrates an example of the load profiles adopted for EVs and water heating, and Fig. 3 shows the addition of these shaped load profiles to the underlying demand and solar generation curves.

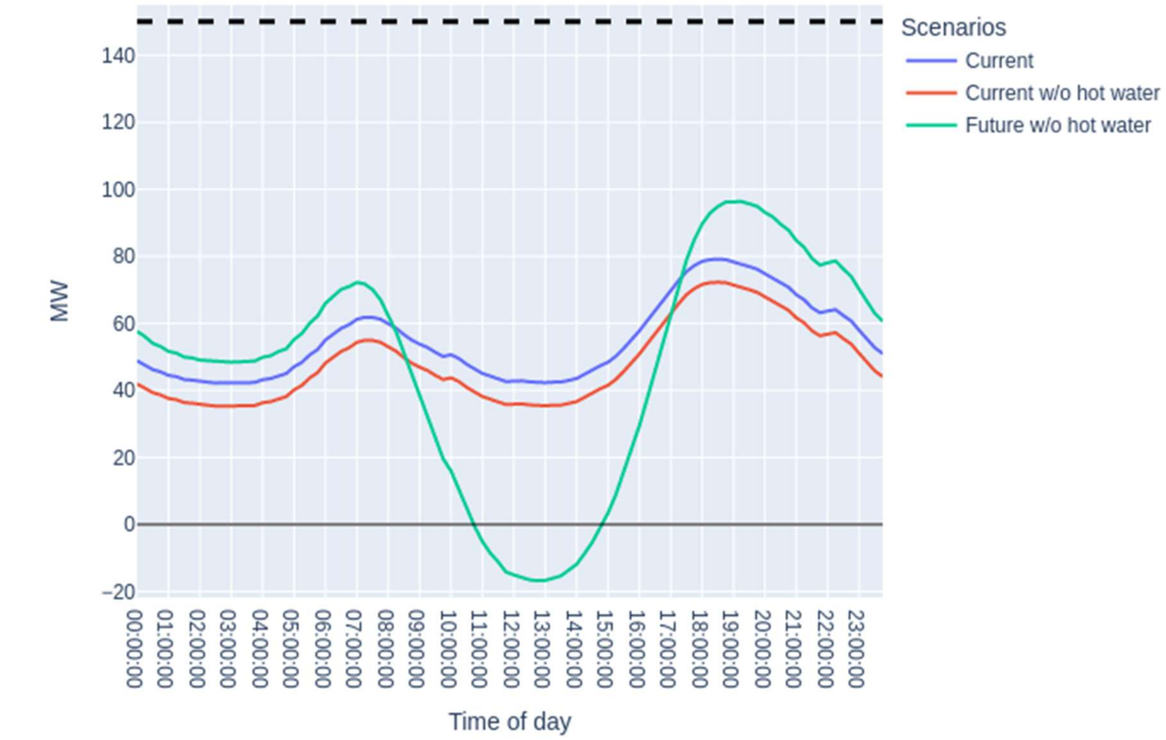


Figure 1. First steps in the method: forecasting future inflexible, underlying demand

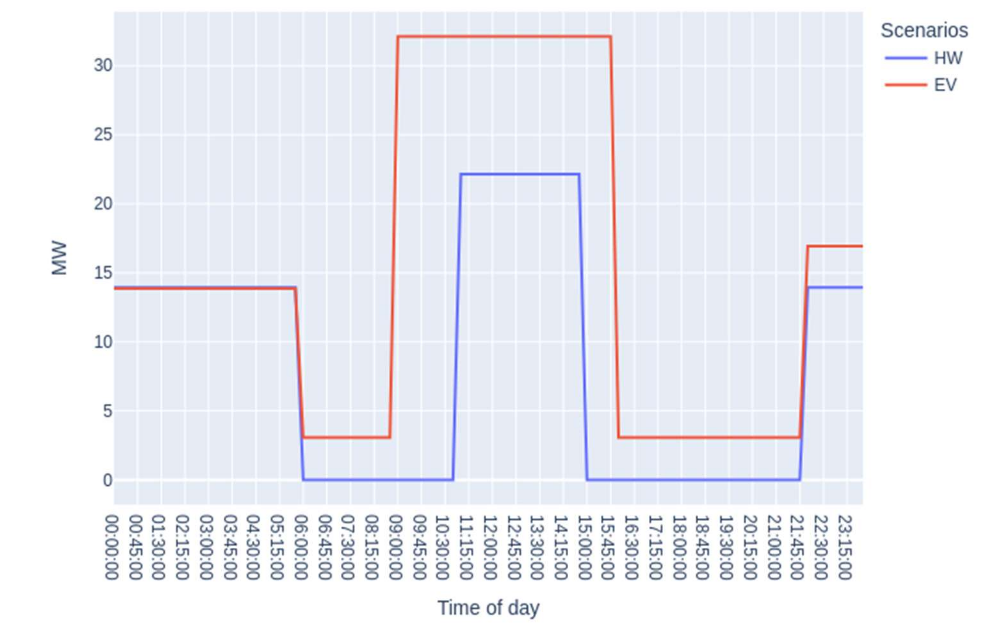


Figure 2. Second step in the method: shaped EV and water heating load profiles

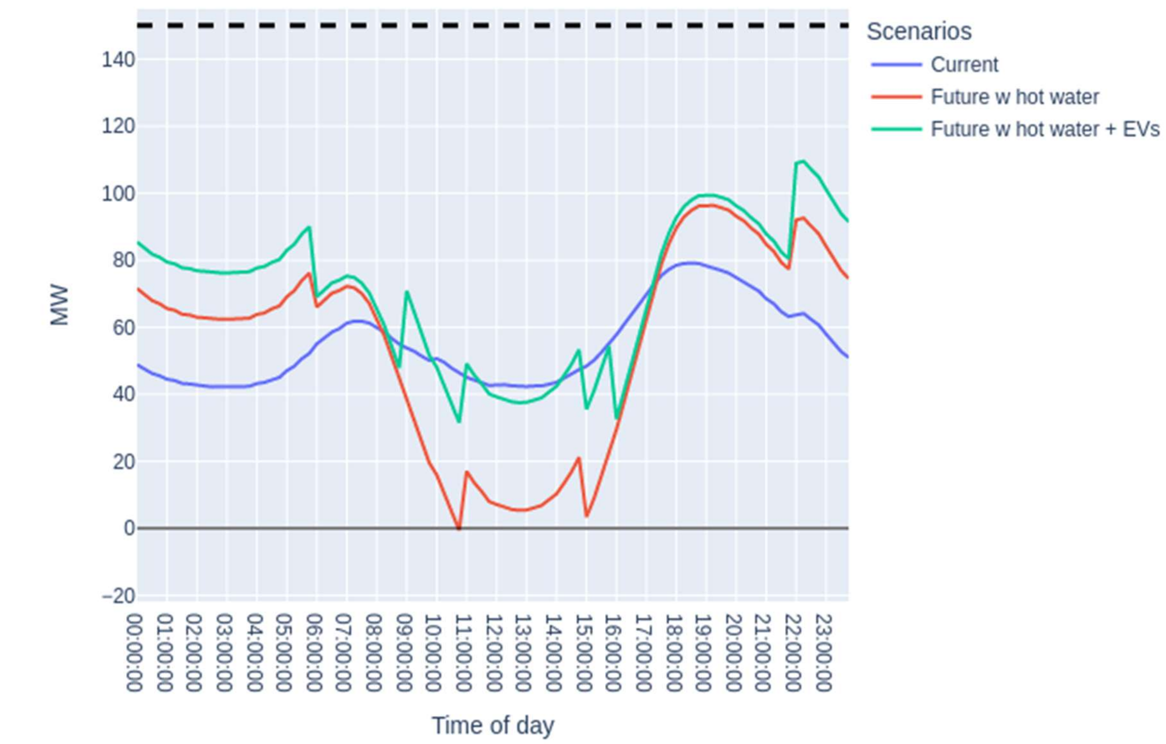


Figure 3. Final step in the method: adding EV and water heating loads to underlying demand

Geographic scope

We modelled all SA3 regions of the ACT, excluding the very sparsely populated Urriarra – Namadgi region. The SA3 discretisation does not align with the zone substations distributing power across the territory. We therefore needed to map substation loads to SA3 regions, which we did proportional to the population in each SA3 region.

The 9 distinct SA3 regions we considered, and their connected substations are:

- Gungahlin – serviced by the Gold Creek substation
- Tuggeranong – serviced by the Wanniassa, Gilmore, and Theodore substations
- Woden Valley – serviced by the Woden and Wanniassa substations
- Canberra East – serviced by the East Lake substation
- South Canberra – serviced by the Telopea Park substation
- Belconnen – serviced by the Belconnen and Latham substations
- North Canberra – serviced by the Civic and City East substations
- Weston Creek – serviced by the Woden substation
- Molonglo – serviced by the Woden substation

Results

Overview and policy implications

Total demand

Our first research objective was to quantify electricity demand growth in the ACT to 2045. Our analysis found that:

- The electrification of water heating has a neutral effect on demand as the increase in customer numbers – both from households transitioning off gas and population growth – is compensated for by the 3-4 times greater efficiency of heat pumps. This assumes 10% of current electric water heating households have heat pump systems and that in 2045 this percentage will have risen to 75%.
- Electric vehicles add a very large new load to the system. In Gungahlin and South Canberra, for example, they add 45% and 30% to current demand.

Peak demand and network expansion

Our second research objective was to demonstrate how EV and water heating loads could be efficiently accommodated in the distribution network by shaping their load profiles. We adopted a simple scheduling method of distributing the load of EV charging and water heating across the middle of the day, when there is high solar generation, and overnight, when there is little other load.

Even this rudimentary approach demonstrated that the large energy needs of EVs and water heating could be met without these appliances, generally, being responsible for the peak loads on the zone substation. On the occasions on which EVs and water heating did contribute to moments of peak demand, there is sufficient spare capacity at other times of the same day where a more responsive and network aware demand shifting strategy would be able to avoid pushing demand above the peak caused by underlying demand.

Noting that zone substations are only one of many components of the distribution network, and that investments may be required in the Low Voltage network independently of zone substation loading, our findings have three clear policy implications:

1. There is a **tremendous opportunity to efficiently accommodate the electrification** of water heating and private vehicles within the existing capacity of the distribution network if – and only if – these loads are scheduled to occur outside of peaks in underlying, inflexible demand (in mornings and evenings). The great majority of this **opportunity can be realised using simple measures** that shift loads to fixed hours each day.
2. There are significant **additional benefits to be realised by deploying more sophisticated, dynamic approaches to load scheduling** that account for variations in solar generation and underlying demand. Increasing the length of time that EVs are plugged in to their chargers and expanding the time horizon for EV charging to multiple days is another way to greatly increase the flexibility of this demand – as shown in our previous research[9]. The merits of such sophisticated systems must be counterbalanced by the imperative to move quickly – **simple approaches should not be delayed**.
3. The **inflexibility of current appliances comes at the major cost** of peak demands and these will grow – independently of electrification – with population growth. There is much that should be done to make the loads that we model as underlying and inflexible (everything other than EVs and water heating) more flexible. Space heating is the prime subject of such initiatives, as our model has ACT demand continue to peak on winter evenings.

---

[9] https://apo.org.au/node/327865

The role and value of rooftop solar

Our modelling highlights the value of continued expansion of rooftop solar across the ACT. The capacity of the existing distribution network is nowhere near enough to accommodate the load growth from electrification and population growth in the absence of more embedded generation. This is clearly visible in the limited headroom in the zone substations for limited hours overnight.

The **50% increase in additional solar installations** between our *Low rooftop solar* and *High rooftop solar* scenarios **leads to a reduction in 300 GWh p.a.** that need not be delivered through a zone substation per annum.

The qualifier on this is that our modelling shows that – in the absence of more sophisticated load management – solar has little effect on peak demand in suburban areas where peak demand occurs on winter evenings after the sun has set. In the city, the co-location of solar with daytime peaking workplace loads and workplace/public EV charging does substantively reduce peak demand.

Opportunities for vehicle-to-grid

Our study does not include the emerging possibility to discharge the energy stored in EV batteries in service of supporting the grid ('vehicle-to-grid' technology[10]). The very large power and energy capacities of EV batteries[11] would radically enhance the opportunities for EV charging and discharging to be accommodated within current zone substation limits – and to furthermore reduce the peak loading.

Detailed results for a suburban and city region

Our analysis of the 9 SA3 regions revealed similar results amongst outer-suburban regions and amongst the inner-city regions. In the interest of clarity, this section presents detailed results for one representative region of each class:

1. Gungahlin, as an outer suburb/centre where there is significant water heating and vehicle charging demands in homes.
2. South Canberra, the southern half of the inner-city where significant workplace and public charging can be expected.

These are complemented in the Appendix by summary results for the remaining regions.

[10] https://arena.gov.au/assets/2021/01/revs-the-a-to-z-of-v2g.pdf
[11] https://reneweconomy.com.au/are-19-million-electric-vehicle-batteries-equal-to-five-snowy-2-0s-61400/

Gungahlin – an outer suburb example

The region of Gungahlin is forecast to see strong population growth to 2045, growing from roughly 30 thousand to 40 thousand households.

Figure 3 summarizes the electricity consumption of the region under the four scenarios, showing the current consumption (in 2022) as a reference. The total length of each bar indicates the total electricity consumption (in average GWh per day) under a scenario, with the different colours indicating specific energy uses: Electric Vehicle (EV) charging and Hot Water (HW). All electricity demand that is not from one of these appliances is indicated in blue and is considered to be inflexible 'underlying' demand.

The figure also specifies the amount of electricity consumption that is delivered through the zone substation and how much is met with generation from rooftop solar systems within the Gungahlin region (black and yellow bars respectively).

The effect of population growth is evident in comparing the sum of the blue and red bars in 2022 and 2045 – the values being constant across all scenarios as population growth was a fixed variable. Population growth, together with full electrification of water heating, accounts for about a 30% increase in consumption. This is in line with the 30% increase in population, revealing that the 3-4 times greater efficiency of heat pump hot water systems not only compensates for the transition of households from gas to electric heating but also accommodates a substantial growth in population without increasing electricity consumption above current levels – assuming 10% of current and 75% of future water heaters are heat pumps.

In contrast, the green bars denote the additional demand consumed by EVs. This is many times greater than the water heating load and is entirely additional to current demand. The size of the EV demand varies between the *High home EV* and *Low home EV* scenarios as the Low home EV scenario sees more charging occurring in the city.

The last feature to note is that the *High solar* scenarios significantly reduce the demand placed on the zone substation (the black bars).

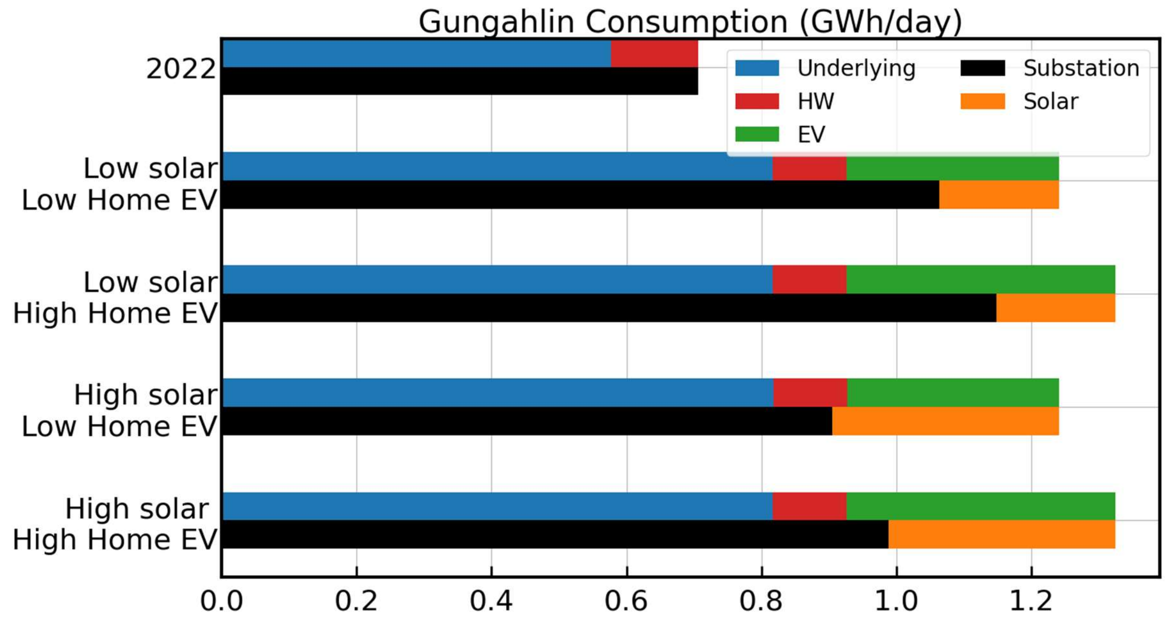


Figure 4. Daily electricity consumption in Gungahlin in 2022 and in 2045 under 4 scenarios.

This analysis of total demand **answers research question 1: there is a roughly 75% increase in average electricity demand by 2045** in the Gungahlin region. This is composed of roughly:

- a 30% increase in demand due to 30% population growth,
- neutral change in water heating electricity consumption despite the transition of households off gas and population growth, due to the efficiency of heat pumps,
- a 45% increase in demand due to the addition of EV charging.

To understand the implications of this increased demand on the distribution system, and the associated costs of capacity upgrades, we need to analyse the instantaneous power load placed on the system. This also allows us to address research question 2 and demonstrate the opportunities to efficiently accommodate this demand into the distribution network by shaping when electric vehicles and water heaters draw power.

For this analysis we also focus on the zone substation as the appropriate level of granularity and a network asset with capacity limits that are expensive to upgrade. Figure 5 shows the peak power (light blue) placed on the Gungahlin zone substation under the four scenarios, with the 2022 value for reference. Also shown is the 90th centile values in purple. For 0% of the year the substation load is below this value, while for the remaining 10% of the year it is between this value and the absolutely peak value.

For Gungahlin, we observe that in 2022 the substation was frequently operating above its 2-hour emergency capacity (as commented on in the Evoenergy annual report). While frequent, this was occurring less than 10% of the year, with the 90^{th} centile value being below the capacity limit. With population growth and electrification, the substation becomes significantly more overloaded in all 2045 scenarios, with the 90^{th} centile value being far above the capacity limit.

To provide an example where the substation is not already needing upgrading, we present results for the Belconnen region in Fig. 6. In this case the analysis is a little less directly connected to a particular substation because the Belconnen region is serviced by two substations. Figure 6 indicates that the modelled demand growth will place these substations under similar strain in 2045 to what Gungahlin experiences today, with the substation capacity limits exceeded occasionally, but less than 10% of the year.

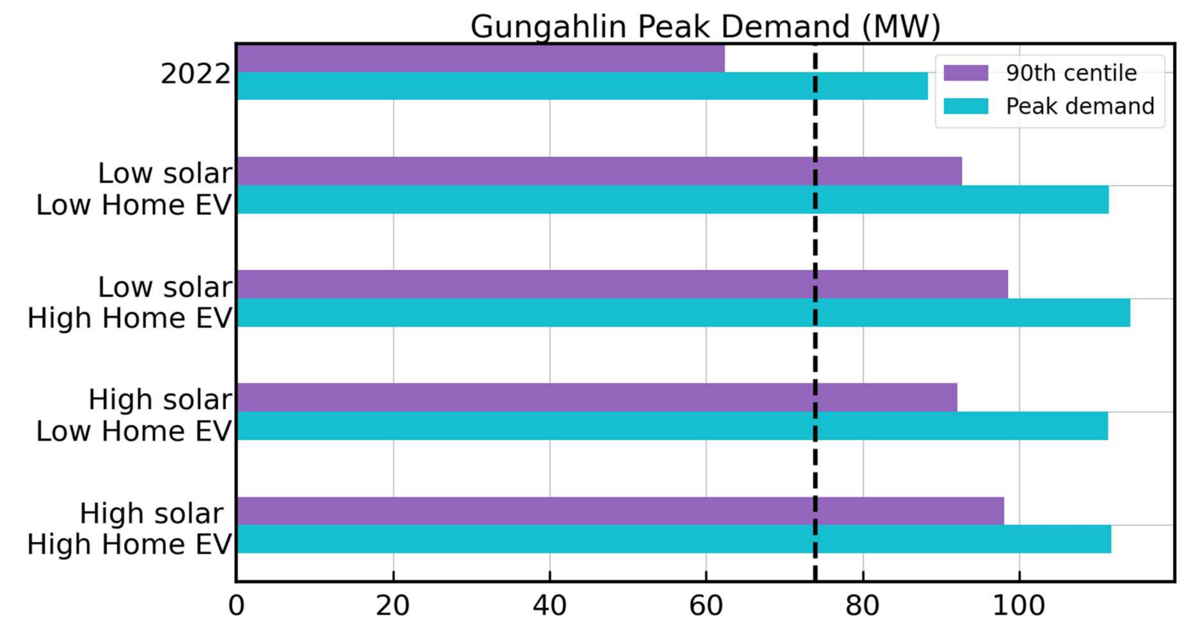


Figure 5. Peak demand and 90th centile in Gungahlin in 2022 and in 2045 under 4 scenarios. Dotted line indicates the current substation capacity.

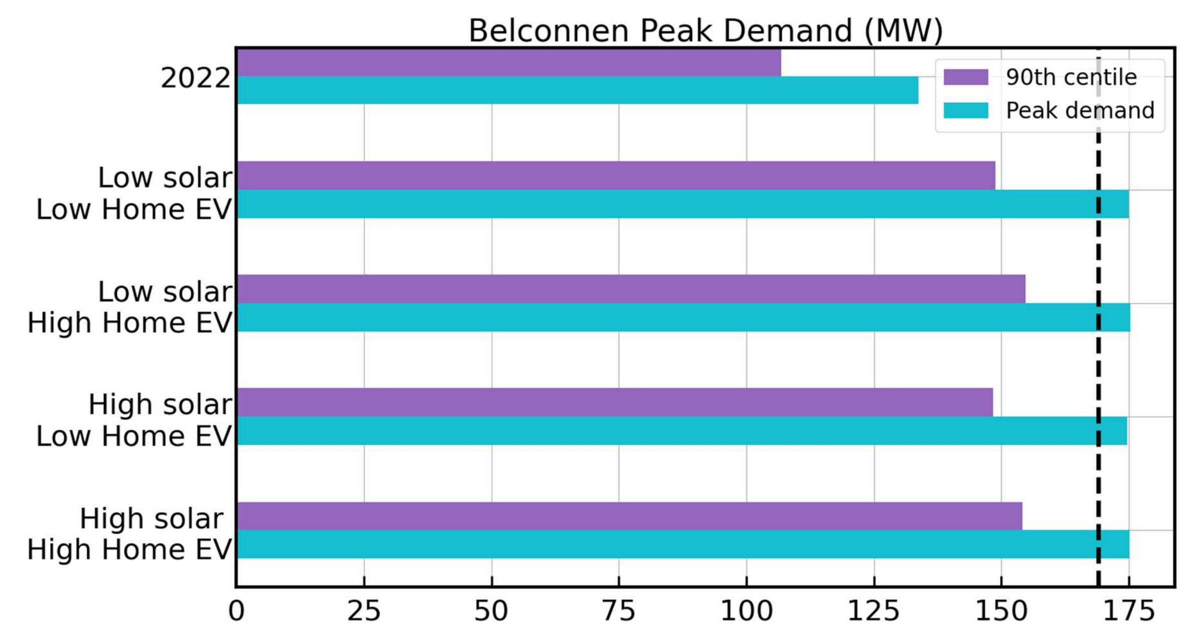


Figure 6. Peak demand and 90th centile in Belconnen in 2022 and in 2045 under 4 scenarios.

To gain a richer view of the dynamics of the substation loading we present an example load duration curve, in Fig. 7 and plot the frequency distributions of substation load under each scenario in Fig. 8. These all demonstrate the marked increase in very low and negative loads due to the increase in rooftop solar, the consistent increase in substation utilisation across the year at moderate to high loading, and the spike in very high loading above the capacity limit for around 700 hours a year.

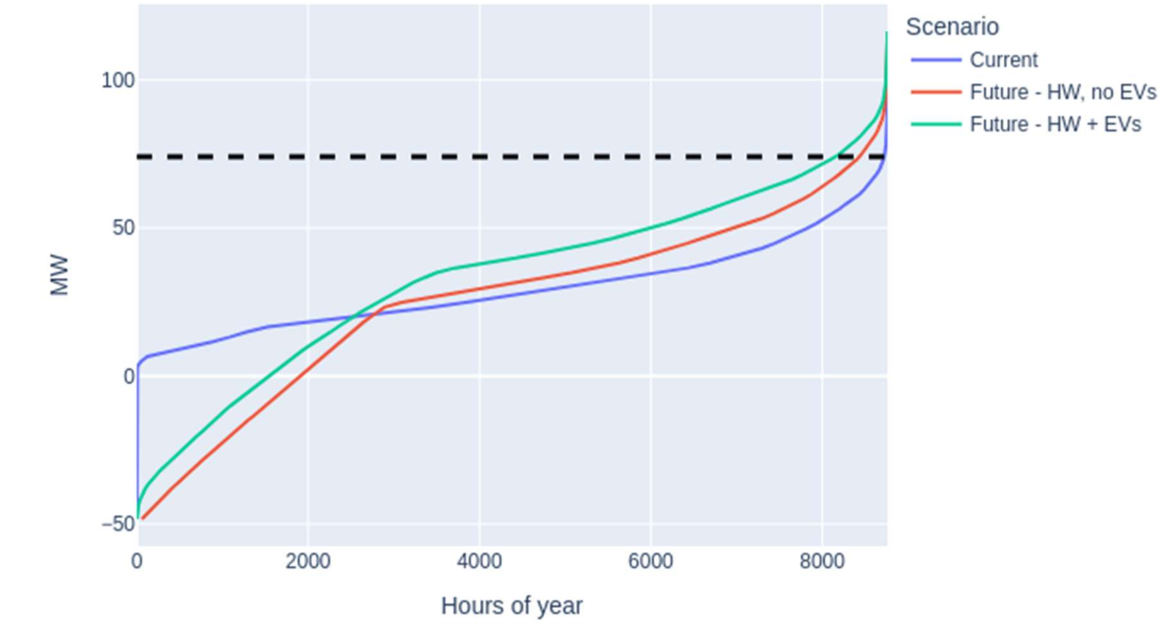


Figure 7. Load duration curve of Gungahlin substation loading under the High rooftop solar and Low home EV scenario, comparing distributions to current loading and loading without EVs.

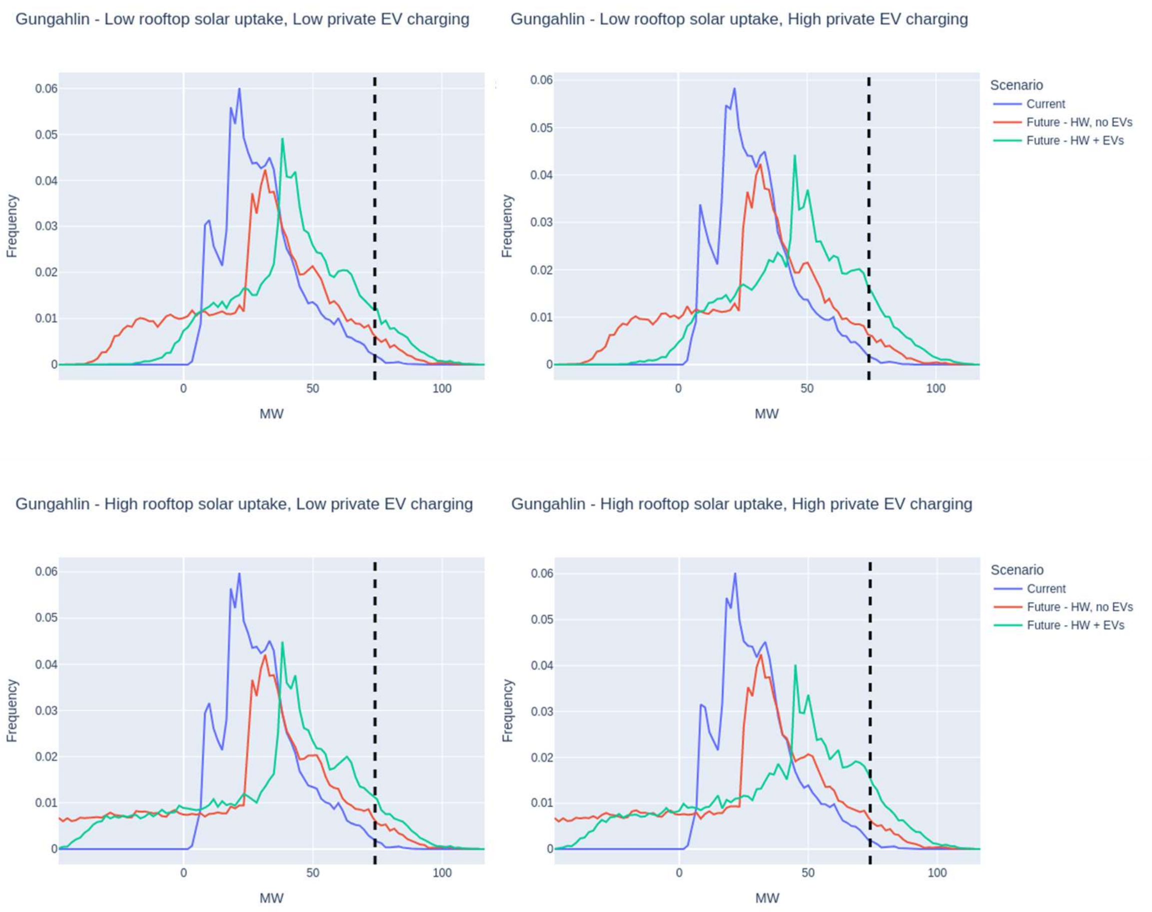


Figure 8. Frequency distributions of Gungahlin substation loading under 4 scenarios, comparing distributions to current loading and loading without EVs.

That the peak power placed on the network should increase as the total energy delivered increases significantly is not surprising. But we want to understand how much of this increase in peak demand is due to electrification and how much is due to population growth. In particular, we want to assess how effective our rudimentary EV and water heating load shaping has been at accommodate these appliances into the spare capacity of the distribution network. To analyse this, we look at the instantaneous power load profiles of the days where the substation experiences peak loads. These are shown in Figs. 9-12 for the four scenarios.

These figures reveal two insights:

1. **Peak demand continues to occur during winter**, with all peaks occurring in June-August.
2. **Peak demand continues to occur in the evening time** between 17:30 and 20:00.

The crucial implication of which is that: **the very large amounts of EV charging and water heating loads that we have scheduled** (so rudimentarily overnight and during the sunny parts of the day) **are not driving capacity upgrade requirements**. Instead, they have been accommodated within the spare capacity of the substation, or specifically within the capacity that the substation will require to service growth in underlying demand.

To the extent to which very high loads are caused by scheduled EV and hot water loads, around 22:00 and 15:00 during low solar irradiance days, this is a consequence of the variability of solar generation and our very simplistic approach to their scheduling implemented in our model (always operating at a set time each day, without any ramping at the beginning or end of the operating period, nor with any responsiveness to the dynamics of the weather or underlying demand).

In addition to worrying about the peak demand placed on substations, the presence of large amounts of rooftop solar means that minimum demand has become another cause for concern. We investigate this issue in Figs. 13-16, where we plot the daily demand profiles on the 17 days that place the lowest (often negative) demand on the substation. Unsurprisingly, these days are in the middle of summer, when solar generation is at its greatest. As with the peak demand results, these plots demonstrate the limitations of our simple, non-responsive scheduling and the variability of solar generation. But once again, visual inspection suggests that most, if not all, negative demand could be avoided if more EV and water heating loads were shifted more responsively, particularly from the evening time.

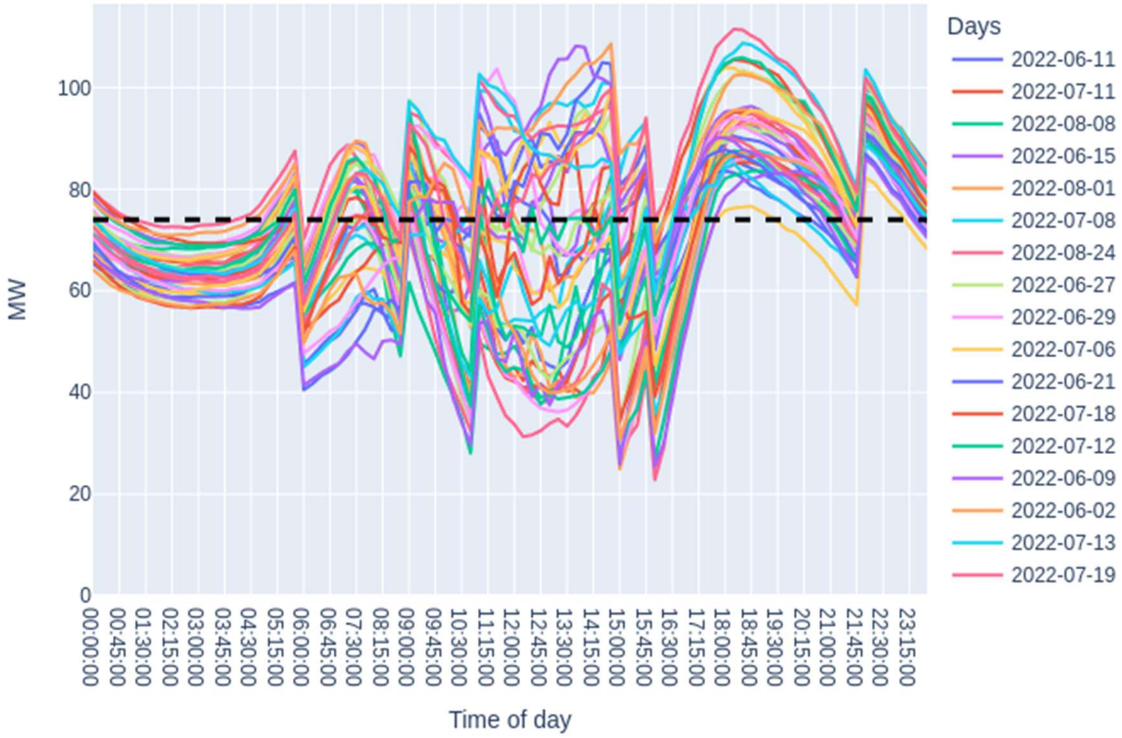


Figure 9. Substation loading on peak demand days for Low solar, Low home EV scenario.

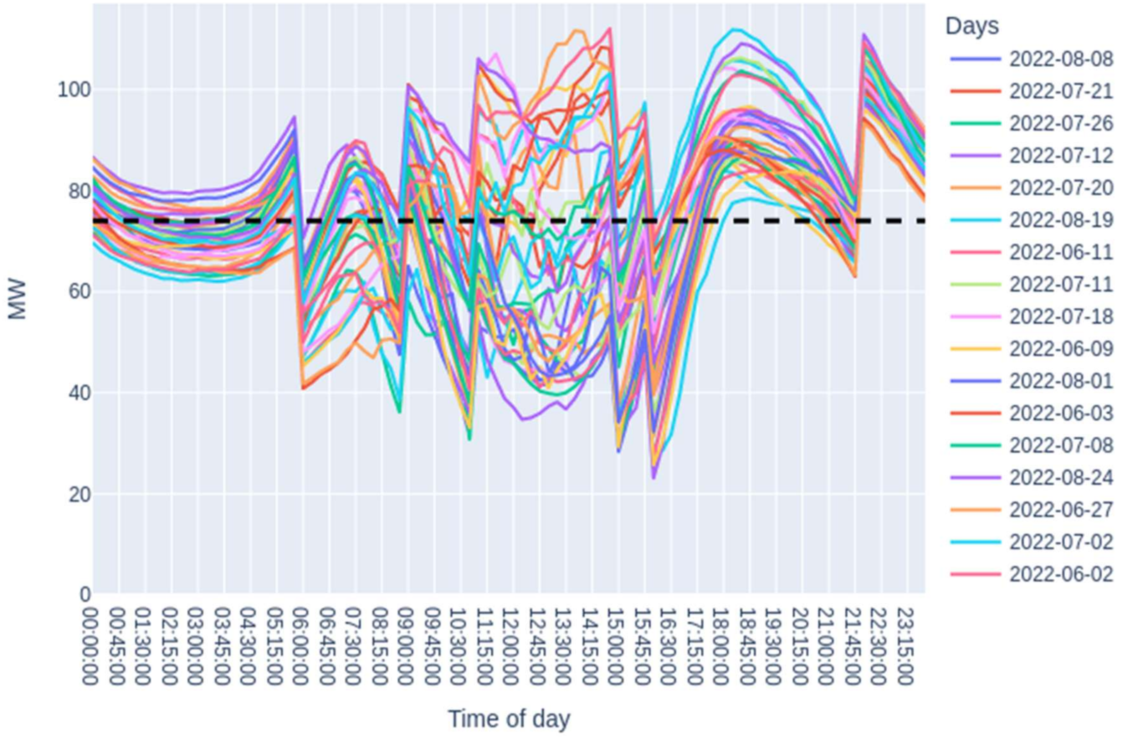


Figure 10. Substation loading on peak demand days for Low solar, High home EV scenario.

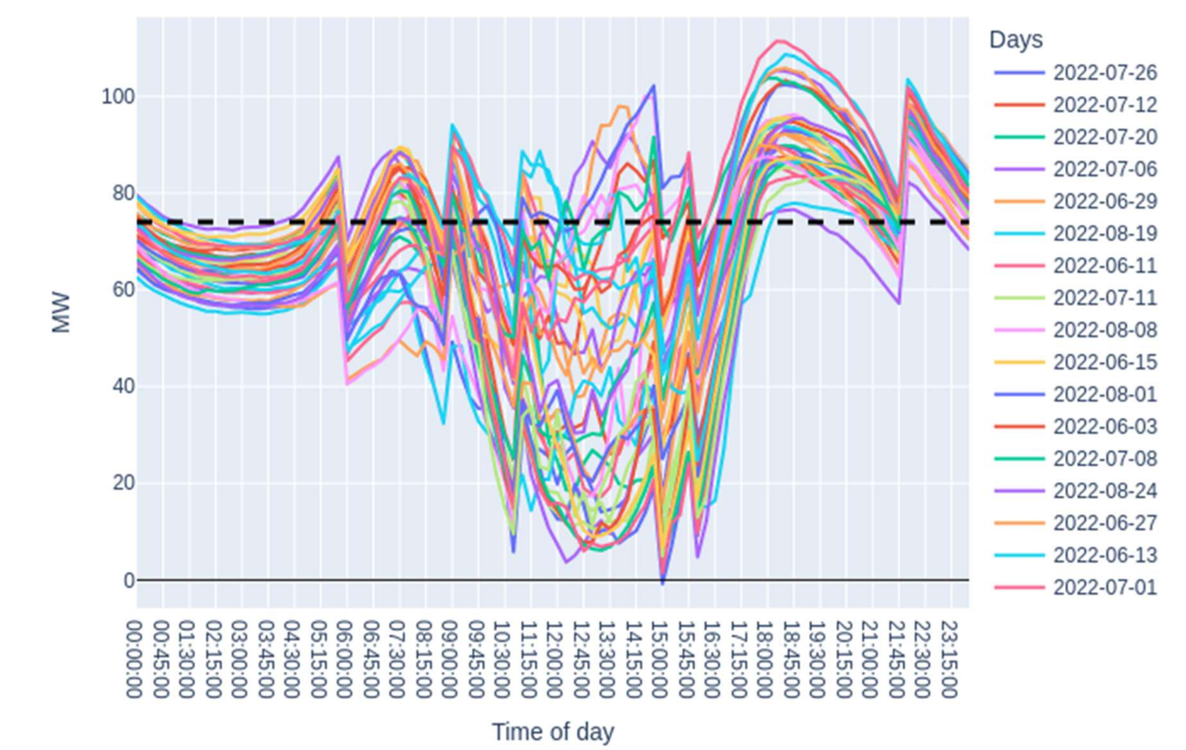


Figure 11. Substation loading on peak demand days for High solar, Low home EV scenario.

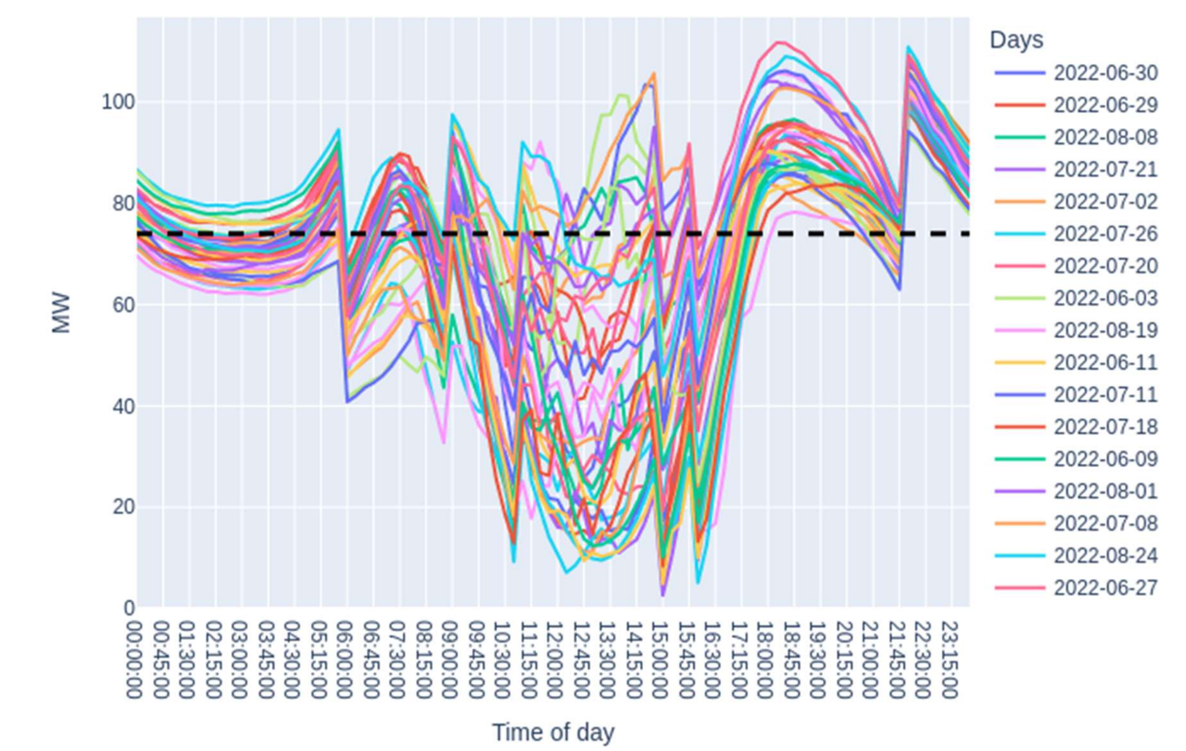


Figure 12. Substation loading on peak demand days for High solar, High home EV scenario.

Figure 13. Substation loading on minimum demand days for Low solar, Low home EV scenario.

Figure 14. Substation loading on minimum demand days for Low solar, High home EV scenario.

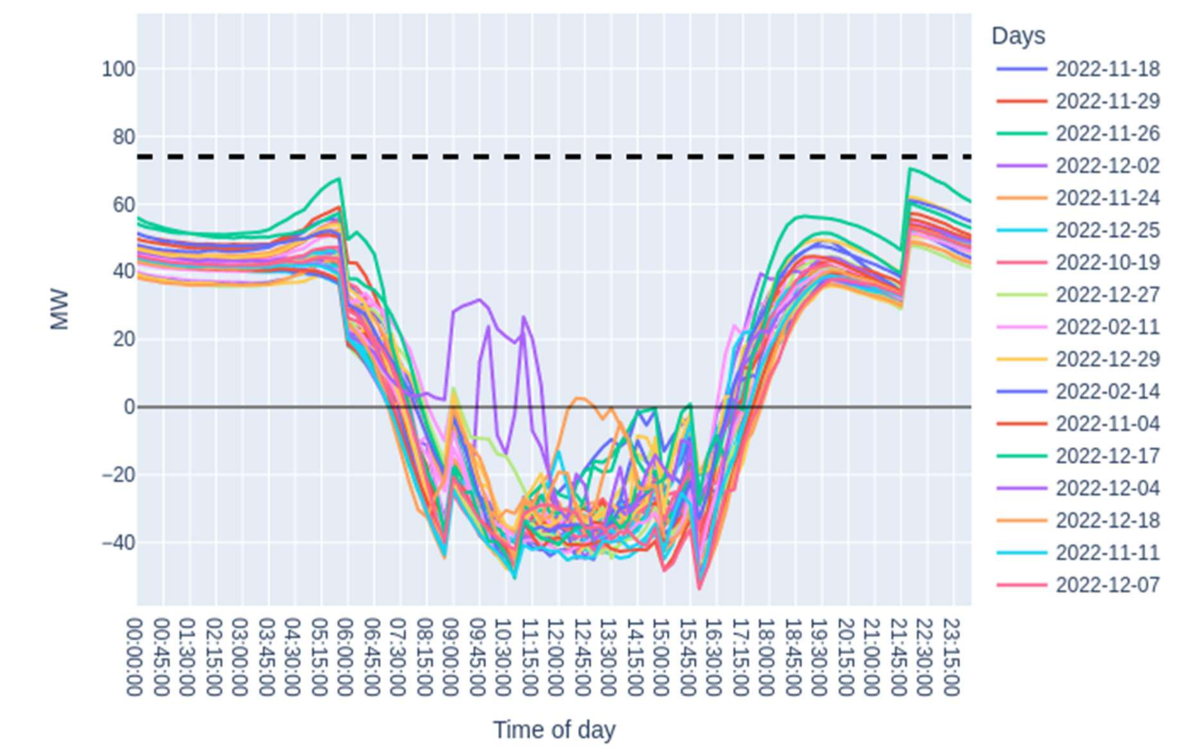


Figure 15. Substation loading on minimum demand days for High solar, Low home EV scenario.

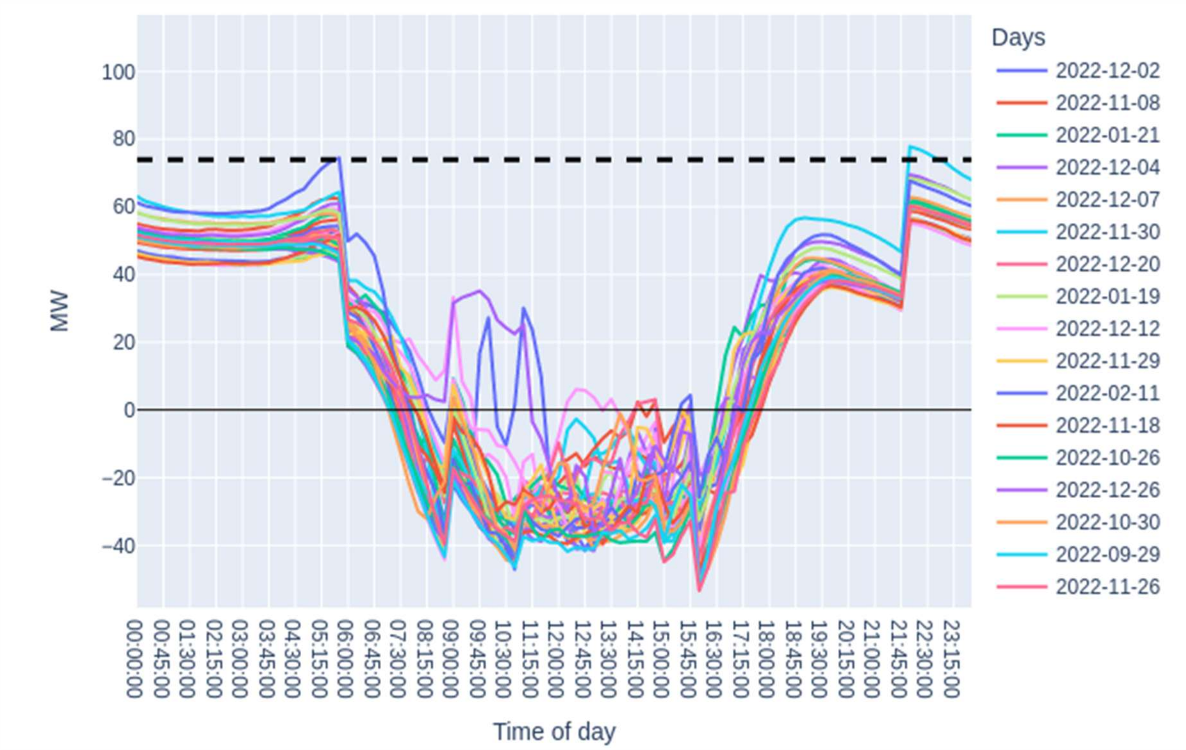


Figure 16. Substation loading on minimum demand days for High solar, High home EV scenario.

South Canberra – an inner-city example

The region of South Canberra is serviced by the Telopea Park zone substation. It contains a high proportion of office and commercial properties and is expected to have modest population growth from 14.9 thousand to 20.5 thousand households by 2045. As an inner-city area into which many people drive during work hours greater public and workplace charging (*Low home EV* charging) increases the demands on this zone substation (the impact of *High* or *Low home EV* charging is the opposite to the outer suburbs like Gungahlin). This is shown in Fig. 17.

The benefits of higher rooftop solar generation are especially pronounced in this region, as the solar generation aligns with worktime charging. In contrast to the Gungahlin example, high solar uptake is effective at reducing the peak power placed on the substation, as evidenced in Fig. 18.

Figures 19 summarise the demand on the substation as the frequency distributions, and Figs. 20-27 show the peak demand and minimum demand days. These highlight the greater amount of daytime EV charging, which is more regularly the cause of peak demand than evening demand as offices are typically vacated at those times. Once again, a more sophisticated management of EV charging would easily reduce the EV caused demand peaks to be below the evening peak demand caused by underlying demand.

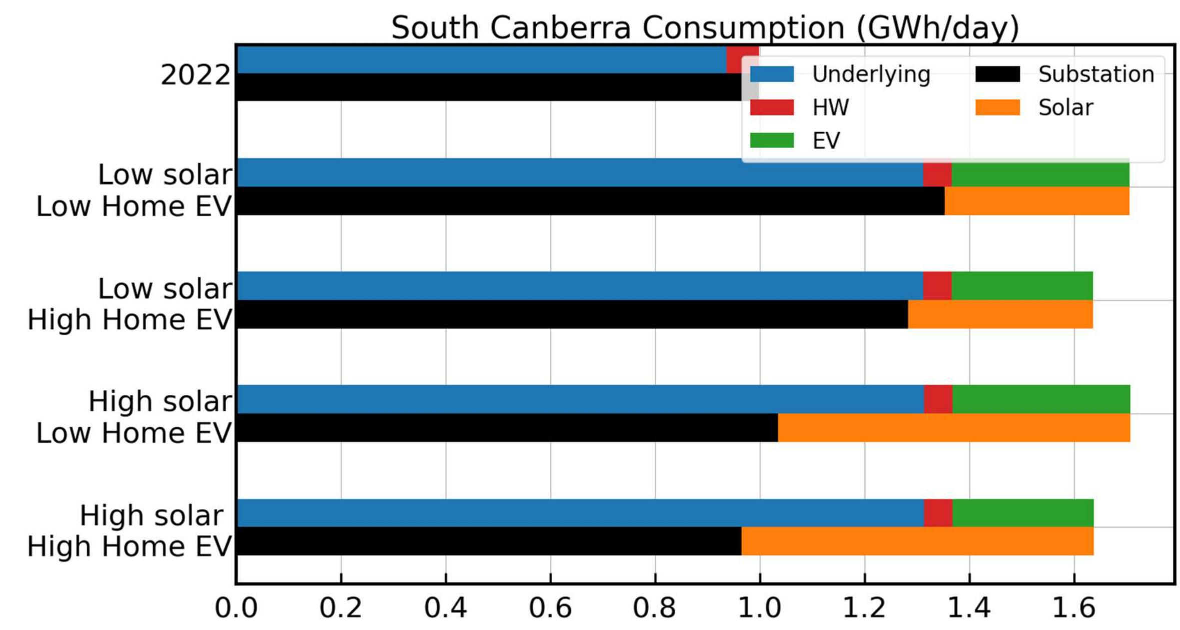


Figure 17. Electricity consumption in South Canberra in 2022 and in 2045 under 4 scenarios.

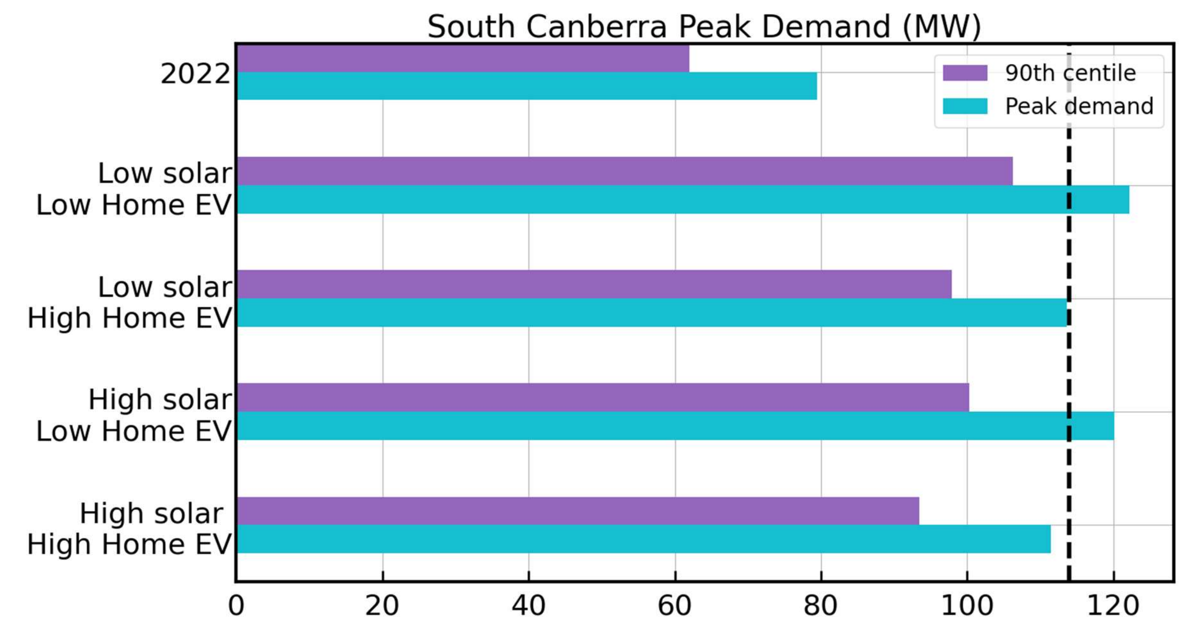


Figure 18. Peak demand and 90th centile in South Canberra in 2022 and in 2045 under 4 scenarios.

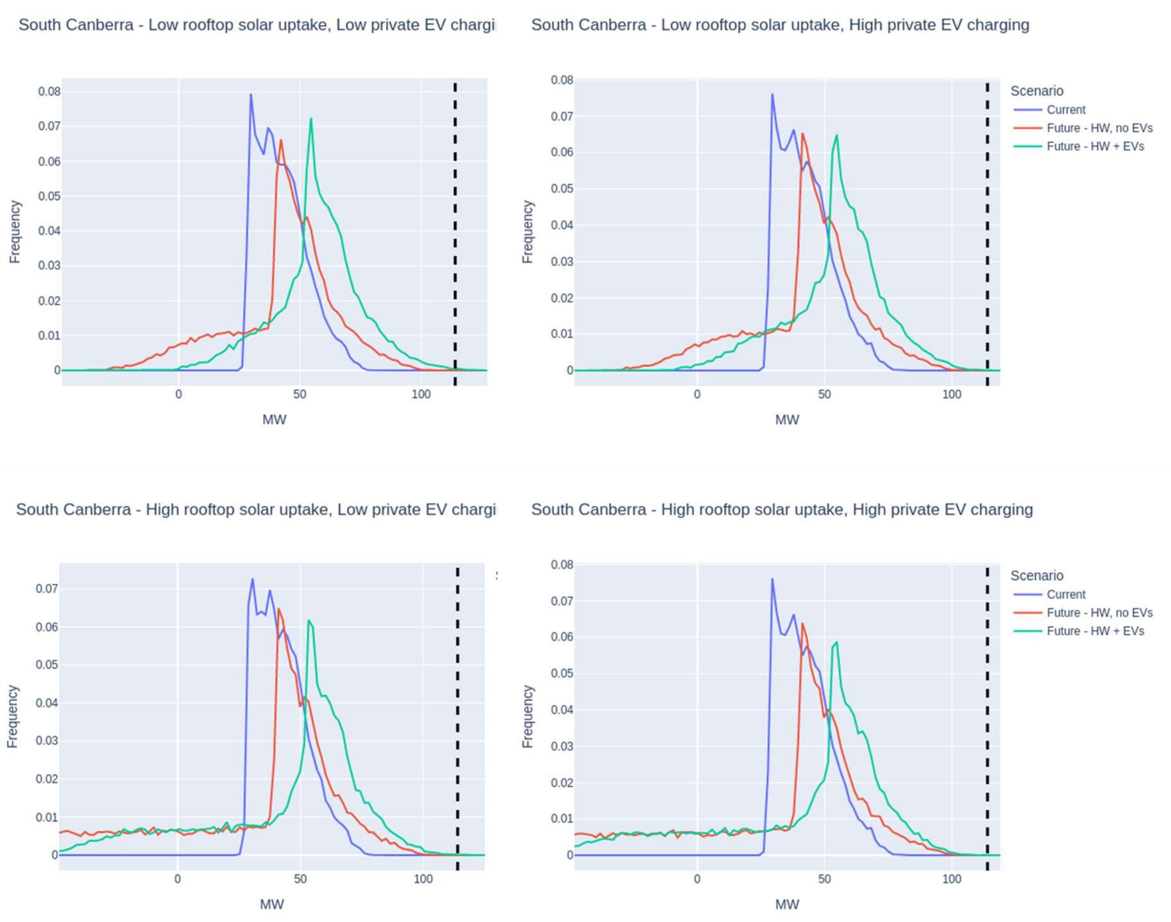


Figure 19. Frequency distributions of South Canberra substation loading under 4 scenarios, comparing distributions to current loading and loading without EVs.

TEQSA Provider ID: PRV12002 (Australian University) | CRICOS Provider Code: 00120C

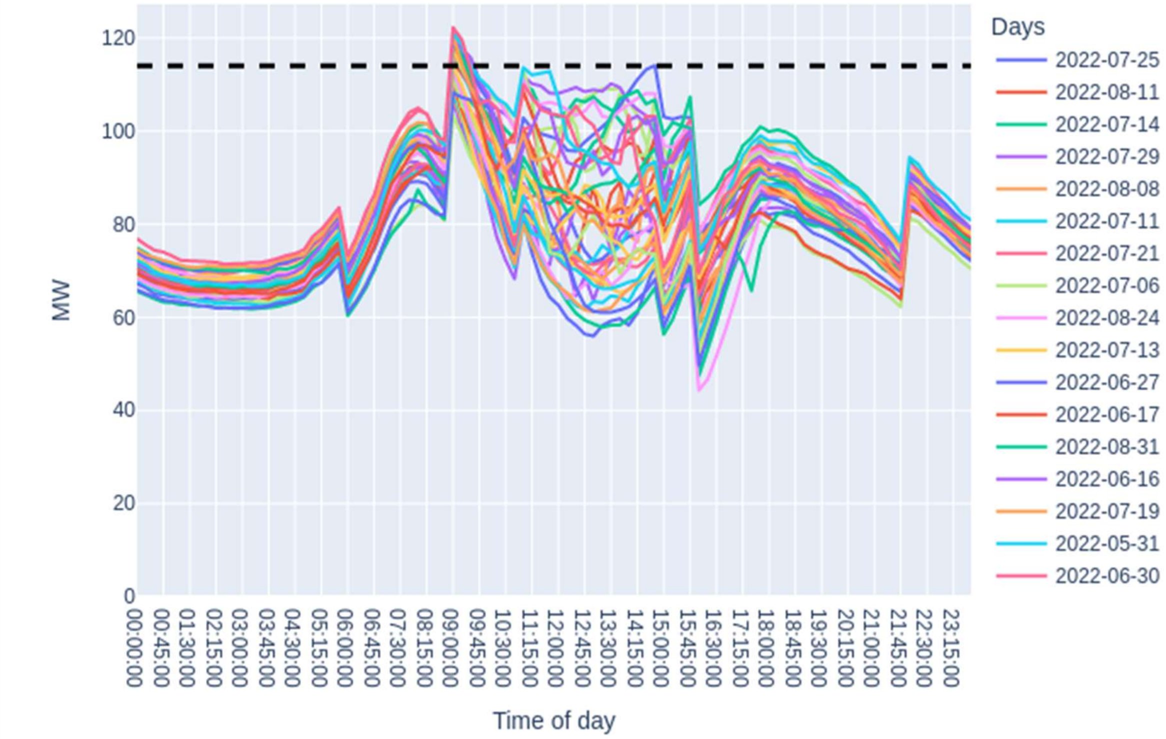


Figure 20. Substation loading on peak demand days for Low solar, Low home EV scenario.

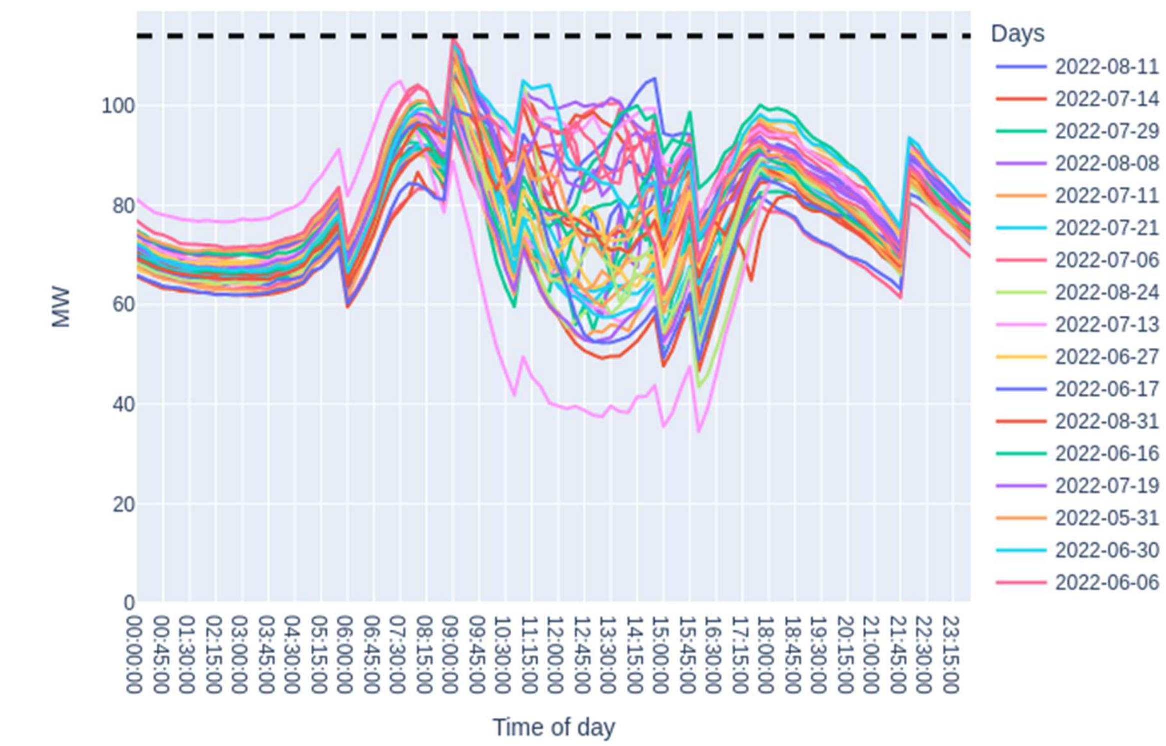


Figure 21. Substation loading on peak demand days for Low solar, High home EV scenario.

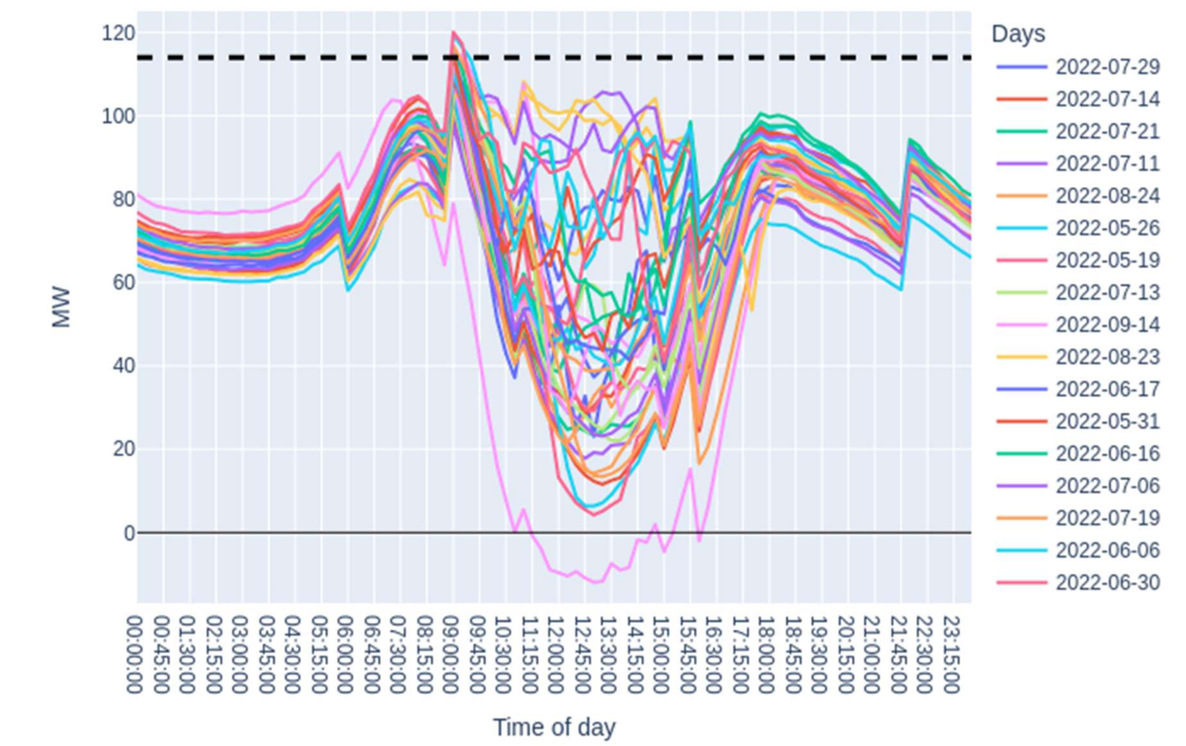


Figure 22. Substation loading on peak demand days for High solar, Low home EV scenario.

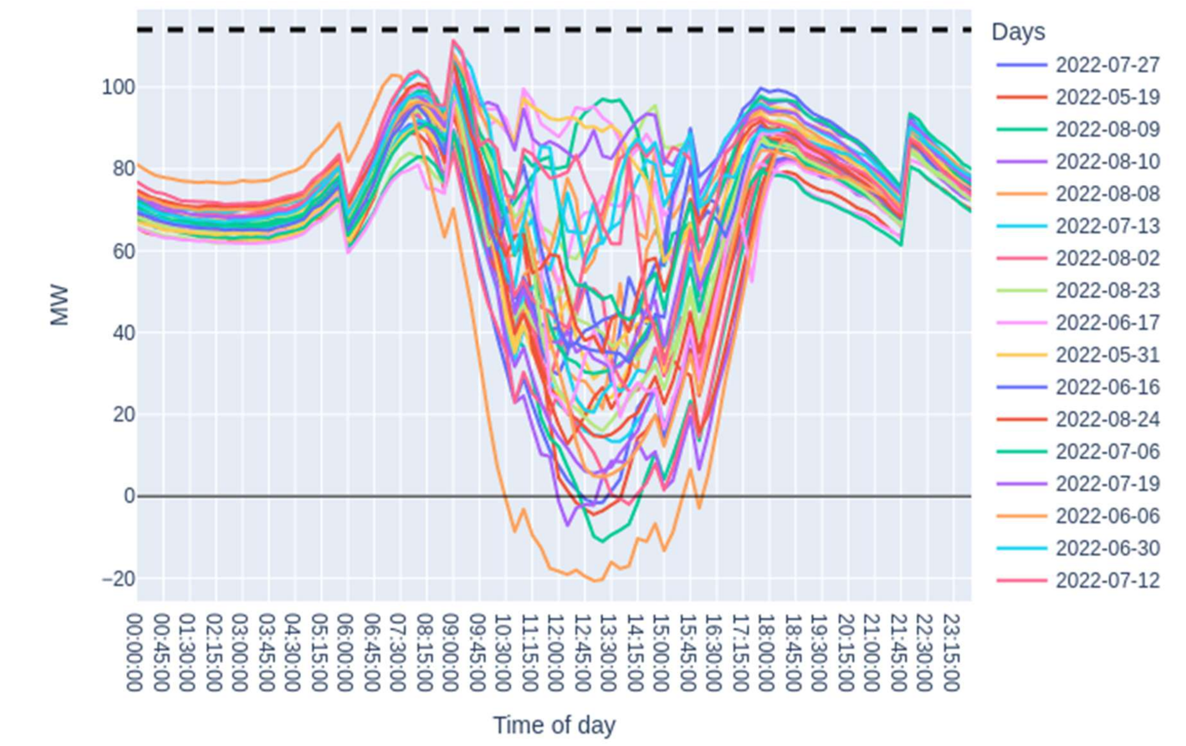


Figure 23. Substation loading on peak demand days for High solar, High home EV scenario.

Figure 24. Substation loading on minimum demand days for Low solar, Low home EV scenario.

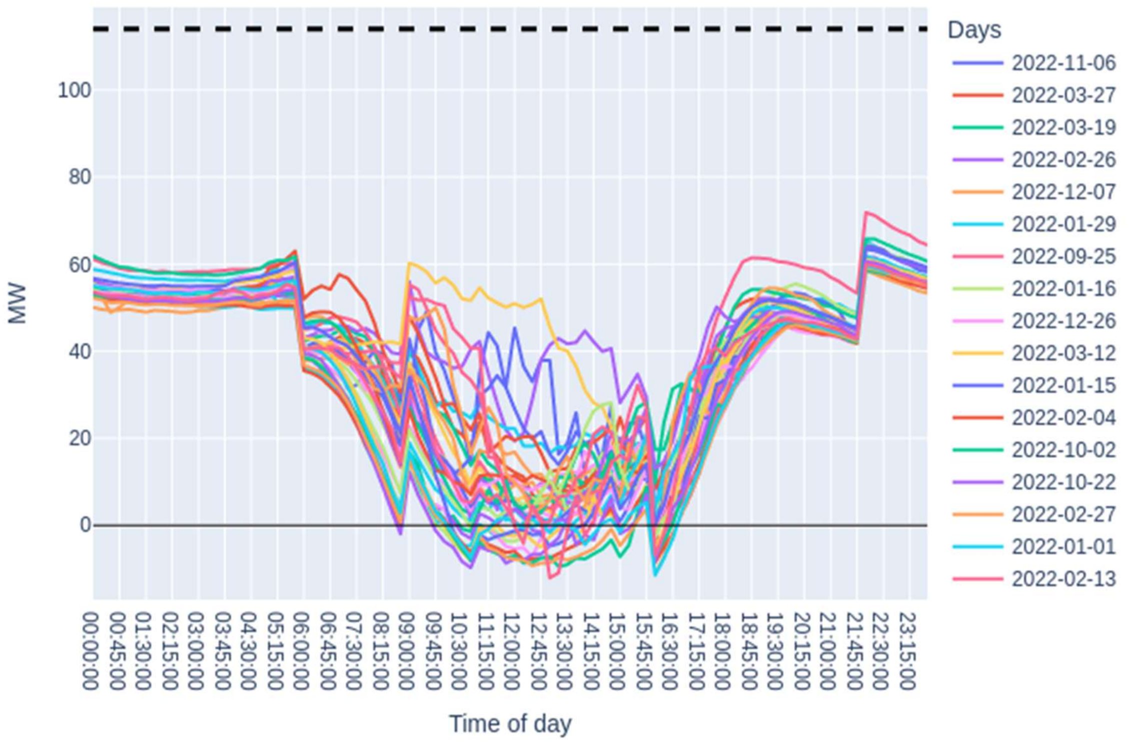


Figure 25. Substation loading on minimum demand days for Low solar, High home EV scenario.

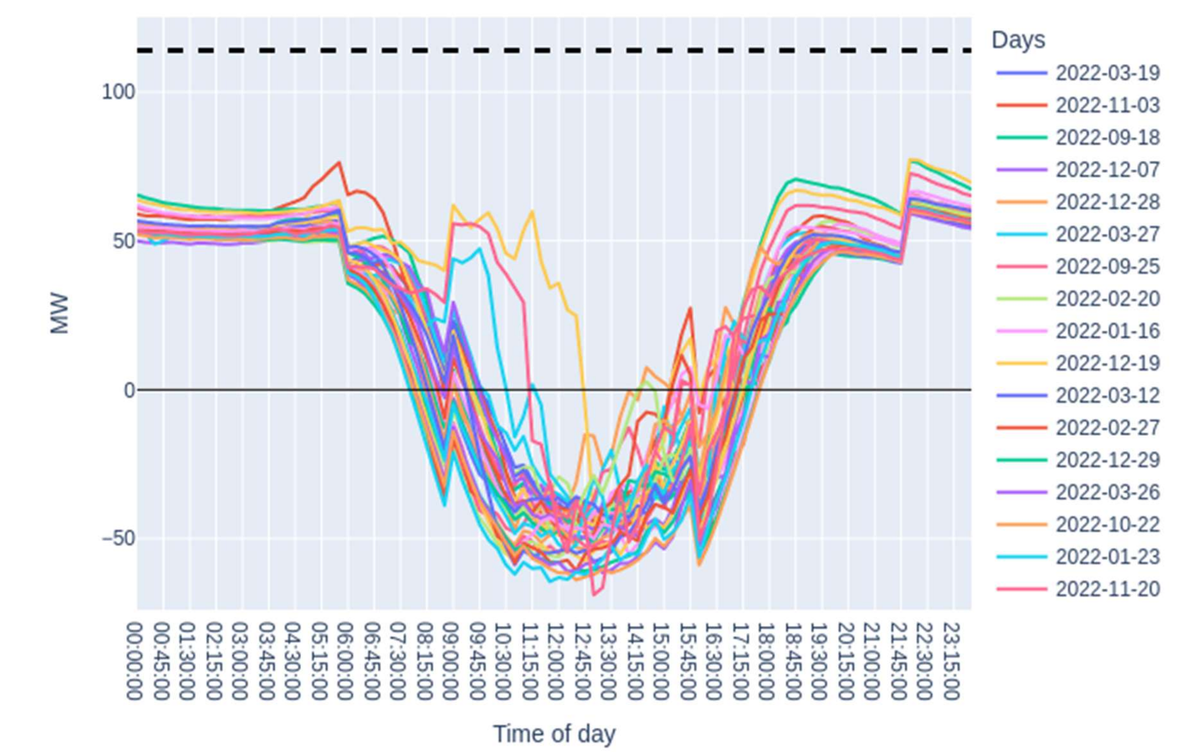


Figure 26. Substation loading on minimum demand days for High solar, Low home EV scenario.

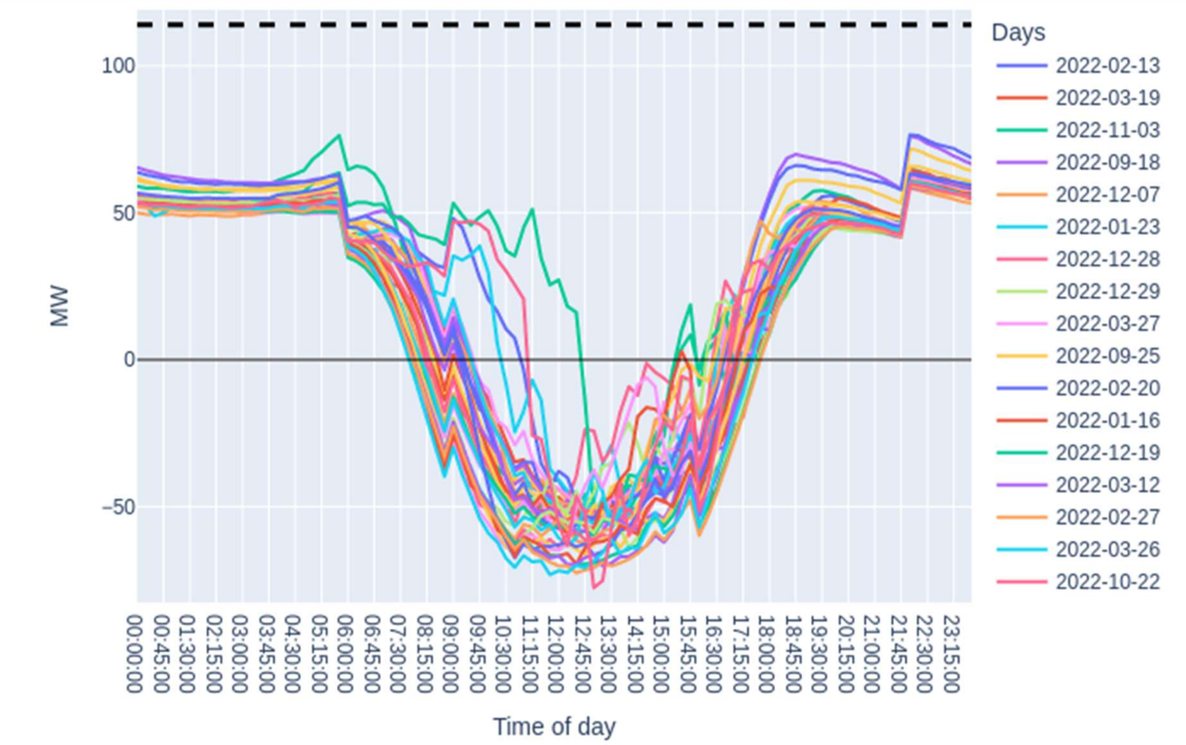


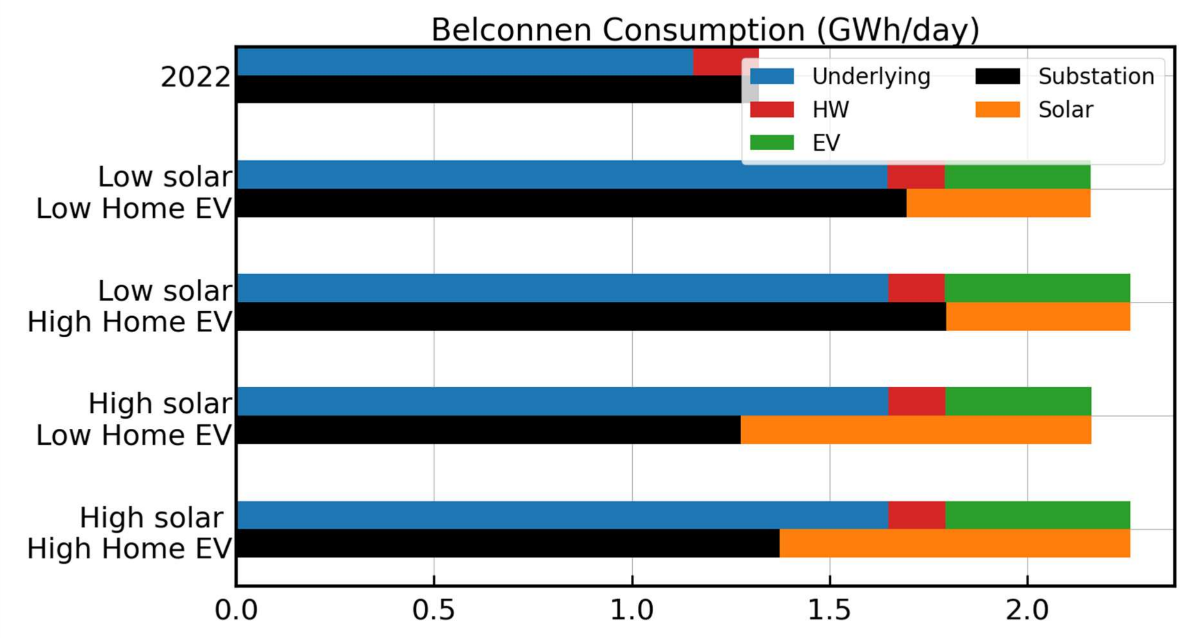
Figure 27. Substation loading on minimum demand days for High solar, High home EV scenario.

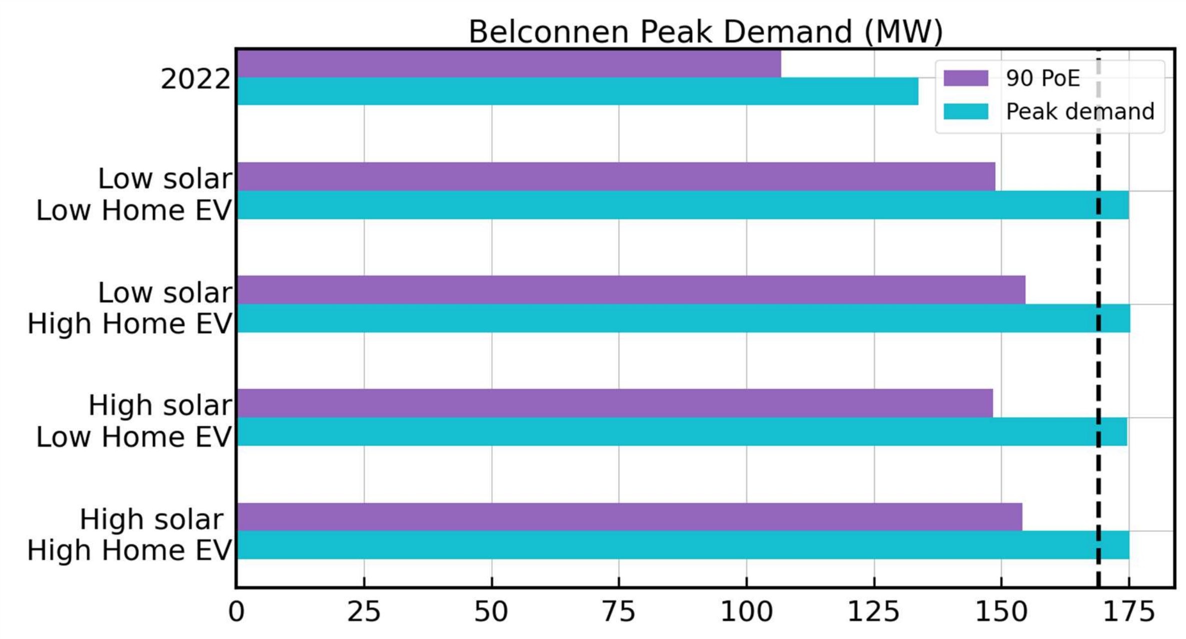
Appendix

Remaining regions

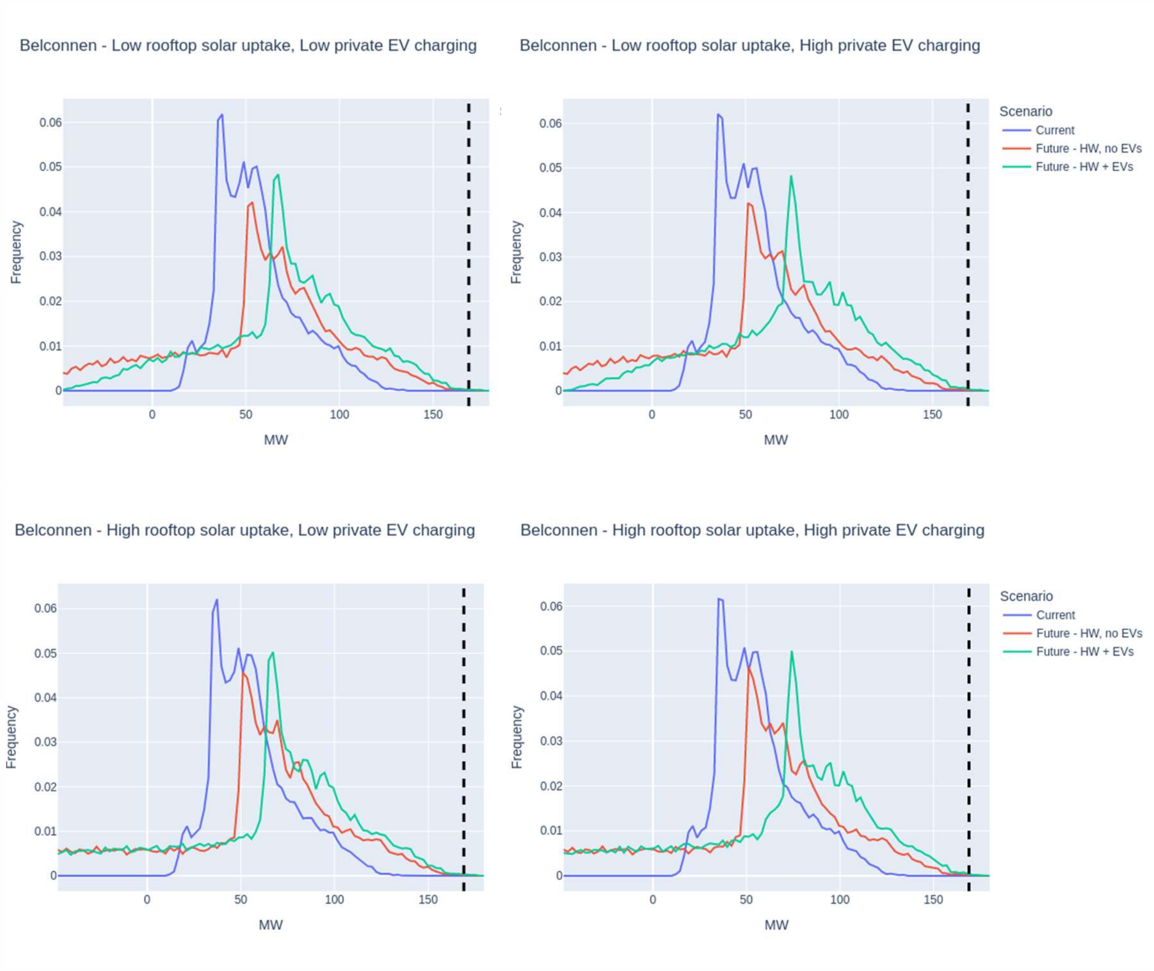
We summarise the results for the remaining SA3 regions by presenting the frequency distribution plots of zone substation loading under the four scenarios. These demonstrate how the electrification (and population growth) loads can be accommodated into each region's substation(s).

Belconnen shows similar results to Gungahlin, as the demographics and electricity uses are quite similar. The most striking difference is that Belconnen is serviced by two zone substations - Belconnen and Latham substations – which collectively have considerable spare capacity that can support significant electrification before needing expansion.

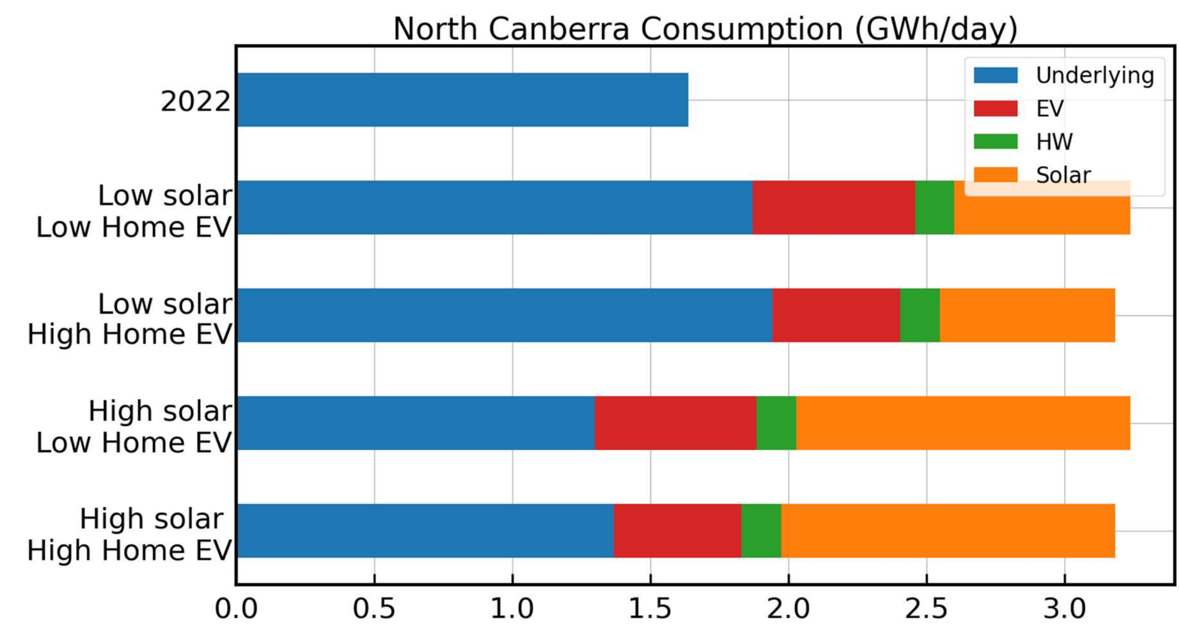


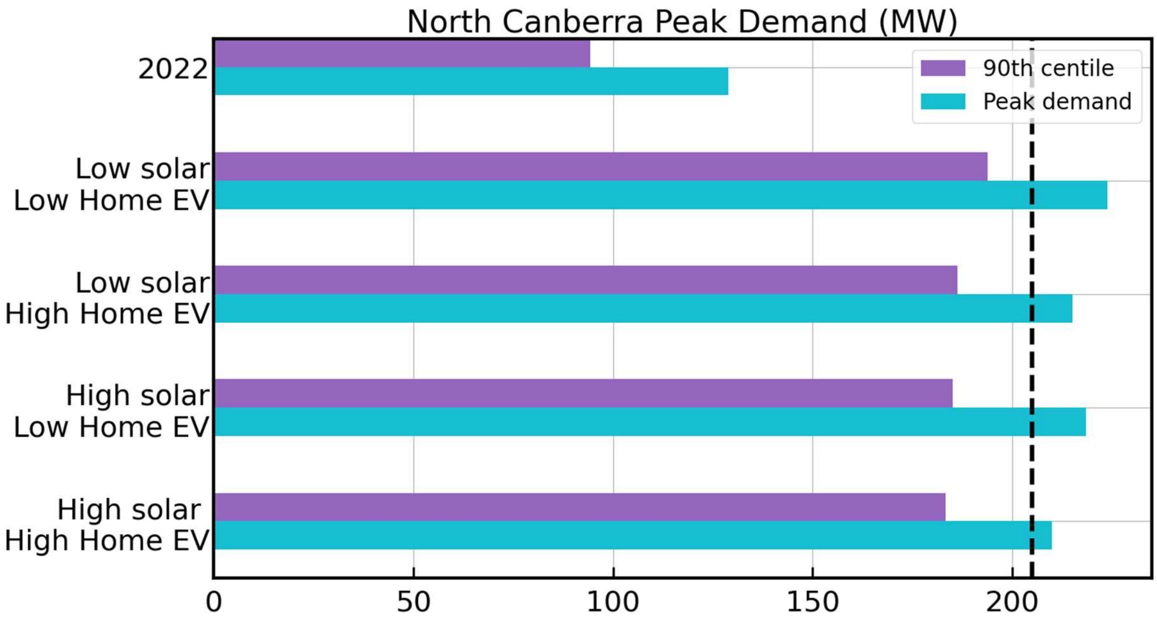


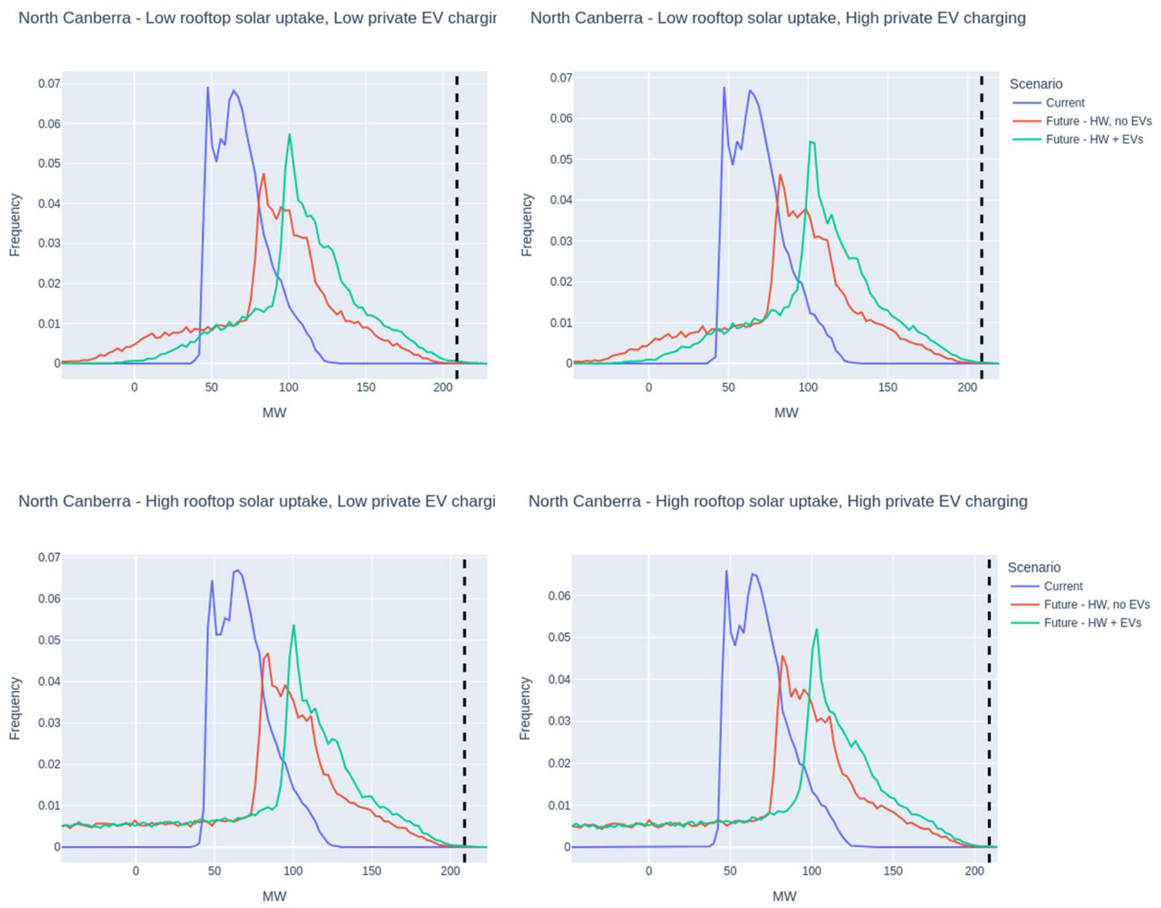
TEQSA Provider ID: PRV12002 (Australian University) | CRICOS Provider Code: 00120C


Belconnen - Low rooftop solar uptake, Low private EV charging
Belconnen - Low rooftop solar uptake, High private EV charging
Belconnen - High rooftop solar uptake, Low private EV charging
Belconnen - High rooftop solar uptake, High private EV charging
Scenario
Current
Future - HW, no EVs
Future - HW + EVs
Frequency
MW
0
0.01
0.02
0.03
0.04
0.05
0.06
50
100
150

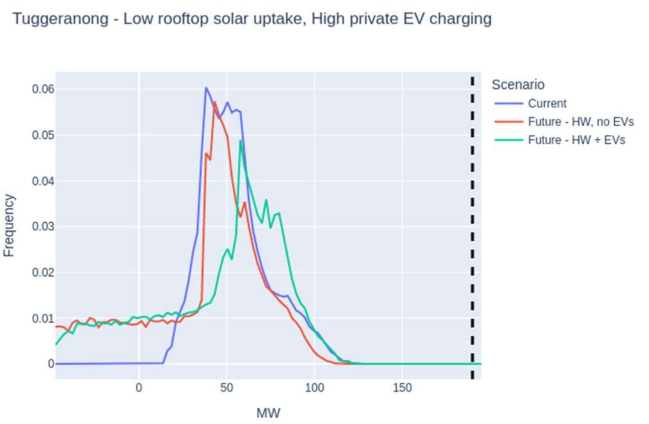
North Canberra

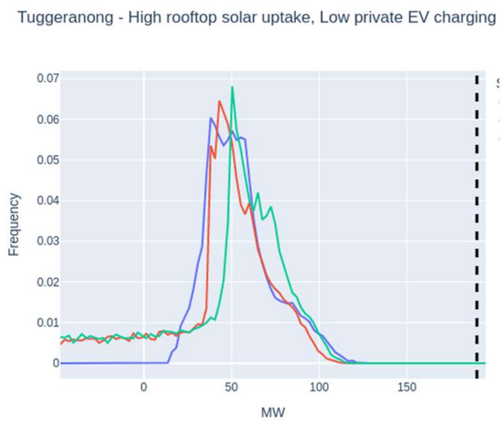


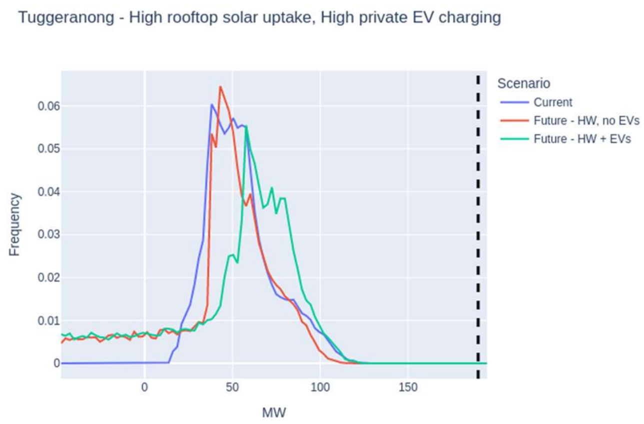



North Canberra - Low rooftop solar uptake, Low private EV chargir
North Canberra - Low rooftop solar uptake, High private EV charging
North Canberra - High rooftop solar uptake, Low private EV chargi
North Canberra - High rooftop solar uptake, High private EV charging
Frequency
MW
Scenario
Current
Future - HW, no EVs
Future - HW + EVs
0
0.01
0.02
0.03
0.04
0.05
0.06
0.07
50
100
150
200

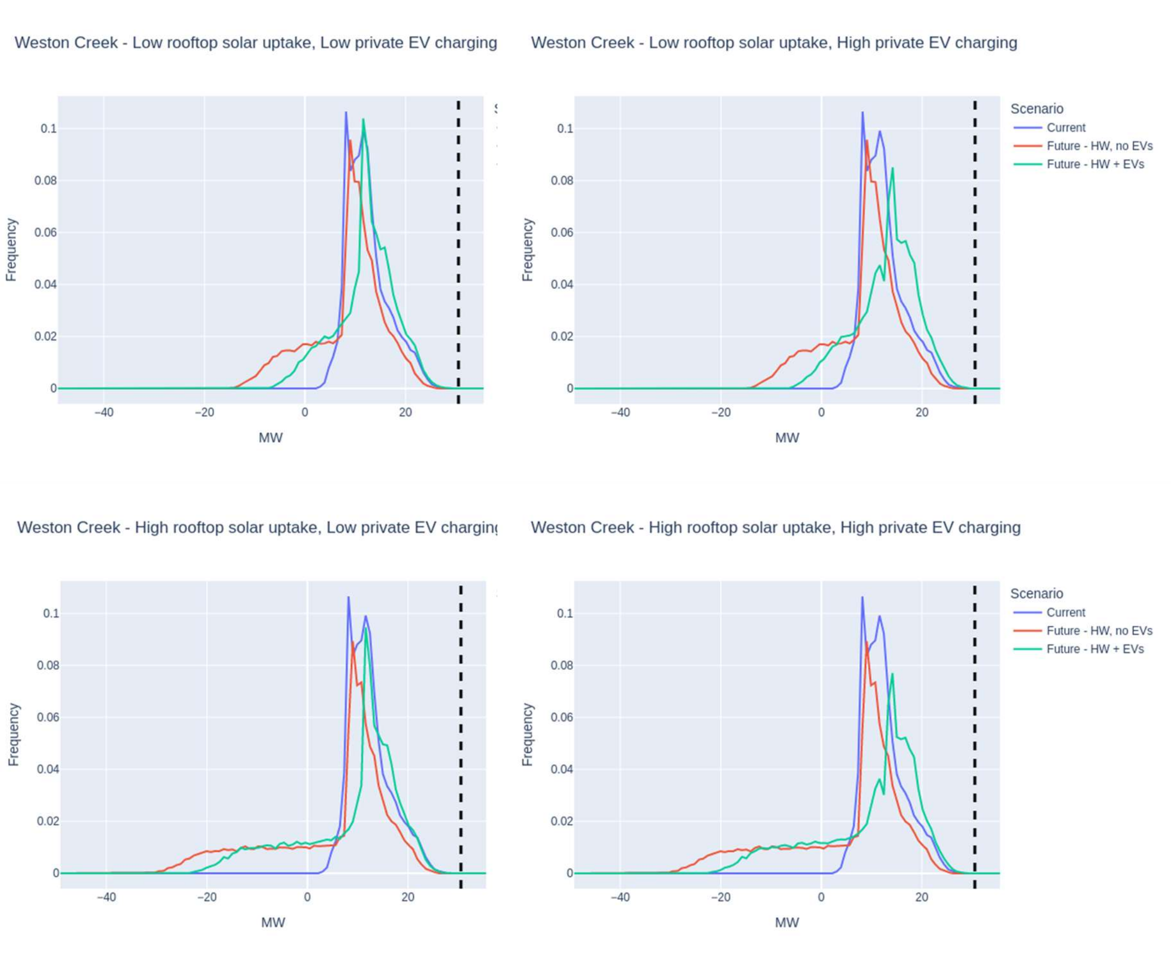
Tuggeranong



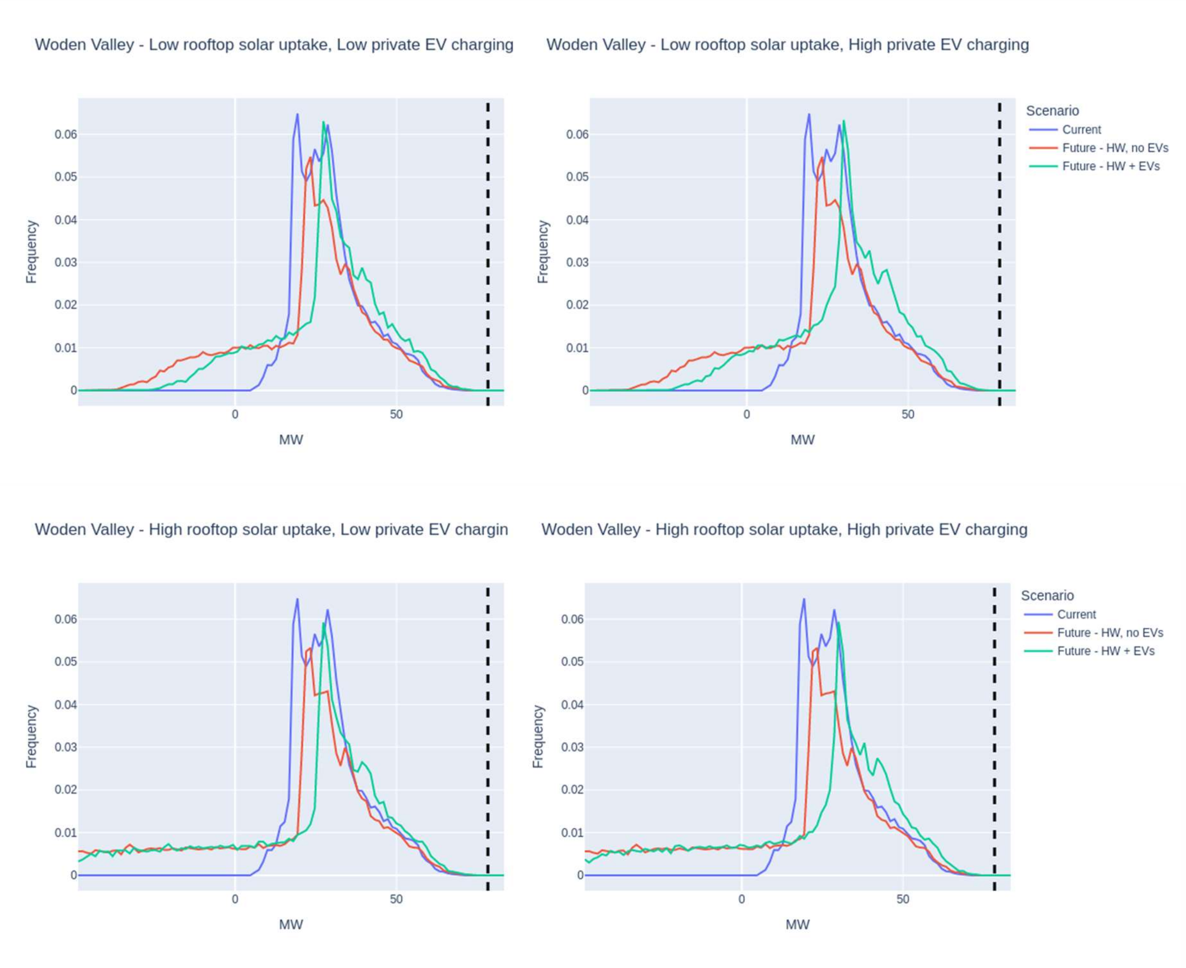




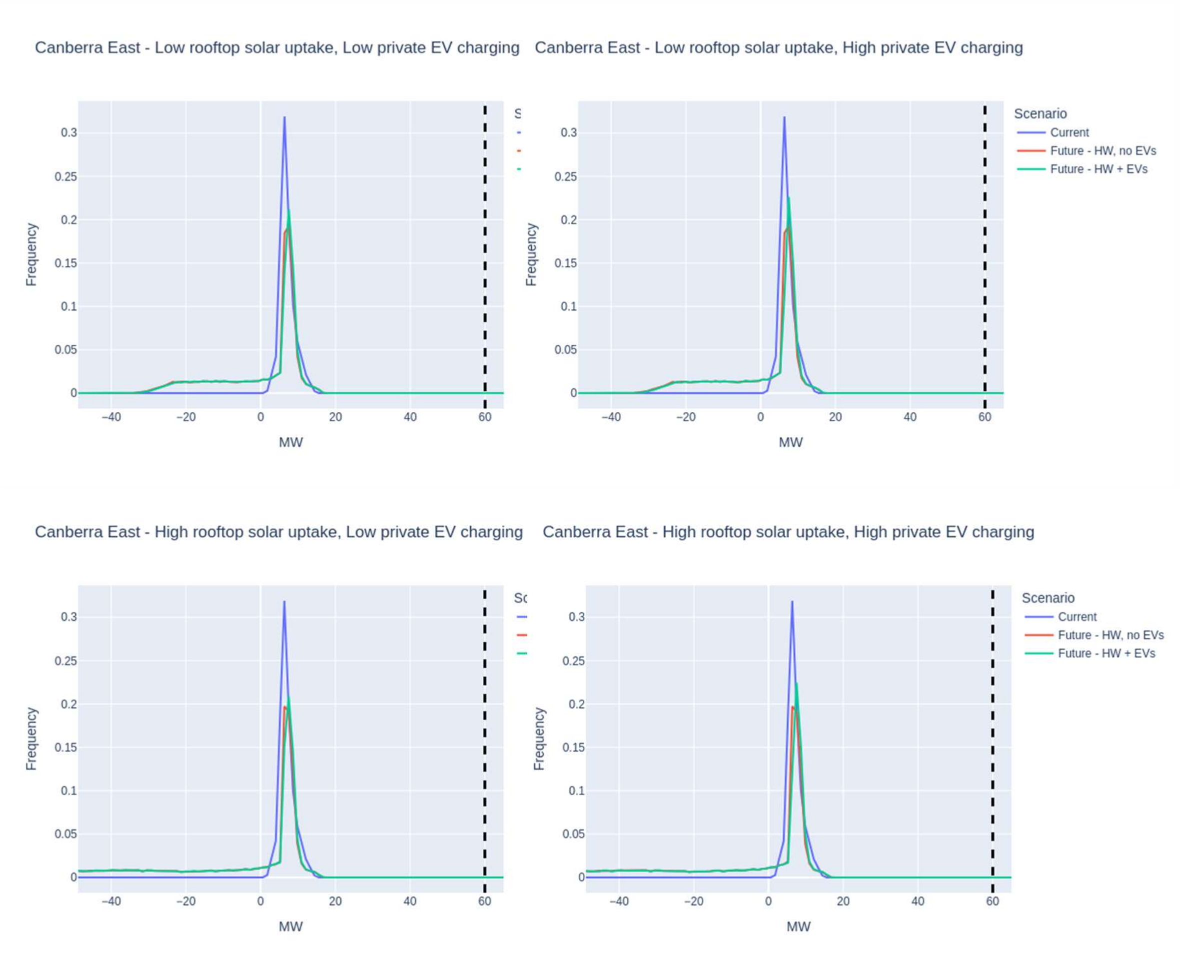
Weston Creek



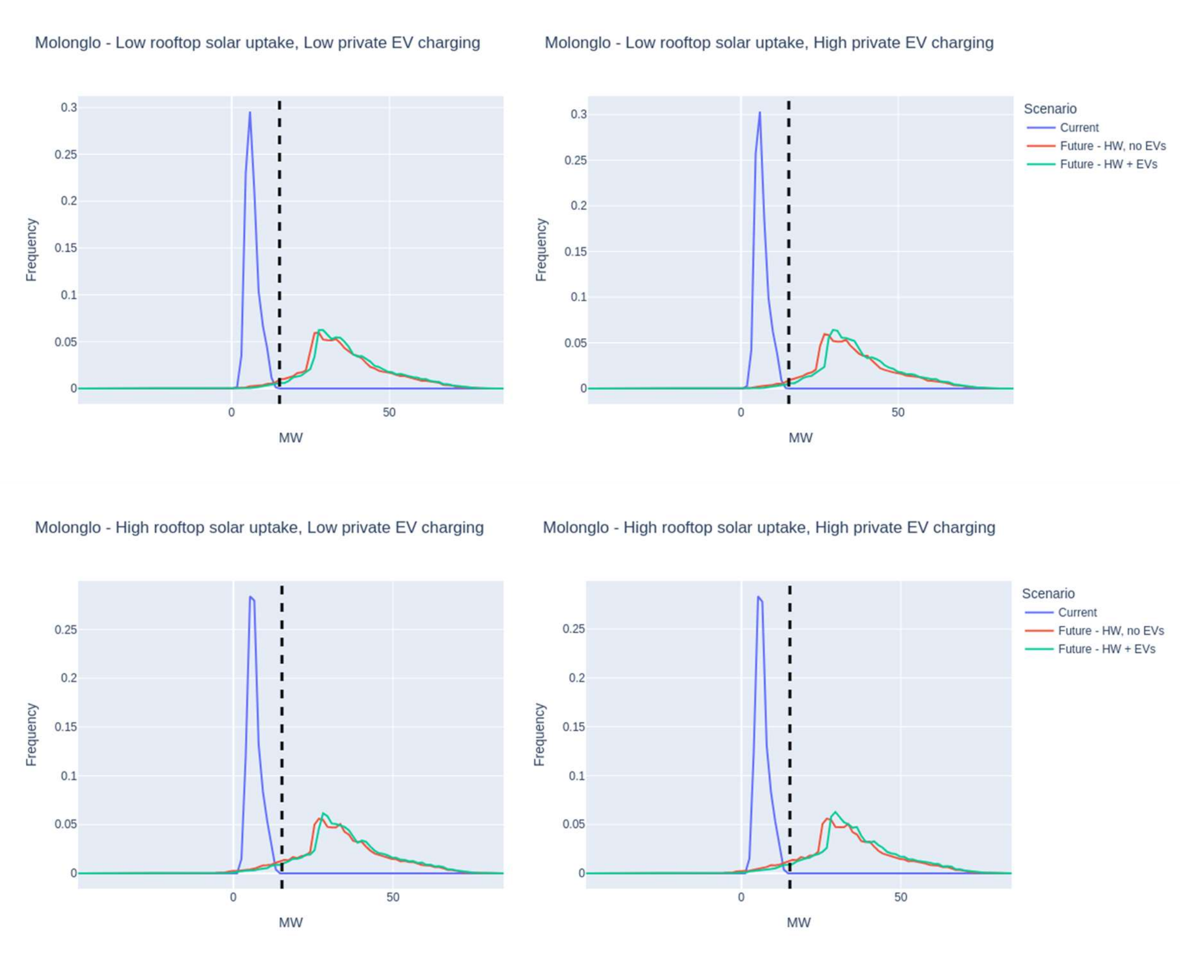
Woden Valley



Canberra East



Molonglo


Molonglo - Low rooftop solar uptake, Low private EV charging
Molonglo - Low rooftop solar uptake, High private EV charging
Molonglo - High rooftop solar uptake, Low private EV charging
Molonglo - High rooftop solar uptake, High private EV charging
Frequency
MW
Scenario
Current
Future - HW, no EVs
Future - HW + EVs