Low voltage distribution network investment requirements from electrification

The effects of high levels of solar and battery uptake on distribution network investment costs and consumer benefit derived from battery uptake

Contributing to the "Modelling the impact of solar and battery uptake on household electricity bills" project

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Disclaimer:

This analysis is based on existing LV network constraint risk analysis results for a limited number of EDBs. It uses solar generation previously provided to MBIE that does not represent all major centres in New Zealand. The Results are supplied in good faith and reflect the expertise and experience of the authors. The Models are subject to assumptions and limitations including but not limited to those listed herein. Any reliance on the Results is a matter for the Client's own commercial judgement, taking into account the stated inputs, assumptions and limitations. ANSA Holdings Limited accepts no responsibility for any loss by any person acting, or otherwise, as a result of reliance on the Results.

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Executive Summary

Given the drive to electrification, including high solar (PV) and electric vehicle (EV) uptake, and the transition of heating to electricity, it is necessary to understand the implications on distribution networks. It is expected that high levels of PV export, EV charging, and electrification of demand will increase distribution network capital expenditure (capex) requirements. Further, it is hypothesised that PV combined with battery energy storage systems (BESS), and possibly other forms of energy storage, will offer a means of reducing this capex expenditure.

With respect to network loading and voltages, the primary drivers of capex are solar exports and peak demand increases from their current levels. This study looks at the capex requirements to upgrade LV networks to alleviate constraints caused by these effects. Constraints considered are steady-state voltage and thermal loading constraints. Assets considered include all conductors (overhead lines and underground cables), buses, consumer mains, and distribution transformers in each LV network. The analysis uses results from studies previously carried out by ANSA for three EDBs. These results cover approximately 9,000 LV networks and 260,000 ICPs across Wellington, Christchurch and Otago.

The study also looks at ways of avoiding capex by using BESS and other storage to reduce midday solar exports, and using BESS and shifting of EV charging to reduce future increases in peak demand.

Scenarios

Scenarios investigated are combinations of:

- Early and late electrification

  Forecasts for each of these scenarios reach almost 100% of ICPs with one or more EV by 2037 and 2060 respectively.

- Early and late solar and battery uptake

  Forecasts for each of these scenarios reach almost 80% of households with 10 kW solar and 10 kWh batteries by 2044 and 2063 respectively.

Together with the four combinations of these uptake scenarios, different scenarios of after diversity maximum demand (ADMD) increases of 0 kW, 1 kW, and 2 kW per ICP are investigated.

Base cases investigated

To quantify the LV network capex that can be avoided, two base cases were first established and run using the LV Capex Model for each scenario of electrification. They are:

- Unmanaged PV Export Base Case

  To understand the impact of PV exports on capex and, in conjunction with the test cases, how to reduce PV exports and thereby capex back to a level similar to the case with no PV or BESS. This identifies a test case for use with the next base case.

  This uses a 10% upper voltage limit and the Partially Shifted 3.7 EV charging schedule and capacity. 10 kW-ac PV and 10 kWh BESS are assumed.

- Unmanaged Electrification Base Case

  To understand the impact of reducing peak demand increase from electrification above existing levels by using a BESS, complemented by PV. Using the test case identified earlier and this Unmanaged Electrification Base Case, the capex avoided from electrification demand increases is tested.

  This also uses a 10% upper voltage limit and the Partially Shifted 3.7 EV charging schedule and capacity.

A number of variations from these base cases were also run using the LV Capex Model to understand the sensitivity of the results and the impact of different parameters, including:

Variations on Unmanaged PV Export Base Case

- +6% upper voltage limit, to understand the avoided capex resulting from raising the upper voltage limit.
- Upper (100%) and lower (60%) constraint risk thresholds, to understand the sensitivity of the results to the constraint risk threshold.

Variation on Unmanaged Electrification Base Case

- All EV charging is moved to around 6pm (the 6pm Only 3.7 charging case) to understand the impact on capex from unmanaged EV charging.

Test cases investigated

Various test cases were then run and the difference between the Unmanaged PV Exports Base Case and each test case were considered. This gave the avoided capex of each test case for each scenario.

The test cases investigated are:

1. BESS used to reduce midday summer exports by 2.5 kW

   Consistent with the midday PV export reduction discussion below, this is to test the capex reduction from a BESS reducing exports on a maximum PV generation day in summer around midday.

2. All EV charging moved from 6pm and 9pm to off-peak

   While most EV charging is already scheduled to off-peak in the base case, this is to understand the capex reduction possible by optimally scheduling *all* EV charging to off-peak times.

3. The combination of 1 and 2, where midday PV exports are reduced by 2.5 kW and *all* EV charging is moved to off-peak

4. BESS, hot water storage, and EV charging reduce midday summer exports by 5 kW, with *all* EV charging moved to off-peak.

   Also consistent with the midday PV export reduction discussion below, this is to test the capex reduction from a combination of BESS and other storage reducing PV exports on a maximum PV generation day in summer around midday.

5. In addition to 4, a further reduction in PV exports to reach a 7.5 kW reduction.

To understand the reduction in capex possible from 4 and further export reduction from curtailment.

All test cases include management of peak demand increase from electrification using the BESS complemented by PV. This allows the appropriate test case to then be tested against the Unmanaged Electrification Base Case, to understand the avoided capex from reducing peak demand increases.

Assumptions

It is assumed that EVs are almost entirely moved away from peak demand periods to off-peak and are perfectly scheduled so as not to cause new peaks. The energy required to charge each EV is based on the approximate average daily travel distance by light passenger vehicles in New Zealand and typical EV energy use. Further, only incremental demand, above existing after diversity maximum demand, is accounted for when assessing avoided capex from battery storage.

Renewals of ageing and/or defective assets are not accounted for, nor is urban infill. This will overstate the capex reductions possible, giving an upper bound on capex reduction in the results.

However, not accounting for MV and HV networks will understate the capex reductions possible. Modelling of these should be considered in the future.

This study focused on LV networks in the first instance because those networks have been designed and constructed over decades to certain standards prior to the prospect of higher rates of electrification and the introduction of PV. Those standards include using transformers and conductors that are selected for a certain level of after diversity maximum demand (ADMD), as well as boosting the voltage at the distribution transformer to allow for greater voltage-drop at times of peak demand.

Midday summer PV export reduction

The study includes an assessment of the reduction in maximum PV exports in summer around midday that can be achieved by battery storage. It then assesses how much export reduction can be achieved with battery storage and storage hot water heating and EV charging at midday.

It is found that 10 kWh of battery storage can provide about a 2.5 kW reduction in PV export in most cities when solar generation is at the 99th percentile and minimum coincident demand at the 1st percentile, assuming the battery is charged evenly over the solar generation window.

Using a diverter to redirect excess solar energy to supply a storage hot water heating system at each ICP, as well as to charge an EV (to meet the daily average travel distance), was also tested. It was found that the addition of these provided very little additional reduction in peak PV exports, due to the diverter technology maximising energy capture in the early part of the day – before midday and early afternoon solar generation peaks. However, adding hot water demand and EV demand averaged over the entire solar generation window provided almost a further 2.5 kW of export reduction, bringing the total export reduction possible to almost 5 kW. While simple in concept, this would require a controller of the battery, hot water heating, and EV charger that considers all devices together, and forecasts their demand and solar generation. This is possibly an innovation opportunity to both reduce PV exports and therefore capex, and to develop home automation technology available to *all* consumers.

When using heat pump storage hot water heating the export reduction possible reduces to about 4 kW, purely because of the coefficient of performance of the heat pump and its lower demand.

It is probable that curtailment of exports beyond a 5 kW reduction may be required on peak solar generation and minimum demand days. Due to the nature of solar generation, which peaks in summer around midday, curtailment may not be required that often. Even if it is, forgoing some energy in summer from higher capacity PV systems will provide more energy in the winter from solar generation. At the forecast levels investigated, solar could provide a reasonable proportion of New Zealand's energy requirement over the months of May-July for example. In this respect, it may be better to consider lower capacity inverters (8 kW) with oversized panels (DC:AC ratio of 1.3-1.4), so that more energy can be delivered in winter, and export reduction in summer to a level on the order of 2.5 kW can be achieved more easily.

Results

The Base Case results (as $/ICP) and variations on it are given in the following table, as single values discounted from each year to a present cost. These are discussed in detail in the main report, where the values by year are also given for the two main base cases. Note that the orange and blue shaded columns are the actual base cases. The other columns in these tables are variations from the base case for interest, as outlined earlier. Also note that the peak demand growth of 0 kW, 1kW, and 2 kW is per ICP demand growth.

Avoided capex from the Unmanaged PV Export Base Case by each test case are given in the next table, as a proportion of the Base Case.

The third table below gives the avoided capex from electrification.

Base case results given as absolute capex in $/ICP, with capex at each year discounted to a present cost at 5% per annum. Results are across the three EDBs for both urban and rural LV networks. The orange and blue shaded columns are used in subsequent sections to compare with test cases. The other columns in these tables are variations from the base cases for interest. The peak demand growth of 0 kW, 1kW, and 2 kW is per ICP.

Peak demand growth (kW)	Electrification (including EV)	Solar and battery	Total capex ($ per ICP), discounted at 5% per annum					
			Unmanaged PV Export Base Case To test Section 2.2.2 Point 1	Variations on 'Unmanaged PV Export Base Case'			**Unmanaged Electrification Base Case To test Section 2.2.2 Point 2**	Variation on 'Unmanaged Electrification Base Case'
			+10% upper voltage limit Partially Shifted 3.7 EV	+6% upper voltage limit Partially shifted 3.7 EV	60% constraint risk threshold +10% upper voltage limit Partially shifted 3.7 EV	100% constraint risk threshold +10% upper voltage limit Partially shifted 3.7 EV	**No PV or BESS Partially Shifted 3.7 EV**	No PV or BESS EV charging all around 6pm (6pm Only 3.7 EV)
0	Late electrification	Late solar and battery	2,524	5,306	2,879	1,694	184	821
		Early solar and battery	5,216	9,653	5,771	3,809	184	821
	Early electrification	Late solar and battery	2,545	5,322	2,914	1,694	205	1,351
		Early solar and battery	5,218	9,652	5,771	3,809	205	1,351
1	Late electrification	Late solar and battery	2,528	5,310	2,888	1,694	272	1,161
		Early solar and battery	5,216	9,652	5,772	3,809	272	1,161
	Early electrification	Late solar and battery	2,622	5,372	3,024	1,708	358	1,869
		Early solar and battery	5,218	9,654	5,774	3,810	358	1,869
2	Late electrification	Late solar and battery	2,612	5,355	3,001	1,718	1,039	2,137
		Early solar and battery	5,218	9,654	5,776	3,809	1,039	2,137
	Early electrification	Late solar and battery	3,345	5,864	3,807	2,141	1,696	3,314
		Early solar and battery	5,226	9,658	5,788	3,813	1,696	3,314

Test cases, showing the avoided capex as a proportion of the Unmanaged PV Export Base Case capex, showing how much of the capex resulting from unmanaged PV exports can be avoided. The peak demand growth of 0 kW, 1kW, and 2 kW is per ICP.

Peak demand growth (kW)	Electrification (including EV)	Solar and battery	Avoided Capex: Unmanaged PV Export Base Case less test case as a proportion of Unmanaged PV Export Base Case, discounted at 5% per annum				
			BESS used to reduce midday summer exports by 2.5 kW	All EV charging moved from 6pm & 9pm to off-peak (Fully Shifted 3.7 EV)	BESS used to reduce midday summer exports by 2.5 kW AND all EV charging moved to off-peak (Fully Shifted 3.7 EV)	BESS, hot water storage, and EV charging used to reduce midday summer exports by 5 kW AND all EV charging moved to off-peak (Fully Shifted 3.7 EV)	BESS, hot water storage, and EV charging used to reduce midday summer exports by 7.5 kW AND all EV charging moved to off-peak (Fully Shifted 3.7 EV)
0	Late electrification	Late solar and battery	34%	0%	34%	73%	93%
		Early solar and battery	32%	0%	32%	72%	96%
	Early electrification	Late solar and battery	33%	0%	33%	72%	92%
		Early solar and battery	32%	0%	32%	72%	96%
1	Late electrification	Late solar and battery	33%	0%	34%	73%	93%
		Early solar and battery	32%	0%	32%	72%	96%
	Early electrification	Late solar and battery	32%	1%	34%	72%	90%
		Early solar and battery	32%	0%	32%	72%	96%
2	Late electrification	Late solar and battery	32%	1%	33%	71%	89%
		Early solar and battery	32%	0%	32%	72%	96%
	Early electrification	Late solar and battery	25%	5%	30%	60%	68%
		Early solar and battery	32%	0%	32%	72%	95%

*The decrease in capex from the Unmanaged Electrification Base Case, giving the **avoided capex from electrification**. The first capex results column gives the Unmanaged Electrification Base Case for reference. The second results column gives the capex resulting from the management of PV exports, in which maximum exports are reduced by 7.5 kW (10 kW down to 2.5 kW) - this corresponds to Test Case 5, the last test case column of the above table. The third column gives the avoided capex due to the use of the managed PV and battery storage. The final column gives the same avoided capex as a proportion of unmanaged electrification.*

Peak demand growth (kW)	Electrification (including EV)	Solar and battery	Capex ($ per ICP), discounted at 5% per annum			Avoided capex from electrification as a proportion of Unmanaged Electrification Base Case capex
			Unmanaged Electrification Base Case (No PV or BESS) Note: Absolute value	Highly Managed PV Exports BESS, hot water storage, and EV charging used to reduce midday summer exports by 7.5 kW AND all EV charging moved to off-peak	Avoided capex from electrification by use of PV and BESS, after capex from PV exports has been managed (Unmanaged Electrification Base Case - Highly Managed PV Exports Test Case)	
0	Late electrification	Late solar and battery	184	182	2	1%
		Early solar and battery	184	190	-7	-4%
	Early electrification	Late solar and battery	205	198	7	3%
		Early solar and battery	205	203	2	1%
1	Late electrification	Late solar and battery	272	183	89	33%
		Early solar and battery	272	190	82	30%
	Early electrification	Late solar and battery	358	253	105	29%
		Early solar and battery	358	203	155	43%
2	Late electrification	Late solar and battery	1,039	297	742	71%
		Early solar and battery	1,039	209	830	80%
	Early electrification	Late solar and battery	1,696	1,069	628	37%
		Early solar and battery	1,696	279	1,418	84%

Conclusions

Capex drivers and reduction under electrification

Under the uptake rates in the scenarios considered, the capex requirements in almost all scenarios are substantial when PV exports and electrification peak demand go unmanaged. The per ICP capex requirement equates to in the order of $200-$300 per ICP per annum in the Unmanaged PV Export Base Case. This is roughly half what the capex would be if the upper voltage limit is not raised.

If PV exports are highly managed, by use of a BESS, hot water energy storage, local EV charging, and curtailment when necessary on peak generation days, capex requirements from PV exports can be reduced substantially. Under this case the resulting capex tends to be driven by peak demand growth. It can reach levels on the order of $100 per ICP per annum under the high peak demand growth scenario, as shown in the Unmanaged Electrification Base Case.

Further capex reductions from the high peak demand growth scenario can be achieved by use of a BESS to reduce peak demand. This limits capex increases to the tens of dollars per ICP per annum or less. As shown in the '*avoided capex from electrification*' results table, solar and battery uptake at a similar or earlier time and rate as electrification is necessary to achieve these capex reductions. The last two rows demonstrate this for example, showing that avoided capex from electrification is higher with early solar and battery uptake. Viewed another way, early electrification that occurs before solar and batteries are installed will require additional network build out, which may result in some infrastructure stranded assets.

To achieve these capex reductions by a battery, time of use retail and buyback prices with a suitable battery controller are necessary, as identified in EECA's recent report on residential solar.

The importance of managing EV charging

By virtue of moving EV charging away from the peak and scheduling it carefully in this study, most of the requirement for capex is from PV export and peak demand growth. As discussed above, these can be managed down to low capex requirements. However, if EV charging is not scheduled carefully away from the peak, while also avoiding the creation of new peaks, the additional capex due to EV charging and other peak demand increase can be substantial.

Considering this in conjunction with the earlier conclusions, it is concluded that well managed EV charging is essential, and combined with batteries for peak demand management, capex due to electrification can be reduced substantially.

Managing PV exports and consideration of lower capacity inverters with higher capacity arrays to lower summer exports and maximise winter energy

It is concluded that a combination of BESS and hot water storage with midday EV charging can reduce the capex increases from each scenario by about 70%. This reduces to 60% under high peak demand growth, early electrification and late solar and battery uptake. By further reducing PV export to a maximum of 2.5 kW via BESS, hot water energy storage, and curtailment the capex reduces by about 90-96%, or only 68% under high peak demand growth, early electrification and late solar and battery uptake. It is these highly managed reductions in PV export that avoid capex due to PV exports, and allow the BESS to further reduce capex by managing peak demand. Caution however must be exercised, as capex resulting from unmanaged PV exports can overshadow avoided capex from BESS peak demand management.

Solar export reduction by 5 kW or 7.5 kW, partly by charging an EV, would obviously require an EV uptake earlier than or at the same rate as solar, so is unlikely to work in the early PV and late electrification scenarios. Further, it requires EVs to be at the ICP, so its effectiveness (in terms of guaranteeing a 5 kW or 7.5 kW export reduction at times of peak export) may be limited. In that respect, more curtailment of exports in summer may be required. It may be better to consider lower capacity inverters (8 kW) with oversized arrays (DC:AC ratio of 1.3-1.4), so that more energy can be delivered in winter, and export reduction in summer to a level in the order of 2.5 kW can be achieved more easily. Further assessment of the capex implications of more winter PV export should be undertaken.

Nature of constraints

Many of the constraints due to PV are voltage constraints, and lead to the need for conductor replacements. The main constraints due to peak demand growth are conductor overloading, with some transformer overloading. Since the cost of replacing underground cable is so high, much of the resulting capex is due to cable replacement. Transformers provided as a second transformer to allow splitting existing LV networks is also a high cost, together with MV extensions (much of which is underground) and bus work.

Other than splitting networks and the need for new transformers, transformer replacements are a relatively small part of the capex required. This is partly due to using the 130% of nameplate capacity for transformers in winter. As demand increases, and as demand is shifted away from peak demand, it may result in transformers being overloaded for longer, thereby reducing their lifetime. Thus, the suitability of higher transformer loading limits may have to be reviewed at high electrification levels.

Overall, it is seen that, at the capacity and uptake levels forecast, PV tends to have a bigger impact on capex than EV and peak demand increases. The primary reasons for this are:

- The resulting PV export from 10 kW PV systems is close to 10 kW when demand is minimum in midday summer. This exceeds the after diversity maximum demand that most LV networks have been designed for, which is in the order of 3-5 kW. Further, even with the upper voltage limit at +10%, the 'tapping up' of distribution transformer secondary voltages gives less room for voltage rise resulting from the reversal of power flows.
- PV export occurs coincidentally in LV networks, meaning there is almost no diversity in PV exports.
- A threshold of 100% of each transformer's nameplate rating is used in summer to determine overloading, instead of a higher limit such as 110%, due to expected high temperatures coincident with high solar generation. Thus, transformers do not have any 'head room' for overloading compared to peak demand in winter.
- EVs are modelled as largely shifted away from peaks and perfectly scheduled so as not to cause new peaks. Concentrating EV charging into peak periods does lead to large increases in capex, although not as large as very high PV exports.

The above further highlights the importance of managing PV exports down to avoid capex increases, and to gain the benefit of a BESS to manage peak demand and therefore avoid further capex.

Conclusions beyond the LV network

While this study has focused on LV networks, similar conclusions could be extended to MV and HV networks, through peak demand management. By extension, the avoided capex may be higher than calculated, although further investigation is required to quantify this. However, a large proportion of capex spend by EDBs is on renewals, and any overlap between renewals capex and capex due to electrification growth needs to be understood.

Improving energy management of all devices within a home or business

Finally, it is concluded that there may be more effective ways to reduce PV exports from high-capacity PV systems than hot water diverter and EV charger diversion. Control of these devices together by an energy management system, for example, can provide a more evenly spread export reduction throughout the day. In turn total PV exports could effectively be reduced by a greater amount.

1 Introduction

There is a drive to demand electrification, including electric vehicle (EV) uptake and photovoltaic solar (PV or solar) uptake. Given this, it is of interest to understand the cost implications for electricity distribution businesses (EDBs) and ultimately consumers.

It is expected that demand electrification and PV uptake will lead to new investment requirements in distribution networks, and therefore the need for increased capital expenditure (capex) by EDBs in the future. Ultimately this could translate to higher bills for consumers. However, it is of particular interest to understand the level of future capex that can be avoided by combining PV with a battery energy storage system (BESS or battery). In turn, how rises in consumer bills may be limited.

The capex requirements from demand electrification and PV uptake in LV networks are calculated using ANSA's LV Capex Model, a model developed by ANSA to advise EDBs on such matters.[1] The impact of using batteries, alongside other forms of energy storage, on projected future capex are also evaluated using ANSA's LV Capex Model.

Section 2 of this report sets out the scenarios and methodology used to address the question of how much capex is expected to increase, if this capex increase can be avoided and, if so, by how much. Section 2 includes discussions on the drivers of capex due to electrification, how BESS might be used to manage peak demand growth and PV exports, and the use of ANSA's LV Capex Model to answer these questions. Section 2 also quantifies the export reduction that can be achieved using BESS and other storage such as storage hot water heating and EV charging. In addition, Section 2 sets out how EV charging has been treated in this study.

Section 3 summarises the results and discusses them, with conclusions from the study in Section 4. Several existing papers and reports are referenced throughout the document as supporting information. Section 5 lists these.

[1] An LV network is the network to which most consumers are directly connected. In an electrical sense, each LV network comprises a distribution transformer (often 11 kV to 400 V) and all downstream circuits from the transformer comprising conductors, branches from those circuits, and consumer mains (or service mains) and connections to each ICP. More information about LV networks is given in the Appendix of (Miller and Lemon 2024a). ANSA's LV Capex Model builds on ANSA's hosting capacity and constraint risk models that model LV networks in detail. These are discussed further in (Miller and Lemon 2024b) with the preparation of data required for these models discussed in (Lemon and Miller 2022).

2 Scenarios and Methodology

Various scenarios of PV with BESS and EV uptake were tested, together with scenarios of peak demand increase resulting from electrification of heating and cooking mainly. Scenarios are discussed in Section 2.1.

The impact of these scenarios from overloading distribution network assets and/or breaching voltage standards was then assessed in approximately 9,000 LV distribution networks. The LV networks used are from three EDBs, Aurora Energy, Orion, and Wellington Electricity, and cover nearly 260,000 residential and commercial consumer ICPs (installation control points). The size of each LV network, in terms of the number of ICPs supplied by each distribution transformer, are shown in Figure 1.

The results are from modelling previously carried out by ANSA for those EDBs, expanded to include different scenarios of peak demand increase. The resulting risk of constraint, or more correctly risk of upgrade of each asset when referring to voltage constraints, was used by ANSA's LV Capex Model to understand the capex requirements from electrification. ANSA's Constraint Risk and LV Capex Model is summarised briefly in Section 2.4. More detail about the model and its applications by EDBs can be found in (Miller and Lemon 2024b) and (Miller, Scrimgeour, et al. 2024).

The drivers of capex from electrification are discussed in Section 2.2, with exclusions also discussed. Ways of avoiding capex from electrification are also discussed in Section 2.2.

Section 2.3 expands on Section 2.2 by quantifying the potential for BESS and other forms of storage to contribute to avoiding capex. These numbers are used by ANSA's LV Capex Model to produce results of base capex and capex reductions (avoided capex). The various cases tested, and LV Capex Model parameters used, are discussed in Section 2.4, with the results themselves presented in the next section, Section 3. Section 2.3 also includes a discussion on EV charging schedules used in ANSA's LV Capex Model.

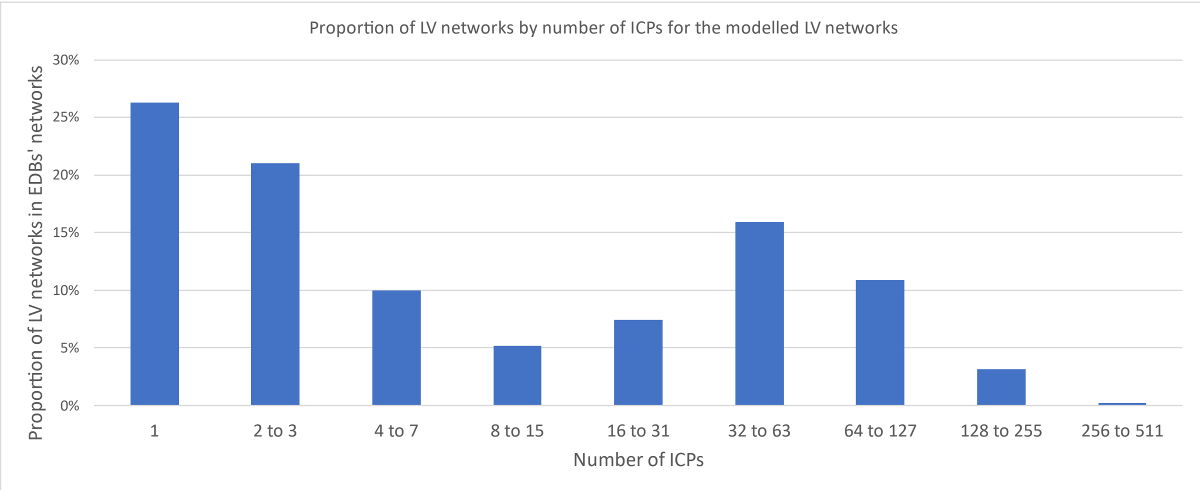


Figure 1: Characteristics of the LV networks in terms of number of ICPs in each LV network. The networks comprised a range of overhead and underground conductors, with 136 highly meshed networks in the sample, meaning multiple transformers per LV network.

2.1 Scenarios

The scenarios of PV with BESS and electrification investigated were provided by Rewiring Aotearoa and the Ministry of Business, Innovation & Employment (MBIE), and are summarised in Table 1.

Table 1: PV with BESS and electrification scenarios.

	Late solar and battery uptake High solar and battery uptake by consumers, but this uptake happens later	**Early solar and battery uptake** High solar and battery uptake that happens early, with around 80% of households having solar and battery systems by 2040
Late electrification Fully electrified economy by 2070	Late electrification Late solar and battery	Late electrification Early solar and battery
Early electrification Fully electrified economy by 2040	Early electrification Late solar and battery	Early electrification Early solar and battery

2.1.1 EV and PV uptake rates

PV and BESS uptake forecasts and EV/electrification uptake forecasts for each of the scenarios have been provided by Rewiring Aotearoa and MBIE, and are shown in Figure 2. The PV and BESS forecasts have been devised such that the average installed solar capacity is 10 kW-ac. This means that the uptake rate has been adjusted (lowered) to account for smaller, lower capacity systems being installed in earlier years. The PV uptake rate has also been set to equal the BESS uptake rate, with the assumption of a 10 kWh BESS at each ICP with solar.

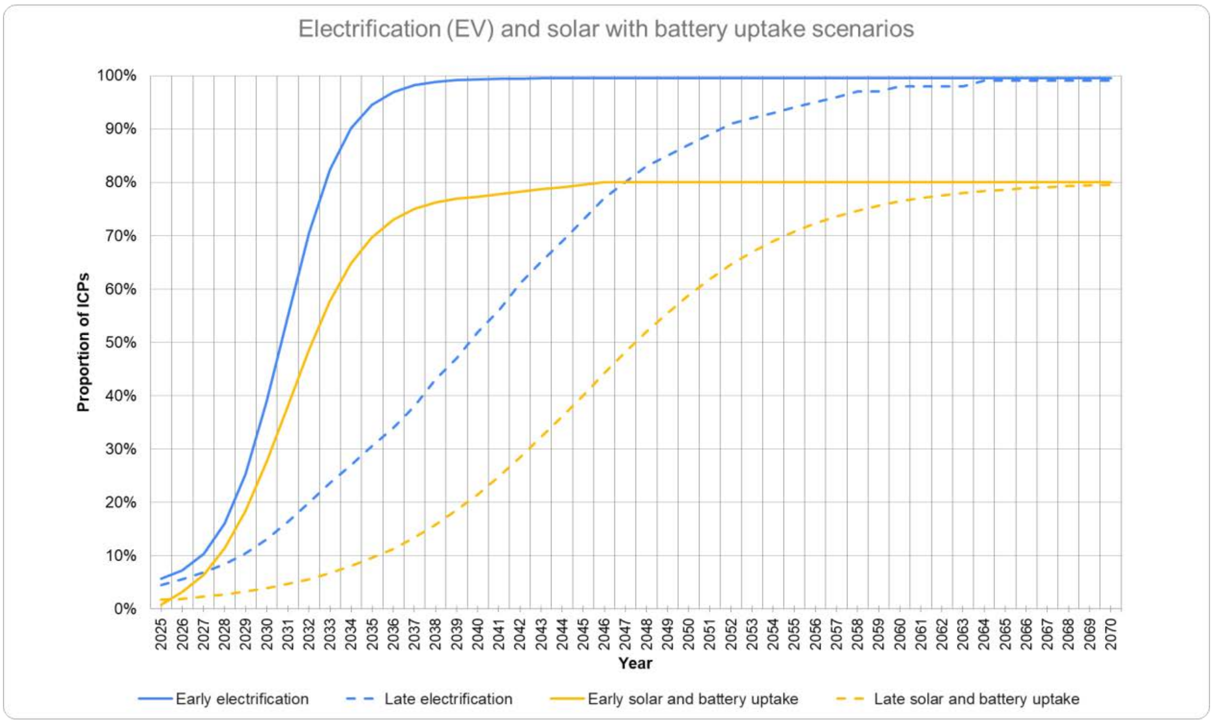


Figure 2: Electrification and PV with BESS uptake scenarios.

2.1.2 Other electrification demand increase

In addition to EV uptake, several scenarios of after diversity maximum demand (ADMD) increase from electrification of demand other than EV uptake are tested (from such things as space heating, cooking, and water heating). There is some uncertainty over how much ADMD will increase with electrification other than EV uptake. Some researchers suggest that a heat pump will add about 1 kW to ADMD (in winter) and electric cooking roughly 10% of this (Jack and Suomalainen 2018).

In this current study the variation in maximum coincident demand across residential load profiles, used in the constraint risk assessment, shows a difference of about 1.5 kW between P25 and P75 at both 6pm and 9pm, and about 1.0 kW at 12am and 3am. However, without additional information, it is not possible to determine how much of this variance across ICPs is attributable to different forms of heating versus house size and occupancy, and other demographic factors. Indeed, (Heinen and Richards 2020) indicate that house size and type have a larger impact on individual ICP demand differences than electrification. Therefore, we do not use this difference.

There is also evidence that the transition from incandescent to LED lighting reduces peak demand, although it is assumed that most lighting has already transitioned to LEDs. In addition, demand may increase by more in areas and networks that have a gas connection, and which currently use gas for heating and cooking. Consequently, several average increases in ADMD are modelled at each ICP. Such an approach can also be used to effectively model urban intensification, although in this study urban intensification is excluded, as we are interested in PV uptake and electrification only. Furthermore, it is better to apply increases in demand by geographical areas where infill housing development is expected – something that ANSA's LV Capex Model can do by using uptake curves specific to statistical areas (such as "Statistical Area 2" areas, as defined by Statistics New Zealand) and/or each individual LV network.

Since the actual increase in background demand from electrification other than EVs is unknown, the maximum demand was increased at 6pm and 9pm at each ICP by three levels: 0 kW, 1 kW (aligned to the earlier cited research), and 2 kW per ICP. The actual increases were at the rate of electrification shown in Figure 2, meaning that, in the 1 kW case for example, the maximum demand was increased by 0.5 kW per ICP at 50% electrification (EV uptake), and by 1.0 kW per ICP at 100% electrification (EV uptake). While the background demand increase was at the same rate as electrification, a separate forecast input in the LV Capex Model was used to model background electrification. This allowed for the modification of background demand electrification by PV and BESS uptake to emulate management of this peak demand increase down using a BESS – this is discussed in Sub-section 2.3.2.

No changes to 12am and 3am demand were made, and the demand changes were only applied to residential ICPs. No demand changes were made to commercial ICPs, as it was assumed that they either do not operate from 6pm to 3am, or those that do already have electric heat pump space heating and full LED rollout, and hence the background demand analysis performed by ANSA in the original studies captures this.

2.2 Electrification and capex in distribution networks

2.2.1 Drivers of capex in low voltage (LV) distribution networks from electrification

Under scenarios of PV and electrification / EV uptake, the two primary drivers of capex requirements in low voltage distribution networks are:

1. Excess solar generation, usually in the summer daytime coincident with low residential demand, that is exported on LV networks, eventually reversing power flows.
   This has the primary effect of raising voltages, and the secondary effect of overloading equipment at high export levels. Both lead to requirements to upgrade equipment.
2. Peak demand growth from current levels in winter mornings and evenings resulting from patterns of consumer behaviour and higher cooking and space heating requirements, combined with little to no solar generation. Increased EV charging coincident with the evening peak may exacerbate the peak demand but can be moved due to the inherent storage in an EV.

This increases the maximum coincident demand in networks, which has the primary effect of overloading equipment, and a secondary effect of reducing voltage. These lead to requirements to upgrade equipment.

Both of these can lead to the need to upgrade assets, including overhead lines, underground cables, and distribution transformers. Since ANSA's LV Capex Model considers the risk of constraint of each asset in an LV network from both effects, it can provide an indication of LV network capex from both effects combined. This is discussed in more detail in Section 2.4.

2.2.2 Avoiding capex in distribution networks from electrification

The capex resulting from each of the drivers discussed above may be reduced by the use of storage. In each case:

1. Batteries may be used to store some excess solar energy, and thereby reduce peak exports. Other forms of storage, such as storage hot water heating and EV charging, may also be able to store excess solar energy during the daytime, and thereby further reduce peak exports in the daytime.
2. Batteries may be used to store daytime winter solar energy and/or energy from lower consumption periods to reduce demand, and possibly even export, during morning and evening peak periods. This is demonstrated by (Miller, Crownshaw and Gretton 2025).

2.2.3 Exclusions

There are other drivers of LV network capex that have not been accounted for in this modelling. In particular, renewals of aging and/or defective or damaged assets and the impact of urban infill. The modelling also focuses on LV networks, and therefore does not account for capex required in medium voltage (MV) distribution networks (typically 11 kV and sometimes 22 kV) and high voltage (HV) sub-transmission networks (typically 33 kV, 66 kV, and 110 kV). Hence, capex reductions from the methods discussed will not be accounted for.

Not accounting for renewals of aging assets and the impact of urban infill will tend to overstate the capex reductions possible, as there is highly likely to be a need for capex irrespective of how BESS, for example, is used to reduce the impacts of electrification. The capex reduction numbers presented in the results will therefore give an upper bound, with actual reductions likely to be lower.

By contrast, not accounting for MV and HV networks will tend to understate the capex reductions possible, as there will be some benefit from avoiding capex in those networks. Modelling of higher voltage networks could be considered in the future.

In general, focusing on LV networks in the first instance is considered reasonable, as those networks have been designed and built over decades based on certain rules prior to the prospect of higher rates of electrification and the introduction of PV. This includes designing networks and circuits to handle a predetermined level of ADMD, as well as boosting distribution transformer voltages (typically from 400 to 415 V) to accommodate larger voltage drops at times of peak demand. These are discussed in more detail in the Appendix of (Miller and Lemon 2024a). Higher demand at peak from EVs, heating, and cooking will increase ADMD in LV networks, and PV export will increase voltage along feeders from the distribution transformer.

2.3 Quantifying the ability of storage to manage electrification – peak demand reduction and PV export reduction

This section discusses how storage may be used to manage peak demand and midday summer exports. At the outset it is assumed that the distribution networks modelled are built to supply maximum demand at its current level. Hence, any demand reduction available from battery storage only has a benefit by reducing demand increases above their current levels – otherwise benefit in terms of reduced capex would be attributed to capex that has already been incurred.

In addition, minimal peak demand increase from EVs is modelled on the basis that such devices, with inherent storage, are used to their utmost to avoid peak demand increases and therefore capex. Sub-section 2.3.1 discusses how EV charging is modelled.

Sub-section 2.3.2 discusses the potential for BESS to move solar generation from winter midday to a winter evening, while sub-section 2.3.3 discusses the potential for BESS, storage hot water heating, and EV charging to reduce midday summer PV export.

2.3.1 Modelling of EV charging

In addition to being more efficient, it is considered more rational to use the inherent storage of an EV battery to move EV demand away from peak demand periods to lower demand periods than it is for a BESS to supply EV peak demand. In the model this is achieved by assuming EVs predominantly charge during times of traditionally low demand, namely 12am-6am. Further, it is assumed that EV charging is carefully scheduled to avoid creation of new peaks. However, it is assumed that some EV demand cannot be moved from peak times; hence there is some EV demand at 6pm and at 9pm.

The proportion of EVs plugged in and charging at each time period was determined according to the principle outlined above and the energy required to be delivered to fully charge a typical EV. This energy is derived from estimated average daily travel requirements and EV efficiency. In all cases a 3.7 kW charger capacity is used – given that EV charging is assumed to be perfectly scheduled over each time period, 1.8 kW, 3.7 kW, and 7.4 kW chargers gave similar results.

The main EV charging case, used in all base cases and capex reduction cases, unless otherwise stated, is:

- Partially Shifted 3.7 EV:
    - 5% of EVs charge uniformly from 6pm – 9pm;
    - 10% of EVs charge uniformly from 9pm – 12am; and
    - 20% of EVs charge uniformly from 12am – 6am.

The percentages here refer to the percentage of installed EV chargers actively charging during each time window. For example, at a 50% electrification/EV uptake level, 50% of ICPs have an EV charger installed, but only 5% of them (0.05 x 50% = 2.5% of all ICPs) are modelled as actively charging at the time of peak demand between 6 and 9pm.

The assumptions used to develop the EV charging schedules used in the model are summarised in Table 2. Peak travel charging needs were not modelled, as it is assumed that these can also be managed by scheduling EV charging over a longer period, such as a week before the peak need (such as a holiday), and through the use of public charging infrastructure during the day.

Table 2: EV charging assumptions.

Assumption	Value	Units	Notes
Average daily travel distance	35.0	km	Average daily distance - does not model peak daily travel, as might occur on holidays
Average EV efficiency	5.8	km/kWh	Winter travel with heater on uses more energy
Average daily EV energy use per EV (35.0 km / 5.8 km/kWh)	6.0	kWh	
Charger efficiency	96%		
Time required to charge with a 1.8 kW charger	3.5	hours	
Time required to charge with a 3.7 kW charger	1.7	hours	
Proportion of EV chargers charging at any point in time is spread evenly across the alloted three-hour time period			Maximum EV charger demand is scheduled so as to avoid concurrent charging and new demand peaks

Some cases of moving *all* EV charging to traditionally low demand periods (12am – 6am) and moving *all* EV charging to the traditional peak period are introduced to understand the impacts and benefits of scheduling EV charging. These are:

- Fully Shifted 3.7 EV:
    - all EVs are charged between 12am – 6am with no EVs charging over the peak periods.
- 6pm Only 3.7 EV:
    - all EVs are charged over three hours at the evening peak period starting at 6pm.

2.3.2 Evening peak demand reduction

To reduce demand at the evening peak, the BESS is assumed to store excess solar energy during the day and release it during the evening peak period, which in most cases is from 5pm to 9pm. As shown by (Miller, Crownshaw and Gretton 2025), more than 2 kW demand reduction can be achieved in winter morning and evening peak periods by a BESS with 10 kWh usable capacity, with appropriate time of use retail and buyback prices, and with a suitable battery controller. Capacity to reduce peak load is modelled by moving the 5% of EV charging on at 6pm and 10% on at 9pm all to between 12am – 6am (the 'Fully Shifted 3.7 EV' case), and by modifying the background increased demand from electrification by each scenario's solar and battery uptake. Hence there are several different combinations of background demand, depending on the four electrification and solar scenarios. For the 1 kW background demand increase, the resulting effective peak demand increase, after BESS control, is depicted in Figure 3. For the 2 kW case Figure 4 shows the effective background demand increase.

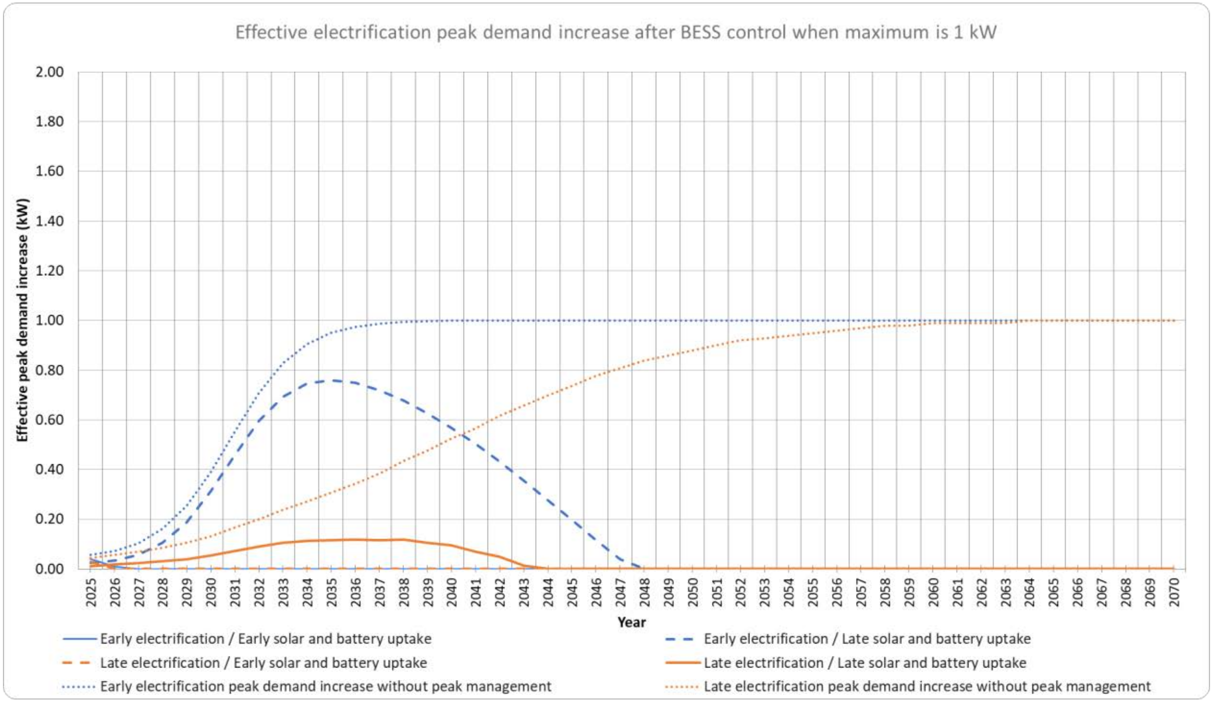


Figure 3: Effective electrification peak demand increase after BESS control when electrification increases peak demand by 1 kW. This does not include shifting of 5% of EV chargers from 6pm to 12am-6am.

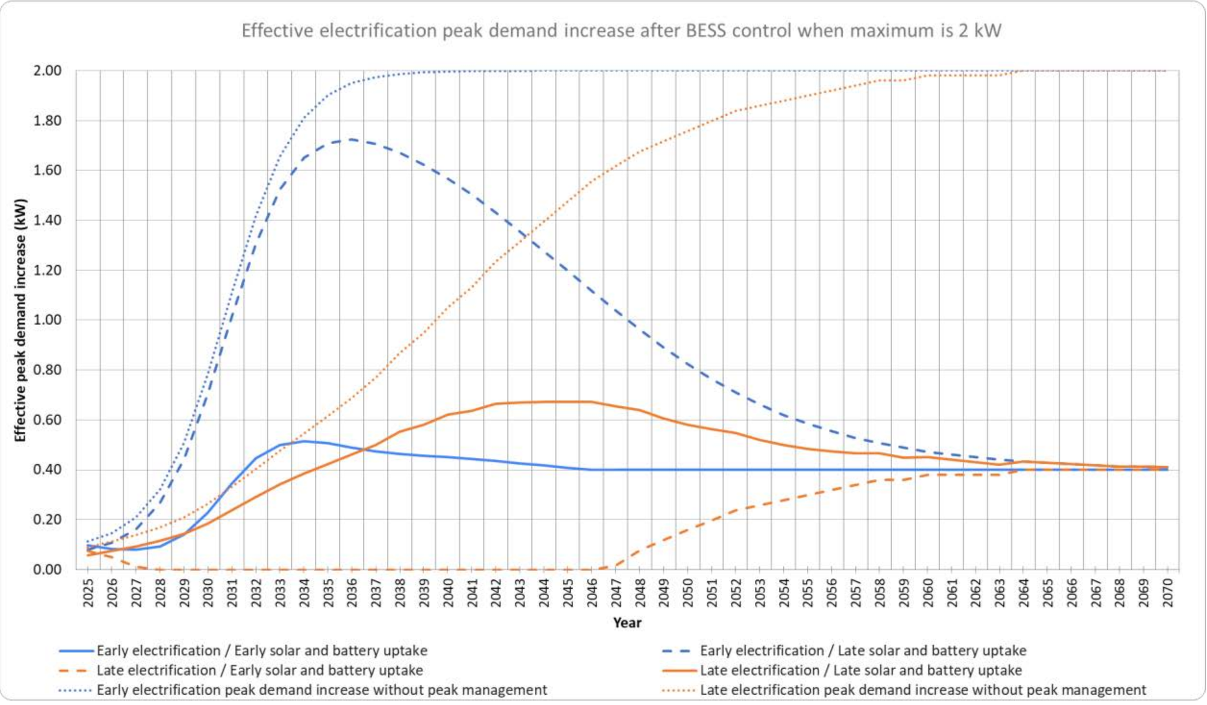


Figure 4: Effective electrification peak demand increase after BESS control when electrification increases peak demand by 2 kW. This does not include shifting of 5% of EV chargers from 6pm to 12am-6am.

It is of interest to understand how much solar energy is available to move to the evening peak. A rigorous understanding of this would require a time series of coincident solar generation and demand at each location. The solar generation available would correspond to the peak demand days. Such information was not available for this study, but to give an indication, Table 3 shows the daily energy from solar generation available at various percentiles. The first percentile has little solar generation available. However, it cannot be assumed that this corresponds to the peak demand day. Nor can it be assumed that this limits what is available for the evening peak demand management, as the demand over the day may be such that energy can still be stored in the battery from the network. Hence, it is considered that 2.0 kW of demand reduction is possible over the morning peak and 2.2 kW demand reduction is possible over the evening peak (the additional 0.2 kW accounts for reducing average demand from 5% of EVs charging at 6pm).

Table 3: Solar energy (kWh/day) generated at different locations and percentiles from a 10 kW-ac system, north facing with a 20° tile and DC:AC ratio of 1.2. The solar data set used was an existing MBIE data set previously used in the upper voltage limit analysis, and spans 1970 to 2021 inclusive. A number of the main centres (Dunedin, Invercargill, and Greymouth) are missing from the table as they were not included in the data set.

	P1	P5	P10	P25	P50
Whakatane	5.2	12.7	19.1	29.0	40.8
Auckland	5.3	11.9	17.5	27.9	41.7
Hamilton	4.6	10.8	15.8	26.2	40.7
Tauranga	4.0	10.5	16.7	30.6	45.3
Gisborne	4.0	10.5	16.7	30.6	45.3
Napier	3.7	9.3	14.7	27.5	42.0
New Plymouth	3.6	8.2	12.5	22.9	37.8
Whanganui	3.6	8.2	12.5	22.9	37.8
Wellington	3.8	8.0	12.0	22.4	37.6
Richmond	3.8	9.7	16.3	30.9	45.5
Nelson	3.8	9.7	16.3	30.9	45.5
Blenheim	3.8	9.7	15.5	29.6	43.7
Christchurch	3.5	8.0	12.4	23.9	38.5
Central Otago District	6.1	12.1	16.6	25.7	40.9

2.3.3 Estimation of solar export reduction with storage

To reduce summer midday solar export, the BESS can be programmed to store excess solar exports and use that energy, or possibly export it at a lower rate, at other times. The key point is that peak exports are reduced, while some export is maintained. This sub-section attempts to understand the level of reduction of peak export possible by appropriate control of:

1. The BESS with 10 kWh usable capacity on its own.

It then attempts to understand the peak export reduction possible by appropriate use of:

1. The BESS with 10 kWh usable capacity; and

2. Storage hot water assuming one cylinder per ICP and assuming 10 kWh of energy required to heat hot water per day in the summer (equating to about 125 litres).[2] There may be more hot water systems available on the connected LV network compared to PV and BESS systems, but one per ICP is assumed as a minimum assuming that hot water is one of the first demands electrified if not already, and to accommodate the higher uptake levels in this analysis. Both resistive and heat pump hot water storage systems are considered; and
3. EV charging at midday to provide energy of 6 kWh to meet the same average daily travel distance, calculated in Sub-section 2.3.1. Clearly this would require the EV to be at the ICP and charging.

There will clearly be differences between ICPs in their hot water usage and EV charging from day-to-day, however it is assumed that these will average out across the ICPs in an LV network. This may not always be the case, and additional curtailment of solar exports may also be required. For this reason, this section also examines the duration of exports at various levels to understand how often curtailment may be required if the energy storage above does not provide sufficient solar export reduction on maximum generation days.

The analysis of storage of maximum solar exports is performed on the maximum solar energy generation days of a year (the top 99th percentile of solar energy export days) and minimum coincident demand days of a year (the 1st percentile of demand), when exports are expected to be highest. Since all solar is on the same LV network, and therefore located in the same area, solar generation will be coincident, and therefore consideration of the maximum solar generation is necessary.[3] Maximum solar energy generation is considered, rather than peak export capacity, because the battery, and other devices, must store energy. Moreover, energy can be equated to duration, and duration of overloading assets or voltage is important in terms of their nominal ratings.

Table 4 gives the estimates of solar export reductions possible in various cities for each form of storage and means of control of hot water heating and EV charging. In terms of solar capacity reductions, this supports testing reductions of 2.5 kW and 5 kW, since they are levels that appear to be practical. The following summarises the findings from this analysis, with reference to the columns in Table 4:

1. With a 10kWh BESS alone, on the order of 2.6 to 3.1 kW of export reduction can be achieved. Figure 5 illustrates how this reduction occurs.
2. With a 10 kWh BESS and 10 kWh hot water storage controlled by a diverter that modulates power to the cylinder based on excess solar available, and a smart EV charger that functions in a similar way to a diverter, it is surprising that there is not much more solar export capacity reduction possible. This is primarily because the diverter technology uses solar energy in the first part of the day, then switches off once the hot water is fully heated and the EV is fully charged, as shown in Figure 6.
3. The above is typical of individually controlled equipment. If this equipment could be controlled together, with power to each device allocated over the entire solar generation

[2] 10 kWh per day is based on the estimated 27% of electricity use by a household to heat hot water, an assumption used in the EECA Solar Tool. There will be considerable variation from this, and therefore 10 kWh per day between households and between each day. However, 10 kWh allows an estimate of export reduction to be made.

[3] Local shading from trees and buildings is assumed to be minimal, but may also limit the export from solar. However, the worst-case conditions of solar exporting at capacity over an extended duration are considered. In reality there will also be a variety of solar orientations and tilts, but we assume midday summer with full direct irradiation.

window (averaged over the day), a greater reduction in exports could be achieved, as shown in Figure 7. This is not as easy as it might seem, as it would require a forecast of solar generation to know how much to regulate to each device, and the EV may not be available over this entire window. However, as noted in (Miller, Crownshaw and Gretton 2025) in relation to battery control systems to optimise response to time of use retail and buyback prices, the large-scale adoption of PV should give rise to solar energy forecasting services.

In any case, there appears to be an opportunity for innovation in hot water energy storage from PV and EV charging from PV to maximise energy capture and avoid curtailment.

4. The case with a heat pump storage hot water cylinder and diverter control gives similar solar reduction as a resistive storage hot water cylinder. Figure 8 shows the resulting solar export profile.
5. The level of solar export reduction increases with averaging across the solar window, but is roughly 1 kW less with a heat pump storage hot water cylinder than with a resistive storage hot water cylinder, due to the coefficient of performance of the heat pump and lower power demand. Figure 9 shows the resulting solar export profile.

Table 4: Estimated solar export reduction available (kW) from stated solar AC capacity.

		Resistive storage hot water heating, 3.7 kW EV charger		Heat pump storage hot water heating	
	10 kWh battery	10 kWh battery, 10 kWh hot water diversion, and 6 kWh EV charging via diversion	10 kWh battery, 10 kWh hot water and 6 kWh EV charging averaged over day	10 kWh battery, 3.3 kWh hot water diversion, and 6 kWh EV charging via diversion	10 kWh battery, 3.3 kWh hot water and 6 kWh EV charging averaged over day
Column reference	**1**	**2**	**3**	**4**	**5**
Whakatane	2.7	3.0	5.0	2.7	4.1
Auckland	3.1	3.2	5.2	3.1	4.4
Hamilton	2.8	2.9	5.1	2.8	4.2
Tauranga	2.7	2.8	4.9	2.7	4.0
Gisborne	2.7	2.8	4.9	2.7	4.0
Napier	2.7	2.8	4.9	2.7	4.1
New Plymouth	2.6	2.6	4.8	2.6	3.9
Whanganui	2.6	2.6	4.8	2.6	3.9
Wellington	2.6	2.6	4.8	2.6	3.9
Richmond	2.8	2.9	5.0	2.9	4.1
Nelson	2.7	2.8	4.8	2.7	4.0
Blenheim	2.6	2.6	4.7	2.6	3.9
Greymouth	2.7	2.8	4.9	2.7	4.1
Christchurch	2.7	2.8	4.9	2.7	4.1
Dunedin	2.7	2.8	4.9	2.7	4.1
Invercargill	2.7	2.8	4.9	2.7	4.1
Central Otago District	2.8	2.8	4.9	2.8	4.1
Queenstown-Lakes District	2.8	2.9	5.0	2.9	4.2

Notes:

Network demand:	Minimum coincident P1 demand
Solar generation:	Maximum P99 daily solar energy. This percentile is used, as the solar selected is not coincident with minimum demand
Solar AC capacity	10 kW-ac
Solar tilt from horizontal:	20°
Solar orientation:	North
Solar DC:AC ratio	1.2

Assumes one hot water cylinder per building with solar

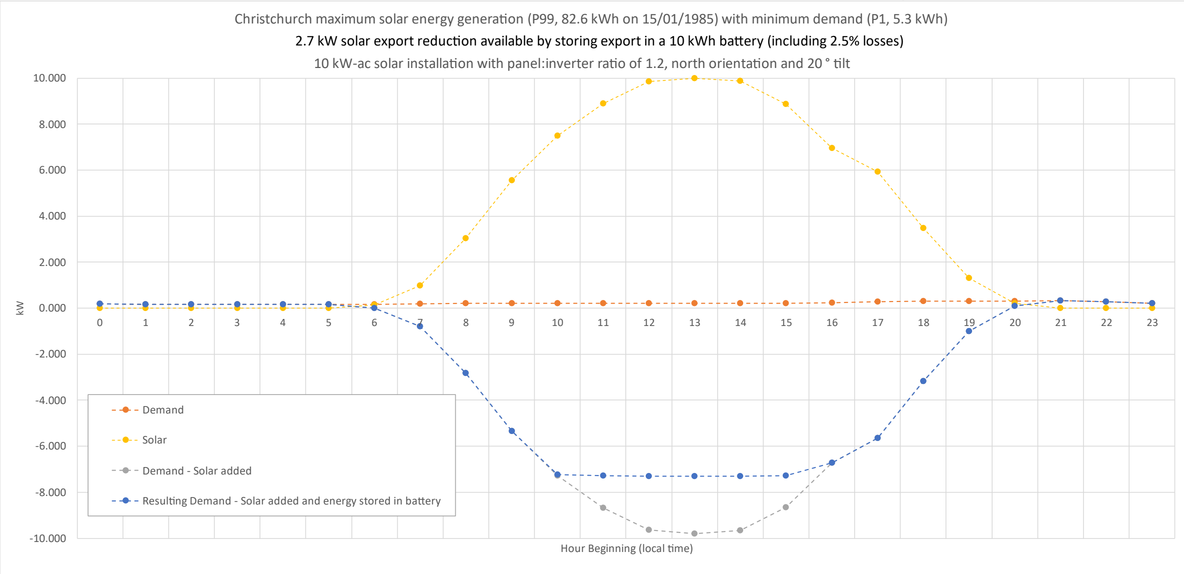


Figure 5: Example of solar export reduction in Christchurch with a battery only (Column reference 1 of Table 4).

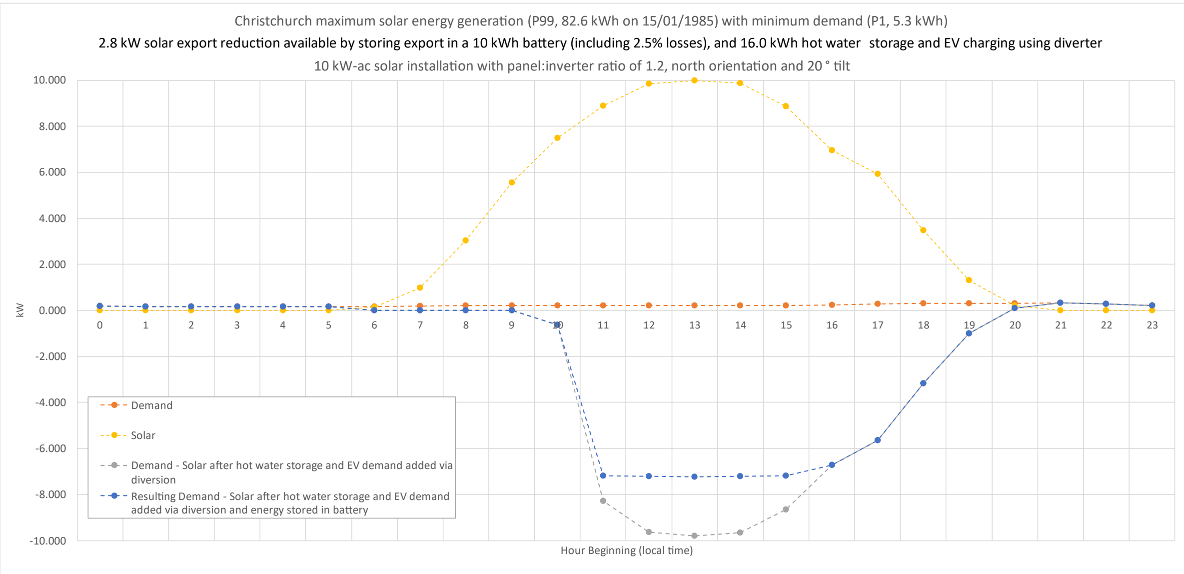


Figure 6: Example of solar export reduction in Christchurch with a battery, storage hot water heating (resistive element) and EV charging (Column reference 2 of Table 4).

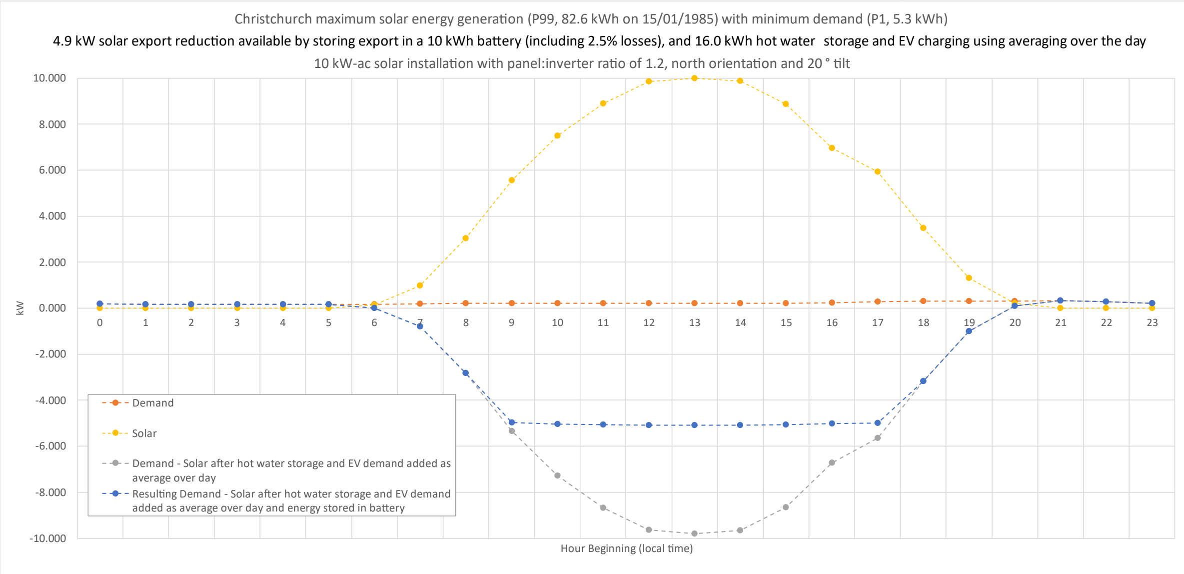


Figure 7: Example of solar export reduction in Christchurch with a battery, storage hot water heating (resistive element) and EV charging, by averaging energy to the hot water and EV over a day (Column reference 3 of Table 4).

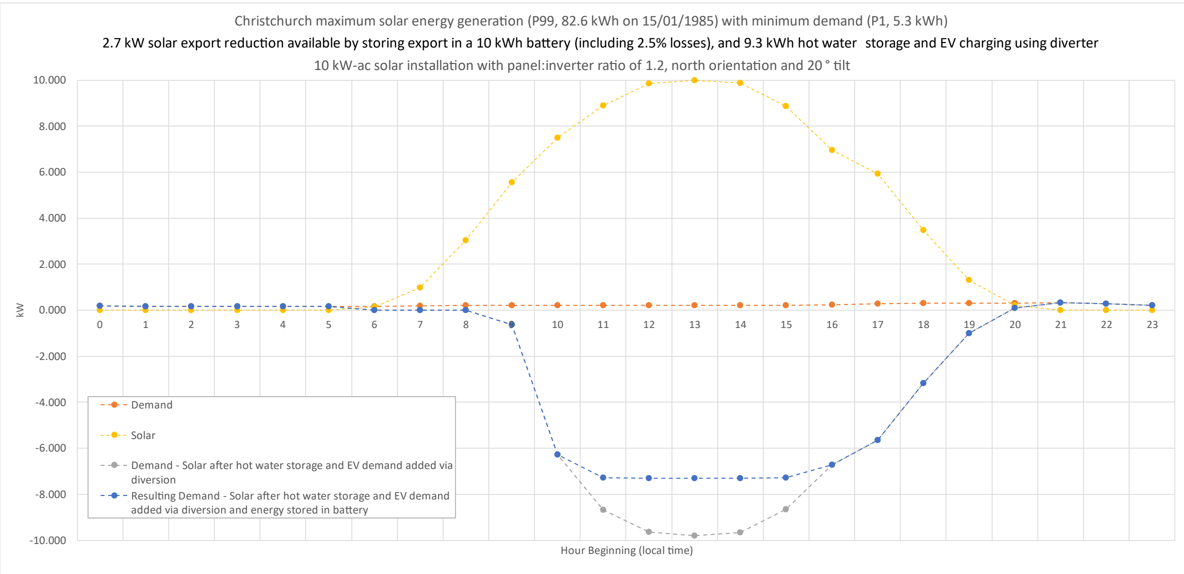


Figure 8: Example of solar export reduction in Christchurch with a battery, storage hot water heating (heat pump) and EV charging (Column reference 4 of Table 4).

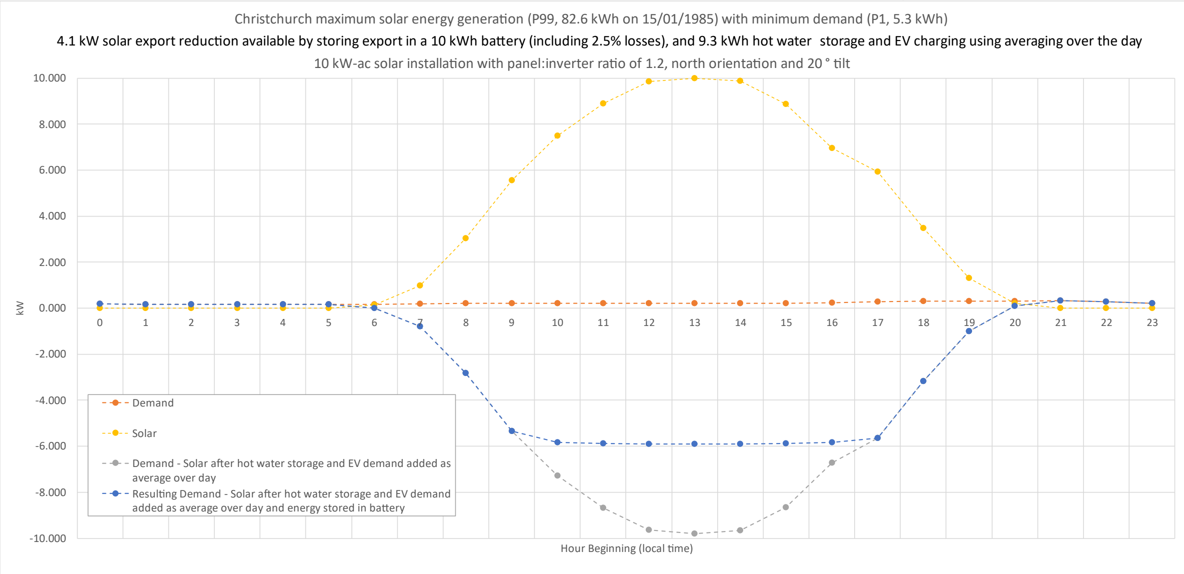


Figure 9: Example of solar export reduction in Christchurch with a battery, storage hot water heating (heat pump) and EV charging, by averaging energy to the hot water and EV over a day (Column reference 5 of Table 4).

2.3.3.1 Solar export reduction beyond 5 kW

It can be seen from the blue trace in Figure 7, for example, that due to the shape of the solar generation profile, the bulk of energy able to be exported sits in the section between the blue trace and the x-axis. This is how a relatively small amount of energy storage can have such an impact on export reduction – and it is better to store that energy and use it later than spill it. Table 5 places some actual numbers on this. In Column 2 the exported energy possible on the P99 day is given. The estimated amounts stored by the BESS, resistive storage hot water, and EV are shown in Column 4, with Column 3 showing how much can still be exported after storage and export reduction by about 5 kW (the more exact figures are in Column 1). If it is required to further curtail exports by another 2.5 kW to reach a maximum export level of 2.5 kW for example, a relatively large amount of energy must be curtailed, as shown in Column 5. In summary:

- Reducing exports from 10 kW to about 5 kW by energy storage stores about 26 kWh of energy.
- Reducing exports further from 5 kW to 2.5 kW requires roughly the same amount of energy (26 kWh) to be curtailed.

Table 5: P99 day of solar generation energy able to be exported for a 10 kW-ac system, 1.2 DC:AC ratio with P1 minimum coincident demand. The table columns refer to Figure 7. Note that this table is for a single specific day where solar energy generation is in the top 1% of days.

P99 solar generation over 52 years and P1 minimum demand	Solar export reduction available (kW) from stated solar AC capacity	Maximum possible exported energy (area between grey trace exports and x-axis) (kWh)	Energy able to be exported after export reduction by energy storage (area between blue trace exports and x-axis) (kWh)	Energy stored (area between grey trace and blue trace) (kWh)	Further energy curtailed if exports curtailed to 2.5 kW (area between reduced solar export amount after storage and export curtailment to
Column reference	**1**	**2**	**3**	**4**	**5**
Whakatane	5.0	76	50	26	21
Auckland	5.2	76	50	26	21
Hamilton	5.1	77	51	26	22
Tauranga	4.9	78	52	26	24
Gisborne	4.9	78	52	26	24
Napier	4.9	79	53	26	24
New Plymouth	4.8	81	55	26	26
Whanganui	4.8	81	55	26	26
Wellington	4.8	81	55	26	25
Richmond	5.0	79	53	26	24
Nelson	4.8	81	55	26	25
Blenheim	4.7	82	56	26	26
Greymouth	4.9	79	53	26	24
Christchurch	4.9	79	53	26	24
Dunedin	4.9	79	53	26	24
Invercargill	4.9	79	53	26	24
Central Otago District	4.9	81	55	26	25
Queenstown-Lakes District	5.0	80	54	26	24

While this may seem alarming at first, there are two mitigating factors that need to be considered:

1. This is the P99 solar generation day, combined with P1 minimum coincident demand, meaning it is close to the case of highest exports, but a low frequency occurrence – at least 1 in 100, and possibly less frequent given the combination with P1 minimum demand. Hence further curtailment should be an infrequent event. Table 6 shows the same details as Table 5, but at lower solar generation percentiles.
   Nevertheless, it is necessary to consider the case of highest exports when considering distribution network capex, as it is highly likely to be maximum solar generation that will lead to constraints and drive the need for network upgrades. Moreover, since solar generation will be largely coincident across the small spatial area of an LV network, all ICPs with solar installed will be likely to export at the same time, notwithstanding diversity of self-consumption, solar layouts, and local shading.
2. Forgoing some energy production in summer resulting from larger PV installations may not be terribly consequential, despite the higher installation cost, as it is expected that the summer energy price will be lower, potentially across the day and night if energy storage results in exports during the night. By contrast, with New Zealand's energy demand higher in winter, more solar capacity would provide more energy in winter. For example, at the uptake rates used in this study, some very approximate estimates are given below:

- At 25% penetration (2030 Early solar and battery / 2041 Late solar and battery) with average 10 kW-ac solar capacity and 2024 dwelling numbers the installed capacity of rooftop solar would be 6 GW. An estimate of energy able to be generated over May- July by this is 1,000 GWh, very roughly 9% of current energy demand over that period.
- At 50% penetration (2032 Early solar and battery / 2047 Late solar and battery) the estimated capacity would be 10 GW, able to generate about 2,000 GWh over May-June, very roughly 18% of current energy demand over that period.

- At 75% penetration (2037 Early solar and battery / 2058 Late solar and battery) the estimated capacity would be 15 GW, able to generate about 3,000 GWh, very roughly 27% of current energy demand over that period.

In this respect, installation of large capacity PV systems, combined with energy storage, may provide more benefit to New Zealand through partially meeting winter energy requirements. This assumes that networks are able to handle the amount of exports in winter expected from these solar capacities and penetration levels, something that would require further analysis.

Table 6: P90, P75, and P50 days of solar generation energy able to be exported with P1 minimum coincident demand. As demand is expected to increase as solar generation and temperatures decrease, these illustrate a worst case.

(a)

P90 solar generation over 52 years and P1 minimum demand	Solar export reduction available (kW) from stated solar AC capacity	Maximum possible exported energy (area between grey trace exports and x-axis) (kWh)	Energy able to be exported after export reduction by energy storage (area between blue trace exports and x-axis) (kWh)	Energy stored (area between grey trace and blue trace) (kWh)	Further energy curtailed if exports curtailed to 2.5 kW (area between reduced solar export amount after storage and export curtailment to
Column reference	**1**	**2**	**3**	**4**	**5**
Whakatane	6.5	63	37	26	9
Auckland	6.1	65	39	26	12
Hamilton	6.4	64	38	26	10
Tauranga	5.8	70	44	26	16
Gisborne	5.8	70	44	26	16
Napier	5.5	70	44	26	17
New Plymouth	5.5	71	45	26	16
Whanganui	5.5	71	45	26	16
Wellington	5.4	70	44	26	17
Richmond	5.4	72	46	26	19
Nelson	5.3	73	47	26	20
Blenheim	5.6	73	47	26	18
Greymouth	5.7	69	43	26	16
Christchurch	5.7	69	43	26	16
Dunedin	5.7	69	43	26	16
Invercargill	5.7	69	43	26	16
Central Otago District	5.8	70	44	26	15
Queenstown-Lakes District	5.9	69	43	26	14

(b)

P75 solar generation over 52 years and P1 minimum demand	Solar export reduction available (kW) from stated solar AC capacity	Maximum possible exported energy (area between grey trace exports and x-axis) (kWh)	Energy able to be exported after export reduction by energy storage (area between blue trace exports and x-axis) (kWh)	Energy stored (area between grey trace and blue trace) (kWh)	Further energy curtailed if exports curtailed to 2.5 kW (area between reduced solar export amount after storage and export curtailment to
Column reference	**1**	**2**	**3**	**4**	**5**
Whakatane	7.6	52	26	26	0
Auckland	7.2	54	28	26	2
Hamilton	7.3	52	26	26	1
Tauranga	6.8	59	33	26	5
Gisborne	6.8	59	33	26	5
Napier	7.1	58	32	26	3
New Plymouth	7.2	56	30	26	2
Whanganui	7.2	56	30	26	2
Wellington	7.1	56	30	26	3
Richmond	6.4	61	35	26	10
Nelson	6.2	62	36	26	11
Blenheim	6.3	61	35	26	10
Greymouth	6.8	56	30	26	5
Christchurch	6.8	56	30	26	5
Dunedin	6.8	56	30	26	5
Invercargill	6.8	56	30	26	5
Central Otago District	6.6	58	32	26	8
Queenstown-Lakes District	6.6	58	32	26	7

(c)

P50 solar generation over 52 years and P1 minimum demand	Solar export reduction available (kW) from stated solar AC capacity	Maximum possible exported energy (area between grey trace exports and x-axis) (kWh)	Energy able to be exported after export reduction by energy storage (area between blue trace exports and x-axis) (kWh)	Energy stored (area between grey trace and blue trace) (kWh)	Further energy curtailed if exports curtailed to 2.5 kW (area between reduced solar export amount after storage and export curtailment to
Column reference	**1**	**2**	**3**	**4**	**5**
Whakatane	8.7	38	12	26	0
Auckland	8.4	40	14	26	0
Hamilton	8.6	39	13	26	0
Tauranga	7.9	44	18	26	0
Gisborne	7.9	44	18	26	0
Napier	8.3	40	14	26	0
New Plymouth	8.8	36	10	26	0
Whanganui	8.8	36	10	26	0
Wellington	9.1	35	9	26	0
Richmond	8.4	42	16	26	0
Nelson	8.3	44	18	26	0
Blenheim	8.5	42	16	26	0
Greymouth	8.8	36	10	26	0
Christchurch	8.8	36	10	26	0
Dunedin	8.8	36	10	26	0
Invercargill	8.8	36	10	26	0
Central Otago District	8.4	40	14	26	0
Queenstown-Lakes District	8.5	39	13	26	0

2.4 ANSA's LV Capex Model and its use for this analysis

The models used to forecast capex from EVs, PV, and electrification demand are depicted in Figure 10. ANSA has completed constraint risk studies for three EDBs, and was able to use those results presented as a total of all EDBs, with the permission of each EDB. These are the same EDBs who contributed results to the Upper Voltage Limit study (Miller and Lemon 2024a). Since that study two of the EDBs have undertaken data quality improvements, using data quality information provided by ANSA in the first round of modelling. This has allowed for more accurate LV network models. The operation of ANSA's LV Capex Model is described in more detail in (Miller and Lemon 2024b), with information directly relevant to this study set out below.

2.4.1 Constraint risk

The results produced by ANSA's model give the risk of constraint of each asset, which results from probabilistic simulations. This includes the set of conductors and transformers that must be replaced to prevent loading constraints, and the lowest cost set of conductors that require replacement to alleviate voltage constraints. Constraint risk is a direct result of probabilistic simulations, where every combination of PV and EV location, phase connection (if unknown for an ICP), and maximum and minimum coincident demand (if unknown for an ICP), is effectively modelled. To achieve this, Monte Carlo modelling is employed, since it is practically impossible to model every possible combination in networks with more than about 10 ICPs. Different Monte Carlo cases encompass a range of different network configurations and results. For example, in some cases PV and EV will be located closer to the transformer and be more uniformly balanced across phases, resulting in fewer voltage constraints. In other cases, the PV and EV may be located closer to the ends of each circuit, and may be highly imbalanced across phases, resulting in higher voltage and conductor loading constraints.

To obtain a single capex value, a constraint risk threshold is set. This defines the percentage of all simulated cases in which an element must be constrained before it is flagged as requiring upgrade. In this analysis a threshold of 80% is used, rather than 100%, since 100% would give the most optimistic (lowest capex) results, which may be unrealistic. A very low constraint risk threshold is not used because it is assumed that EDBs can mitigate or avoid low risk constraints through actions that do not involve significant capex expenditure. For example, moving ICPs between phases to reduce imbalance, or changing the topology of networks by opening/closing switches to move ICPs between circuits or networks to prevent smaller voltage and loading constraints. To investigate the sensitivity of the results to this constraint risk threshold, the study includes results for the Base Case at a lower (60%) and higher (100%) constraint risk threshold.

2.4.2 Modelling of every LV network and every element

The studies that produce the constraint risk results are termed Impact Studies. These studies involve modelling every LV network, and element within those networks, including conductors (overhead lines and underground cables), distribution transformers, service mains, earthing, ICPs, and existing PV. All phases are modelled to capture the effects of imbalance across phases, with the phase connectivity of service mains and ICPs being used when available.

Running the power flow simulations for these studies requires exact and detailed electrical models. These are constructed using a machine learning model developed by ANSA called ANSA-Network. ANSA-Network determines element connectivity from spatial geographic information system (GIS) data and available topological information (such as switch states and ICP assignment), and electrical conductor and transformer parameters (such as impedance and current/power rating) from GIS data and asset databases. Any missing or erroneous connectivity or electrical data is imputed by the machine learning model using models of known good networks. A list of all issues found in each network is constructed and used to determine a data quality score for each network. This can be provided to EDBs to allow them to undertake prioritised data quality improvement.

In the Impact Studies, the constraint risk is calculated for each element in each network for every EV and PV penetration level between 0 and 100% for a range of different input parameters, including:

- Transformer summer and winter loading limits
- Upper voltage limits (+6%, +10%)
- EV charger rating (1.8 kW, 3.7 kW, 7.4 kW)
- PV inverter rating (2.5 kW, 5.0 kW, 7.5 kW, 10.0 kW)
- Volt-VAr level
- EV charging schedule

While EV shifting and export reduction were considered in this study, Volt-VAr control was not modelled due to concern over high reactive power flows resulting from such high PV uptake and its effect on voltages in the upstream sub-transmission and transmission networks, as well as the desire to understand how energy storage might be used to reduce capex from high PV uptake.

Since the upper voltage limit is to be increased to 230 V +10%, modelling is carried out using a +10% voltage limit. However, modelling is also carried out at a +6% limit as a variation from a base case to give an indication of the capex required at the existing voltage limit of +6%, and to highlight the benefits of moving to a higher voltage limit.

2.4.3 LV Capex Model functions

The LV Capex Model is capable of undergrounding overhead conductors that are constrained, and replacing entire circuits or LV networks if a section of conductor is found to be constrained. However, both functions are turned off in this study, as these are functions that might be used by an EDB for specific network planning, rather than an explorative study such as this.

The LV Capex Model is also able to decide to split an LV network into two separate LV networks by adding a second transformer, MV conductor, and bus gear, if the resultant cost is lower than upgrading conductors. This function is turned on in this study, as it can result in significant cost reductions when significant proportions of a network are constrained.

2.4.4 Asset costs

For the purpose of this analysis, the conductor replacement costs outlined in Table 7 are used.

Table 7: Conductor replacement costs.

Cost category	Conductor kind	Fixed costs, per section ($)	Variable cost, per length ($/m)
Urban	Underground Cable	2,000	2,000
Urban	Overhead Line	1,000	150
Rural	Underground Cable	3,000	1,000
Rural	Overhead Line	1,500	150

Transformer replacements costs start at $100,000 for 50 kVA urban and rural pole mounted, and $120,000 for ground mounted urban and rural. Costs climb steadily to $285,000 for 1,000 kVA urban and rural ground mounted transformers.

2.4.5 Other LV Capex Model inputs

A number of LV Capex Model inputs are adjusted for each scenario and case. These are addressed in the next section.

2.4.6 Base Cases and Test Cases considered

To quantify the LV network capex that can be avoided by the means set out in Section 2.2.2 Points 1 and 2, two base cases were first established and run using the LV Capex Model for each scenario of electrification. They are:

- Unmanaged PV Export Base Case

  To understand the impact of PV exports on capex and, in conjunction with the test cases, how to reduce PV exports and thereby capex back to a level similar to the case with no PV or BESS. This tests Section 2.2.2 Point 1 and identifies a test case for use with the next base case.

  This uses a 10% upper voltage limit and the Partially Shifted 3.7 EV charging schedule and capacity. As outlined in Section 2.1.1, 10 kW-ac PV and 10 kWh BESS are assumed.

- Unmanaged Electrification Base Case

  To understand the impact of reducing peak demand increase from electrification above existing levels by using a BESS, complemented by PV. After establishing that additional capex from PV exports can be largely reduced with appropriate storage and curtailment using the Unmanaged PV Export Base Case and test cases, this tests Section 2.2.2 Point 2.

  This also uses a 10% upper voltage limit and the Partially Shifted 3.7 EV charging schedule and capacity.

A number of variations from these base cases were also run using the LV Capex Model to understand the sensitivity of the results and the impact of different parameters, including:

  Variations on Unmanaged PV Export Base Case
  - +6% upper voltage limit, to understand the avoided capex by raising the upper voltage limit.
  - Upper (100%) and lower (60%) constraint risk thresholds, to understand the sensitivity to constraint risk threshold.

  Variation on Unmanaged Electrification Base Case

  - All EV charging is moved to around 6pm (the 6pm Only 3.7 charging case) to understand the impact on capex from unmanaged EV charging.

Various test cases were then run and the difference between the Unmanaged PV Exports Base Case and each test case were considered. This gave the avoided capex of each test case for each scenario.

The test cases investigated are:

1. BESS used to reduce midday summer exports by 2.5 kW

   Consistent with the discussion in Section 2.3.3, this is to test the capex reduction from a BESS reducing exports on a maximum PV generation day in summer around midday.

2. All EV charging moved from 6pm and 9pm to off-peak

   While most EV charging is already scheduled to off-peak in the base case, this is to understand the capex reduction possible by optimally scheduling *all* EV charging to off-peak times.

3. The combination of 1 and 2, where midday PV exports are reduced by 2.5 kW and *all* EV charging is moved to off-peak

4. BESS, hot water storage, and EV charging reduce midday summer exports by 5 kW, with *all* EV charging moved to off-peak.

   Also consistent with the discussion in Section 2.3.3, this is to test the capex reduction from a combination of BESS and other storage reducing PV exports on a maximum PV generation day in summer around midday.

5. In addition to 4, a further reduction in PV exports to reach a 7.5 kW reduction.

   To understand the reduction in capex possible from 4 and further export reduction from curtailment.

All test cases include management of peak demand increase from electrification using the BESS. This allows the appropriate test case to then be tested against the Unmanaged Electrification Base Case, to understand the avoided capex from reducing peak demand increases.

Network data (includes conductor types where available, transformer ratings and taps settings)

Demand by consumer or consumer type

Forecast EV uptake, PV uptake, and gas-to-electricity demand transition (if studied). Forecasts by default apply to the whole network level, but can be given to lower levels such as territory, SA2, or for individual LV networks

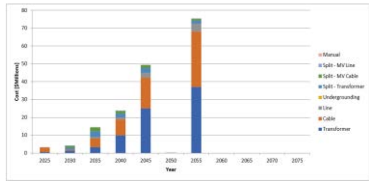
Asset replacement costs for transformers, cables, and lines for urban and rural

(1)
GIS to electrical network models of each LV network & data quality assessment
(ANSA-Network)

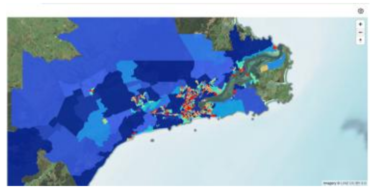
(2)
Impact studies
& Hosting Capacity
of EV, gas-to-electricity, PV
(ANSA-EV, ANSA-PV)

(3)
Assess constraint risk, optimise upgrades & count constrained elements

(4)
LV Capex Model
Assigns costs to constrained elements for forecast scenarios and calculates total cost



LV Visibility Dashboard application giving constraint maps, heat maps, etc



AI based model develops exact electrical models of each LV network, enabling power flow simulations to be performed. Where connectivity is ambiguous and/or conductor information is unknown, the model employs machine learning to impute connections and/or conductor ratings and provides data quality for each LV network

Figure 10: ANSA's LV modelling tools used.

3 Results and Discussion

Capex results for the base cases, as well as the difference in capex (capex delta or avoided capex) for a number of test cases, are presented and discussed in this section. In all results, unless otherwise stated in a column heading:

- PV and BESS uptake is the 'Solar and battery' scenario given in the results
- EV uptake is the 'Electrification (including EV)' scenario given in the results
- The upper voltage limit is 10%
- The EV charger rating is 3.7 kW
- The EV charging schedule is 'Partially shifted 3.7' (5% at 6pm, 10% at 9pm, 20% at 12am, and 20% at 3am), as discussed in Section 2.3.1
- The PV inverter rating is 10 kW-ac
- The constraint risk threshold is 80%
- The summer transformer rating is its nameplate rating, and the winter transformer rating is 130% of its nameplate rating
- The Volt-VAr inverter response mode is off (no reactive power is injected or absorbed to control voltage)

Results are also initially given as the sum of capex at each year discounted to a single value. This allows for easier comparison between cases, with a single capex value per case and scenario. However, it also incorporates the time value of money, ensuring that capex that occurs earlier is weighted more than capex that occurs later. More detailed capex results are then given by year.

3.1 Base case total capex

Capex results discounted to a present cost are tabulated in Table 8 for a number of cases. With reference to Table 8 and each case:

1. Unmanaged PV Export Base Case (+10% upper voltage limit)

   This roughly halves the capex compared to the +6% upper voltage limit case (in the next point). The halving is achieved through fewer voltage constraints, although conductor constraints are still experienced. The modelling of spatial diversity in ANSA's model gives a more accurate indication of capex reduction from the increased voltage limit. Models that assume PV export is uniformly distributed across ICPs, and which thus do not take into account the impacts of spatial diversity and imbalance, may show a higher reduction.

   As shown in Figure 11, increasing the upper voltage limit reduces the number of conductor constraints compared to the +6% voltage limit in Figure 12, because fewer conductors require replacement to alleviate voltage constraints. This in turn results in fewer LV networks being split, with it being more cost effective to replace overloaded transformers and conductors individually when thermal constraints occur.

2. +6% upper voltage limit column

   This has been included purely to give an indication of the benefit from increasing the upper voltage limit from +6% to +10%. Evident are:

   - Late solar and battery discounted results are roughly half, because these costs occur later, as shown in Table 9(a).

- There is not much increase in costs with either electrification (early electrification compared to late electrification) or peak demand growth. This is because PV exports are the major source of constraint. The high export levels lead to conductor overloading and extreme overvoltage constraints, which in turn require significant conductor upgrades and network splitting to alleviate, as shown in Figure 12. Conductors are overloaded due to the unmanaged PV systems exporting nearly 10 kW without diversity back through the network.

3. Unmanaged PV Export Base Case with 60% constraint risk threshold

   Lowering the constraint risk threshold would normally be expected to substantially increase the capex, with more assets in each LV network being flagged as constrained and requiring replacement. However, comparing the 60% and 80% constraint risk threshold results for the Unmanaged PV Export Base Case shows that the 60% constraint risk threshold capex values are only 10-15% higher. This is due to the magnitude and scale of the PV uptake resulting in a large proportion of all simulated configurations showing constraints. At high uptake levels, where the majority of ICPs have a PV system, there are fewer different spatial configurations of PV and thus less variability in voltage and loading levels across cases. For example, at 10% PV uptake there is more likelihood of clusters of PV occurring at the start or end of each circuit, which have very different constraint characteristics. However, at 80% PV uptake the PV export will be relatively uniformly distributed across ICPs, with fewer extreme cases.

   The magnitude of the PV impacts is evident in the difference between the Unmanaged PV Export Base Case and the Unmanaged Electrification Base Case (that has no PV or BESS). Once again, nearly 10 kW coincident export from many ICPs leads to many constraints, which largely disappear in the Unmanaged Electrification Base Case, where there is no PV export and relatively few constraints from EV charging which is largely scheduled away from 6pm.

4. Unmanaged PV Export Base Case with 100% constraint risk threshold

   Capex is lower, but still very high, indicating that many constraints exist in every Monte Carlo case. This will also largely be due to coincident exports from PV and the small number of different spatial PV and EV configurations at high uptake levels. Note that at a constraint risk threshold of 100%, an element has to be constrained or flagged as requiring replacement in every simulated Monte Carlo case before it is considered for replacement in the LV Capex Model.

5. Unmanaged Electrification Base Case (No PV or BESS)

   A number of observations are made:

   - There is some capex increase in early electrification compared to late electrification, purely because constraints and capex occur earlier.

   - There is also a clear increase in capex as peak demand grows. Capex in this case is limited by the 130% winter transformer loading limit. Electrification results are very sensitive to the transformer loading limit. If reduced from 130% to 100% there is a significant increase in capex as shown in (b), almost double in the Early electrification scenarios. As demand increases, and as demand is shifted away from peak demand, it may result in transformers being overloaded for longer, thereby reducing their lifetime. Thus, the suitability of higher transformer loading limits may have to be reviewed at high electrification levels.

   - In general, the capex with only electrification and no PV is a lot lower than with electrification and PV. This is due to the default EV schedule (Partially shifted 3.7 EV) being almost entirely shifted away from the peak demand period between 6pm and 9am to between 12am and 6am. At 100% EV uptake only 5% of ICPs actively charge an EV at 6pm, and 10% at 9pm, resulting in a relatively small ADMD increase at these times of 0.185 kW (5% of 3.7 kW) and 0.37 kW (10% of 3.7 kW).

6. No PV or BESS, EV charging all around 6pm (54% of EVs charging)

   Moving all charging to 6pm, even with 54% charging diversity, results in a large increase in capex due to the addition to peak demand. The capex is due to both transformer and cable loading constraints. This emphasises the importance of moving EV charging away from the peak as much as possible (in the Unmanaged Electrification Base Case (No PV or BESS) only 5% of available EVs are charging at 6pm, whereas in this case 54% of available EVs are charging at 6pm).

Table 9 shows the annual forecast capex for the Base Cases for each of the electrification, solar and battery and peak demand growth scenarios. In the Unmanaged PV Export Base Case of Table 9(a), the timing of the capex is largely determined by the timing of the solar and battery uptake. This is due to the magnitude of the coincident PV exports compared to the relatively small increase in ADMD by the shifted EV charging. This changes at higher levels of peak demand growth, which start having a larger impact on when capex occurs. For example, in the early electrification, late solar and battery scenario at 2 kW peak demand growth, the capex exhibits a more bimodal profile with a large amount of early spend due to electrification followed by a later peak in spend due to high levels of PV. Averaging the discounted capex over all years, the per ICP capex requirements are in the order or $200-$300 when PV exports and electrification peak demand are unmanaged. While considerable, it is roughly half what the capex would be if the upper voltage limit is not raised.

In the Unmanaged Electrification Base Case of Table 9(b), the timing of capex is determined by the timing of electrification, as expected.

Across all scenarios capex can be observed in 2025 for both base cases. This is due to networks that are already constrained, or which are near constrained, and how the network splitting function works in the LV Capex Model. As shown in Figure 11 and Figure 12, the majority of these early costs are due to splitting LV networks and installing a new distribution transformer. This is because the model determines whether to split a network based on the cost of splitting the network relative to the total cost of future upgrades on the network. For a small number of networks, the model determines it is more cost effective overall to split those networks now, to handle both the present constraints and the forecast future constraints, rather than replacing some conductors and transformers now and then having to replace them again or split the network later. This effectively results in some of the future forecast capex being brought forward to the present year due to the very high level of constraints predicted in those networks. In practice EDBs are likely to take a more conservative approach to upgrading such networks, potentially reconfiguring the networks to reduce constraints as much as possible, monitoring the networks more closely for near-term issues, or accelerating asset renewal for those networks.

Table 10 gives the absolute capex results in the same form as Table 8 but separated out by urban and rural LV networks. Whether an LV network is urban or rural is determined based on whether the majority of the ICPs within the LV network fall within an urban or rural geographic area, as defined by (Statistics New Zealand 2024). Note that because the results are given as $/ICP, and the number of ICPs varies between urban and rural areas across EDBs, the total capex figures for all LV networks in Table 8 are equal to the weighted sum of the separate urban/rural results (weighted by the ICP counts) not to the direct sum.

The capex requirements set out in these results need to be considered in the context of roughly $635m spent on distribution network capex in 2024 (Commerce Commission 2025), equating to roughly $277 per ICP. Therefore, an increase of several hundred dollars per ICP per year, as noted above, is significant. However, the $635m network capex spend in 2024 was largely on renewals (85% on renewals, 15% on network growth), and there is expected to be overlap between renewals and growth to meet the electrification scenarios. Quantification of these would require further work. Nevertheless, the results so far show significant scope for LV network capex reductions by carefully scheduling EV charging and using battery systems and other energy storage to reduce PV exports. Results in the next section show further scope to reduce capex from increased demand due to electrification.

Table 8: Absolute capex in $/ICP, with capex at each year discounted to a present cost at 5% per annum. Results are across the three EDBs for both urban and rural LV networks. The orange and blue shaded columns are used in subsequent sections to compare with test cases. The other columns in these tables are variations from the base cases for interest. The peak demand growth of 0 kW, 1kW, and 2 kW is per ICP.

(a) Winter transformer loading limit set at 130% of the transformers' nameplate rating

Peak demand growth (kW)	Electrification (including EV)	Solar and battery	Total capex ($ per ICP), discounted at 5% per annum					
			Unmanaged PV Export Base Case To test Section 2.2.2 Point 1	Variations on 'Unmanaged PV Export Base Case'			**Unmanaged Electrification Base Case To test Section 2.2.2 Point 2**	Variation on 'Unmanaged Electrification Base Case'
			+10% upper voltage limit Partially Shifted 3.7 EV	+6% upper voltage limit Partially shifted 3.7 EV	60% constraint risk threshold +10% upper voltage limit Partially shifted 3.7 EV	100% constraint risk threshold +10% upper voltage limit Partially shifted 3.7 EV	**No PV or BESS Partially Shifted 3.7 EV**	No PV or BESS EV charging all around 6pm (6pm Only 3.7 EV)
0	Late electrification	Late solar and battery	2,524	5,306	2,879	1,694	184	821
		Early solar and battery	5,216	9,653	5,771	3,809	184	821
	Early electrification	Late solar and battery	2,545	5,322	2,914	1,694	205	1,351
		Early solar and battery	5,218	9,652	5,771	3,809	205	1,351
1	Late electrification	Late solar and battery	2,528	5,310	2,888	1,694	272	1,161
		Early solar and battery	5,216	9,652	5,772	3,809	272	1,161
	Early electrification	Late solar and battery	2,622	5,372	3,024	1,708	358	1,869
		Early solar and battery	5,218	9,654	5,774	3,810	358	1,869
2	Late electrification	Late solar and battery	2,612	5,355	3,001	1,718	1,039	2,137
		Early solar and battery	5,218	9,654	5,776	3,809	1,039	2,137
	Early electrification	Late solar and battery	3,345	5,864	3,807	2,141	1,696	3,314
		Early solar and battery	5,226	9,658	5,788	3,813	1,696	3,314

(b) Winter transformer loading limit set at 100% of the transformers' nameplate rating

Peak demand growth (kW)	Electrification (including EV)	Solar and battery	Total capex ($ per ICP), discounted at 5% per annum Winter transformer limit set to 100% of rated capacity					
			Unmanaged PV Export Base Case To test Section 2.2.2 Point 1	Variations on 'Unmanaged PV Export Base Case'			**Unmanaged Electrification Base Case To test Section 2.2.2 Point 2**	Variation on 'Unmanaged Electrification Base Case'
			+10% upper voltage limit Partially Shifted 3.7 EV	+6% upper voltage limit Partially shifted 3.7 EV	60% constraint risk threshold +10% upper voltage limit Partially shifted 3.7 EV	100% constraint risk threshold +10% upper voltage limit Partially shifted 3.7 EV	**No PV or BESS Partially Shifted 3.7 EV**	No PV or BESS EV charging all around 6pm (6pm Only 3.7 EV)
0	Late electrification	Late solar and battery	2,624	5,413	3,016	1,748	314	1,311
		Early solar and battery	5,274	9,707	5,841	3,847	314	1,311
	Early electrification	Late solar and battery	2,657	5,441	3,072	1,748	345	2,032
		Early solar and battery	5,276	9,709	5,843	3,847	345	2,032
1	Late electrification	Late solar and battery	2,632	5,419	3,034	1,748	492	1,687
		Early solar and battery	5,274	9,708	5,842	3,847	492	1,687
	Early electrification	Late solar and battery	2,808	5,553	3,273	1,782	657	2,564
		Early solar and battery	5,276	9,710	5,846	3,847	657	2,564
2	Late electrification	Late solar and battery	2,799	5,523	3,245	1,800	1,554	2,717
		Early solar and battery	5,280	9,715	5,852	3,848	1,554	2,717
	Early electrification	Late solar and battery	3,776	6,302	4,263	2,500	2,373	3,942
		Early solar and battery	5,295	9,720	5,875	3,857	2,373	3,942

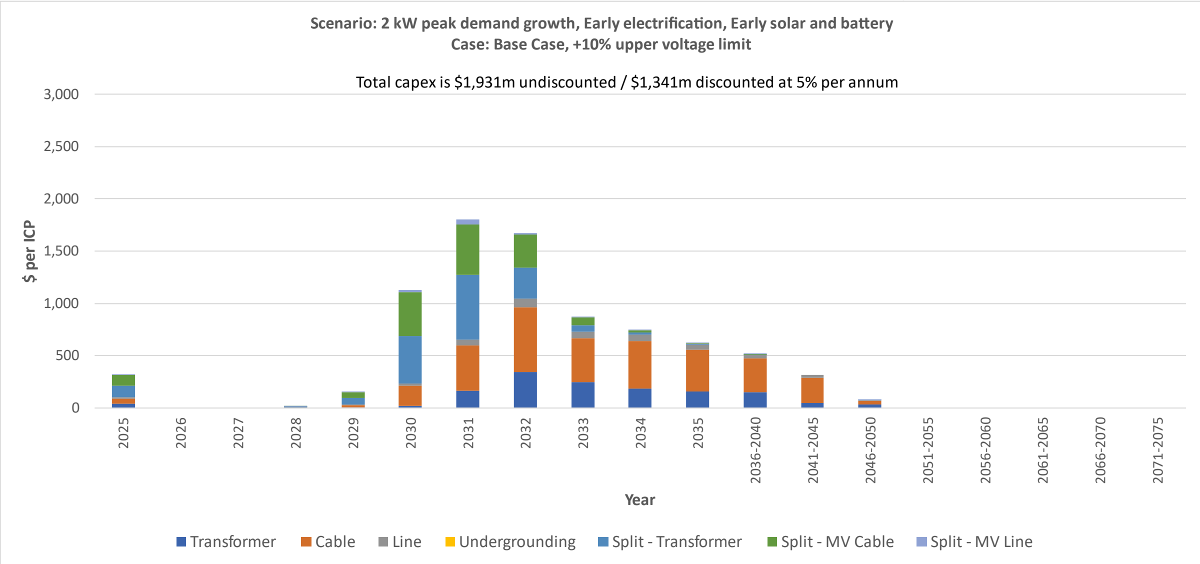


Figure 11: Base Case results with the upper voltage limit at +10%. Results are across the three EDBs for both urban and rural LV networks.

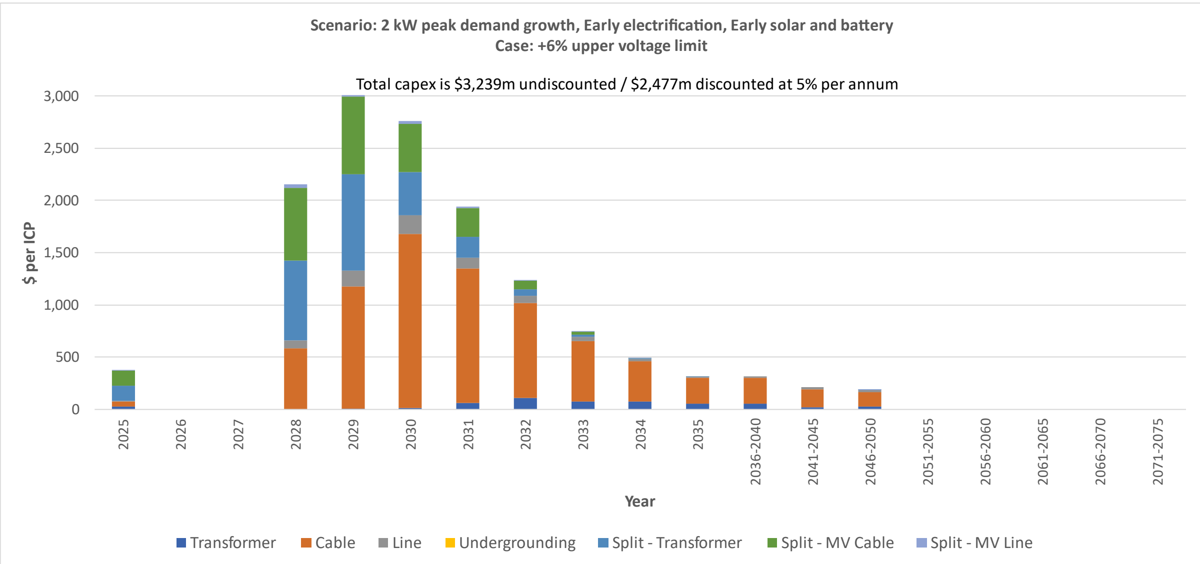


Figure 12: Base Case results with the upper voltage limit at +6%. Results are across the three EDBs for both urban and rural LV networks.

Table 9: Absolute capex in $/ICP for (a) the Unmanaged PV Export Base Case of Table 8(a) and (b) the Unmanaged Electrification Base Case of Table 8(a). Results are across the three EDBs for both urban and rural LV networks. The peak demand growth of 0 kW, 1kW, and 2 kW is per ICP.

(a) Unmanaged PV Export Base Case

Peak demand growth (kW)	Electrification (including EV)	Solar and battery	Unmanaged PV Export Base Case capex ($ per ICP) (+10% upper voltage limit, PV and BESS as given in the 'Solar and battery' scenario, EV charging using the 'Partially Shifted 3.7 EV' schedule)																		
			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036-2040	2041-2045	2046-2050	2051-2055	2056-2060	2061-2065	2066-2070	2071-2075
0	Late electrification	Late solar and battery	282	0	0	0	1	0	3	3	0	0	0	401	2,909	2,022	1,026	346	224	146	30
		Early solar and battery	280	0	0	5	136	1,018	1,670	1,540	796	679	566	471	291	69	0	0	0	0	0
	Early electrification	Late solar and battery	282	0	1	3	3	11	8	16	4	19	4	375	2,881	2,020	1,026	346	224	146	30
		Early solar and battery	280	0	1	8	138	1,017	1,671	1,537	796	680	566	471	290	69	0	0	0	0	0
1	Late electrification	Late solar and battery	282	1	0	0	3	0	1	6	8	0	6	388	2,904	2,021	1,026	346	224	146	30
		Early solar and battery	281	0	0	5	135	1,019	1,670	1,540	797	680	566	471	291	69	0	0	0	0	0
	Early electrification	Late solar and battery	283	0	3	1	23	32	96	60	35	48	19	242	2,784	2,011	1,025	346	224	146	30
		Early solar and battery	281	0	0	8	138	1,017	1,671	1,538	796	680	566	470	290	69	0	0	0	0	0
2	Late electrification	Late solar and battery	287	1	9	8	6	12	31	75	53	16	16	416	2,708	2,004	1,023	346	223	146	30
		Early solar and battery	285	0	0	5	135	1,016	1,669	1,540	797	679	566	470	291	69	0	0	0	0	0
	Early electrification	Late solar and battery	292	13	11	77	128	295	419	564	404	255	136	5	1,338	1,831	1,006	341	221	145	30
		Early solar and battery	294	0	0	12	142	1,035	1,648	1,530	793	678	566	470	290	69	0	0	0	0	0

(b) Unmanaged Electrification Base Case

Peak demand growth (kW)	Electrification (including EV)	Solar and battery	Unmanaged Electrification Base Case capex ($ per ICP) (No PV or BESS, EV charging using the 'Partially Shifted 3.7 EV' schedule)																		
			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036-2040	2041-2045	2046-2050	2051-2055	2056-2060	2061-2065	2066-2070	2071-2075
0	Late electrification	Late solar and battery	164	0	0	0	1	0	1	0	0	0	0	12	10	19	12	8	0	0	0
		Early solar and battery	164	0	0	0	1	0	1	0	0	0	0	12	10	19	12	8	0	0	0
	Early electrification	Late solar and battery	164	0	1	1	0	5	7	10	7	18	6	7	0	0	0	0	0	0	0
		Early solar and battery	164	0	1	1	0	5	7	10	7	18	6	7	0	0	0	0	0	0	0
1	Late electrification	Late solar and battery	173	0	1	0	1	0	9	2	3	5	7	70	45	57	30	24	13	0	0
		Early solar and battery	173	0	1	0	1	0	9	2	3	5	7	70	45	57	30	24	13	0	0
	Early electrification	Late solar and battery	173	1	1	9	9	31	60	24	56	23	19	35	2	0	0	0	0	0	0
		Early solar and battery	173	1	1	9	9	31	60	24	56	23	19	35	2	0	0	0	0	0	0
2	Late electrification	Late solar and battery	222	7	4	8	19	23	64	25	23	30	80	389	524	493	206	160	72	0	0
		Early solar and battery	222	7	4	8	19	23	64	25	23	30	80	389	524	493	206	160	72	0	0
	Early electrification	Late solar and battery	229	6	24	73	77	227	304	408	417	214	146	212	13	1	0	0	0	0	0
		Early solar and battery	229	6	24	73	77	227	304	408	417	214	146	212	13	1	0	0	0	0	0

Table 10: Absolute capex in $/ICP, with capex at each year discounted to a present cost at 5% per annum. Results are across the three EDBs. The peak demand growth of 0 kW, 1kW, and 2 kW is per ICP.

(a) Urban LV networks

Peak demand growth (kW)	Electrification (including EV)	Solar and battery	Total capex ($ per ICP), discounted at 5% per annum					
			Unmanaged PV Export Base Case To test Section 2.2.2 Point 1	Variations on 'Unmanaged PV Export Base Case'			**Unmanaged Electrification Base Case To test Section 2.2.2 Point 2**	Variation on 'Unmanaged Electrification Base Case'
			+10% upper voltage limit Partially Shifted 3.7 EV	+6% upper voltage limit Partially shifted 3.7 EV	60% constraint risk threshold +10% upper voltage limit Partially shifted 3.7 EV	100% constraint risk threshold +10% upper voltage limit Partially shifted 3.7 EV	**No PV or BESS Partially Shifted 3.7 EV**	No PV or BESS EV charging all around 6pm (6pm Only 3.7 EV)
0	Late electrification	Late solar and battery	2,577	5,334	2,922	1,739	171	830
		Early solar and battery	5,319	9,584	5,820	3,914	171	830
	Early electrification	Late solar and battery	2,598	5,350	2,957	1,739	193	1,378
		Early solar and battery	5,321	9,582	5,820	3,913	193	1,378
1	Late electrification	Late solar and battery	2,581	5,338	2,931	1,739	263	1,180
		Early solar and battery	5,319	9,583	5,821	3,914	263	1,180
	Early electrification	Late solar and battery	2,677	5,402	3,072	1,754	351	1,911
		Early solar and battery	5,321	9,584	5,822	3,915	351	1,911
2	Late electrification	Late solar and battery	2,666	5,383	3,047	1,764	1,056	2,169
		Early solar and battery	5,321	9,584	5,825	3,914	1,056	2,169
	Early electrification	Late solar and battery	3,423	5,903	3,872	2,200	1,734	3,363
		Early solar and battery	5,328	9,588	5,836	3,917	1,734	3,363

(b) Rural LV networks

Peak demand growth (kW)	Electrification (including EV)	Solar and battery	Total capex ($ per ICP), discounted at 5% per annum					
			Unmanaged PV Export Base Case To test Section 2.2.2 Point 1	Variations on 'Unmanaged PV Export Base Case'			**Unmanaged Electrification Base Case To test Section 2.2.2 Point 2**	Variation on 'Unmanaged Electrification Base Case'
			+10% upper voltage limit Partially Shifted 3.7 EV	+6% upper voltage limit Partially shifted 3.7 EV	60% constraint risk threshold +10% upper voltage limit Partially shifted 3.7 EV	100% constraint risk threshold +10% upper voltage limit Partially shifted 3.7 EV	**No PV or BESS Partially Shifted 3.7 EV**	No PV or BESS EV charging all around 6pm (6pm Only 3.7 EV)
0	Late electrification	Late solar and battery	1,668	4,838	2,182	965	390	683
		Early solar and battery	3,532	10,781	4,971	2,099	390	683
	Early electrification	Late solar and battery	1,680	4,853	2,199	965	402	907
		Early solar and battery	3,536	10,785	4,975	2,099	402	907
1	Late electrification	Late solar and battery	1,673	4,845	2,185	965	432	841
		Early solar and battery	3,532	10,781	4,971	2,099	432	841
	Early electrification	Late solar and battery	1,712	4,885	2,256	969	465	1,184
		Early solar and battery	3,536	10,785	4,975	2,099	465	1,184
2	Late electrification	Late solar and battery	1,720	4,888	2,257	972	772	1,618
		Early solar and battery	3,536	10,785	4,977	2,099	772	1,618
	Early electrification	Late solar and battery	2,069	5,234	2,741	1,175	1,082	2,514
		Early solar and battery	3,552	10,801	5,000	2,099	1,082	2,514

3.2 Test cases with capex delta from the Base Case

Sub-section 3.2.1 of this section tests the avoided capex from PV exports, by use of storage to reduce midday exports, consistent with Section 2.2.2 Point 1. After establishing a level of PV export reduction that largely avoids capex from PV exports in Sub-section 3.2.1, Sub-section 3.2.2 then tests the avoided capex from electrification, consistent with Section 2.2.2 Point 2.

3.2.1 Avoided capex from PV Exports

The reduction in capex (avoided capex) from the Unmanaged PV Export Base Case of Table 8 are given in Table 11. Each of these is discussed below:

1. BESS used to reduce midday summer exports by 2.5 kW

   Clearly there is a large reduction in capex as PV exports are reduced. Consistent with earlier discussion, this is due to the reduction of coincident exports. Results by year are given in Table 12.

2. All EV charging moved from 6pm & 9pm to off-peak

   It is initially surprising to see little reduction in capex by moving all EV charging. However, the amount on at 6pm and 9pm was low to begin with (given in the schedule in Section 2.3.1), and as discussed previously, it is PV export that is the major constraint, overshadowing any capex increase due to EVs.

   Under 'Early electrification' and 'Late solar and battery' more reduction can be seen, particularly as peak demand increases from electrification. This is because the increase in coincident peak demand, and consequent loading constraints, occur before enough batteries are installed to appreciably reduce the demand.

   Seen in conjunction with the 'No PV or BESS, EV charging all around 6pm' variation on the Unmanaged Electrification Base Case from Table 8, it is clearly important to move as much EV charging from 6pm as possible, but some uncontrolled charging at 6pm can be handled.

   Results by year are given in Table 13.

3. The combination of a 2.5 kW PV export reduction and all EV charging moved away from 6pm and 9pm gives very similar results to just 2.5 kW PV export reduction. Detailed results for this are in Table 14.

4. BESS, hot water storage, and EV charging used to reduce midday summer exports by 5 kW AND all EV charging moved to off-peak

   The capex decrease is clearly large, once again because it removes coincident exports. This shows the importance of BESS combined with hot water energy storage and charging EVs during the day if possible. Results by year are given in Table 15.

   Solar export reduction by 5kW, partly by charging an EV, would obviously require an EV uptake earlier than or at the same rate as solar, so is unlikely to work in the early PV late electrification scenarios. Further, it requires EVs to be at the ICP, so its effectiveness (in terms of actually achieving 5kW export reduction) may be limited. In that respect, more curtailment of exports in summer may be required.

5. BESS, hot water storage, and EV charging used to reduce midday summer exports by 7.5 kW AND all EV charging moved to off-peak

From the earlier discussion in Section 2.3.3 high coincident exports will be confined to a fairly small proportion of time. Therefore, curtailing exports further to reach a 7.5 kW reduction should be palatable, especially given the additional energy the larger PV capacity will provide in winter. The capex reduction is substantial, in many cases reaching or exceeding 90% reduction of Base Case capex. Results by year are given in Table 16. Averaging the discounted capex over all years, the per ICP capex requirements are in the order or $100 per ICP per annum when PV exports are highly managed. This is less than half what the capex would be without managing PV exports.

It can be seen that PV tends to have a bigger impact than EV and peak demand increases. The primary reasons for this are:

- The resulting PV export from 10 kW PV systems is close to 10 kW when demand is minimum in midday summer. This exceeds the after diversity maximum demand of most LV networks, which is in the order of 3.5 kW. Further, even with the upper voltage limit at +10%, the 'tapping up' of distribution transformer secondary voltages gives less room for voltage rise from reversal of power flow – see discussion in (Miller and Lemon 2024a).
- PV export occurs coincidentally in LV networks, meaning there is almost no diversity in PV exports.
- 100% of transformer rating is used in summer, instead of a higher limit such as 110% due to expected high temperatures coincident with high solar generation.
- EVs are modelled as largely shifted away from peaks and perfectly scheduled.

Note that while the avoided capex in Table 11 are always positive, indicating an overall reduction in capex across all cases, the annual values in Tables 12-16 contain negative values, indicating the capex increases in some years. This is a result of capex being shifted from earlier years to later years. This can occur, for example, when the constraints in a network are reduced to such a degree that it is no longer more cost-effective to split the network early, and instead the conductors are simply replaced when they occur in later years. This is evident in the significant capex savings in Table 15 and Table 16 in 2025, which is predominantly due to networks no longer being split early. In addition, as solar export is reduced, the capex becomes increasingly determined by the timing and magnitude of peak demand increase rather than solar and battery uptake. This in turn results in the annual capex values shifting from the base capex, which is largely driven by the solar uptake, to be more closely aligned with the electrification uptake.

Table 11: Test cases, showing the decrease in capex from the Unmanaged PV Export Base Case. Values in (a) are absolute, values in (b) are avoided capex, and values in (c) are the avoided capex as a proportion of base case capex. The peak demand growth of 0 kW, 1kW, and 2 kW is per ICP.

(a) Test case absolute capex

Peak demand growth (kW)	Electrification (including EV)	Solar and battery	Test case absolute capex ($ per ICP), discounted at 5% per annum					Unmanaged PV Export Base Case Total capex ($ per ICP), discounted at 5% per annum Note: Absolute value
			BESS used to reduce midday summer exports by 2.5 kW	All EV charging moved from 6pm & 9pm to off-peak (Fully Shifted 3.7 EV)	BESS used to reduce midday summer exports by 2.5 kW AND all EV charging moved to off-peak (Fully Shifted 3.7 EV)	BESS, hot water storage, and EV charging used to reduce midday summer exports by 5 kW AND all EV charging moved to off-peak (Fully Shifted 3.7 EV)	BESS, hot water storage, and EV charging used to reduce midday summer exports by 7.5 kW AND all EV charging moved to off-peak (Fully Shifted 3.7 EV)	
0	Late electrification	Late solar and battery	1,677	2,522	1,673	687	182	2,524
		Early solar and battery	3,545	5,217	3,544	1,449	190	5,216
	Early electrification	Late solar and battery	1,699	2,543	1,694	706	198	2,545
		Early solar and battery	3,548	5,216	3,546	1,452	203	5,218
1	Late electrification	Late solar and battery	1,682	2,523	1,675	688	183	2,528
		Early solar and battery	3,545	5,217	3,544	1,449	190	5,216
	Early electrification	Late solar and battery	1,774	2,583	1,735	747	253	2,622
		Early solar and battery	3,547	5,216	3,545	1,452	203	5,218
2	Late electrification	Late solar and battery	1,777	2,590	1,747	769	297	2,612
		Early solar and battery	3,546	5,218	3,545	1,453	209	5,218
	Early electrification	Late solar and battery	2,504	3,182	2,331	1,340	1,069	3,345
		Early solar and battery	3,561	5,221	3,552	1,471	279	5,226

(b) Test case avoided capex

Peak demand growth (kW)	Electrification (including EV)	Solar and battery	Avoided capex: Unmanaged PV Export Base Case less test case total capex ($ per ICP), discounted at 5% per annum					Unmanaged PV Export Base Case Total capex ($ per ICP), discounted at 5% per annum Note: Absolute value
			BESS used to reduce midday summer exports by 2.5 kW	All EV charging moved from 6pm & 9pm to off-peak (Fully Shifted 3.7 EV)	BESS used to reduce midday summer exports by 2.5 kW AND all EV charging moved to off-peak (Fully Shifted 3.7 EV)	BESS, hot water storage, and EV charging used to reduce midday summer exports by 5 kW AND all EV charging moved to off-peak (Fully Shifted 3.7 EV)	BESS, hot water storage, and EV charging used to reduce midday summer exports by 7.5 kW AND all EV charging moved to off-peak (Fully Shifted 3.7 EV)	
0	Late electrification	Late solar and battery	848	2	851	1,837	2,342	2,524
		Early solar and battery	1,672	0	1,672	3,767	5,026	5,216
	Early electrification	Late solar and battery	846	3	851	1,839	2,347	2,545
		Early solar and battery	1,670	1	1,672	3,765	5,015	5,218
1	Late electrification	Late solar and battery	847	6	854	1,841	2,345	2,528
		Early solar and battery	1,671	0	1,673	3,767	5,026	5,216
	Early electrification	Late solar and battery	848	38	886	1,875	2,368	2,622
		Early solar and battery	1,671	1	1,672	3,765	5,015	5,218
2	Late electrification	Late solar and battery	835	22	864	1,843	2,315	2,612
		Early solar and battery	1,672	0	1,673	3,764	5,009	5,218
	Early electrification	Late solar and battery	841	162	1,013	2,005	2,276	3,345
		Early solar and battery	1,665	5	1,673	3,755	4,947	5,226

(c) Avoided capex as a percentage of the Unmanaged PV Export Base Case capex.

Peak demand growth (kW)	Electrification (including EV)	Solar and battery	Avoided Capex: Unmanaged PV Export Base Case less test case as a proportion of Unmanaged PV Export Base Case, discounted at 5% per annum				
			BESS used to reduce midday summer exports by 2.5 kW	All EV charging moved from 6pm & 9pm to off-peak (Fully Shifted 3.7 EV)	BESS used to reduce midday summer exports by 2.5 kW AND all EV charging moved to off-peak (Fully Shifted 3.7 EV)	BESS, hot water storage, and EV charging used to reduce midday summer exports by 5 kW AND all EV charging moved to off-peak (Fully Shifted 3.7 EV)	BESS, hot water storage, and EV charging used to reduce midday summer exports by 7.5 kW AND all EV charging moved to off-peak (Fully Shifted 3.7 EV)
0	Late electrification	Late solar and battery	34%	0%	34%	73%	93%
		Early solar and battery	32%	0%	32%	72%	96%
	Early electrification	Late solar and battery	33%	0%	33%	72%	92%
		Early solar and battery	32%	0%	32%	72%	96%
1	Late electrification	Late solar and battery	33%	0%	34%	73%	93%
		Early solar and battery	32%	0%	32%	72%	96%
	Early electrification	Late solar and battery	32%	1%	34%	72%	90%
		Early solar and battery	32%	0%	32%	72%	96%
2	Late electrification	Late solar and battery	32%	1%	33%	71%	89%
		Early solar and battery	32%	0%	32%	72%	96%
	Early electrification	Late solar and battery	25%	5%	30%	60%	68%
		Early solar and battery	32%	0%	32%	72%	95%

Table 12: Avoided capex by year for the 'BESS used to reduce midday summer exports by 2.5 kW' test case.

Peak demand growth (kW)	Electrification (including EV)	Solar and battery	Avoided Capex: Unmanaged PV Export Base Case less test case capex ($ per ICP)																		
			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036-2040	2041-2045	2046-2050	2051-2055	2056-2060	2061-2065	2066-2070	2071-2075
0	Late electrification	Late solar and battery	42	0	0	0	0	0	0	0	0	0	0	333	1,489	259	15	50	-31	-1	-4
		Early solar and battery	40	0	0	5	126	808	730	423	8	71	-46	62	-32	15	0	0	0	0	0
	Early electrification	Late solar and battery	42	0	0	0	0	0	0	0	0	5	0	323	1,484	267	16	50	-31	-1	-4
		Early solar and battery	40	0	0	5	126	803	732	419	9	72	-45	63	-31	15	0	0	0	0	0
1	Late electrification	Late solar and battery	42	0	0	0	0	0	0	0	0	0	0	332	1,489	258	14	50	-31	-1	-4
		Early solar and battery	40	0	0	5	126	809	729	423	8	72	-47	61	-32	15	0	0	0	0	0
	Early electrification	Late solar and battery	41	0	0	0	0	4	20	1	4	4	4	232	1,534	276	19	51	-29	-1	-4
		Early solar and battery	40	0	0	5	126	803	733	420	9	72	-45	62	-31	15	0	0	0	0	0
2	Late electrification	Late solar and battery	41	0	0	0	0	4	2	13	5	1	0	185	1,566	295	22	52	-29	-1	-4
		Early solar and battery	39	0	0	5	126	809	729	423	8	72	-44	61	-32	14	0	-1	0	0	0
	Early electrification	Late solar and battery	35	0	0	11	17	19	51	55	46	3	20	4	1,162	606	81	55	-24	0	-4
		Early solar and battery	39	0	0	5	122	786	736	426	12	75	-42	64	-30	15	0	0	0	0	0

Table 13: Avoided capex by year for the 'All EV charging moved from 6pm & 9pm to off-peak (Partially Shifted EV charging to Fully Shifted EV charging)' test case.

Peak demand growth (kW)	Electrification (including EV)	Solar and battery	Avoided Capex: Unmanaged PV Export Base Case less test case capex ($ per ICP)																		
			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036-2040	2041-2045	2046-2050	2051-2055	2056-2060	2061-2065	2066-2070	2071-2075
0	Late electrification	Late solar and battery	0	0	0	0	1	0	0	3	0	0	-1	5	-4	-2	0	0	-1	0	0
		Early solar and battery	0	0	0	0	0	0	1	0	0	-1	-1	1	0	0	0	0	0	0	0
	Early electrification	Late solar and battery	0	0	1	0	3	4	7	-4	-15	11	-7	3	0	-1	0	0	-1	0	0
		Early solar and battery	0	0	1	0	2	0	2	-3	-1	0	0	0	-1	0	0	0	0	0	0
1	Late electrification	Late solar and battery	0	1	0	0	2	0	-2	6	5	0	5	-4	-8	-3	0	0	-1	0	0
		Early solar and battery	1	0	0	0	-1	0	0	0	0	0	-1	0	0	0	0	0	0	0	0
	Early electrification	Late solar and battery	1	0	2	-5	21	15	67	10	-29	10	19	-53	-48	-4	-1	0	0	0	0
		Early solar and battery	0	0	0	0	3	0	3	-3	-1	0	0	0	-1	0	0	0	0	0	0
2	Late electrification	Late solar and battery	1	-1	7	2	-4	4	5	38	-12	-23	2	82	-86	-7	-2	1	-1	0	0
		Early solar and battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Early electrification	Late solar and battery	5	12	-5	29	-14	77	95	150	-58	93	24	-7	-303	-58	-5	0	-2	0	0
		Early solar and battery	8	0	0	5	-2	19	-23	-4	2	-2	1	-1	0	0	0	0	0	0	0

Table 14: Avoided capex by year for the 'BESS used to reduce midday summer exports by 2.5 kW AND all EV charging moved to off-peak' test case.

Peak demand growth (kW)	Electrification (including EV)	Solar and battery	Avoided Capex: Unmanaged PV Export Base Case less test case capex ($ per ICP)																		
			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036-2040	2041-2045	2046-2050	2051-2055	2056-2060	2061-2065	2066-2070	2071-2075
0	Late electrification	Late solar and battery	42	0	0	0	1	0	0	3	0	0	-1	344	1,482	256	13	50	-31	-1	-4
		Early solar and battery	40	0	0	5	127	808	731	423	8	71	-47	62	-31	15	0	0	0	0	0
	Early electrification	Late solar and battery	42	0	1	0	3	4	7	-4	-10	11	-7	328	1,496	258	13	50	-31	-1	-4
		Early solar and battery	40	0	1	6	129	805	733	420	8	72	-47	62	-32	15	0	0	0	0	0
1	Late electrification	Late solar and battery	42	1	0	0	2	0	-2	6	5	0	5	332	1,480	256	13	50	-31	-1	-4
		Early solar and battery	40	0	0	5	126	808	730	423	8	72	-47	62	-31	15	0	0	0	0	0
	Early electrification	Late solar and battery	42	0	2	-5	21	15	70	18	-22	16	19	218	1,469	265	17	51	-31	-1	-4
		Early solar and battery	40	0	0	6	128	806	733	421	8	72	-46	61	-32	15	0	0	0	0	0
2	Late electrification	Late solar and battery	42	-1	7	2	-4	5	11	44	-5	-18	2	317	1,454	271	17	51	-30	-1	-4
		Early solar and battery	39	0	0	5	126	809	730	423	8	72	-45	62	-31	14	0	0	0	0	0
	Early electrification	Late solar and battery	44	12	-5	35	4	93	127	199	-11	111	42	4	1,028	418	57	51	-28	-1	-4
		Early solar and battery	46	0	0	10	120	814	702	431	12	74	-43	62	-32	15	0	0	0	0	0

Table 15: Avoided capex by year for the 'BESS, hot water storage, and EV charging used to reduce midday summer exports by 5 kW AND all EV' test case.

Peak demand growth (kW)	Electrification (including EV)	Solar and battery	Avoided Capex: Unmanaged PV Export Base Case less test case capex ($ per ICP)																		
			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036-2040	2041-2045	2046-2050	2051-2055	2056-2060	2061-2065	2066-2070	2071-2075
0	Late electrification	Late solar and battery	104	0	0	0	1	0	3	3	0	0	-1	395	2,770	1,318	371	123	-44	24	6
		Early solar and battery	101	0	0	5	136	1,011	1,587	1,238	486	312	140	143	-13	45	0	0	0	0	0
	Early electrification	Late solar and battery	104	0	1	3	3	6	7	-4	-8	10	-1	360	2,786	1,331	372	122	-44	24	6
		Early solar and battery	101	0	1	8	138	1,005	1,588	1,229	480	316	146	144	-11	45	0	0	0	0	0
1	Late electrification	Late solar and battery	104	1	0	0	2	0	0	6	8	0	5	383	2,766	1,317	371	122	-44	24	6
		Early solar and battery	102	0	0	5	135	1,011	1,586	1,238	486	313	140	143	-13	45	0	0	0	0	0
	Early electrification	Late solar and battery	103	0	2	1	21	17	73	23	-7	24	19	238	2,711	1,359	379	124	-42	25	6
		Early solar and battery	101	0	0	8	138	1,005	1,589	1,230	480	316	146	144	-11	45	0	0	0	0	0
2	Late electrification	Late solar and battery	102	0	7	2	0	5	16	54	3	-7	2	342	2,629	1,408	387	126	-40	25	6
		Early solar and battery	103	0	0	5	135	1,008	1,586	1,238	486	313	141	141	-13	44	-4	-2	0	0	0
	Early electrification	Late solar and battery	94	12	-2	44	27	137	201	287	88	138	70	5	1,337	1,742	583	161	-6	44	6
		Early solar and battery	109	0	0	12	130	1,008	1,528	1,245	488	323	152	146	-9	45	0	0	0	0	0

Table 16: Avoided capex by year for the 'BESS, hot water storage, and EV charging used to reduce midday summer exports by 7.5 kW AND all EV' test case.

Peak demand growth (kW)	Electrification (including EV)	Solar and battery	Avoided Capex: Unmanaged PV Export Base Case less test case capex ($ per ICP)																		
			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036-2040	2041-2045	2046-2050	2051-2055	2056-2060	2061-2065	2066-2070	2071-2075
0	Late electrification	Late solar and battery	119	0	0	0	1	0	3	3	0	0	-1	395	2,886	2,014	1,018	340	217	143	28
		Early solar and battery	116	0	0	5	136	1,018	1,670	1,538	795	677	561	457	267	59	-1	-3	0	0	0
	Early electrification	Late solar and battery	119	0	1	3	3	6	7	-3	-6	16	1	371	2,881	2,019	1,022	344	217	143	28
		Early solar and battery	116	0	1	8	138	1,012	1,670	1,518	786	676	561	458	284	66	0	0	0	0	0
1	Late electrification	Late solar and battery	119	1	0	0	3	0	0	6	8	0	5	382	2,882	2,013	1,018	340	217	143	28
		Early solar and battery	117	0	0	5	135	1,019	1,670	1,538	795	678	560	456	267	59	-1	-3	0	0	0
	Early electrification	Late solar and battery	118	0	2	1	21	19	84	34	-9	25	19	241	2,784	2,011	1,022	344	219	144	28
		Early solar and battery	117	0	0	8	138	1,012	1,670	1,519	786	676	561	458	284	66	0	0	0	0	0
2	Late electrification	Late solar and battery	116	0	7	4	-1	8	24	67	2	-8	6	363	2,662	2,003	1,022	346	223	145	30
		Early solar and battery	117	0	0	5	135	1,016	1,669	1,538	795	678	561	456	266	57	-19	-50	-5	0	0
	Early electrification	Late solar and battery	98	12	0	53	35	160	233	298	89	137	65	5	1,338	1,831	1,006	341	221	145	30
		Early solar and battery	125	0	0	12	132	1,021	1,584	1,489	781	675	565	465	287	67	0	0	0	0	0

3.2.2 Avoided capex from peak demand increases due to electrification

Sub-section 3.2.1 has established that capex required due to high PV uptake and coincident exports can largely be managed by reducing the PV exports of 10 kW-ac systems by 7.5 kW (Test case 5). Because of the way PV has been modelled using the LV Capex Model, this could alternatively be viewed in terms of the level of self-consumption required for a PV system of a given size. For example, a 7.5 kW-ac inverter with 5 kW reduction by self-consumption to achieve 2.5 kW PV generation coincident with minimum demand would equally suffice (Test case 4 with a 7.5 kW-ac inverter instead of a 10 kW-ac inverter).

Assuming this level of export reduction can be achieved as required, this sub-section investigates the use of PV and BESS to reduce peak demand, and thereby avoid capex due to electrification. This is done by comparing the capex results with PV and BESS to the Unmanaged Electrification Base Case of Table 8, which has no PV or BESS to manage peak demand.

The third results column of Table 17 gives the avoided capex due to electrification after management of peak demand by PV and BESS, assuming that PV exports are highly managed. The final column gives this as a proportion of unmanaged electrification capex. This shows that a large proportion of electrification capex can be avoided with early solar and battery uptake, especially when electrification is early and peak demand growth is high.

Under the no peak demand growth scenarios, the early solar and battery scenarios show:

- negative avoided capex in the late electrification scenario, and
- very low avoided capex in the early electrification scenario.

This is because the early solar uptake still requires some capex to deal with exports, and that capex occurs earlier than in the late solar and battery scenarios. In other words, the PV exports are not completely managed by reduction by 7.5 kW to 2.5 kW, leading to some capex still occurring early. However, as peak demand grows from electrification, the avoided capex from electrification overshadows any residual capex requirement from PV exports. In turn, a reasonable per ICP avoided capex is achieved, especially in the early solar and battery scenarios, and more so when electrification occurs early. Averaging the discounted capex over all years shows that the per ICP capex is limited to the tens of dollars per ICP per annum or less, when solar and battery uptake occurs at a similar or earlier time and rate as electrification.

Table 17: The decrease in capex from the Unmanaged Electrification Base Case, giving the avoided capex from electrification. In (a) the first capex results column gives the Unmanaged Electrification Base Case for reference. The second results column gives the capex resulting from the management of PV exports, in which maximum exports are reduced by 7.5 kW (10 kW down to 2.5 kW) - this corresponds to Test case 5, the last test case column of Table 11 (a). The third column gives the avoided capex due to the use of the managed PV and battery storage. The final column gives the same avoided capex as a proportion of unmanaged electrification. In (b) the avoided capex results are given by year.

(a)

Peak demand growth (kW)	Electrification (including EV)	Solar and battery	Capex ($ per ICP), discounted at 5% per annum			Avoided capex from electrification as a proportion of Unmanaged Electrification Base Case capex
			Unmanaged Electrification Base Case (No PV or BESS) Note: Absolute value	Highly Managed PV Exports BESS, hot water storage, and EV charging used to reduce midday summer exports by 7.5 kW AND all EV charging moved to off-peak	Avoided capex from electrification by use of PV and BESS, after capex from PV exports has been managed (Unmanaged Electrification Base Case - Highly Managed PV Exports Test Case)	
0	Late electrification	Late solar and battery	184	182	2	1%
		Early solar and battery	184	190	-7	-4%
	Early electrification	Late solar and battery	205	198	7	3%
		Early solar and battery	205	203	2	1%
1	Late electrification	Late solar and battery	272	183	89	33%
		Early solar and battery	272	190	82	30%
	Early electrification	Late solar and battery	358	253	105	29%
		Early solar and battery	358	203	155	43%
2	Late electrification	Late solar and battery	1,039	297	742	71%
		Early solar and battery	1,039	209	830	80%
	Early electrification	Late solar and battery	1,696	1,069	628	37%
		Early solar and battery	1,696	279	1,418	84%

(b)

Peak demand growth (kW)	Electrification (including EV)	Solar and battery	Avoided capex from electrification by use of PV and BESS, after capex from PV exports has been managed ($ per ICP) (Unmanaged Electrification Base Case less Highly Managed PV Exports Test Case)																		
			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036-2040	2041-2045	2046-2050	2051-2055	2056-2060	2061-2065	2066-2070	2071-2075
0	Late electrification	Late solar and battery	0	0	0	0	1	0	1	0	0	0	-1	6	-13	11	4	2	-7	-3	-2
		Early solar and battery	0	0	0	0	1	0	1	-2	-2	-2	-5	-3	-14	9	11	5	0	0	0
	Early electrification	Late solar and battery	0	0	1	1	0	0	5	-9	-3	15	3	2	0	-1	-4	-2	-6	-3	-2
		Early solar and battery	0	0	1	1	0	0	5	-9	-3	15	2	-5	-6	-2	0	0	0	0	0
1	Late electrification	Late solar and battery	9	0	1	0	0	0	9	2	2	4	6	65	23	49	22	19	6	-3	-2
		Early solar and battery	9	0	1	0	1	0	9	0	1	3	2	56	21	47	29	22	13	0	0
	Early electrification	Late solar and battery	7	1	0	9	7	17	48	-2	12	0	19	35	2	0	-3	-2	-5	-2	-2
		Early solar and battery	9	1	1	9	9	26	58	5	47	20	14	23	-5	-2	0	0	0	0	0
2	Late electrification	Late solar and battery	51	6	2	4	13	19	57	17	-28	6	69	336	478	493	205	160	72	-1	0
		Early solar and battery	54	7	4	8	19	23	64	23	22	28	74	375	499	481	186	109	67	0	0
	Early electrification	Late solar and battery	35	5	13	50	-15	92	119	142	102	96	75	212	13	1	0	0	0	0	0
		Early solar and battery	60	6	24	73	67	213	241	368	405	211	145	207	10	0	0	0	0	0	0

3.3 Capex changes by time and scenario

3.3.1 Avoided capex from PV Exports by time and scenario

To provide additional insight into the capex requirement by asset type over time, the capex for the Unmanaged PV Export Base Case from Table 8(a) is graphed for each electrification and solar and battery scenario at 1 kW peak demand growth in Figure 13(a) to Figure 16(a). Similarly, Figure 13(b) to Figure 16(b) show how capex changes across the same scenarios, but with a 5 kW PV export reduction.

From all of these figures it is clear that capex comprises a large amount of cable replacement (the orange portions), which is largely due to voltage constraints caused by PV export, with some loading constraints as well. There are also a number of transformer replacements (dark blue) and transformer additions (light blue) and MV extension (green) to split LV networks, which the LV Capex Model has calculated as lower cost than upgrading many constrained conductors (and potentially also the transformer). When export reduction is implemented the relative number of networks being pre-emptively split decreases significantly, as it becomes more cost effective to replace a small number of constrained conductors as they become constrained rather than having to add new LV networks. This results in a decrease in the overall magnitude of the capex, as well as deferring capex to later years as constraints occur.

Because EV charging is almost entirely moved away from peak demand, and carefully scheduled so as not to create new demand peaks, peak demand impact is not particularly evident in these figures, except for a slight amount in Figure 15(a), where electrification occurs before solar and battery uptake. This is more evident in Figure 17(a) where peak demand growth is higher, and capex occurs in two waves: first from peak demand, then from PV. In Figure 17(b) the magnitude of both waves is reduced, first by the batteries available in the early years reducing peak demand (not to the full extent due to slower uptake), then by batteries reducing PV exports. It is preferable that PV and BESS are available earlier to manage electrification demand.

The other main difference between Figure 17(a) and Figure 17(b) is the significant decrease in network splitting across all years. With the high early peak demand growth followed by high PV uptake, constraints first occur due to peak demand increases as shown in Figure 17(a). Given these early constraints, the LV Capex Model looks forward to see numerous future constraints due to PV export, and therefore decides to split the networks to handle both the present peak demand constraints (usually transformer and/or line loading) and the future PV export constraints (usually line voltage). By significantly reducing the maximum PV exports, many future conductor constraints are avoided, as evident in Figure 17(b). Thus, instead of splitting these networks, the LV Capex Model determines that individual conductor and/or transformer upgrades over time will result in a lower total cost. In turn, there is a small increase in transformer and cable spend in the early years, and reduced overall spend in the later years.

This illustrates the complexity of the interaction between constraints caused by both peak demand increases and PV exports, particularly when there are different uptake rates of electrification and PV/BESS.

3.3.2 Avoided capex from peak demand increases due to electrification by time and scenario

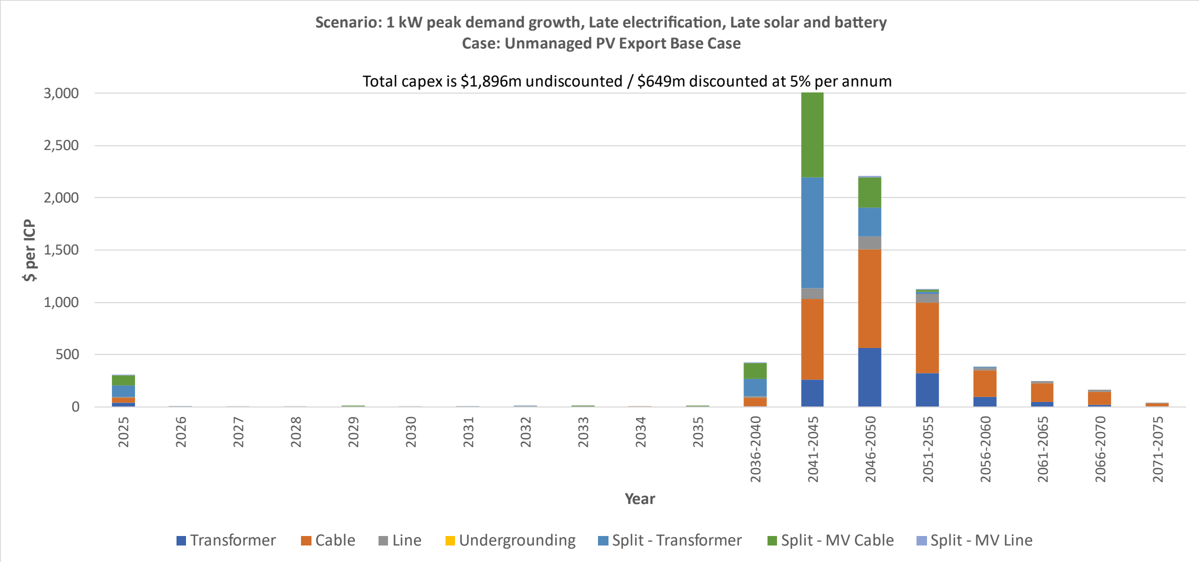
Having managed PV exports down to a level where there is very little capex increase from PV exports, Figure 18 shows the resulting capex by type and year. In Figure 18(a) solar and battery uptake occurs later than electrification, leading to capex requirements from electrification amounting to $274 m discounted. This is equivalent to the 1,069 $/ICP shown in the second to last row of Table 17 in the

Highly Managed PV Exports column. This leads to an avoided capex of only 37% of the Unmanaged Electrification Base Case.

By contrast, when solar and battery uptake occurs early, the resulting capex requirement from electrification reduces to $71 m discounted. This is equivalent to the 279 $/ICP shown in the last row of Table 17 in the Highly Managed PV Exports column. This leads to an avoided capex of 84% of the Unmanaged Electrification Base Case.

Such large reductions are not apparent with lower peak demand growth of 1 kW, because the capex growth is lower, and some level of PV export still contributes to capex in the highly managed PV exports test case. However, the benefits from early solar and battery uptake are still discernible. This highlights the sensitivity of capex to peak demand growth, and the importance of managing peak demand to limit capex requirements. In line with this, it supports the carefully scheduled EV charging adopted in this model to move EV charging away from the peak, while also avoiding the creation of new peaks.

(a) Unmanaged PV Export Base Case



(b) Test case with 5 kW PV export reduction

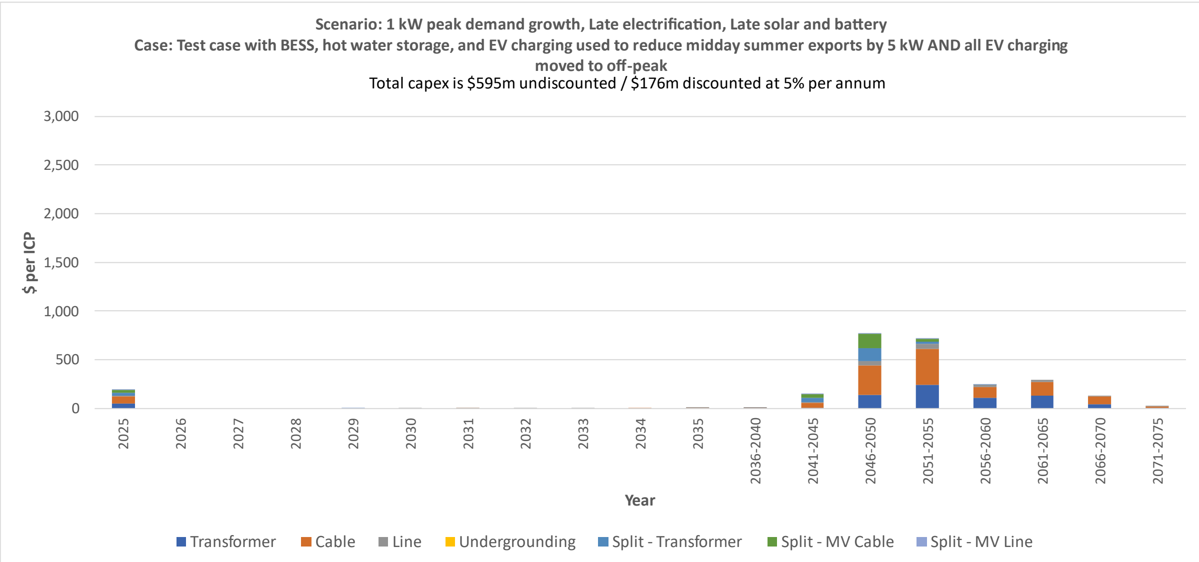
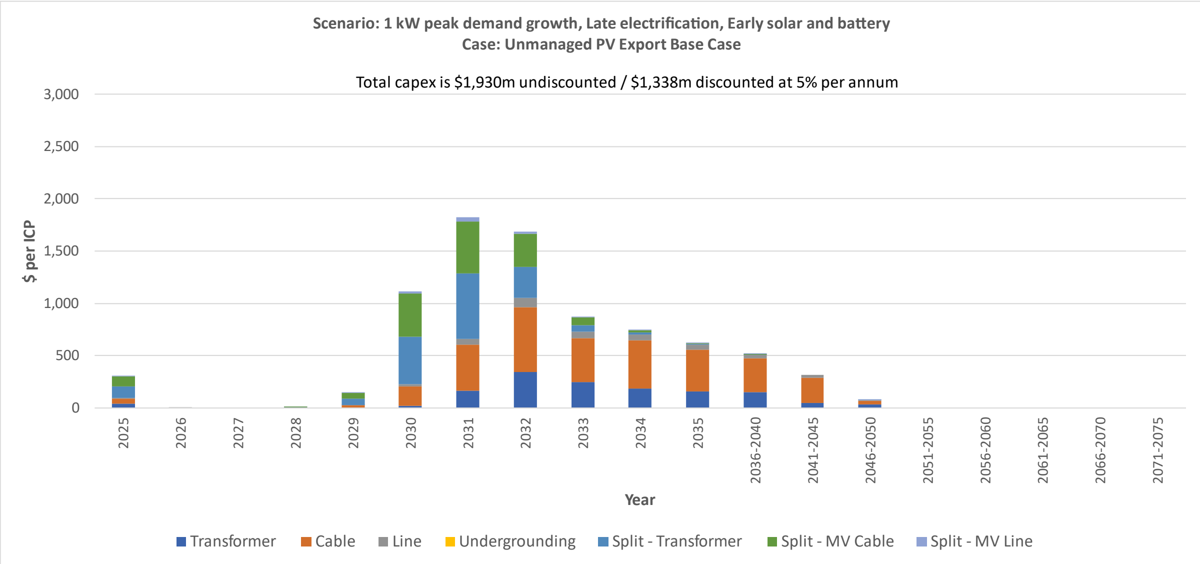


Figure 13: 1 kW peak demand growth, Late electrification and Late solar and battery. (a) Unmanaged PV Export Base Case, (b) Test case with 5 kW PV export reduction using BESS, storage hot water, and daytime EV charging.

(a) Unmanaged PV Export Base Case



(b) Test case with 5 kW PV export reduction

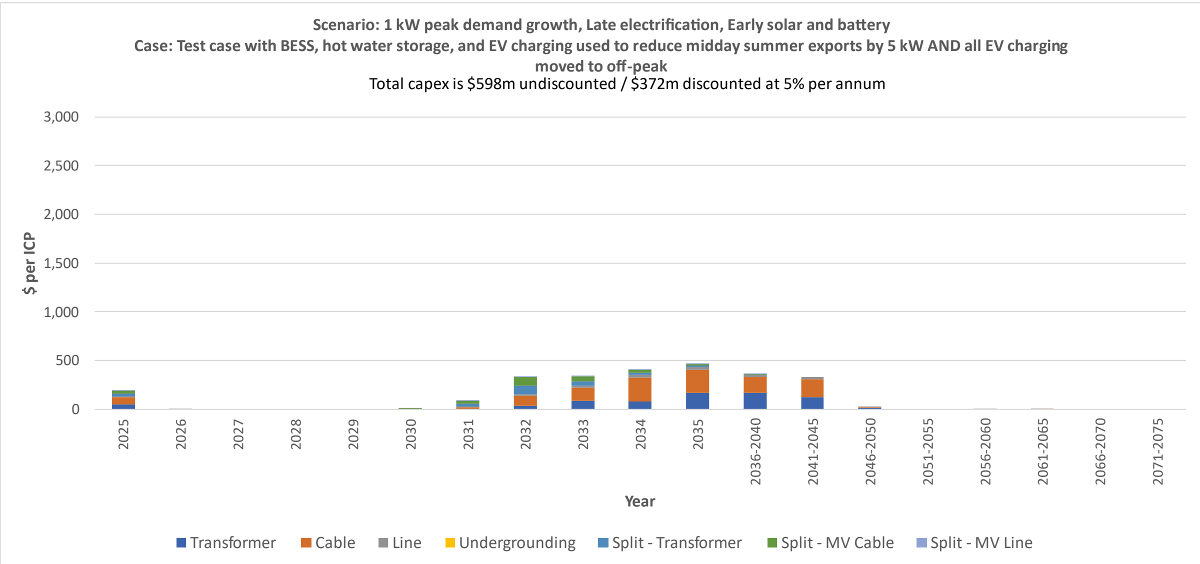
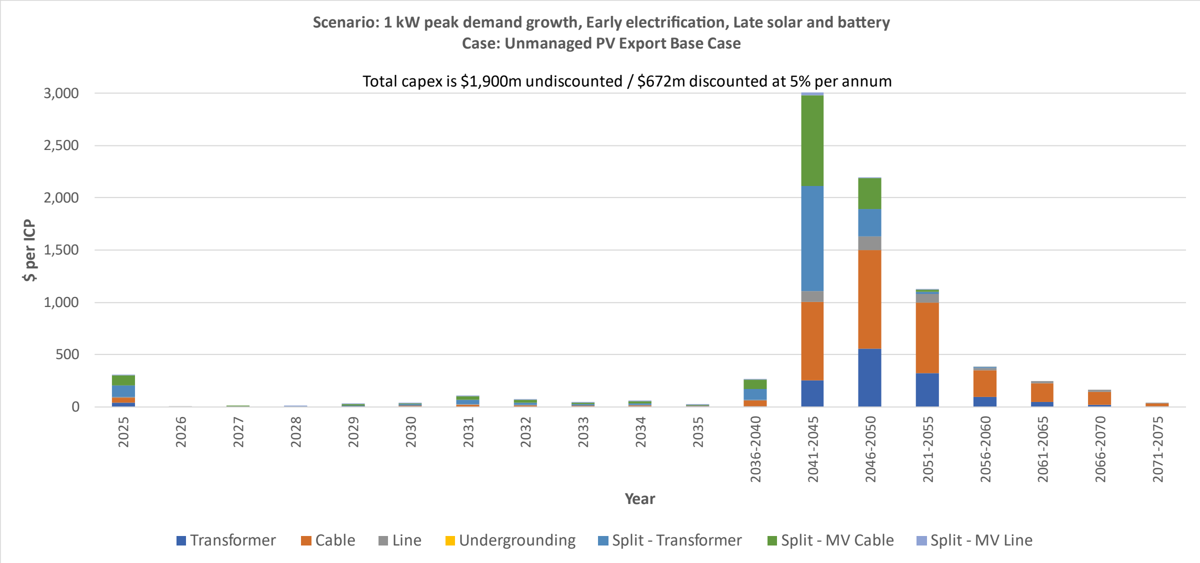


Figure 14: 1 kW peak demand growth, Late electrification and Early solar and battery. (a) Unmanaged PV Export Base Case, (b) Test case with 5 kW PV export reduction using BESS, storage hot water, and daytime EV charging. Note that the capex from 2025-2035 is given on a yearly basis, while capex after 2035 is aggregated into 5-year intervals. Earlier values that appear low may be higher on an annual basis than the later aggregated values.

(a) Unmanaged PV Export Base Case



(b) Test case with 5 kW PV export reduction

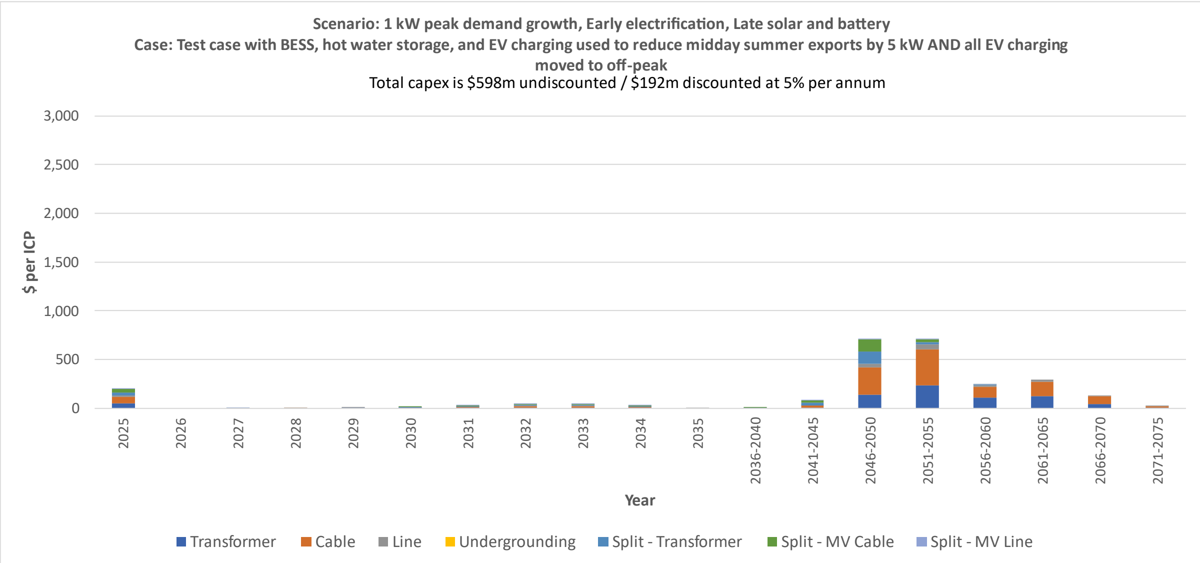
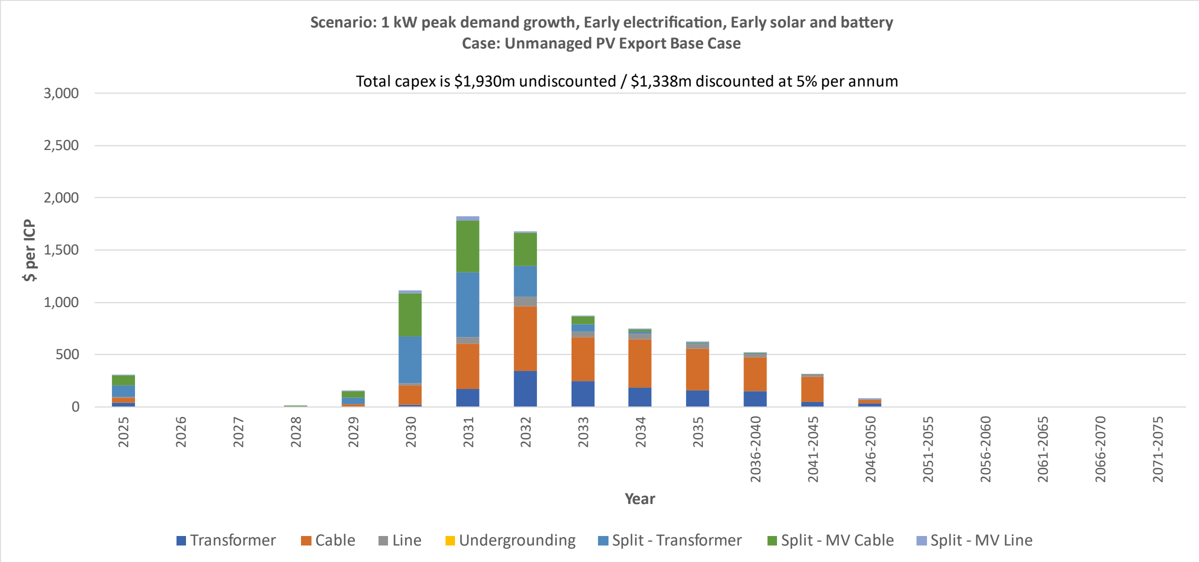


Figure 15: 1 kW peak demand growth, Early electrification and Late solar and battery. (a) Unmanaged PV Export Base Case, (b) Test case with 5 kW PV export reduction using BESS, storage hot water, and daytime EV charging.

(a) *Unmanaged PV Export Base Case*



(b) *Test case with 5 kW PV export reduction*

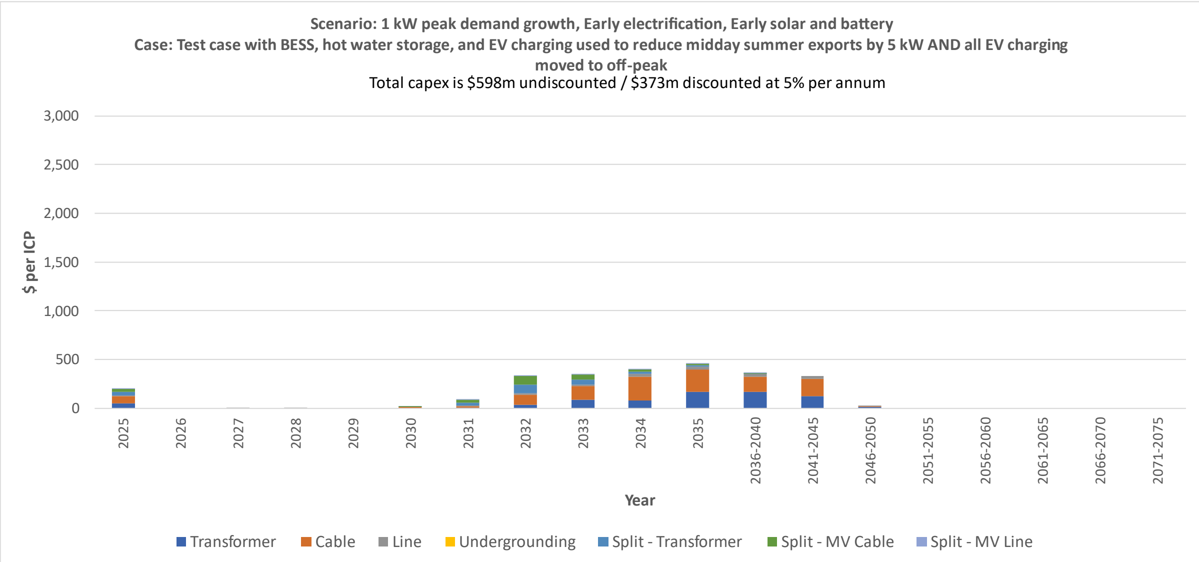
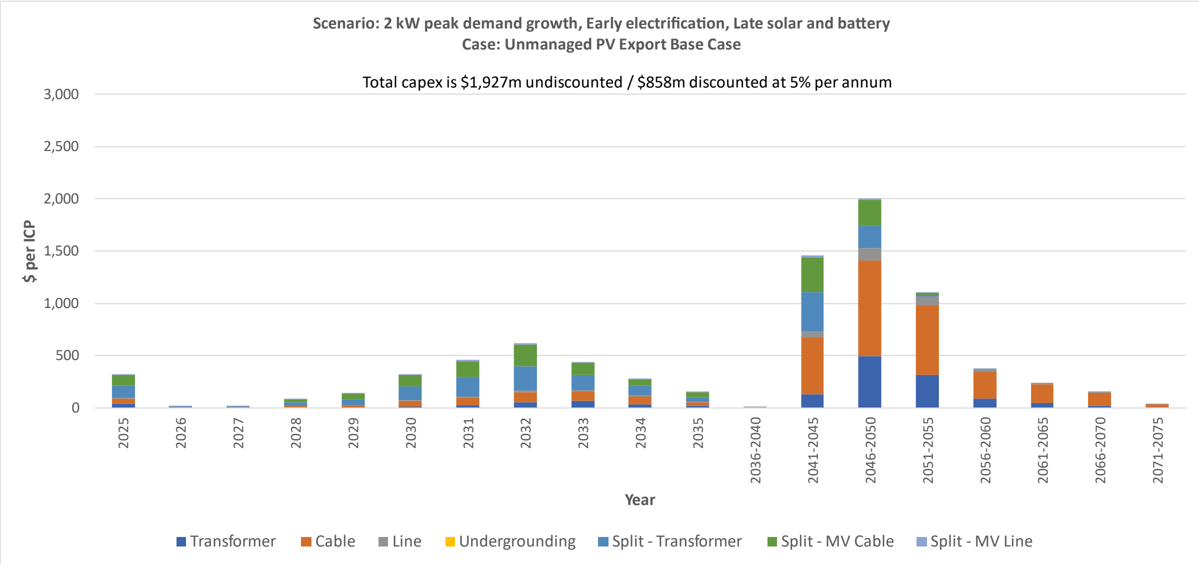


Figure 16: 1 kW peak demand growth, Early electrification and Early solar and battery. (a) Unmanaged PV Export Base Case, (b) Test case with 5 kW PV export reduction using BESS, storage hot water, and daytime EV charging

(a) Unmanaged PV Export Base Case



(b) Test case with 5 kW PV export reduction

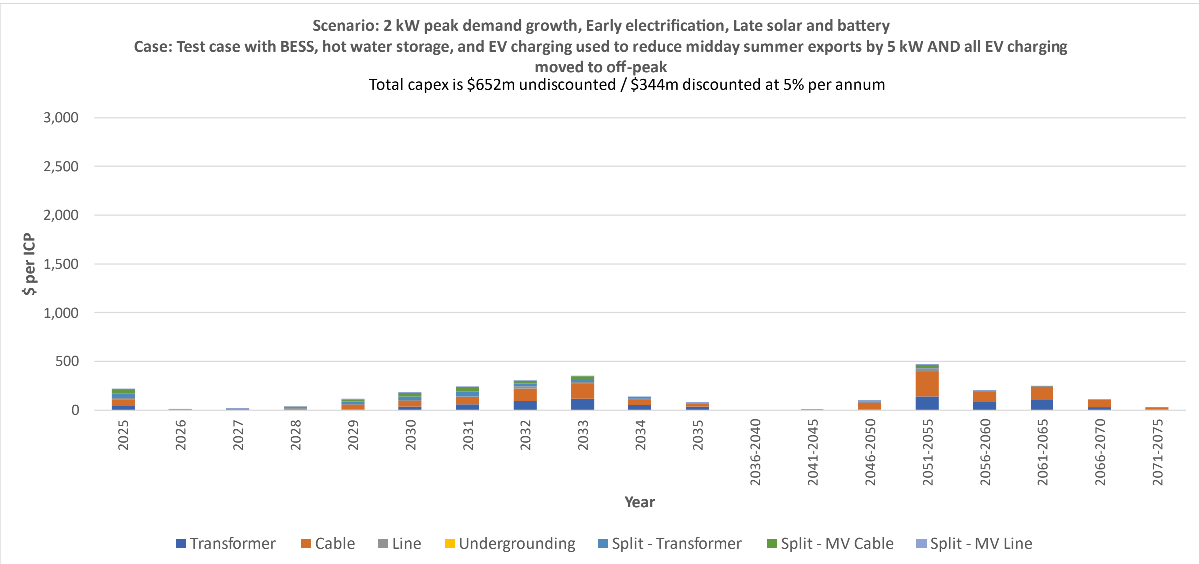
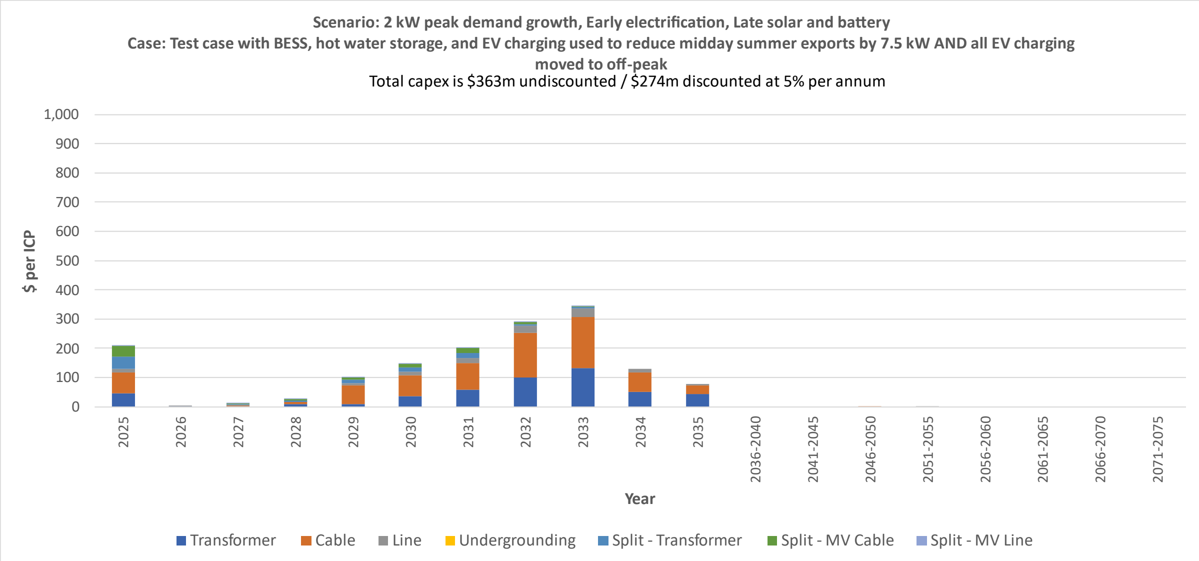


Figure 17: 2 kW peak demand growth, <u>Early</u> electrification and <u>Late</u> solar and battery. (a) Unmanaged PV Export Base Case, (b) Test case with 5 kW PV export reduction using BESS, storage hot water, and daytime EV charging.

(a) Early electrification, Late solar and battery with 7.5 kW export reduction



(b) Early electrification, Early solar and battery with 7.5 kW export reduction

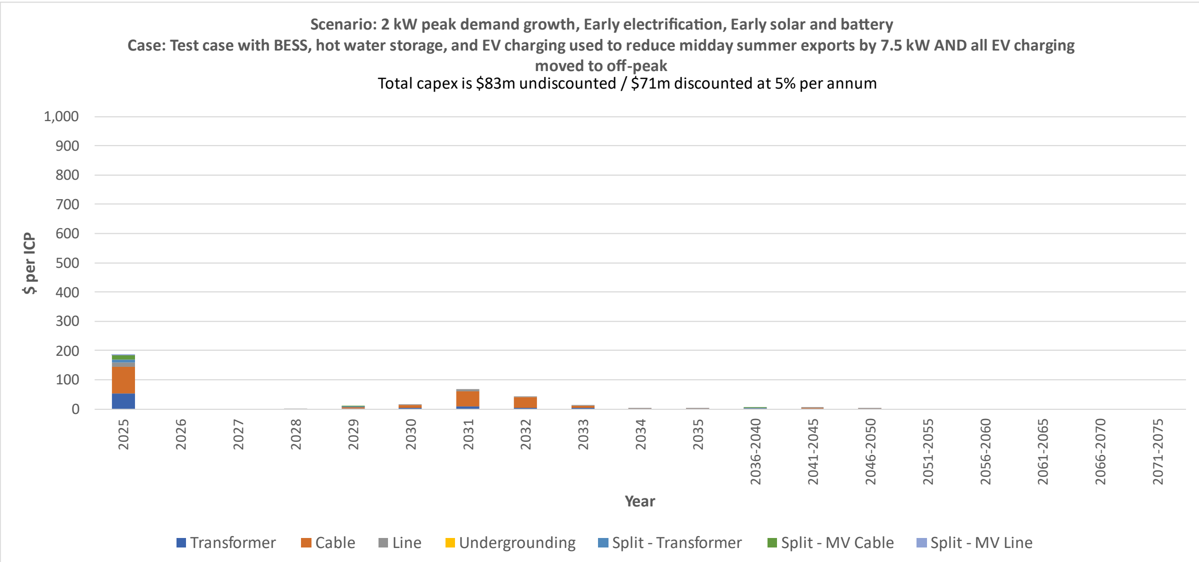


Figure 18: 2 kW peak demand growth, Early electrification and the test case with 7.5 kW PV export reduction using BESS, storage hot water, daytime EV charging, and further PV export curtailment when required, (a) with Late solar and battery uptake, the second to last row of Table 17, and (b) Early solar and battery uptake, the last row of Table 17. Note that the y-axis scale has been decreased relative to the preceding graph due to the lower values.

3.4 Total capex

Finally, an extremely approximate estimate of the cost across all ICPs in New Zealand is made by scaling the capex by the number of ICPs in New Zealand to the number of ICPs in the study. The total capex for the Base Cases is given in Table 18. It must be emphasised that the results in this section are extremely approximate, as it simply scales the known results by the ratio of ICPs in New Zealand to ICPs in the study. To correctly understand a national estimate would require similar modelling across a large number of EDBs.

Table 19 shows the results for each test case, as absolute capex in Table 19(a) and the avoided capex from the base case for the test cases given in Table 19(b). Table 20 shows the avoided capex from electrification after PV exports are managed, as an indication of the total for New Zealand.

Table 18: Absolute capex in $m, with capex at each year discounted to a present cost at 5% per annum. Results are scaled from the three EDBs' results to an indication only of New Zealand simply by multiplying by the ratio of all ICPs to ICPs in the study.

Peak demand growth (kW)	Electrification (including EV)	Solar and battery	Estimated total capex ($m), discounted at 5% per annum					
			Unmanaged PV Export Base Case To test Section 2.2.2 Point 1	Variations on 'Unmanaged PV Export Base Case'			**Unmanaged Electrification Base Case To test Section 2.2.2 Point 2**	Variation on 'Unmanaged Electrification Base Case'
			+10% upper voltage limit Partially Shifted 3.7 EV	+6% upper voltage limit Partially shifted 3.7 EV	60% constraint risk threshold +10% upper voltage limit Partially shifted 3.7 EV	100% constraint risk threshold +10% upper voltage limit Partially shifted 3.7 EV	**No PV or BESS Partially Shifted 3.7 EV**	No PV or BESS EV charging all around 6pm (6pm Only 3.7 EV)
0	Late electrification	Late solar and battery	5,780	12,150	6,593	3,879	421	1,880
		Early solar and battery	11,945	22,104	13,215	8,722	421	1,880
	Early electrification	Late solar and battery	5,828	12,186	6,672	3,880	469	3,093
		Early solar and battery	11,948	22,101	13,215	8,721	469	3,093
1	Late electrification	Late solar and battery	5,790	12,158	6,613	3,880	624	2,658
		Early solar and battery	11,945	22,102	13,218	8,723	624	2,658
	Early electrification	Late solar and battery	6,003	12,302	6,926	3,912	820	4,279
		Early solar and battery	11,948	22,105	13,221	8,724	820	4,279
2	Late electrification	Late solar and battery	5,980	12,261	6,872	3,934	2,380	4,894
		Early solar and battery	11,948	22,105	13,226	8,722	2,380	4,894
	Early electrification	Late solar and battery	7,659	13,429	8,717	4,903	3,884	7,590
		Early solar and battery	11,966	22,115	13,253	8,730	3,884	7,590

Table 19: Test cases, showing the decrease in capex from the Base Case (values in (a) are absolute ($m), and values in (b) are avoided capex, being Base Case capex less the capex ($m) resulting from the test case). Results are scaled from the three EDBs' results to an indication only of New Zealand simply by multiplying by the ratio of all ICPs to ICPs in the study.

(a) Test case absolute capex estimate ($m).

Peak demand growth (kW)	Electrification (including EV)	Solar and battery	Test case absolute capex ($m), discounted at 5% per annum					Unmanaged PV Export Base Case Total capex ($ per ICP), discounted at 5% per annum Note: Absolute value
			BESS used to reduce midday summer exports by 2.5 kW	All EV charging moved from 6pm & 9pm to off-peak (Fully Shifted 3.7 EV)	BESS used to reduce midday summer exports by 2.5 kW AND all EV charging moved to off-peak (Fully Shifted 3.7 EV)	BESS, hot water storage, and EV charging used to reduce midday summer exports by 5 kW AND all EV charging moved to off-peak (Fully Shifted 3.7 EV)	BESS, hot water storage, and EV charging used to reduce midday summer exports by 7.5 kW AND all EV charging moved to off-peak (Fully Shifted 3.7 EV)	
0	Late electrification	Late solar and battery	3,839	5,774	3,831	1,573	418	5,780
		Early solar and battery	8,117	11,945	8,115	3,318	436	11,945
	Early electrification	Late solar and battery	3,890	5,822	3,879	1,618	452	5,828
		Early solar and battery	8,124	11,945	8,119	3,325	464	11,948
1	Late electrification	Late solar and battery	3,851	5,777	3,835	1,575	419	5,790
		Early solar and battery	8,118	11,945	8,115	3,318	436	11,945
	Early electrification	Late solar and battery	4,062	5,915	3,974	1,710	580	6,003
		Early solar and battery	8,122	11,944	8,118	3,326	464	11,948
2	Late electrification	Late solar and battery	4,068	5,930	4,001	1,760	680	5,980
		Early solar and battery	8,120	11,949	8,117	3,328	478	11,948
	Early electrification	Late solar and battery	5,734	7,287	5,338	3,067	2,447	7,659
		Early solar and battery	8,154	11,954	8,135	3,368	638	11,966

(b) Test case avoided capex estimate from the base case ($m).

Peak demand growth (kW)	Electrification (including EV)	Solar and battery	Avoided capex: Unmanaged PV Export Base Case less test case total capex ($m), discounted at 5% per annum					Unmanaged PV Export Base Case Total capex ($ per ICP), discounted at 5% per annum Note: Absolute value
			BESS used to reduce midday summer exports by 2.5 kW	All EV charging moved from 6pm & 9pm to off-peak (Fully Shifted 3.7 EV)	BESS used to reduce midday summer exports by 2.5 kW AND all EV charging moved to off-peak (Fully Shifted 3.7 EV)	BESS, hot water storage, and EV charging used to reduce midday summer exports by 5 kW AND all EV charging moved to off-peak (Fully Shifted 3.7 EV)	BESS, hot water storage, and EV charging used to reduce midday summer exports by 7.5 kW AND all EV charging moved to off-peak (Fully Shifted 3.7 EV)	
0	Late electrification	Late solar and battery	1,941	6	1,949	4,207	5,362	5,780
		Early solar and battery	3,828	-1	3,829	8,627	11,509	11,945
	Early electrification	Late solar and battery	1,938	6	1,949	4,210	5,375	5,828
		Early solar and battery	3,824	3	3,829	8,622	11,484	11,948
1	Late electrification	Late solar and battery	1,939	13	1,955	4,215	5,371	5,790
		Early solar and battery	3,827	0	3,830	8,627	11,509	11,945
	Early electrification	Late solar and battery	1,941	88	2,029	4,293	5,423	6,003
		Early solar and battery	3,825	3	3,829	8,622	11,483	11,948
2	Late electrification	Late solar and battery	1,912	51	1,980	4,220	5,300	5,980
		Early solar and battery	3,828	-1	3,830	8,620	11,469	11,948
	Early electrification	Late solar and battery	1,925	372	2,321	4,591	5,212	7,659
		Early solar and battery	3,812	12	3,832	8,598	11,329	11,966

Table 20: The decrease in capex from the Unmanaged Electrification Base Case, giving the avoided capex from electrification. Results are scaled from the three EDBs' results to an indication only of New Zealand simply by multiplying by the ratio of all ICPs to ICPs in the study. This is equivalent to Table 17(a) but as a total capex estimate for New Zealand.

Peak demand growth (kW)	Electrification (including EV)	Solar and battery	Capex ($m), discounted at 5% per annum			Avoided capex from electrification as a proportion of Unmanaged Electrification Base Case capex
			Unmanaged Electrification Base Case (No PV or BESS) Note: Absolute value	Highly Managed PV Exports BESS, hot water storage, and EV charging used to reduce midday summer exports by 7.5 kW AND all EV charging moved to off-peak	Avoided capex from electrification by use of PV and BESS, after capex from PV exports has been managed (Unmanaged Electrification Base Case less Highly Managed PV Exports Test Case)	
0	Late electrification	Late solar and battery	421	418	4	1%
		Early solar and battery	421	436	-15	-4%
	Early electrification	Late solar and battery	469	452	16	3%
		Early solar and battery	469	464	5	1%
1	Late electrification	Late solar and battery	624	419	204	33%
		Early solar and battery	624	436	188	30%
	Early electrification	Late solar and battery	820	580	240	29%
		Early solar and battery	820	464	356	43%
2	Late electrification	Late solar and battery	2,380	680	1,700	71%
		Early solar and battery	2,380	478	1,902	80%
	Early electrification	Late solar and battery	3,884	2,447	1,437	37%
		Early solar and battery	3,884	638	3,246	84%

4 Conclusion

4.1 Capex drivers and reduction under electrification

Under the uptake rates in the scenarios considered, the capex requirements in almost all scenarios are substantial when PV exports and electrification peak demand go unmanaged. The per ICP capex requirement equates to in the order of \$200-\$300 per ICP per annum in the Unmanaged PV Export Base Case. This is roughly half what the capex would be if the upper voltage limit is not raised.

If PV exports are highly managed, by use of a BESS, hot water energy storage, local EV charging, and curtailment when necessary on peak generation days, capex requirements from PV exports can be reduced substantially. Under this case the resulting capex tends to be driven by peak demand growth. It can reach levels on the order of \$100 per ICP per annum under the high peak demand growth scenario, as shown in the Unmanaged Electrification Base Case.

Further capex reductions from the high peak demand growth scenario can be achieved by use of a BESS to reduce peak demand. This limits capex increases to the tens of dollars per ICP per annum or less. As shown in Table 17(a), solar and battery uptake at a similar or earlier time and rate as electrification is necessary to achieve these capex reductions. The last two rows demonstrate this for example, showing that avoided capex from electrification is higher with early solar and battery uptake. Viewed another way, early electrification that occurs before solar and batteries are installed will require additional network build out, which may result in some infrastructure stranded assets.

To achieve these capex reductions by a battery, time of use retail and buyback prices with a suitable battery controller are necessary, as identified in EECA's recent report on residential solar (Miller, Crownshaw and Gretton 2025).

4.2 The importance of managing EV charging

By virtue of moving EV charging away from the peak and scheduling it carefully in this study, most of the requirement for capex is from PV export and peak demand growth. As discussed above, these can be managed down to low capex requirements. However, if EV charging is not scheduled carefully away from the peak, while also avoiding the creation of new peaks, the additional capex due to EV charging and other peak demand increase can be substantial.

Considering this in conjunction with the earlier conclusions, it is concluded that well managed EV charging is essential, and combined with batteries for peak demand management, capex due to electrification can be reduced substantially.

4.3 Managing PV exports and consideration of lower capacity inverters with higher capacity arrays to lower summer exports and maximise winter energy

It is concluded that a combination of BESS and hot water storage with midday EV charging can reduce the capex increases from each scenario by about 70%. This reduces to 60% under high peak demand growth, early electrification and late solar and battery uptake. By further reducing PV export to a maximum of 2.5 kW via BESS, hot water energy storage, and curtailment the capex reduces by about 90-96%, or only 68% under high peak demand growth, early electrification and late solar and battery uptake. It is these highly managed reductions in PV export that avoid capex due to PV exports, and allow the BESS to further reduce capex by managing peak demand. Caution however must be exercised, as capex resulting from unmanaged PV exports can overshadow avoided capex from BESS peak demand management.

Solar export reduction by 5 kW or 7.5 kW, partly by charging an EV, would obviously require an EV uptake earlier than or at the same rate as solar, so is unlikely to work in the early PV and late electrification scenarios. Further, it requires EVs to be at the ICP, so its effectiveness (in terms of guaranteeing a 5 kW or 7.5 kW export reduction at times of peak export) may be limited. In that respect, more curtailment of exports in summer may be required. It may be better to consider lower capacity inverters (8 kW) with oversized arrays (DC:AC ratio of 1.3-1.4), so that more energy can be delivered in winter, and export reduction in summer to a level in the order of 2.5 kW can be achieved more easily. Further assessment of the capex implications of more winter PV export should be undertaken.

4.4 Nature of constraints

Many of the constraints due to PV are voltage constraints, and lead to the need for conductor replacements. The main constraints due to peak demand growth are conductor overloading, with some transformer overloading. Since the cost of replacing underground cable is so high, much of the resulting capex is due to cable replacement. Transformers provided as a second transformer to allow splitting existing LV networks is also a high cost, together with MV extensions (much of which is underground) and bus work.

Other than splitting networks and the need for new transformers, transformer replacements are a relatively small part of the capex required. This is partly due to using the 130% of nameplate capacity for transformers in winter. As demand increases, and as demand is shifted away from peak demand, it may result in transformers being overloaded for longer, thereby reducing their lifetime. Thus, the suitability of higher transformer loading limits may have to be reviewed at high electrification levels.

Overall, it is seen that, at the capacity and uptake levels forecast, PV tends to have a bigger impact on capex than EV and peak demand increases. The primary reasons for this are:

- The resulting PV export from 10 kW PV systems is close to 10 kW when demand is minimum in midday summer. This exceeds the after diversity maximum demand that most LV networks have been designed for, which is in the order of 3-5 kW. Further, even with the upper voltage limit at +10%, the ‘tapping up’ of distribution transformer secondary voltages gives less room for voltage rise resulting from the reversal of power flows.
- PV export occurs coincidentally in LV networks, meaning there is almost no diversity in PV exports.
- A threshold of 100% of each transformer’s nameplate rating is used in summer to determine overloading, instead of a higher limit such as 110%, due to expected high temperatures coincident with high solar generation. Thus, transformers do not have any ‘head room’ for overloading compared to peak demand in winter.
- EVs are modelled as largely shifted away from peaks and perfectly scheduled so as not to cause new peaks. Concentrating EV charging into peak periods does lead to large increases in capex, although not as large as very high PV exports.

The above further highlights the importance of managing PV exports down to avoid capex increases, and to gain the benefit of a BESS to manage peak demand and therefore avoid further capex.

4.5 Conclusions beyond the LV network

While this study has focused on LV networks, similar conclusions could be extended to MV and HV networks, through peak demand management. By extension, the avoided capex may be higher than calculated, although further investigation is required to quantify this. However, a large proportion of capex spend by EDBs is on renewals, and any overlap between renewals capex and capex due to electrification growth needs to be understood.

4.6 Improving energy management of all devices within a home or business

Finally, it is concluded that there may be more effective ways to reduce PV exports from high-capacity PV systems than hot water diverter and EV charger diversion. Control of these devices together by an energy management system, for example, can provide a more evenly spread export reduction throughout the day. In turn total PV exports could effectively be reduced by a greater amount.

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