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Understanding the value of residential solar PV and storage in New Zealand

An analysis of solar generation and demand data across regions under various price pathways

EECA
TE TARI TIAKI PŪNGAO
ENERGY EFFICIENCY & CONSERVATION AUTHORITY

Contents

DC:AC ratio – the ratio of nameplate PV array capacity to inverter capacity, sometimes referred to as inverter loading ratio

EV – electric vehicle

ICP – installation control point (for the purposes of this report, a residence connected to the electricity network; see the Electricity Industry Participation Code 2010 for a comprehensive definition)

LV – low-voltage

pa – per annum

PV – photovoltaic

TMY – typical meteorological year

ToU – time-of-use, referring to an electricity price structure that varies by time of day, and possibly by season

V2G – vehicle-to-grid

All prices given include GST, unless otherwise stated

'Export' refers to power flowing from the ICP to the electricity network

Disclaimer: All estimates of current electricity prices used by both AMCL and EECA are intended to be representative, and all future prices are intended to be explorative.

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Executive Summary

Residential rooftop solar photovoltaic (PV) generation is now one of the most accessible and cost-effective options to increase energy supply from renewable resources. The use of the technology has evolved from its inception to the present day, alongside dramatic cost decreases and rapid uptake around the world. It remains more expensive per unit of delivered energy than commercial- and utility-scale solar PV, however residential solar is distributed and connected ‘behind the meter’ in low-voltage distribution networks. This provides flexibility to the consumer when paired with storage, offering unique economic benefits both to the household and at the network and national levels.

This report presents the findings and recommendations of a year-long research project initiated by EECA to better understand the value proposition of residential solar PV, including with the addition of energy storage options. It investigates how the financial returns vary depending on a range of factors including: the electricity usage profile of the household, the local solar resource and electricity pricing, and the technical parameters of the installation such as capacity, orientation and tilt. Importantly, it also investigates how alternative electricity pricing structures affect the returns.

Aims of the study

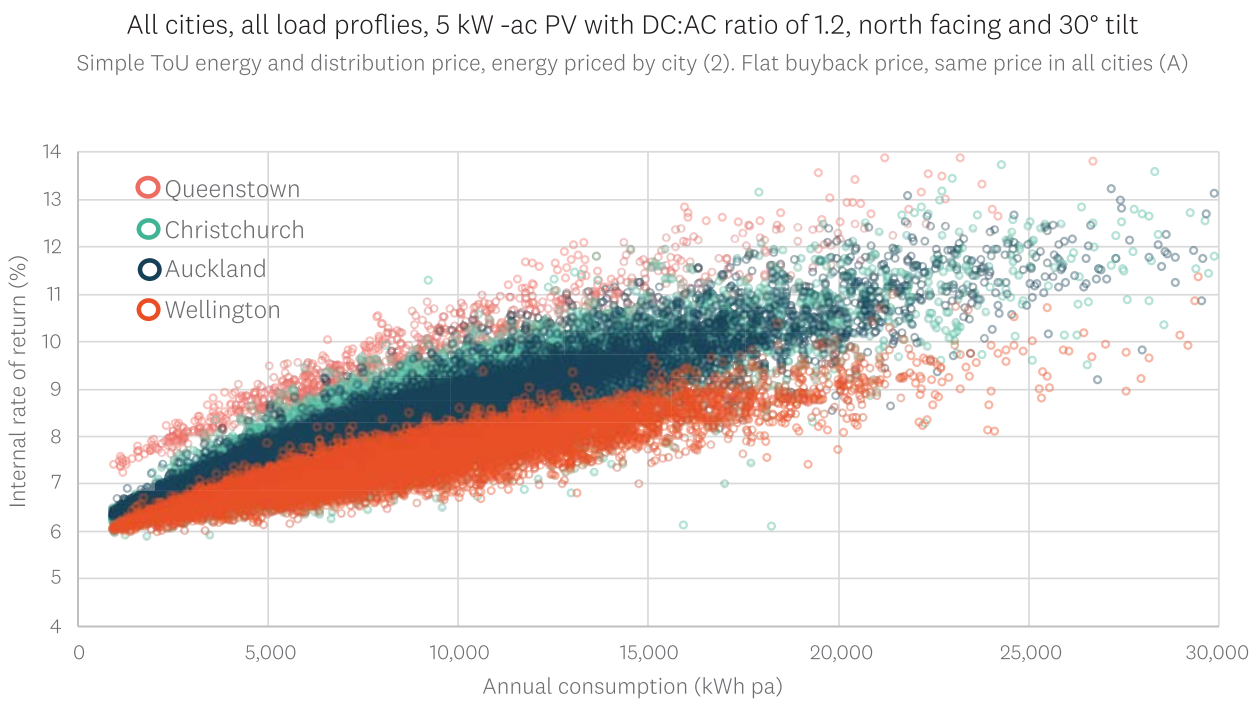
The central aim of this study is to examine the economics of distributed, residential rooftop solar PV across New Zealand to better understand its long-term value proposition. To achieve this, the study investigates in detail how the rate of return to a homeowner from solar PV varies both with and without storage under different price structures. From a system-wide perspective, this characterising of financial returns to households reveals the potential contribution residential solar PV plus storage may ultimately make to reducing peak demand during times of scarce generation and/or network capacity.

The economics of residential solar PV

Solar PV is likely to be financially viable for a significant proportion of households, particularly for high power consumers. Assessing the economics of solar PV for 47,000 consumers in Auckland, Wellington, Christchurch, and Queenstown indicates that rooftop solar is an investment that can provide internal rates of return above 8% and sometimes as high as 11-12%, albeit varying substantially by demand profile as shown in Figure 1 below. This is for our reference case, as indicated in the figure.

Results show that **financial returns tend to increase markedly with annual electricity demand** indicating that it is likely a better choice for higher consuming households. There are also substantive differences in returns both between and within cities included in the study for a given level of annual consumption. This stems from differences in retail prices and the solar resource between cities. Prices are highest in Queenstown, followed by Auckland, Christchurch, and Wellington, while the solar resource is best in Queenstown, followed, as with prices, by Auckland, Christchurch, and Wellington. As such, results show that **it should not be assumed that more northern locations are necessarily more suitable for residential solar PV**, or vice versa.

Figure 1 – The relationship between annual energy consumption and internal rate of return for solar PV (without storage) for each modelled household.



To facilitate studies of the impact of many other variables aside from location, eight distinct load profile types were identified, these being selected to represent various electricity usage patterns. While median financial returns for each load profile type only vary by a few percentage points, there is significant variation within each type (up to approximately two percentage points in the inter-quartile range and seven percentage points across the full range). This indicates that while there is a general trend for the highest rates of return to be realised from load profile types having relatively high energy use in daytime and the morning peak (7-11am), there are also other factors at play, such as overall consumption.

Using these eight load profile types, and with two levels of annual demand for each load profile type, the following variables were investigated to determine the impact on returns from solar PV:

- Retail price structure
- Power export limit for a residential ICP
- Solar PV capacity
- PV cost, real electricity price changes, panel orientation and tilt, and the ratio of panel to inverter capacity
- Relative impact of electricity pricing and solar resource

Key conclusions related to each of these variables are as follows:

- Financial returns from solar PV tend to fall as retail electricity prices become more time-of-use focused. Decreases in internal rate of return are up to three percentage points when moving from a simple two-rate to a more complex time-of-use plan, depending on location. This reflects the fact that solar PV does not closely match most electricity consumption in New Zealand, which follows a dual peak daily pattern with highest consumption in winter evenings.
- Increasing the export limit from 5 kW to 15 kW increases internal rates of return. The increase is up to one percentage point with a complex time-of-use plan, and lower for a simple two-rate plan.
- With 5 kW export limits in place, as required by some electricity distributors, the typical solar PV capacity providing the maximum rate of return is 3 to 5 kW-ac, depending on annual consumption. When the export limit is lifted to 15 kW, the optimal solar PV capacity rises to 10 kW-ac – the maximum capacity considered in this study. (Related to this point and the last concerning export limits, batteries can allow energy that would otherwise be 'spilled' with an export limit in place to be stored and used at other times, and can thereby improve returns of larger PV systems.)
- PV cost and real electricity price changes play a significant role in determining returns, as expected. Orientation is also significant, with east-west systems performing poorly relative to north facing systems. Tilt is less sensitive, although tilts of 30 degrees or above are preferable. A panel to inverter capacity ratio of 1.2 outperforms 1.0.
- Electricity price differences between cities have a significant impact on determining the variation in rate of return between cities. This is most pronounced for higher loads, and simpler tariff structures.

As implied by results shown in Figure 1, and the investigations using the eight load profiles, one way the rate of return of solar PV can be improved is to increase annual electricity consumption by switching from other fuels to electricity for such end uses as transportation (electric vehicles), water heating (electric hot water cylinders, or hot water heat pumps), and space heating. Pairing household electrification with solar PV will produce greater cost savings and concomitant reductions in greenhouse gas emissions, alongside other benefits not considered in this study, such as improved air quality.

A further conclusion from the analysis is that in some cases, the returns available from residential solar PV are comparable to utility-scale solar. However, further price reductions for residential solar PV are required for this to be the case for the majority of households.

Other less tangible benefits for residential consumers not examined in the report also exist, such as energy education (for example, being able to see real-time and historical consumption, generation and export via an app), and the opportunity to directly take part in New Zealand's renewable energy future, including electrification and greenhouse gas emissions reduction.

The economics of energy storage

Five different forms of short-duration energy storage paired with solar PV were investigated, to examine the impact of adding these to a solar PV system:

- A diverter, and a simple timer, applied to a hot water cylinder
- A 5 kWh battery, and a 10 kWh battery
- The utilisation of vehicle to grid (V2G)

Battery costs were modelled at 714 $/kWh for usable capacity, this being lower than current prices, but a level that is predicted to occur in the near term. Conclusions drawn on the returns from batteries are therefore likely to apply in the near term, with the returns available today lower.

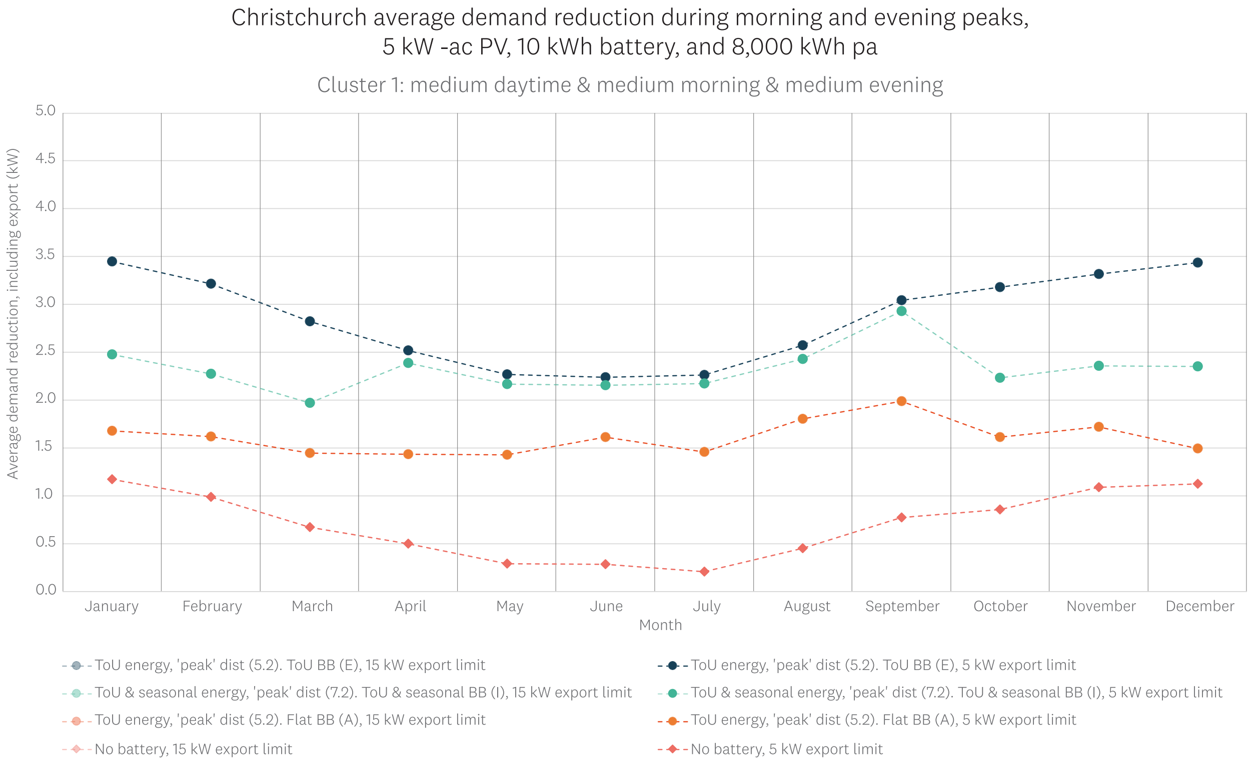
It was found that batteries can improve the economic value of solar PV, but are often outcompeted by the use of existing hot water cylinders for energy storage, such as by installing a diverter to direct excess solar energy into hot water heating. A simple timer can provide a similar benefit, but only for larger solar PV capacities above about 6 kW; this is because larger systems will more frequently provide all of the power required for electric hot water cylinders.

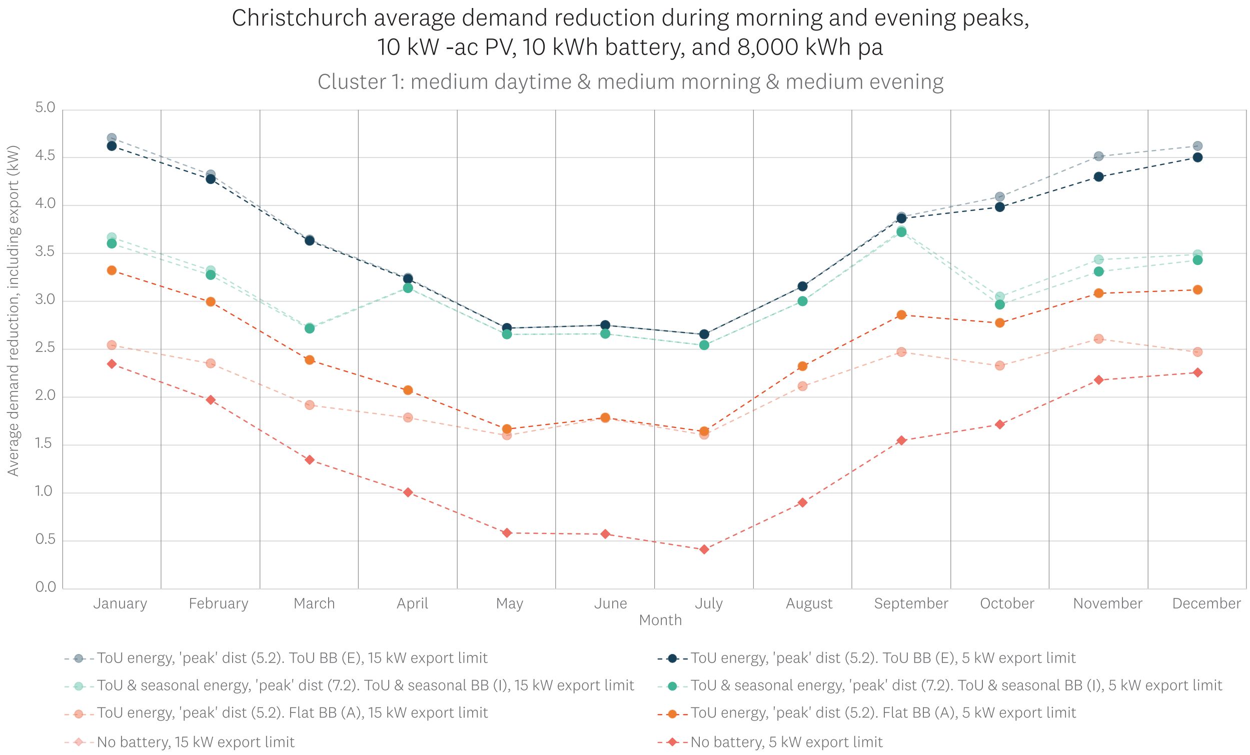
However, unique to **battery storage is the ability to supply other loads within a house, and potentially to export energy to the grid during winter peak periods.** As illustrated in Figure 2, only battery storage capable of responding to time-of-use prices allows significant reductions in peak period demand. At scale, this could reduce the need for peaking generation and distribution and transmission network investment. In turn, this would benefit all consumers through lower electricity costs, not just the owners of solar PV and battery systems.

Realising this outcome relies on the following important prerequisites, reflected in modelled scenarios included in this study:

- Cost-reflective time-of-use retail and buyback prices, with appropriate peak definition, are vital to gain suitable battery responses for optimal network load reduction.
- Battery control systems that can make use of both solar generation and time-of-use pricing to modulate battery charging are necessary.
- Batteries remain too expensive for many households; significant installed cost reductions of batteries in particular, but also solar PV, are required.
- Reliable after-sales support for solar PV and batteries is also crucial.

Figure 2 – Average reduction in peak period demand from solar PV with battery storage under varying time-of-use (ToU) retail and buyback (BB) price structures.[1] Note that for the 5 kW-ac PV system (a), the 15 kW export limit results align exactly with the 5 kW results because the inverter capacity is 5 kW.





1 'ToU energy, 'peak' dist' is a time-of-use retail price structure including distribution pricing compliant with the Electricity Authority pricing principles. 'ToU BB' is a time -of-use buyback price. Time-of-use time periods are peak, off-peak, and night-time. In the 'seasonal energy' case, retail prices and buyback prices are higher in from April to September to signal scarcer energy over the winter period.

Another form of battery energy storage that can add significant benefit with solar PV is vehicle-to-grid (V2G), whereby an electric vehicle is plugged into a V2G charger coupled to a home's AC system. The benefits of this option depend on the availability of an EV; the vehicle must be home and plugged in to be charged or discharged, and doing so must not void the manufacturer's warranty on the vehicle battery. The availability of reliable and affordable V2G chargers in New Zealand is also crucial. Assuming these hurdles can be overcome, the adoption of V2G presents significant opportunities for householders to reduce their electricity costs, and to bring online increasing supplies of low cost, low emissions electricity at the national level.

The impact of electricity price structures on solar PV with battery storage

As with the studies on solar PV without batteries, the impact of electricity structures was examined. One notable conclusion is that including a modest battery (5 kWh capacity) and opting for time-of-use prices (both retail and buyback) reduces the difference between the value of solar PV with and without an export limit. This demonstrates that battery storage can make better use of energy behind the meter than simply exporting it, particularly where pricing is cost-reflective, despite an approximate 10% loss of energy cycled through the battery.

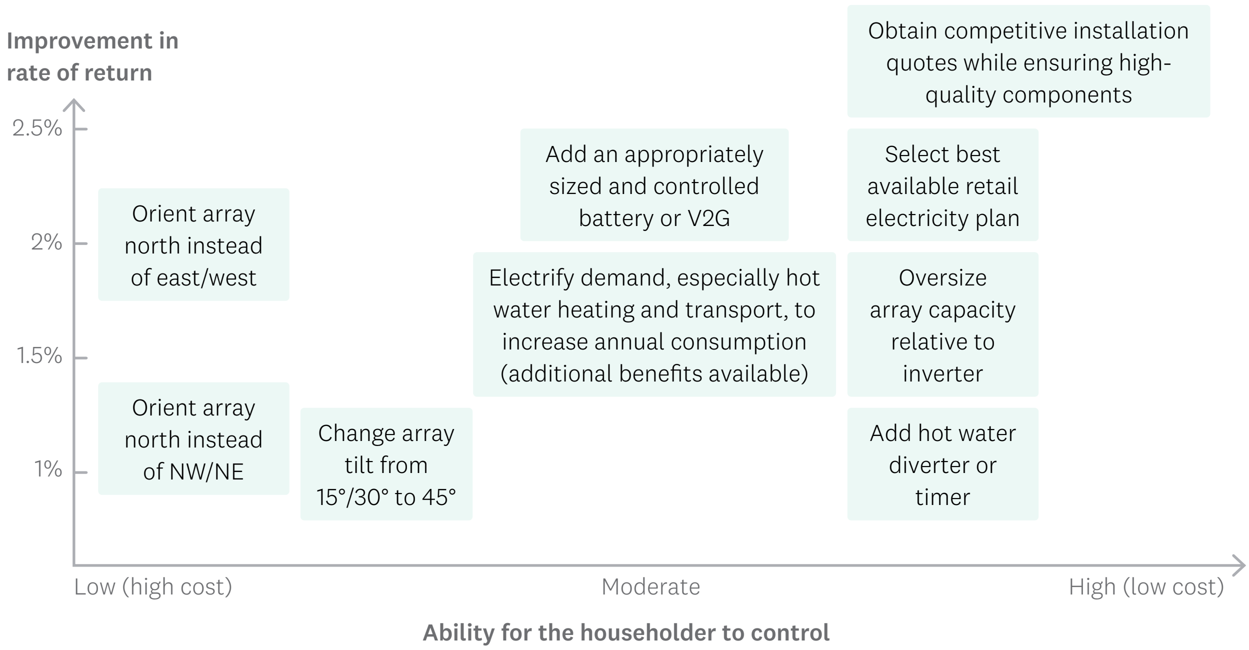
Despite the long-term benefits achieved through cost-reflective pricing, results show that simpler price structures such as 9pm-midnight free during weekdays may offer slightly higher financial returns overall. They are also far simpler for installers to set up, as the battery only needs a simple on/off control system. However, these plans can lead to substantial demand increases by ICPs during periods of low-cost energy (see Appendix 7.2 for details). With large-scale adoption, this may lead to high coincident demand, risking power quality, network loading, and security of supply.

The study also investigated the impact of providing additional buyback payments in peak periods on the economics of solar PV and battery storage systems. While additional buyback payments in peak periods obviously does improve the economics of solar PV with battery storage, time-of-use retail and buyback prices are similarly important in improving the economic performance of solar PV and battery systems.

Maximising value from an investment in solar PV

Options for households to maximise their returns from solar PV are summarised in Figure 3. The information produced in this study can benefit decision making, provided it is communicated in an intuitive and user-friendly format. Future work may target this, such as enhancements to the EECA Gen Less solar tool to incorporate new features, including battery energy storage, time-of-use price structures, and actual consumption profiles to allow consumers to accurately assess choices regarding solar PV and battery storage relevant to their unique situation. Such a tool would help consumers understand the combination of solar PV capacity, storage, and electricity retail plan most suitable for their needs.

Figure 3 – Options available to households to improve financial returns from solar PV, organised by ability to control (or cost to implement) and associated improvement in the rate of return.



Notably, non-standard solar PV system orientations, such as East and West facing arrays, are generally ineffective at improving morning and evening peak generation. There is simply insignificant solar generation early on winter morning and late on winter evenings during peak periods even in northern regions in New Zealand; with current panel costs, orienting arrays as close to North facing as possible remains optimal. Only batteries can meaningfully improve peak period availability of solar PV generation, as shown in Figure 2.

Key conclusions and recommendations

This report makes numerous conclusions and recommendations, described in detail in the following sections and summarised here:

- Residential rooftop solar PV provides a means for consumers to lower their electricity costs, particularly as they move more of their household energy consumption to electricity. Uptake of the technology also provides other less tangible benefits, such as greater understanding of energy as households monitor their own energy production and consumption, and a way to directly supply low-carbon energy and contribute to New Zealand's renewable future.
- Pairing battery storage with solar PV improves the matching of local electricity use and solar PV generation and can improve overall financial returns from solar PV in some cases. By reducing peak demand and contributing to ancillary services such as under-frequency reserve provision, benefits are produced for all consumers, through lower energy costs and a reduced need for network investment.
- Cost-reflective time-of-use prices, with appropriate peak definition, are vital to gain suitable battery responses to achieve peak load reduction and thereby deliver the benefits outlined above to consumers.
- There is a risk of coincident household demand and export causing rapid shifts in aggregate network load around both peak and low-cost period transitions. The industry needs to collectively work on solutions to mitigate this risk by incentivising residential demand smoothing.
- Battery control systems capable of responding to time-of-use pricing and variable solar generation are necessary, but not yet ubiquitous.
- Batteries are currently too expensive to provide net economic benefits for many households, particularly lower consumers and those who contribute little to peak demand. This implies that significant cost reductions for batteries, achieved through economies of scale, are required to unlock the widespread adoption of residential energy storage in New Zealand.

1. Introduction

The Earth exists in a stable energy balance where the roughly two-thirds of the energy radiated by the Sun and incident on Earth is absorbed and then eventually re-radiated to deep space as infrared radiation. This balance provides a stable temperature suitable for life. The remaining one third is simply reflected by the Earth, its atmosphere, ice cover, and clouds. 173 petawatts (PW) of power from the sun is incident on the Earth each year, which is less than one billionth of what the Sun radiates in all directions.

If just one hundredth of a percent (0.01%) of this energy incident on Earth could be captured and utilised, it would exceed the current world's electricity consumption by a factor of six. This power approximates the total energy, of all forms, currently used by the world each year.

The goal of harnessing sunlight directly and converting it to electricity emerged in 1839 when Edmond Becquerel created a photoelectric cell. Einstein published his theory of the photoelectric effect in 1905, which won him the 1921 Nobel prize in Physics. It became a reality with the invention of the first photovoltaic cell at Bell Labs in 1954, and the deployment of photovoltaics to power the USA Vanguard satellites and the then USSR's Sputnik satellite in 1958. For decades it remained an expensive technology, out of reach of the average person. However, in the last 15-20 years, improvements in manufacturing practices and economies of scale have led to significant cost reductions in photovoltaics, with subsequent deployment at large-scale.

In 2023 alone around 500 GWp of PV modules were manufactured, mostly in Asia, with exponential growth since 2008. Global solar PV installed capacity surpassed 1,400 GWp in 2023, including both large-scale solar farms and residential rooftop solar installations. Australia leads the world at roughly 1,166 watts/person in 2022. The Netherlands and Germany were second and third at 1,040 and 807 watts/person, respectively. As of 31 December 2024, New Zealand had a total installed capacity of 576 MWp, equating to about 108 watts/person, with over 2,500 MWp of additional large-scale solar projects being considered.

While New Zealand lags far behind Australia in installed solar PV capacity, 108 Watts/person is a significant increase from just 8 Watts/person only 10 years ago. With solar PV installed at just 68,000 of the more than 2,000,000 ICPs, mainly residential, New Zealand has plenty of remaining potential to increase renewable supply from our solar resource.[2]

EECA has investigated commercial solar in depth previously (Miller and Gretton, 2021). This study builds on that work by examining the economics of distributed, residential rooftop solar (referred to herein as solar PV) to better understand its underlying value proposition and discusses how such benefits vary in the context of changing local- and system-level factors. It also compares the economics of investments in residential solar to that of commercial- and grid-scale alternatives.

[2] An ICP is an installation control point, where electricity is supplied to a building usually.

This report examines the economics of solar PV by first describing a typical residential solar installation and where benefits stem from for the householder. The report then sets out the key aims of the study, chosen methods to assess the benefits of solar PV to the householder, and the data required for these methods.

Following this, the report assesses solar PV with and without storage, and under varying electricity pricing structures including export prices designed to incentivise more power export during peak demand periods. Throughout, there are discussions on related aspects, such as the wider impact of solar in local networks, how solar generation and use might be maximised locally, and the prospect of enhancing energy supply resilience with solar PV. The report concludes with a discussion of results from the study and final conclusions.

The report is structured as follows:

- Section 2 describes a typical residential solar installation and the associated value streams for the householder.
- Section 3 sets out the aims of the study and describes the quantitative modelling approach used to achieve these aims, including general methodology and data required for the study.
- Section 4 details the benefits of residential solar PV without storage.
- Section 5 builds on Section 4 by considering the combined benefits of residential solar PV and storage. It assesses the benefits of solar combined with a variety of types of storage.
- Section 6 builds on Section 5 by comparing the benefits of solar with storage under different retail and buyback price structures to understand how these benefits can be expected to change among different contexts and over time. Included in this analysis is the use of electricity buyback prices designed to reward more power export over peak periods.
- Section 8 provides a summary of findings from each section, key conclusions, and corresponding recommendations for consumers and for industry.

Detailed technical appendices expand on Section 3 and help explain aspects of Section 5.

2. The benefits of residential solar to consumers

A typical residential solar installation is comprised of rooftop mounted solar panels connected to a central string inverter, or micro inverter at each panel. The AC output from the central string inverter or micro-inverters is then coupled directly into the household's AC electricity system, via appropriate isolators, at the switch board. Figure 4 illustrates the configuration of a typical solar installation. It also shows the way in which a battery and hot water cylinder can be integrated; both of which provide a means of storing solar energy for later use. A two-way import/export meter, installed in the meter box, is required with the solar installation to measure the imported energy (as is usually the case with electricity supply), and the exported energy that results from solar generation exceeding a household's electricity use.

Figure 4 also depicts a 'PV system smart meter' in the switchboard. This is usually a proprietary device that is paired with the solar inverter and is typically supplied by the same manufacturer. This provides higher resolution measurement of import and export volumes, and can often measure technical performance parameters, such as voltage, current, active and reactive power, and phase angle. The smart meter is connected to the internet via the household's broadband connection (either Wi-Fi or wired) and provides the householder with both current and historical information on their electricity use and generation.

Figure 5 shows some examples of instantaneous electricity consumption, solar generation, and export data for a PV installation with an 8.2 kW inverter. Figure 6 shows the historical daily consumption, solar generation, and self-consumption of a solar PV installation.

For residential solar, the financial benefits to the consumer stem from two main sources:

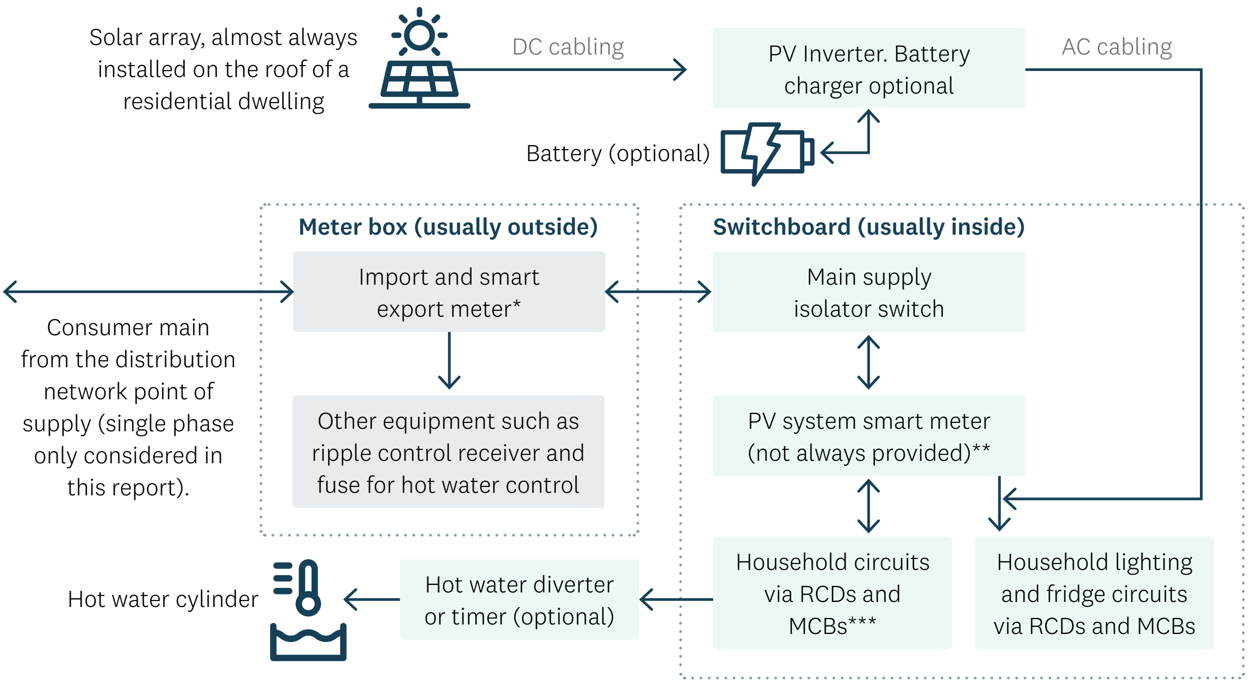
1. Self-consumption of solar generation, which lowers the energy purchased from the retailer and therefore reduces the electricity bill.
2. Export of excess solar generation at a buyback rate set by the retailer, creating a revenue stream that further reduces the household electricity bill and may even lead to a credit, particularly in summer months.

With reference to Figure 6, the yellow areas are where solar is self-consumed. In Figure 6(a), the consumer has adjusted their demand automatically using a hot water diverter to heat hot water during the day, as well as trickle-charge an electric vehicle later in the day. Assuming the retail price of electricity was 31 c/kWh, the self-consumption of 23.08 kWh saves the consumer $7.15 on that day alone. If this is maintained over a year, the cost saving would amount to over $2,000. However, this does not occur in practice, as solar generation is lower in autumn and spring, and even lower in winter, such as in Figure 6(b), where the reduction in the bill would be just $5. Note that the examples in Figure 6 are days when there is little cloud cover, yet New Zealand's weather sees numerous cloudy days in most areas.

The orange areas in Figure 6 indicate exported energy. In the example depicted in Figure 6(a), 41.5 kWh is exported. With an export price of 14 c/kWh the exported energy would result in a $5.81 credit for this day. As before, this would be lower in winter months, for example, Figure 6(b) where only 9.5 kWh is exported equating to a credit of $1.33.

The rate of return on capital outlay required to access these economic benefits is the primary component of economic value this report considers. The next section sets out the aims of the study more explicitly, and discusses the model used to calculate the rate of return, as well as additional performance metrics.

Figure 4 – A typical solar installation. Shown here is a string inverter, with DC (direct current) cabling from strings of solar panels wired in series to the inverter. Alternatively, a micro inverter can be attached to each panel, with AC cabling directly from the micro inverters at each solar panel to the switchboard. An alternative 'AC coupled' configuration for batteries, where they are wired directly into the AC system without the need for connection through the inverter. Micro inverters and AC coupled storage are often used in tandem, and with an off-grid inverter can fully supply a house during power outages, with an almost instantaneous change over from grid to batteries at the onset of an outage.



* An export meter is required when installing solar to measure the energy exported. Depending on the retailer and metering equipment provider, this may be a separate meter or the import and export meter may be combined into one meter. This study includes the cost of the new meter.

** The PV system smart meter usually connects the system to an app allowing the user to see real-time and historical electricity use, solar export, and self-consumption.

RCD Residual current detector, provides protection against electrocution, but must never be relied on. Isolation of the supply, with a warning tag, is vital when working on a circuit.

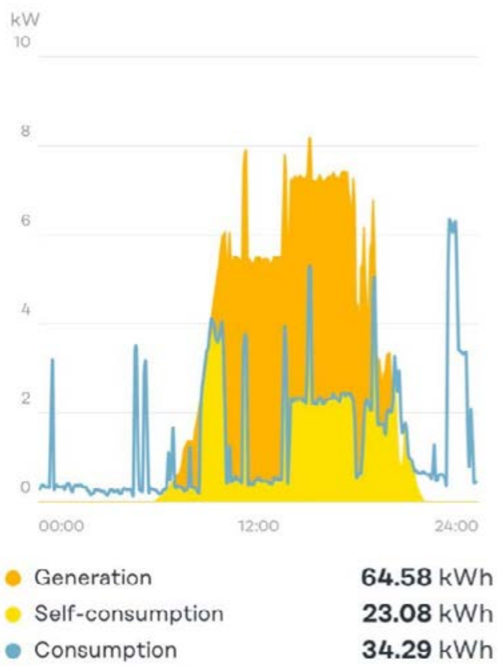
MCB Miniature circuit breaker. A vital protection device that limits the current on a circuit so as to not overload it, and thereby protect it from overheating and becoming a fire risk.

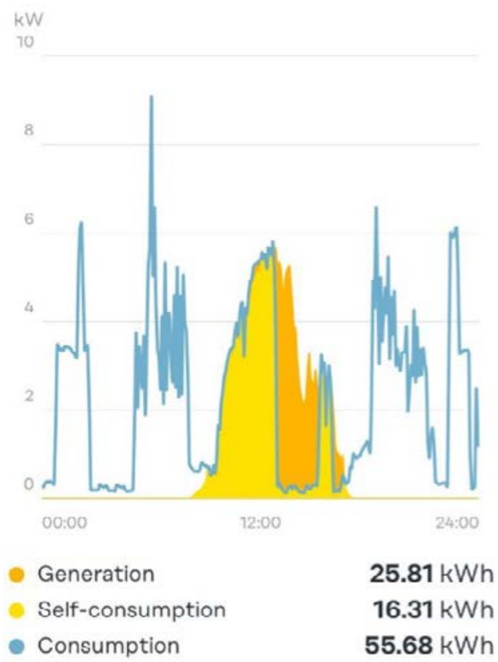
*** These may be configured to isolate when the network supply is lost if a battery is present, so as to supply just lighting and essential appliances.

Figure 5 – Instantaneous electricity use, solar generation, and export data are available from the 'PV system smart meter', often installed in conjunction with the inverter. In the example shown in the left panel, the instantaneous household load is 2.77 kW and the solar generation is 7.74 kW, resulting in 4.97 kW exported. A few minutes later, shown in the middle panel, the instantaneous household load is 7.24 kW and the solar generation is 8.17 kW, resulting is 0.93 kW exported. The third panel example is showing import from the grid, as is typical in the early morning the instantaneous household load is 0.632 kW and the solar generation is 0.299 kW, resulting in 0.333 kW of import. This system does not have a battery installed.

Figure 6a – Residential electricity use and solar generation on a summer day. When the generation exceeds the use (orange), excess power is exported to the electricity network. In this example, there is a 5 kW export limit, resulting in capping output of the 8 kW inverter capacity. High self-consumption in the morning (the yellow area) is due to the hot water diverter (heating water via a hot water cylinder).

Figure 6b – Residential electricity use and solar generation on a winter day. As in the case of the summer day, the high self-consumption is due to the hot water diverter and space heating during the morning and evening periods.





3. Purpose of this study, general methodology, and data requirements

The central aim of this study is to examine the economics of residential rooftop solar to better understand the value proposition of distributed, residential rooftop solar PV generation. To achieve this it:

- Investigates the rate of return of solar PV to a homeowner, firstly without storage, and then with various forms of storage.
- Then investigates the rate of return of solar with storage under different pricing structures. The purpose of this is to understand the changing value proposition of solar and storage and how it might contribute to reducing peak demand during times of scarce generation and network capacity, or in some circumstances increase demand.

  Pricing structure variables include changes to distribution price in line with the Electricity Authority's distribution pricing principles, more cost reflective energy pricing, and a shift in energy prices by season that reflects greater energy scarcity in winter months. They also include higher buyback rates in peak periods to understand how this might improve the value of solar and storage.

The investigation is carried out over four cities: Auckland, Wellington, Christchurch, and Queenstown. These were selected as major populations in the case of the first three, and a rapidly growing population centre in the case of Queenstown, and to align with forthcoming studies by EECA related to home heating.

To carry out these aims the study uses a solar rate of return model from ANSA®. This assesses the economic benefits of solar discussed in the previous section given the investment required. It also models storage, including hot water storage (using a diverter and timer) and battery storage (both stationary batteries and vehicle-to-grid, V2G). As indicated in the previous section this requires the following information:

- Cost of the solar PV hardware and installation and associated equipment such as storage.
- The consumer's ICP load profile over a year to cover all seasons.
- Solar generation over a year to cover all seasons at the consumer's ICP location, and that matches the characteristics of the solar PV such as capacity, roof orientation, and panel tilt.
- Retail electricity prices by time-of-use and solar buyback prices by time-of-use.

The details of the solar rate of return model are set out in Sub-section 3.1, and Sub-section 3.2 discusses each piece of information required from the above list. Supporting the model and the information requirements are nine appendices, all separate documents to this report. These are referred to from each of the following two sub-sections.

3.1 General methodology and model used

3.1.1 Core model

At its core the model used to estimate the financial benefit of solar is a discounted cash flow. This is the same as used in the EECA Gen Less. solar tool, with the following differences:

- Half-hourly analysis instead of hourly analysis is used.
- Real analysis is used. As such, prices and costs are not inflated, and the discount rate used is a real rate. All prices used in the model are related to the beginning of the 2025 calendar year. The real discount rate used is 5%, although results reported are the internal rate of return rather than net present value. This allows comparison across many different PV capacities and therefore capital costs.
- The number of years the model is discounted over is 29 years, whereas the EECA Gen Less solar tool uses 25 years. A period of 29 years is used as a means of estimating the residual value of the PV and battery installation after 25 years and effectively incorporating that in the cash flow.
- The model determines and stores numerous parameters in addition to rate of return, including levelised cost of energy (LCOE), discounted and simple payback times, self-consumption energy and cost saving, exported energy and cost saving, battery cycles, and battery levelised cost of storage (LCOS).
- The model is also able to measure exported energy during pre-defined peak periods, and determine the cost of those exports to a distributor, if the distributor is required to pay for peak period exports at a given price. This addition was made at the request of the Electricity Authority to assist with the Competition Taskforce Part 2, in which it was of interest to understand the effect of increasing the buyback price at peak times, funded by distributors.
- The model includes a battery model, which also includes V2G.

A further difference from the EECA Gen Less solar tool is the inclusion of infrastructure around the core model to run it many times to assess different combinations of PV systems, locations, and consumers. This includes:

- A Base Case and several further cases to assess sensitivities to certain inputs.
- Base Case variables:
  - Retail prices
  - Cities
  - Load profiles
  - PV system capacities
  - Storage
  - Battery capacity if battery storage is selected

With six different retail prices, four cities, eight load profile types, six PV capacities (including 0 kW), five combinations of storage type and capacity, and two different export limits, this gives rise to roughly 12,000 combinations of system. This is a prohibitive number to analyse, thus the combinations are narrowed to specific cases, with each case relating to each of Sections 4, 5, and 6. Appendix 7 explores solar generation by orientation and tilt in more detail.

3.1.2 Modelling approximations

Several approximations are necessary in modelling the rate of return of solar. Some of these are listed below.

1. The same load profile is used across all 29 years of the cashflow, which assumes that a consumer does not change their electricity consumption or time-of-use. It is inevitable that any given consumer will change their consumption, and that this is likely to increase as electrification progresses. The consumer may also change their time-of-use of electricity either through changing lifestyle and/or response to changing retail price structure.
2. The same retail and buyback prices are used over the 29 years of the cashflow, which assumes that the consumer does not change their retailer, and that retailers do not change the level and structure of their prices. It is inevitable that both will change.
3. A typical meteorological year (TMY) is used to model solar generation, whereas it is known that solar generation changes by as much as 10% from one year to the next. If solar generation was significantly higher or lower in the early years of the discounted cashflow, when the resulting cashflow experiences less discounting, the modelled result would differ from the actual.
4. Solar data for each city is selected from one location in each city (as per the TMY file), whereas the ICPs used in the model are from a broad area of each city. There may be differences in solar generation from the single solar location in each city and each ICP, as well as local shading from topography, trees, and other buildings at each ICP’s location. Such effects on solar incident on a site are not accounted for.
5. Another issue with the use of a TMY is that load may be correlated (or anti-correlated) with solar generation at any point in time, an effect that may be lost by using TMY solar generation.
6. The model is half-hourly, whereas the process of solar lowering self-consumption, and possibly leading to export, is a continuous one. More accuracy might be gained by modelling at a higher time resolution.

The impacts of the first two approximations are potentially large but unavoidable, since future changes in the inputs discussed in them are unknown, and not in the scope of this project to forecast or estimate. Approximation 3 leads to results which are equally balanced between under- and over-estimating returns and represents the best approach to dealing with the uncertainty of the solar resource. Approximation 4 introduces no significant error for sites which have essentially the same weather/climate as at the weather station and have no local shading; while these local weather and shading factors could have been considered, they were not the focus of the study.

Approximations 5 and 6, modelling of the benefit of solar from a TMY at a half-hourly resolution, are both approximations to the continuous offsetting of load by actual solar generation illustrated in Figure 5 and Figure 6 of the previous section. Two separate appendices to this report investigate these approximations and how they affect the results in this study. They are:

- **Appendix 1:** *Assessing residential solar at different time scales*, which uses 1-minute resolution household load and solar generation data collected by researchers from the University of Otago and compares the benefits of solar calculated using that resolution with the same data at 30-minute resolution, as used in this study.[3]

  The main conclusion from Appendix 1 is that analysis at a lower resolution of 30-minutes shows a more positive benefit of PV than PV will provide. However, rate of return differences are quite small – roughly 1-2% higher at 30-minute resolution compared to 1-minute resolution. The increase in rates of return is more pronounced at lower PV capacities and varies by household consumption. Higher consuming households tend to have higher rates of return with 30-minute resolution load and solar, especially if consumption is higher during the day.

  Overall, the increase in rates of return from 30-minute resolution data is so small that it is considered insignificant compared with the first two approximations. The use of half-hourly data is therefore suitable for such modelling.

- **Appendix 2:** *Assessment of TMY versus actual year solar generation and the suitability of TMY generation for assessment of residential solar performance*. This appendix uses half-hourly resolution typical meteorological year (TMY) solar generation and half-hourly resolution solar generation from the same year from which household load data was collected (discussed later) and compares solar model results from both. It also compares correlations between load and TMY solar generation, and load and actual solar generation.

  The main conclusions from Appendix 2 are that there is a weak negative correlation between load and solar generation, and that this negative correlation strengthens when solar generation from the same period as load is used. For example, in this assessment, actual 2023 calendar year solar generation is used instead of TMY derived solar generation. However, the correlation remains weak, and any error introduced from the stronger negative correlation of load and solar is overshadowed by the change in solar generation itself. The change in solar generation from year-to-year itself has more of an effect on the results (rate of return) than the increased relationship between load and solar generation.

3.1.3 Further supporting model documentation

The following two appendices provide detail of the diverter and battery models used. The battery model appendix is written to support the discussion in Section 5.

- Appendix 3: *Diverter and timer model*
- Appendix 4: *Battery model description*

[3] As part of the University of Canterbury led and MBIE, Transpower, and EEA funded GREEN Grid research programme.

3.2 Summary of data required

3.2.1 Cost of the solar installation and batteries

Capacities of solar considered in this study and the costs of the solar installation are summarised in Table 1. Costs are based on known information about PV system costs and results from a SEANZ survey from late 2024. More detail of the costs and how they were derived is given in the accompanying separate Appendix 5, *solar PV and battery capacities and costs*. Table 1 includes the costs of all PV equipment and its installation, as well as overhead costs of the export meter, distributor application fee, and inspection fee. The overhead costs in the total PV system costs in Table 1 are $310 per installation, with more detail given in Appendix 5.

Battery capacities and costs are summarised in Table 2, with detail given in Appendix 5.

Table 1 – Capacities of residential rooftop solar modelled, and the total system costs including all overheads and GST. A capacity of 0 kW-ac is included to understand the performance of a battery without solar. In this case the cost relates to the inverter required for the battery and the overheads of an export meter, distributor application fee, and inspection fee.

	"DC:AC ratio of 1.0 (PV array capacity equals the inverter capacity)"		"DC:AC ratio of 1.2 (PV array capacity is 20% higher than the inverter capacity)"	
PV system AC capacity	PV system DC capacity	Total PV system cost with DC:AC ratio of 1.0	PV system DC capacity	Total PV system cost with DC:AC ratio of 1.2
kW-ac	kWp-dc	$	kWp-dc	$
0.0	0.0	$1,810	0.0	$1,810
3.0	3.0	$7,810	3.6	$8,410
5.0	5.0	$11,560	6.0	$12,560
6.0	6.0	$13,510	7.2	$14,650
8.2	8.2	$17,448	9.8	$18,744
10.0	10.0	$20,310	12.0	$21,810

Table 2 – Battery capacities and costs modelled, including all overheads and GST. A capacity of 0 kWh applies to the case of solar PV only. The battery capacity given is after a 70% depth of discharge, so for a 10 kWh battery the nameplate capacity is 14.3 kWh.

Battery capacity after 70% depth of discharge (kWh)	Discharge rate (kW)(1)	Charge rate (kW)(2)	Round trip efficiency	Cost ($/kWh)	Operating and maintenance cost ($/kWh/cycles exceeded in year as a ratio of 11,000 cycle limit)
0				$0	$0
5	PV inverter AC capacity	PV inverter AC capacity	90%	$3,571	$714
10	PV inverter AC capacity	PV inverter AC capacity	90%	$7,143	$714
30 (V2G)(2)	10 kW	10 kW	90%	$6,000	$714

(1) Defaults to 5 kW if PV capacity is zero.

(2) Modelled as a special case only. The cost given is for the V2G charger/inverter. The EV battery cost is not included in the model.

3.2.2 Consumer ICP load profiles and load types / load profile clusters

The study obtained more than 49,000 consumer load profiles from the four cities. After selecting load profiles for single phase residential ICPs this became 47,045. Initially, a simplified model is used to assess all 47,045 load profiles. Subsequently, the load profiles were classified into the eight different load types (clusters) given in Table 3, each assessed with varying storage options and pricing structures. The classification of load profiles is discussed in detail in the accompanying Appendix 6, *Selection of representative load profiles*. No demographic information was available for each load profile, so it was not possible to classify them based on demography. Instead, parameters derived from the load profiles were used to classify them. As described in Appendix 6 numerous parameters were evaluated and eventually narrowed to the three given in Table 3.[4]

Because the load profiles were classified according to their characteristics rather than demographics, the report refers to the clusters in Table 3 and Table 4 as load profile types or just cluster rather than consumer types.

4 For brevity, the key parameters used to define clusters are shortened as follows, with these terms used throughout this report:

- the ratio of average daytime to average all-day demand is referred to as the *daytime demand ratio*. Daytime is 7am to 11pm and covers all days of the year;
- the ratio of average weekday morning peak to average all-day demand is referred to as the *morning peak ratio*. Morning peak is 7am to 11am, and weekdays include public holidays if they fall on a weekday; and
- the ratio of average weekday evening peak to average all-day demand is referred to as the evening peak ratio. Evening peak is 5pm to 9pm.

Table 3 – Classification of load profiles into load profile types (clusters), with the parameters used to classify them.

Load profile cluster	Ratio of average daytime load to average all-day load over the year (daytime demand ratio)	Ratio of average weekday morning peak load to average weekday load over the year (morning peak ratio)	Ratio of average weekday evening peak load to average weekday load over the year (evening peak ratio)
0	Medium	Medium	Medium
1	Very high	High	Very high
2	Very high	Low	Very high
3	Low	Low	Medium
4	High	High	High
5	High	Low	Very high
6	Very low	Very low	Low
7	Very high	Very high	High

The number of load profiles available from each city, and classified into each cluster, is given in Table 4.

Table 4 – Number of load profiles by load profile type (cluster).

Cluster	Total number of load profiles selected	Number of load profiles selected from			
		Auckland	Wellington	Christchurch	Queenstown
0	7,562	2,227	1,758	3,358	219
1	7,361	2,726	1,721	2,794	120
2	3,875	1,529	897	1,387	62
3	4,115	473	783	2,821	38
4	8,646	2,800	2,028	3,573	245
5	9,388	3,784	2,112	3,359	133
6	1,916	47	272	1,588	9
7	4,182	987	943	2,158	94
Total	**47,045**	**14,573**	**10,514**	**21,038**	**920**

3.2.3 Solar generation

Solar generation for each city for the TMY was obtained from ANSA®'s solar farm generation model (ANSA-SolarFarm). This model uses the meteorological parameters such as irradiance, temperature, windspeed, humidity, and precipitation required to determine the generation output of a PV module over a 54-year period at half-hourly resolution. It uses a machine learning model to backfill poor quality ground-based readings. The model is trained using ground-based measurements, satellite data, and weather re-analysis data. Rooftop mounted arrays with monofacial PV modules are assumed since residential PV arrays are almost always mounted against the roof on racks, with only a small separation between the roof and PV modules. More information about the model, and solar performance is given in Appendix 7: *PV solar generation data and performance.*

The system configuration used for most of the study, and referred to as the base case, is a north facing roof and array, with a 30° slope from horizontal. Of course, not all homes have a roof with a north facing orientation on which to mount PV panels, and roof slopes vary considerably from almost flat to steep. For these reasons, several other configurations are considered and tested as sensitivities from the base case. These are covered in Sub-section 4.3.

The TMY solar generation data for each city provides the same number of samples as the load data, with care taken to ensure the two correctly align in time. This ensures that such differences as half-hour ending with no daylight-saving shifts (solar data) and half-hour starting with daylight saving shifts (load data) are managed.

While Appendix 7 gives detailed information about the performance of solar, including performance by month of the year, it is so germane to this study that some details are also provided in the following tables. Table 5 shows annual capacity factors for the main array modelled (north oriented roof with 30° slope) as well as a several other orientations and slopes, which cover the sensitivities investigated in Sub-section 4.3. Capacity factor gives a measure of the capacity of a renewable generator (PV solar in this case) that can be converted to energy. For example, the capacity factor of the north facing array with 30° tilt from horizontal, oversized by 1.2 x the inverter capacity in Auckland is 0.181. This means that, on average in a typical year and the first year of operation, a 5 kW-ac PV system will produce 0.181 x 8,760 x 5 kW-ac = 7,928 kWh of energy.

Given that New Zealand is a winter peaking electricity system, and has associated higher energy demand, the difference between summer and winter generation at different orientations and tilts is of interest. It is likely to have a bearing on the financial performance of solar, especially for consumers who have seasonal pricing.

Table 6 gives the ratios of average energy generated in June relative to January. A north facing array with a higher tilt angle from horizontal produces the most energy in winter, while the least energy in winter is produced by arrays mounted east and west. As noted, not all roof orientations allow north facing arrays with high tilt angles. The results in Section 4.3 demonstrate the solar PV performance differences between tilt angles. Further, even though a roof with a higher slope gives a higher winter generation performance, adding additional racking infrastructure to increase the tilt of PV modules on a lower sloped roof will increase the cost of a PV system and introduce shading from one row of PV models to the next at certain times of the day and year. Neither of these are tested in this report, and may negate the benefit of a higher slope.

Table 5a – Annual AC capacity factors at various tilts from horizontal and roof (and array) orientations for modelled solar PV generation for an inverter loading ratio of 1.2

City	Tilt angle	North	Northwest	1/2 east & 1/2 west
Auckland	15°	0.170	0.161	0.149
	20°	0.175	0.164	0.148
	30°	0.181	0.166	0.146
	45°	0.183	0.163	0.139
Wellington	15°	0.167	0.158	0.147
	20°	0.171	0.160	0.145
	30°	0.177	0.162	0.142
	45°	0.179	0.159	0.134
Christchurch	15°	0.167	0.160	0.145
	20°	0.172	0.162	0.144
	30°	0.178	0.166	0.141
	45°	0.180	0.164	0.133
Queenstown	15°	0.184	0.176	0.159
	20°	0.190	0.180	0.158
	30°	0.197	0.183	0.153
	45°	0.199	0.182	0.145

Table 5b – Annual AC capacity factors at various tilts from horizontal and roof (and array) orientations for modelled solar PV generation for an inverter loading ratio of 1.0. All results are for the first year of operation and a TMY.

City	Tilt angle	North	Northwest	1/2 east & 1/2 west
Auckland	15°	0.141	0.134	0.124
	20°	0.145	0.136	0.123
	30°	0.151	0.138	0.121
	45°	0.153	0.136	0.116
Wellington	15°	0.139	0.132	0.122
	20°	0.143	0.134	0.121
	30°	0.148	0.135	0.118
	45°	0.149	0.132	0.112
Christchurch	15°	0.139	0.133	0.121
	20°	0.143	0.135	0.120
	30°	0.148	0.138	0.117
	45°	0.150	0.137	0.111
Queenstown	15°	0.153	0.147	0.132
	20°	0.158	0.150	0.131
	30°	0.164	0.153	0.128
	45°	0.166	0.152	0.120

Table 6 – Ratio of June to January average monthly solar energy generation, after accounting for the number of days per month. Inverter loading ratio of 1.2.

City	15° degree tilt			30° degree tilt		
	North	Northwest	1/2 east & 1/2 west	North	Northwest	1/2 east & 1/2 west
Auckland	37%	33%	26%	48%	41%	28%
Wellington	30%	27%	20%	40%	33%	22%
Christchurch	33%	29%	21%	45%	36%	24%
Queenstown	32%	28%	20%	44%	35%	22%

3.2.4 Electricity prices

While the configuration and capacity of a PV system determine the amount of self-consumption and export, the retail electricity price and buyback price are required to determine the cost saving and income generated by the PV system. A range of prices are used throughout the modelling to understand solar PV performance with retail and buyback prices and structures obtainable now and potentially available in the future. Retail prices are covered in Sub-section 3.2.4.1, with buyback prices covered in Sub-section 3.2.4.2. Sub-section 3.2.4.3 shows the prices that are used throughout the results sections.

The prices summarised in this section are discussed in Appendix 8 in detail. As discussed in Appendix 8, transmission prices are built into distributor prices as fixed charges rather than unit prices. Further, any time-of-use costs associated with the transmission network at a given location, that reflect capacity of the transmission network, are built into retail prices. This is because losses and constraints on the transmission network are incorporated in nodal spot prices, which are paid for by traders (retailers).

Instantaneous reserve provision is included in the model with battery energy storage. This is priced at roughly half the historical price, assuming that the additional provision of reserves from distributed battery storage will reduce the reserve price, and that an aggregator of the many distributed battery systems will include a margin for the aggregation service.

3.2.4.1 Retail price structures and prices

The retail price structures are summarised in Table 7 with the retail prices shown in Figure 7 to Figure 10.

Table 7 – Price structures used in the model. 'Base' distribution price refers to distributor prices prior to implementing prices consistent with the Electricity Authority's distribution pricing principles. 'LRMC recovery in peak' refers to distributor prices that are almost fully compliant with the Electricity Authority's distribution pricing principles. Essentially this is more long-run marginal cost (LRMC) reflected in peak period unit (c/kWh) price accompanied by reduced off-peak and controlled prices, no transmission price pass through in unit prices, and more cost recovery through fixed costs (the daily charge). Note that retail price 6 is not used in this report, and that only the 'LRMC recovery in peak' prices are used. Hence, this table provides a superset of prices, from which a subset is selected.

Retail price reference	Description
1	Flat retail price (no variation throughout a day or year).
2	Simple day/night time-of-use.
3	Simple two-rate time-of-use with 9pm-midnight free on weekdays, and a flat rate for the rest of the day and weekends.
4.1	Flat energy price with distribution price pass through, 'Base' distribution prices.
4.2	Flat energy price with distribution price pass through, 'LRMC recovery in peak' distribution prices.
5.1	Time-of-use (ToU) energy price with distribution price pass through, 'Base' distribution prices.
5.2	Time-of-use energy price with distribution price pass through, 'LRMC recovery in peak' distribution prices.
7.1	Time-of-use energy price that varies between summer and winter with distribution price pass through, 'Base' distribution prices.
7.2	Time-of-use energy price that varies between summer and winter with distribution price pass through, 'LRMC recovery in peak' distribution prices.
Capacity limiting	A special case where there is an agreement with a customer to limit their maximum demand in exchange for a reduction from their fixed cost (daily charge).

Figure 7a: Auckland weekday retail prices.

Figure 7b: Auckland weekend retail prices.

In these graphs, * Peak is 7am-11am and 5pm-9pm all year and ** Peak is 7am-11am and 5pm-9pm April to September inclusive. Night is 11pm-7am all year. The numerical references given on the x-axis labels refer to the prices in Table 7.

Figure 8a: Wellington weekday retail prices.

Figure 8b: Wellington weekend retail prices.

*, ** Peak is 7am-11am and 5pm-9pm all year. Night is 11pm-7am all year. The numerical references given on the x-axis labels refer to the prices in Table 7

Figure 9a: Christchurch weekday retail prices.

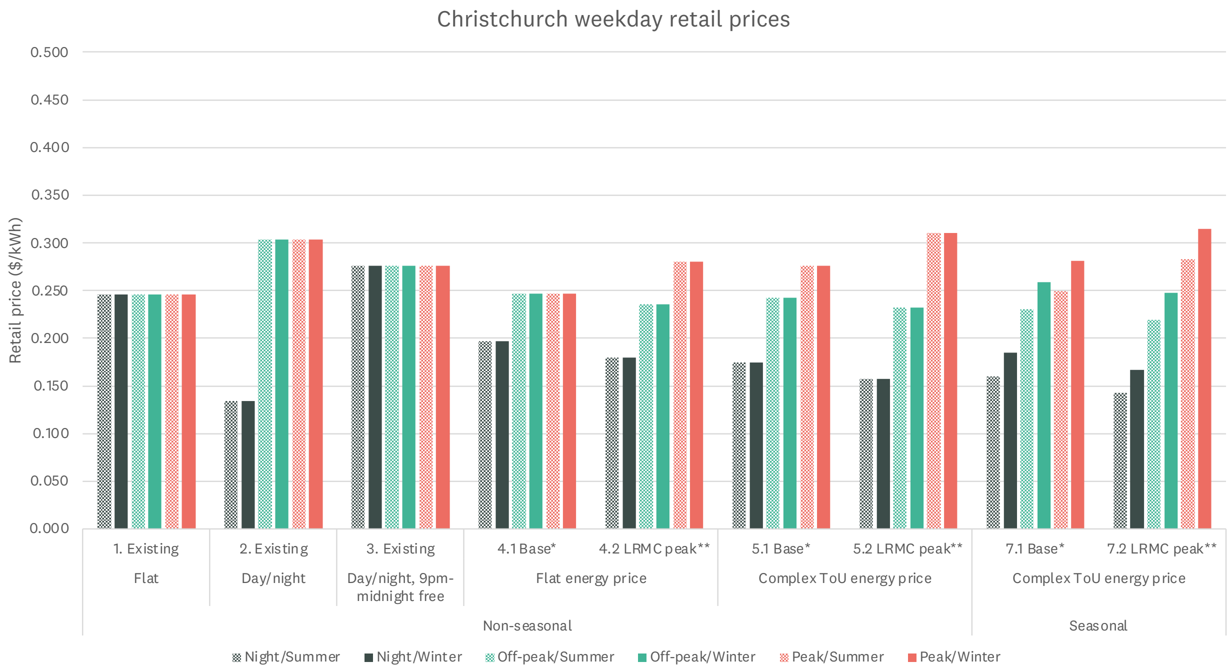


Figure 9b: Christchurch weekend retail prices.

*,** Peak is 7am-11am and 5pm-10pm all year. * Night is 11pm-7am all year, **Off-peak from 10pm-3am (not shown are Super off-peak from 3am-5am and Shoulder from 5am-7am and 11am-5pm). The numerical references given on the x-axis labels refer to the prices in Table 7.

Figure 10a: Queenstown weekday retail prices.

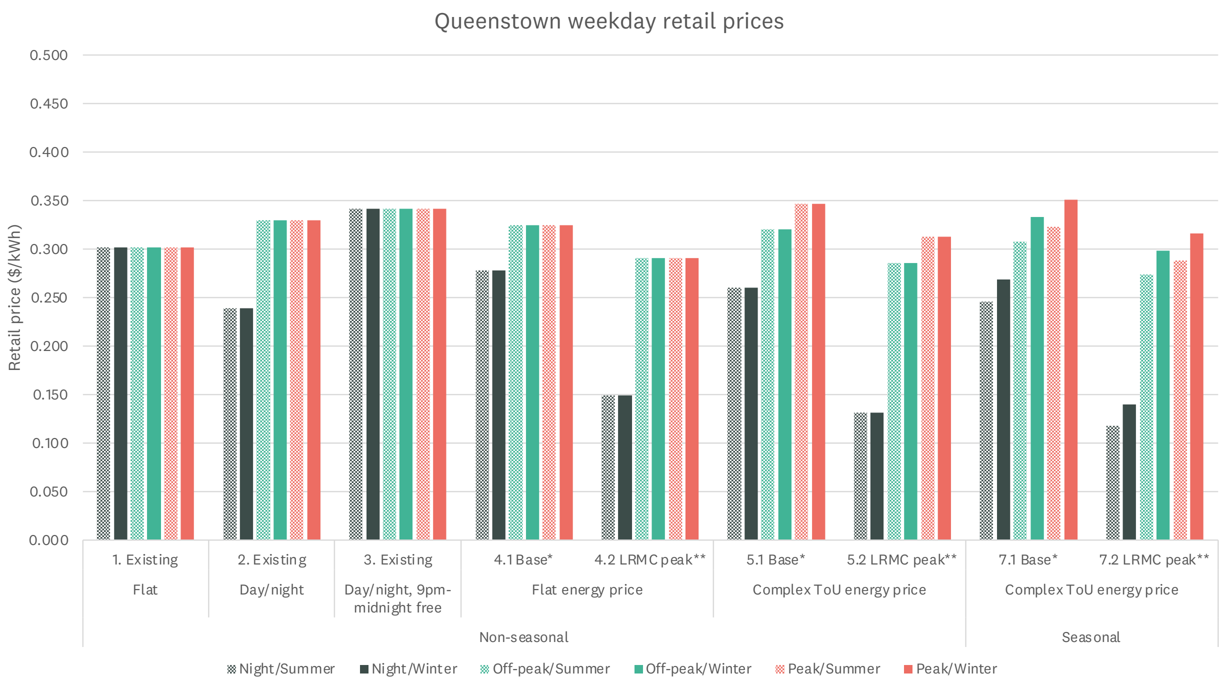


Figure 10b: Queenstown weekend retail prices.

*,** Peak is 7am-12pm and 5pm-10pm all year. Night is 11pm-7am all year. The numerical references given on the x-axis labels refer to the prices in Table 7.

3.2.4.2 Buyback price structures and prices

The retail price structures are summarised in Table 8 with the retail prices shown in Figure 11 to Figure 14.

Table 8 – Buyback prices used in the model. While there was the provision to vary prices by city, all base buyback prices used in the model are the same across all cities. Note that D, H, and L are special cases not used in this report.

Buyback price reference	Description
A	Flat buyback price, the same price in all cities (based on the Christchurch buyback price).
B	Same as A but with 50% of the relevant electricity distributor's LRMC added to the buyback price in peak periods.
C	Same as A but with 100% of the relevant electricity distributor's LRMC added to the buyback price in peak periods.
E	Time-of-use buyback price, the same price in all cities (based on the Christchurch buyback price).
F	Same as E but with 50% of the relevant electricity distributor's LRMC added to the buyback price in peak periods.
G	Same as E but with 100% of the relevant electricity distributor's LRMC added to the buyback price in peak periods.
I	Time-of-use buyback price with seasonal variation between summer (October-March) and winter (April to September).
J	Same as I but with 50% of the relevant electricity distributor's LRMC added to the buyback price in peak periods.
K	Same as I but with 100% of the relevant electricity distributor's LRMC added to the buyback price in peak periods.

Figure 11: Auckland buyback prices. Peak is weekday 7am-11am & 5pm-9pm. Off-peak is weekday 11am-5pm & 9pm-11pm & weekends 7am-11pm. Night is 11pm-7am. Winter is April-October inclusive. The alphabetical references given on the x-axis refer to the prices in Table 8.

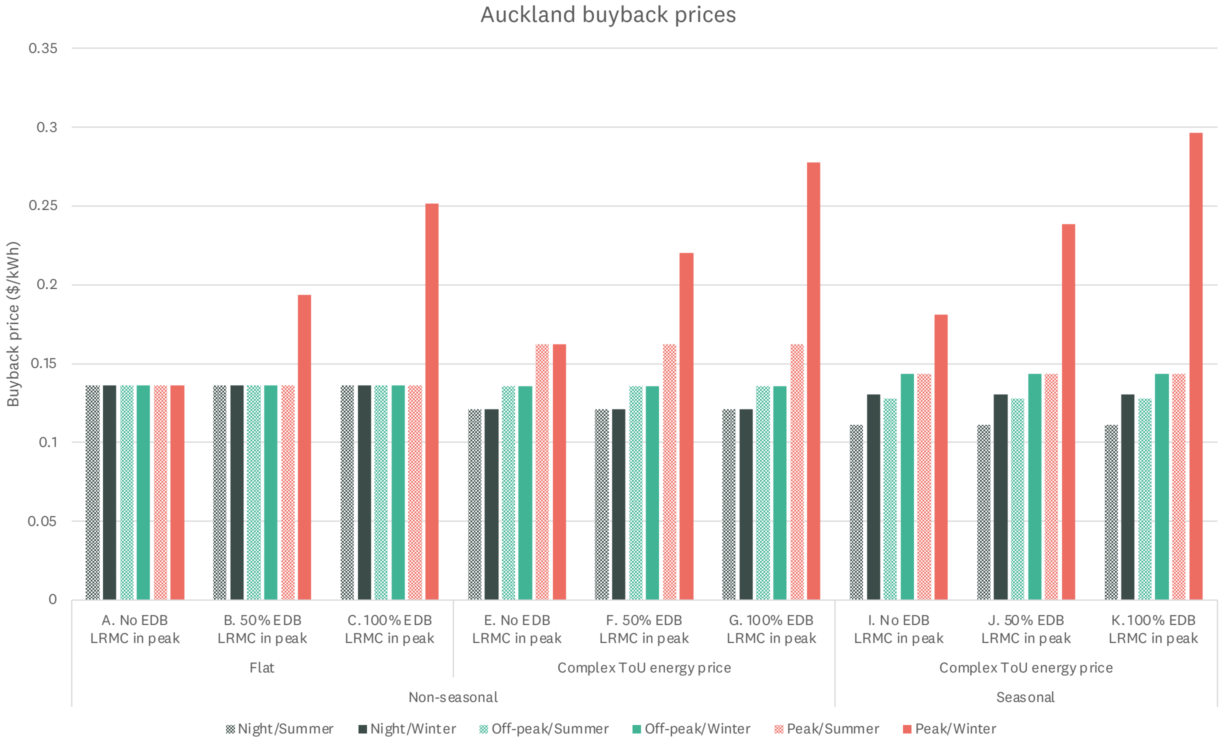


Figure 12: Wellington buyback prices. Peak is weekday 7am-11am & 5pm-9pm. Off-peak is weekday 11am-5pm & 9pm-11pm & weekends 7am-11pm. Night is 11pm-7am. Winter is April-October inclusive. The alphabetical references given on the x-axis refer to the prices in Table 8.

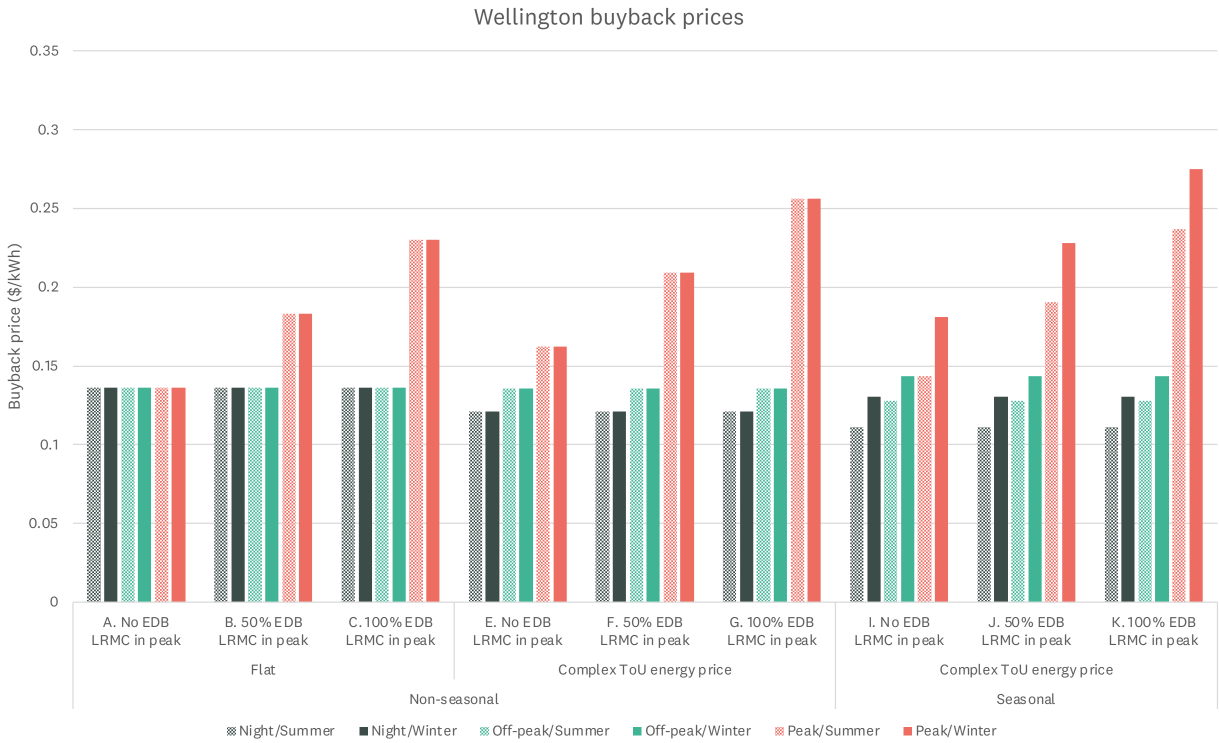


Figure 13. Christchurch buyback prices. Peak is weekday 7am-11am & 5pm-10pm. Off-peak is weekday 11am-5pm & 10pm-11pm & weekends 7am-11pm. Night is 11pm-7am. Winter is April-October inclusive. The alphabetical references given on the x-axis refer to the prices in Table 8.

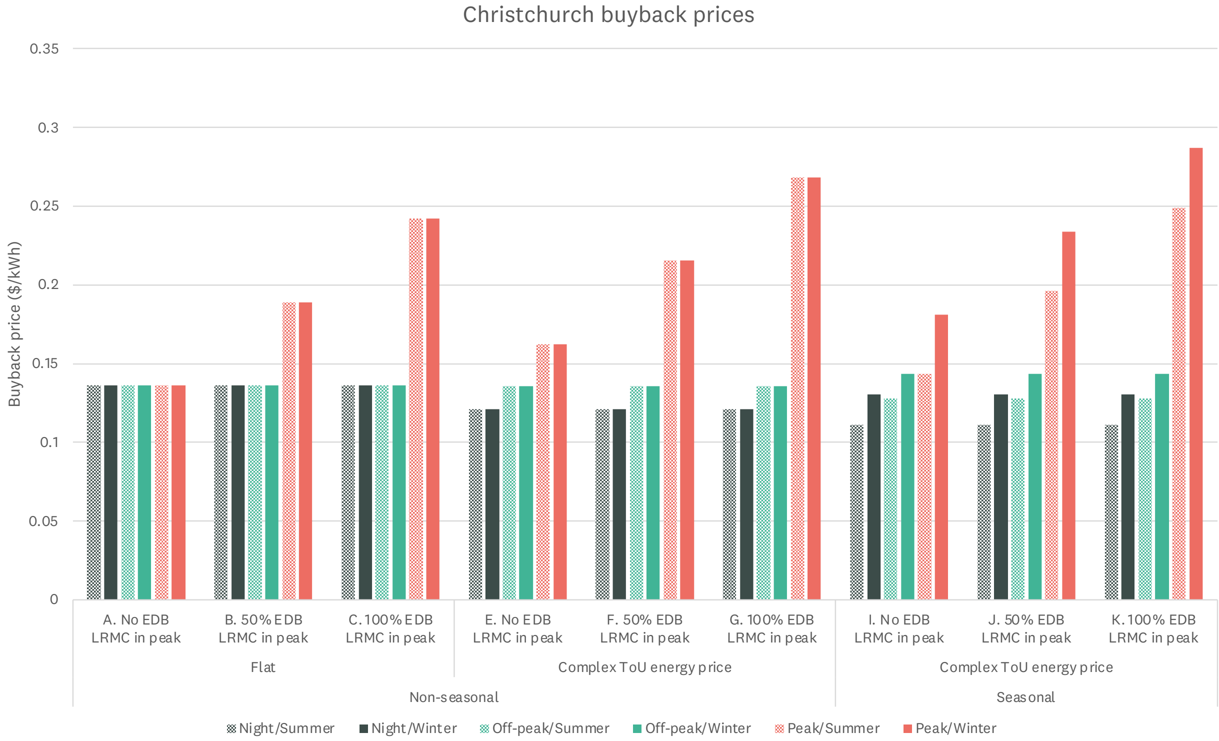
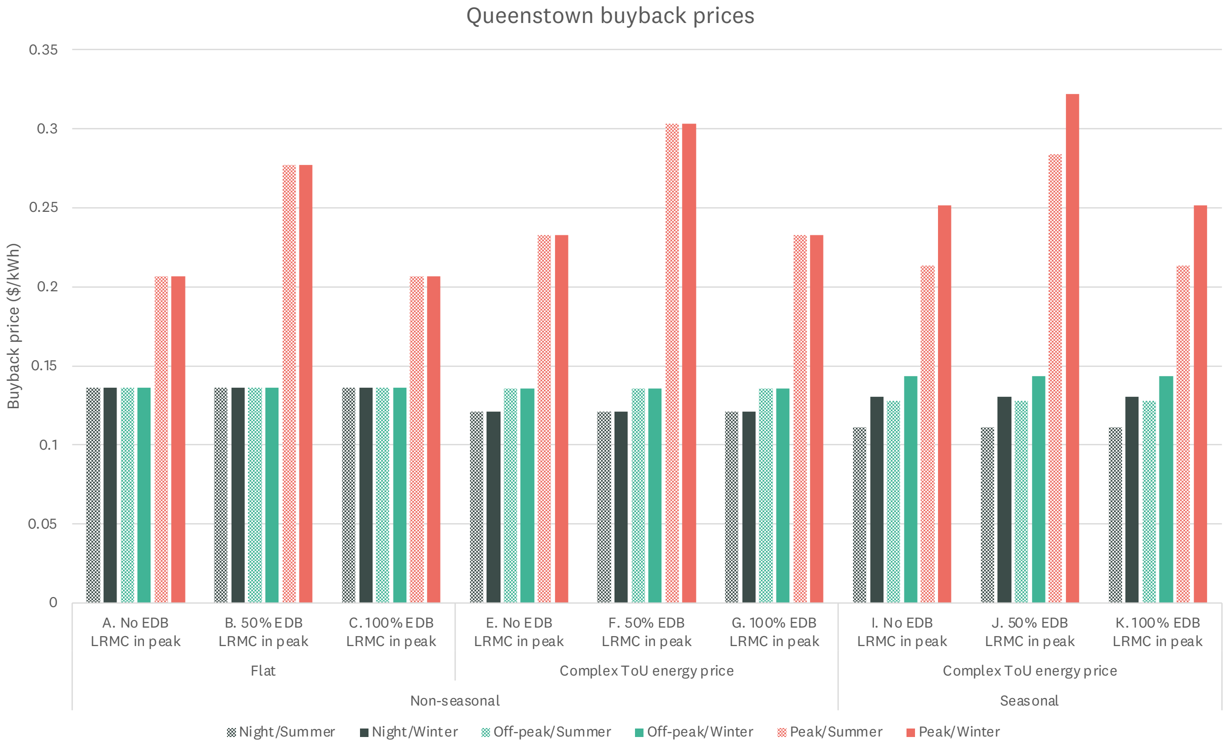


Figure 14. Queenstown buyback prices. Peak is weekday 7am-12am & 5pm-10pm. Off-peak is weekday 12pm-5pm & 10pm-11pm & weekends 7am-11pm. Night is 11pm-7am. Winter is April-October inclusive. The alphabetical references given on the x-axis refer to the prices in Table 8.



3.2.4.3 Use of retail and buyback prices in the results sections

Table 9 summarises how the prices are used for each part of the model. The counterfactual cases refer to the 'status quo', used to assess the improvement in return, if any, of the case tested in each section. For example, Section 5 introduces storage, with the counterfactual case being no storage. The improvement in return is then determined from the return with no storage (the counterfactual).

Table 9 – The use of prices throughout the model.

Retail price reference (Table 7) / Buyback price reference (Table 8)	PV without storage Return by load profile type and PV capacity Sensitivity of return to inputs Section 4	PV with storage technology (counterfactual is no storage) Return by load profile type, storage technology with a given PV capacity Section 5	PV with battery storage and more complex retail and buyback price structures Return by price structure & PV capacity for a given load type and battery battery capacity (counterfactual is no battery) Sub-section 6.1	PV with battery storage and more complex retail and buyback price structures Return by level of peak payment in buyback price in peak period, Sub-section 6.2 Energy exported and demand reduction during peak period, Sub-section 6.3 (Letters in brackets refer to the buyback price in Table 8, with * denoting the counterfactual case of no additional peak-period buyback price)
2 / A	✔			
3 / A			✔	
5.2 / A	✔	✔	✔	✔ (A*, B, C)
5.2 / E		✔	✔	✔ (E*, F, G)
7.1 / I			✔	
7.2 / I			✔	✔ (I*, J, K)

4. The benefits of solar PV without storage

This section focuses on solar PV without energy storage. Its aim is to find the load profile type for which solar gives the highest internal rate of return (IRR or just return), and for that load profile type, the solar capacity that gives the highest return.

It examines the relationship between load profile type and annual consumption and return. Selecting the load profile type that gives the highest return, it then examines the relationship between rooftop solar capacity and return. It does so for each city and for two types of retail price structure:

1. a simple day/night price structure to represent more traditional time-of-use prices (Row 2 from Table 7), and
2. a more complex peak/off-peak/night price structure to represent energy and distribution prices that are more reflective of the cost of energy by time and of distribution (Row 5.2 from Table 7). This represents a price available now and that is assumed will become a more common offering by retailers.

In both cases non time-of-use buyback prices are used, in line with there being no battery storage (A from Table 8).

Part of the reason for using a more complex time-of-use price structure is that it passes through distribution prices compliant with the Electricity Authority's distribution pricing principles, which, amongst other changes, include lower unit rates (c/kWh) and higher fixed charges ($/day). The use of these two price structures is to give an indication of how returns are likely to change as prices evolve. The buyback rates used in this section are flat rates. Later sections in this report investigate how storage might change the returns of solar PV as prices change. Prices and price structures are discussed in Sub-section 3.2.4.

Having found the load profile type and PV capacity for which solar returns are maximised, two further aims are to investigate the sensitivities of the returns to some key solar parameters, and to understand how returns vary between cities from solar alone and price alone. A final aim is to compare the returns available from residential solar with estimated returns from utility-scale solar.

This section is divided into the following sub-sections, each of which explore these aims.

- Sub-section 4.1 examines solar PV returns by load type and annual consumption to demonstrate how returns vary by load type and annual consumption.
- Sub-section 4.1 also finds the load type for two annual consumption levels and the solar PV capacity that give the highest return. Other performance metrics are also shown.

- Sub-section 4.2 examines the relationship between solar PV capacity and return for the load types identified from Sub-section 4.1, with and without electricity distributor export limits.
- Sub-section 4.3 examines the sensitivities of returns for the load type and PV capacities identified from the earlier sub-sections to changing input parameters.
- Sub-section 4.4 investigates the variation in solar PV returns by load type for the capacity that most often gives the highest return when just solar and price are varied between the four cities. This gives an indication of how solar generation variations and price variations between the cities affect rates of return.
- Sub-section 4.5 compares the returns from Sub-section 4.1 with those available from utility-scale solar.

Each sub-section includes a brief discussion and conclusions.

4.1 Solar PV returns by load type and annual consumption

Analysis of rate of return of each of the 47,045 load profiles was carried out with a simplified model. Analysis of all 47,045 load profiles was possible with just PV, no storage, and a limited number of PV capacities and retail price structure options. Analysis of each load profile type (cluster) was also, carried out with the full model (see Sub-section 3.2.2 for a discussion of load profile types and selection of representative load profiles) for later sections.

Following this, the full method was used to assess the cluster representative across all PV capacities for two pricing structures, with and without export limits.

4.1.1 Returns by load type

Figure 15 shows the returns by cluster (load profile type) for each city. The analysis giving these results used a simple two-rate retail price structure with a flat buyback price, referred to in each of the figures in Figure 15 and with the references to the price structures in Table 7 and Table 8 given. Sub-section 3.2.4 discusses prices used in more detail.

Evident from Figure 15 are variations in IRR between cities. Auckland and Christchurch are roughly equivalent, Wellington has the lowest returns, and Queenstown has the highest returns. This is due to:

1. price differences between cities, which themselves vary in quantum and structure, such as distributor peak period durations and time of year; and
2. solar resource differences between cities. Sub-section 3.2.3 discusses solar resource and modelling, which shows that Queenstown has the highest solar generation of the four cities. This is consistent with Queenstown having the highest rate of returns.

These differences are investigated further in Sub-section 4.4.

Also evident from Figure 15 is variation in return between clusters, which is a generally consistent pattern between cities, and generally consistent with differences in their key ratios. For example:

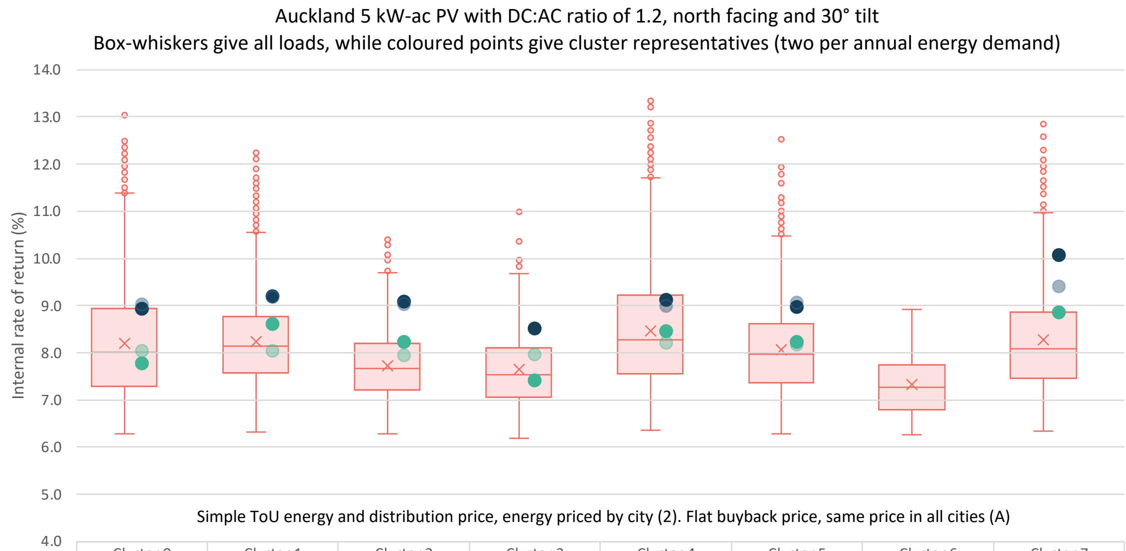
1. Clusters 1, 4, and 7 all have higher returns. These clusters also have a combination of high/very high daytime demand ratios, and high/very high morning and evening peak ratios.
2. Clusters 0 and 5 also show reasonably similar returns between them, and are not far below the above clusters. While Cluster 0 has a medium daytime demand ratio, and medium morning and evening peak ratios, Cluster 5 has a high daytime demand ratio, very high evening peak ratio, but low morning peak demand ratio.
3. Clusters 2, 3, and 6 have consistently lower performance than the other clusters. Clusters 3 and 6 have low/very low daytime and morning peak ratios, but Cluster 2 has very-high daytime and evening peak ratios, but a very low morning peak ratio.

The above observations tend to suggest a relationship between morning peak ratio and returns. Further examination of this in Figure 16 does show a relationship, although there are other factors that appear to override this. For example, at a morning peak ratio just above one, there is still considerable variation in returns.

Particularly evident from Figure 15 is the variation within each cluster, and returns overall. This can be seen for each city in Figure 17, which gives the density functions of returns for each city.

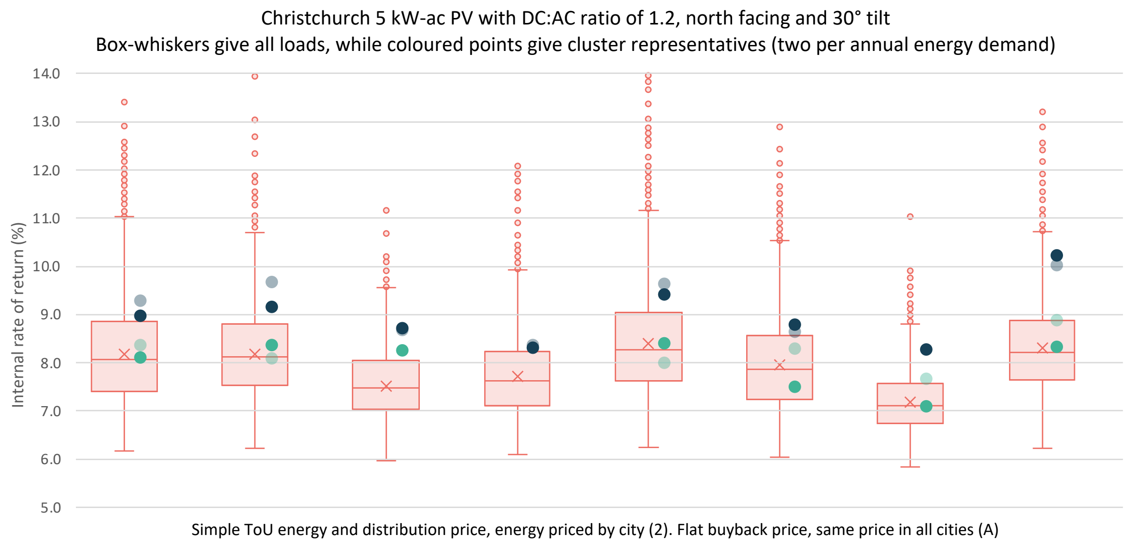
Overlayed on the box-whisker plots in Figure 15 are the returns of the load profiles selected to represent each cluster (see Sub-section 3.2.2), calculated using the same methodology as the box-whisker graphs. In most cases the 8,000 kWh pa samples (the green points) fall within the upper and lower quartiles, and sometimes close to the means. However, the 12,000 kWh pa samples are mostly above the upper quartiles. This indicates a relationship between return and annual consumption, which as shown in Figure 18 is strong and consistent across all consumers and cities.

Figure 15 – Internal rate of return performance for all cities by cluster. Where a value is zero in the cluster representative tables, no cluster representative was found. The x in each box-whisker gives the mean, the line gives the median, while the upper and lower bounds of the box give the upper and lower quartiles (75th and 25th percentiles respectively).



	Cluster 0 Day: Medium AM: Medium PM: Medium	Cluster 1 Day: Very high AM: High PM: Very high	Cluster 2 Day: Very high AM: Low PM: Very high	Cluster 3 Day: Low AM: Low PM: Medium	Cluster 4 Day: High AM: High PM: High	Cluster 5 Day: High AM: Low PM: Very high	Cluster 6 Day: Very low AM: Very low PM: Low	Cluster 7 Day: Very high AM: Very high PM: High
12,000 kWh pa (1)	8.9	9.2	9.1	8.5	9.1	9.0	0.0	10.1
12,000 kWh pa (2)	9.0	9.2	9.0	0.0	9.0	9.1	0.0	9.4
8,000 kWh pa (1)	7.8	8.6	8.2	7.4	8.5	8.2	0.0	8.9
8,000 kWh pa (2)	8.0	8.0	7.9	8.0	8.2	8.2	0.0	0.0

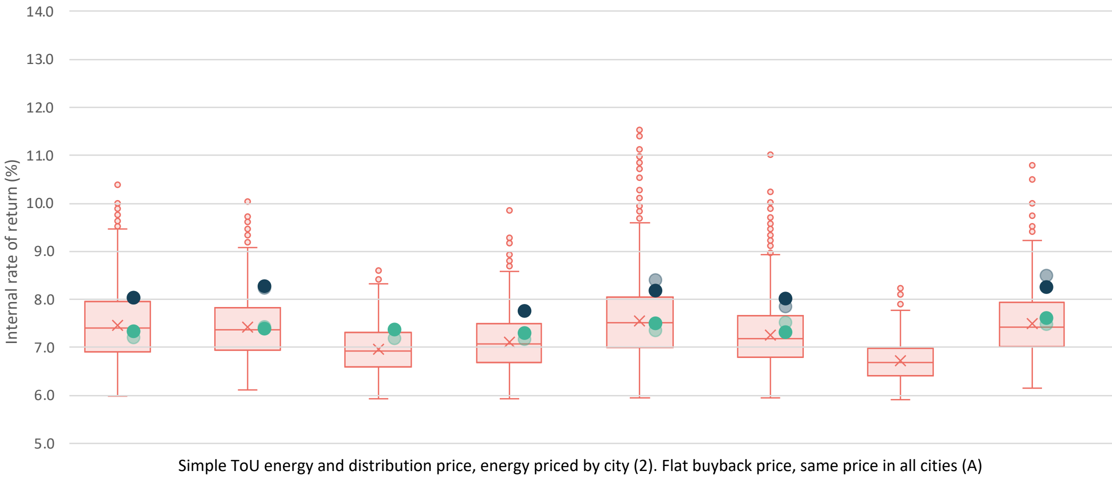
Cluster



	Cluster 0 Day: Medium AM: Medium PM: Medium	Cluster 1 Day: Very high AM: High PM: Very high	Cluster 2 Day: Very high AM: Low PM: Very high	Cluster 3 Day: Low AM: Low PM: Medium	Cluster 4 Day: High AM: High PM: High	Cluster 5 Day: High AM: Low PM: Very high	Cluster 6 Day: Very low AM: Very low PM: Low	Cluster 7 Day: Very high AM: Very high PM: High
12,000 kWh pa (1)	9.0	9.2	8.7	8.3	9.4	8.8	8.3	10.2
12,000 kWh pa (2)	9.3	9.7	8.7	8.4	9.6	8.6	0.0	10.0
8,000 kWh pa (1)	8.1	8.4	8.3	0.0	8.4	7.5	7.1	8.3
8,000 kWh pa (2)	8.4	8.1	0.0	0.0	8.0	8.3	7.7	8.9

Cluster

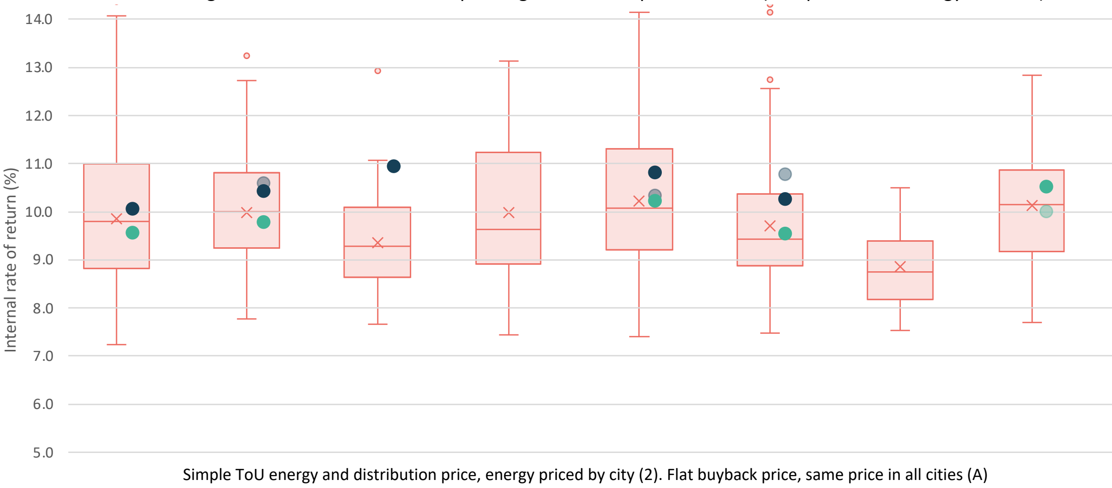
Wellington 5 kW-ac PV with DC:AC ratio of 1.2, north facing and 30° tilt
Box-whiskers give all loads, while coloured points give cluster representatives (two per annual energy demand)



	Cluster 0 Day: Medium AM: Medium PM: Medium	Cluster 1 Day: Very high AM: High PM: Very high	Cluster 2 Day: Very high AM: Low PM: Very high	Cluster 3 Day: Low AM: Low PM: Medium	Cluster 4 Day: High AM: High PM: High	Cluster 5 Day: High AM: Low PM: Very high	Cluster 6 Day: Very low AM: Very low PM: Low	Cluster 7 Day: Very high AM: Very high PM: High
12,000 kWh pa (1)	8.0	8.3	0.0	7.8	8.2	8.0	0.0	8.3
12,000 kWh pa (2)	8.0	8.2	0.0	0.0	8.4	7.9	0.0	8.5
8,000 kWh pa (1)	7.3	7.4	7.4	7.3	7.5	7.3	0.0	7.6
8,000 kWh pa (2)	7.2	7.4	7.2	7.2	7.4	7.5	0.0	7.5

Cluster

Queenstown 5 kW-ac PV with DC:AC ratio of 1.2, north facing and 30° tilt
Box-whiskers give all loads, while coloured points give cluster representatives (two per annual energy demand)



	Cluster 0 Day: Medium AM: Medium PM: Medium	Cluster 1 Day: Very high AM: High PM: Very high	Cluster 2 Day: Very high AM: Low PM: Very high	Cluster 3 Day: Low AM: Low PM: Medium	Cluster 4 Day: High AM: High PM: High	Cluster 5 Day: High AM: Low PM: Very high	Cluster 6 Day: Very low AM: Very low PM: Low	Cluster 7 Day: Very high AM: Very high PM: High
12,000 kWh pa (1)	10.1	10.4	10.9	0.0	10.8	10.3	0.0	0.0
12,000 kWh pa (2)	0.0	10.6	0.0	0.0	10.3	10.8	0.0	0.0
8,000 kWh pa (1)	9.6	9.8	0.0	0.0	10.2	9.5	0.0	10.5
8,000 kWh pa (2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0

Cluster

Figure 16: The relationship between returns and morning peak ratio for Auckland consumers.

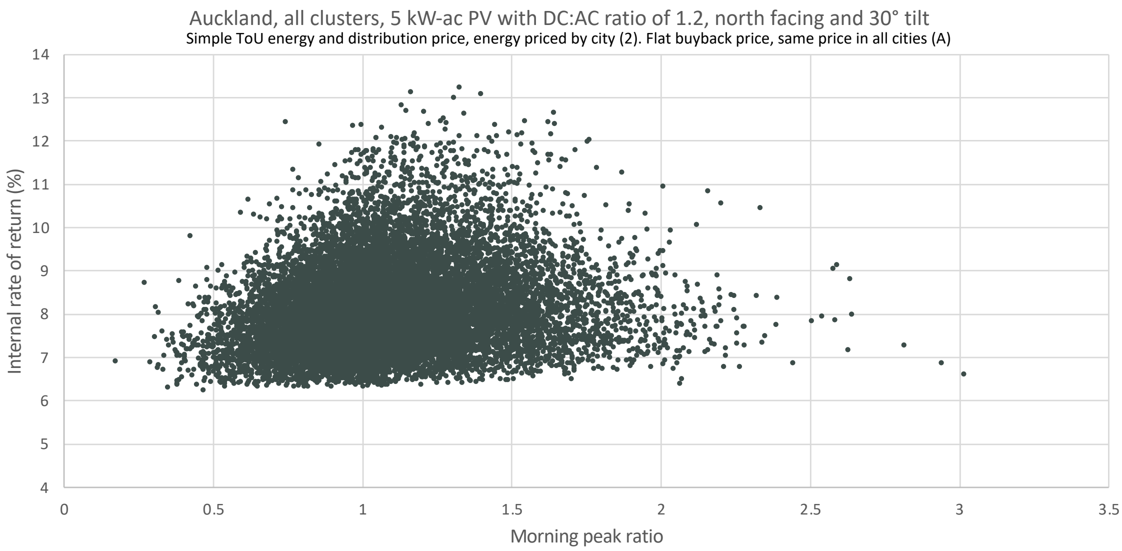


Figure 17: Density functions of internal rate of return for each city.

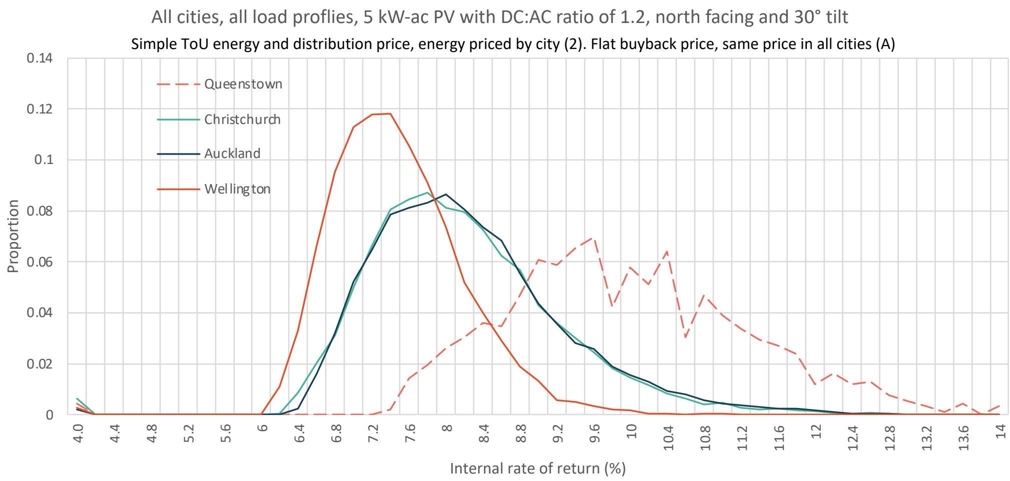
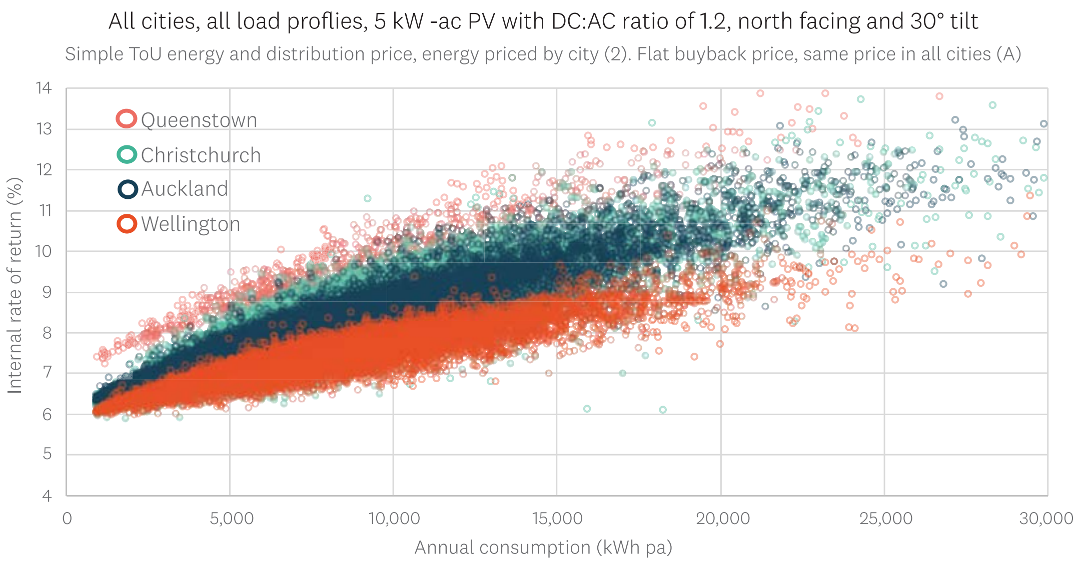


Figure 18: The relationship between annual energy consumption and internal rate of return for each consumer.



4.1.2 Load types that give the highest return

The maximum returns available with the selected load types, and the cluster and solar PV capacities that give the highest return are tabulated in Table 10. This also gives the simple payback and levelised cost of energy (LCOE) corresponding to the maximum rate of return cluster. Out of interest, Table 11 shows the cluster that gives the lowest return, as well as the simple payback and levelised cost of energy of the solar PV.

Table 10b shows that Cluster 7 most often has the highest rates of return (Cluster 7 has a very high daytime demand ratio, very high morning peak ratio, and high evening peak ratio). Examination of self-consumption and export during peak periods shows that:

- Cluster 7 loads have higher self-consumption of solar during the morning peak, especially over the winter months.
- For example, 87% of solar generated during morning peak is used by the household in July compared to around 60% in the other clusters.
- This figure is 89% in August compared to 45% for Cluster 3, which has the lowest rate of return in Auckland from Table 11b (Cluster 3 has a low daytime demand ratio, low morning peak ratio, and medium evening peak ratio).
- The daytime self-consumption and evening-peak self-consumption are also higher for Cluster 7, but not by as much as the morning peak.
- In fact, in the winter months of June, July, and August there is roughly half the energy from solar in the evening peak period than in the morning peak period, and the energy from solar in both the morning peak and evening peak is low by comparison to solar generation over a winter day.
- Nevertheless, this makes a difference of roughly two percentage points to the rate of return and reduces the payback period by 2-3 years.
- Figure 19 shows the load profiles for Cluster 7 and Cluster 3 representatives in Auckland, which show less morning peak energy used by the Cluster 3 representative load compared to the Cluster 7 representative load.

Higher self-consumption leads to higher rates of return through offsetting the higher retail price than the buyback price. This is observed with the complex time-of-use retail price used in the above examples as the peak period price is significantly higher than the buyback price, especially in Auckland in winter.

This section has shown the type of load profile that gives the highest rate of return for solar, which is typically one with high demand in the morning peak and high daytime consumption. However, it does not necessarily mean that solar on its own is the best investment. It may be more effective to shift the time-of-use of load, for example by moving morning hot water related peak energy use to night-time. Section 5 investigates storage to shift load to improve the economics of solar. However, prior to that, the following sub-section investigates the relationship between solar PV capacity and return.

Table 10: Maximum rates of return, the corresponding load types, and the corresponding PV capacity. The retail prices are rows 2 (left half) and 5.2 (right half) from Table 7, and the buyback price is row A from Table 8.

(a) The maximum rates of return across all clusters, for two retail price structures, with and without a 5 kW export limit.

	Two-rate retail price (2), flat rate buyback (A)				Complex ToU retail price (5.2), flat rate buyback (A)			
	5 kW export limit		15 kW export limit		5 kW export limit		15 kW export limit	
City	8,000 kWh pa	12,000 kWh pa	8,000 kWh pa	12,000 kWh pa	8,000 kWh pa	12,000 kWh pa	8,000 kWh pa	12,000 kWh pa
Auckland	10.5%	12.5%	10.6%	12.5%	9.4%	10.6%	9.9%	10.9%
Wellington	8.7%	9.8%	9.2%	10.2%	7.8%	8.6%	8.7%	9.3%
Christchurch	10.7%	12.8%	10.7%	12.8%	8.9%	10.3%	9.4%	10.6%
Queenstown	12.8%	13.1%	12.8%	13.1%	9.5%	9.8%	10.4%	10.6%

(b) The cluster to which the load profile that gives the **maximum** rate of return belongs.

	Two-rate retail price (2), flat rate buyback (A)				Complex ToU retail price (5.2), flat rate buyback (A)			
	5 kW export limit		15 kW export limit		5 kW export limit		15 kW export limit	
City	8,000 kWh pa	12,000 kWh pa	8,000 kWh pa	12,000 kWh pa	8,000 kWh pa	12,000 kWh pa	8,000 kWh pa	12,000 kWh pa
Auckland	7	7	7	7	7	7	7	7
Wellington	5	4	7	7	7	4	7	7
Christchurch	7	7	7	7	7	7	7	7
Queenstown	4	4	4	4	7	2	7	2

(c) The PV capacity (kW-ac) that resulted in the maximum rate of return.

City	Two-rate retail price (2), flat rate buyback (A)				Complex ToU retail price (5.2), flat rate buyback (A)			
	5 kW export limit		15 kW export limit		5 kW export limit		15 kW export limit	
	8,000 kWh pa	12,000 kWh pa	8,000 kWh pa	12,000 kWh pa	8,000 kWh pa	12,000 kWh pa	8,000 kWh pa	12,000 kWh pa
Auckland	5	3	10	3	6	5	10	10
Wellington	5	5	10	10	6	6	10	10
Christchurch	3	3	3	3	5	5	10	10
Queenstown	3	3	3	3	6	6	10	10

(d) Simple payback (years).

City	Two-rate retail price (2), flat rate buyback (A)				Complex ToU retail price (5.2), flat rate buyback (A)			
	5 kW export limit		15 kW export limit		5 kW export limit		15 kW export limit	
	8,000 kWh pa	12,000 kWh pa	8,000 kWh pa	12,000 kWh pa	8,000 kWh pa	12,000 kWh pa	8,000 kWh pa	12,000 kWh pa
Auckland	8	7	8	7	9	8	8	8
Wellington	9	9	9	8	10	9	9	9
Christchurch	8	7	8	7	9	8	9	8
Queenstown	7	7	7	7	9	9	8	8

(e) Levelised cost of energy ($/kWh).

City	Two-rate retail price (2), flat rate buyback (A)				Complex ToU retail price (5.2), flat rate buyback (A)			
	5 kW export limit		15 kW export limit		5 kW export limit		15 kW export limit	
	8,000 kWh pa	12,000 kWh pa	8,000 kWh pa	12,000 kWh pa	8,000 kWh pa	12,000 kWh pa	8,000 kWh pa	12,000 kWh pa
Auckland	0.12	0.14	0.11	0.14	0.12	0.12	0.11	0.11
Wellington	0.13	0.13	0.11	0.11	0.12	0.12	0.11	0.11
Christchurch	0.14	0.14	0.14	0.14	0.13	0.13	0.11	0.11
Queenstown	0.13	0.13	0.13	0.13	0.11	0.11	0.10	0.10

Table 11: Minimum rates of return, the corresponding load types, and the corresponding PV capacity. The retail prices are rows 2 (left half) and 5.2 (right half) from Table 7, and the buyback price is row A from Table 8.

(a) The minimum rates of return across all clusters, for two retail price structures, with and without a 5 kW export limit.

City	Two-rate retail price (2), flat rate buyback (A)				Complex ToU retail price (5.2), flat rate buyback (A)			
	5 kW export limit		15 kW export limit		5 kW export limit		15 kW export limit	
	8,000 kWh pa	12,000 kWh pa	8,000 kWh pa	12,000 kWh pa	8,000 kWh pa	12,000 kWh pa	8,000 kWh pa	12,000 kWh pa
Auckland	7.4%	9.0%	8.1%	10.1%	7.0%	8.4%	7.3%	8.9%
Wellington	6.9%	7.9%	7.7%	8.7%	6.5%	7.2%	6.7%	7.3%
Christchurch	6.7%	8.5%	7.7%	9.7%	6.3%	7.5%	6.8%	7.9%
Queenstown	9.6%	10.2%	11.3%	11.9%	7.9%	8.2%	8.3%	8.4%

(b) The cluster to which the load profile that gives the minimum rate of return belongs.

City	Two-rate retail price (2), flat rate buyback (A)				Complex ToU retail price (5.2), flat rate buyback (A)			
	5 kW export limit		15 kW export limit		5 kW export limit		15 kW export limit	
	8,000 kWh pa	12,000 kWh pa	8,000 kWh pa	12,000 kWh pa	8,000 kWh pa	12,000 kWh pa	8,000 kWh pa	12,000 kWh pa
Auckland	3	3	3	3	3	3	3	3
Wellington	2	3	2	5	2	3	3	3
Christchurch	6	6	6	5	6	3	6	5
Queenstown	5	0	5	0	0	0	0	0

(c) The PV capacity (kW-ac) that resulted in the minimum rate of return.

City	Two-rate retail price (2), flat rate buyback (A)				Complex ToU retail price (5.2), flat rate buyback (A)			
	5 kW export limit		15 kW export limit		5 kW export limit		15 kW export limit	
	8,000 kWh pa	12,000 kWh pa	8,000 kWh pa	12,000 kWh pa	8,000 kWh pa	12,000 kWh pa	8,000 kWh pa	12,000 kWh pa
Auckland	10	10	3	6	10	10	3	3
Wellington	10	10	3	3	10	10	3	3
Christchurch	10	10	3	3	10	10	3	3
Queenstown	10	10	8.2	8.2	10	10	3	3

Figure 19a: (a) Cluster 7 load in Auckland with the highest rate of return, showing the higher energy use in the morning peak, daytime, and evening peak.

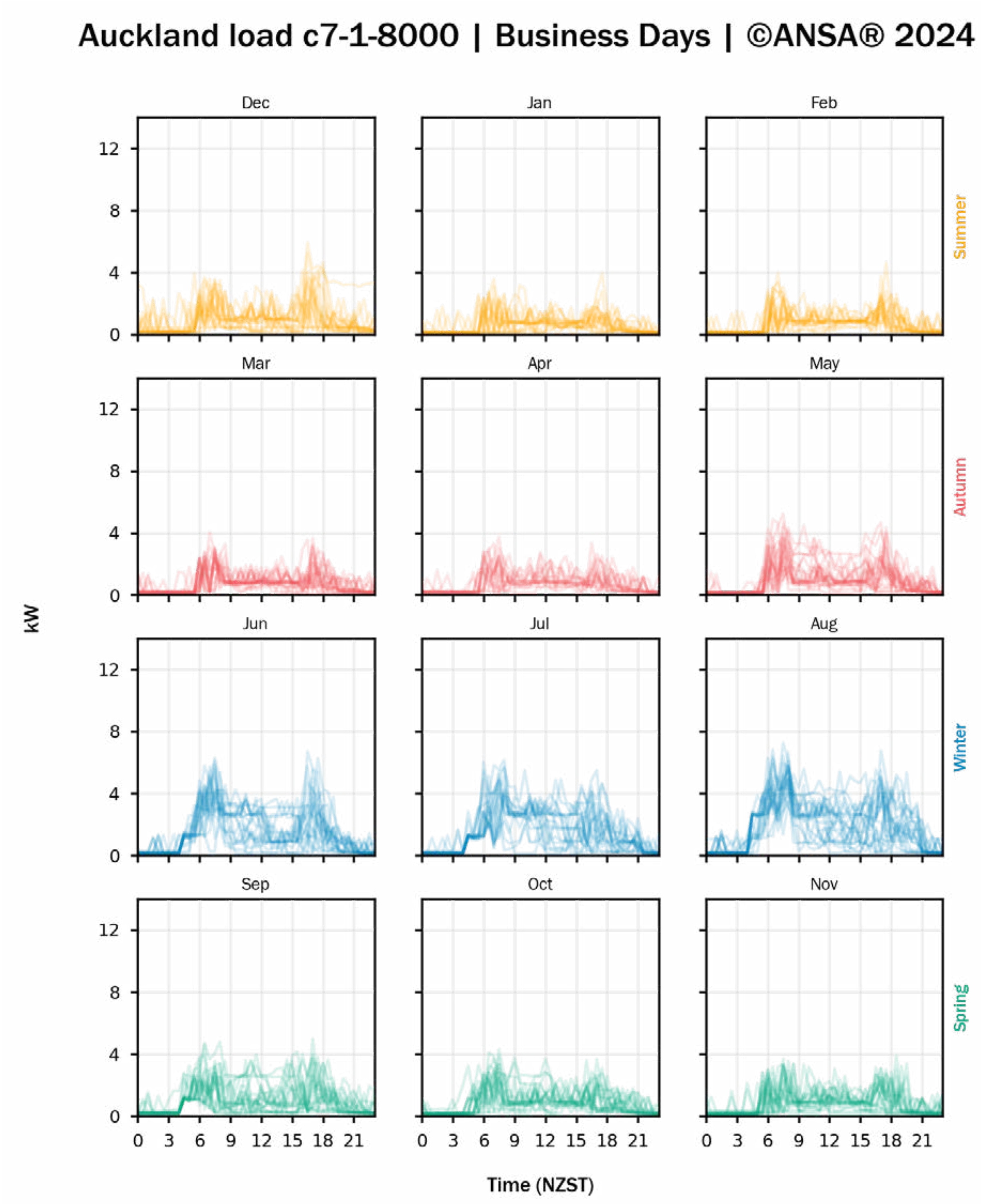
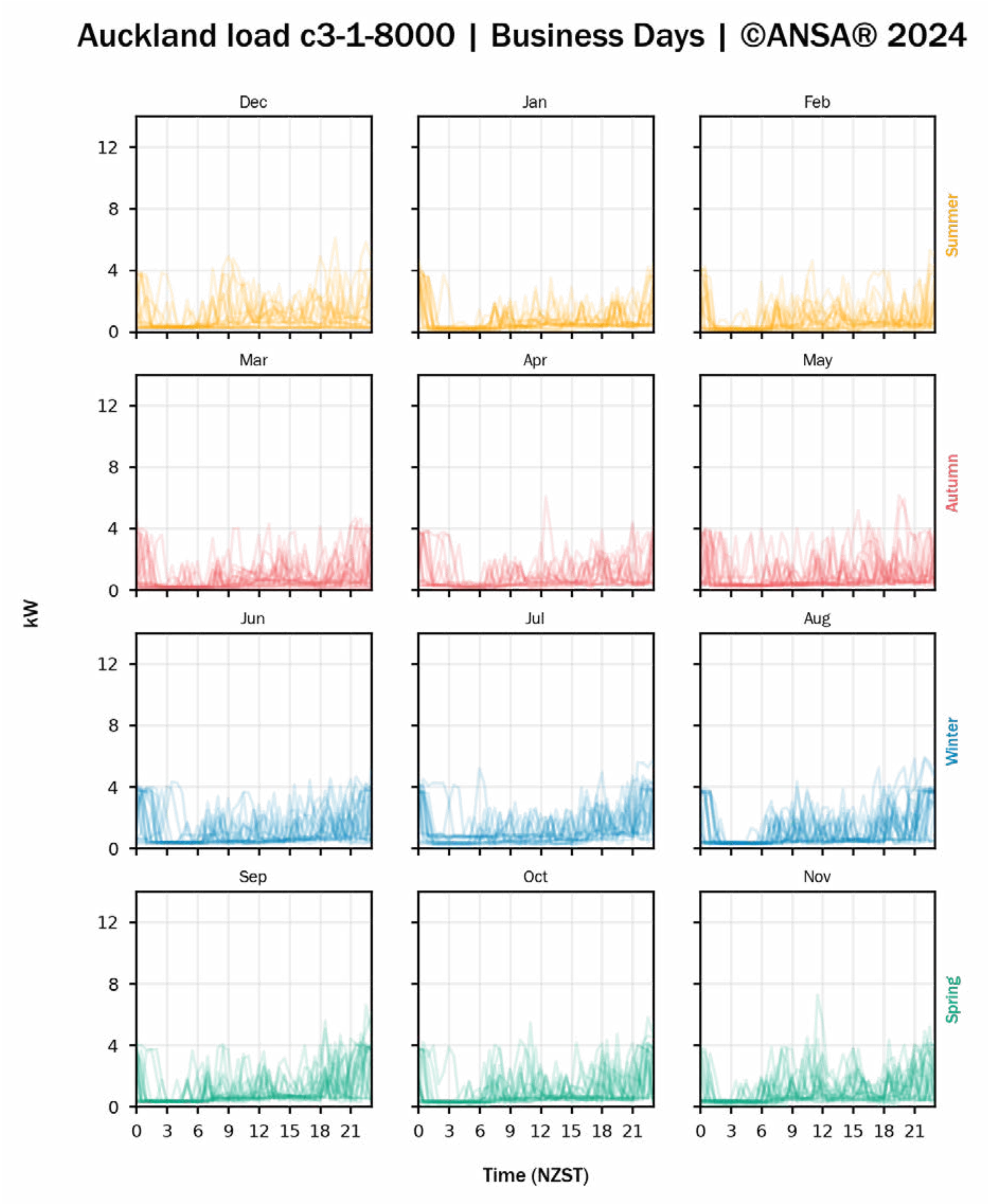


Figure 19b: (b) Cluster 3 load in Auckland which has the lowest rate of return, showing lower energy use in the morning peak, day time, and evening peak periods.



4.2 Solar PV capacity and return

Figure 20 shows the performance of the load profile types in each city that most often have maximum returns from Table 10 versus PV capacity. The retail price used is the simple day/night price structure.

When there is a 5 kW export limit, as is the case with a number of electricity distributors:

- For the 8,000 kWh pa load profiles the maximum return occurs with an inverter capacity of 5 kW-ac, except for Queenstown, where it occurs at 3kW-ac.
- For the 12,000 kWh pa load profiles the maximum return generally occurs with a lower inverter capacity of 3 kW-ac, except for Wellington, where it remains at 5 kW-ac and 6 kW-ac. Despite the maximum return of the 12,000 kWh pa loads occurring at a lower solar capacity, it is still higher than the 8,000 kWh pa loads. The maximum return occurs at a lower solar capacity because of the simple day/night retail price structure as the 3 kW-ac systems have a higher self-consumption and lower exports. Self-consumption offsets the constant day price, which is much higher than the buyback price (referring to the prices summarised in Sub-section 3.2.4). For all cities, the retail price is around 30 c/kWh, except Wellington which is 25 c/kWh, and the buyback price is around 14 c/kWh or about half the retail price. Note that the absolute return (NPV in $) will still tend to be higher for the larger systems, but returns relative to investment are higher at lower solar capacities.

When the export limit is lifted to 15 kW it can be seen that:

- For the 8,000 kWh pa load profiles the maximum return occurs with an inverter capacity of 10 kW-ac in Auckland and Wellington. It remains about the same at all PV capacities in Christchurch, and still occurs with a 3 kW-ac capacity in Queenstown.
- For the 12,000 kWh pa load profiles the maximum return still occurs with lower inverter capacities, with Wellington still the exception, where it now occurs at a PV capacity of 10 kW-ac.

The relative retail and buyback prices are the reason for these differences, leading to different self-consumption cost savings and export incomes. With different prices, load profiles, and solar resource between cities, it is difficult to compare one city with another. Sub-section 4.6 investigates the returns for each city by separately varying just the prices and solar between the cities, allowing a better understanding of how these affect returns.

More complex time-of-use tariffs, that better reflect the cost of energy in peak periods compared with off-peak periods and night-time are now available from some retailers. Combining these with the move to more cost reflective distribution pricing gives even more cost reflective prices. As shown in the previous section, these also lead to lower returns for PV, something that is tested with storage in the next section. While the results might be lower, this price structure reverses the pattern seen with the simple day/night price structure, as shown in Figure 21, and can be summarised more succinctly as:

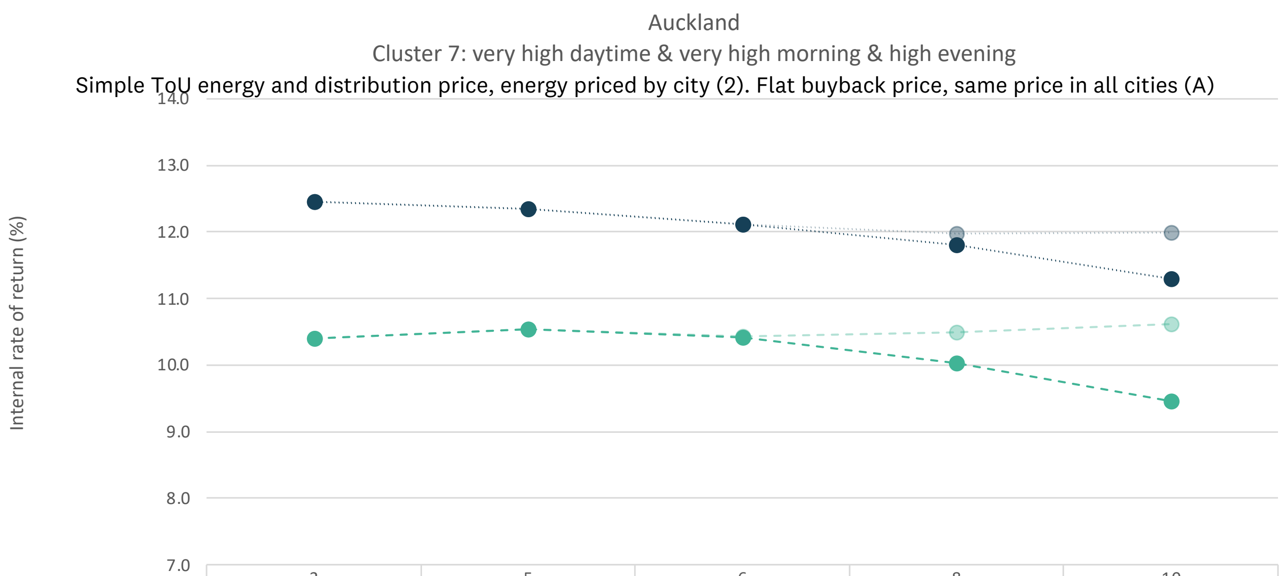
- For all load profiles, the maximum return occurs at 5 kW-ac to 6 kW-ac when the export limit is 5 kW.
- For all load profiles, the maximum return occurs at 10 kW-ac when the export limit is 10 kW.

The reason for this is the higher retail peak prices. Larger PV capacities give more self-consumption volume in peak periods, leading to higher revenue in peak periods. There is still the question over whether seasonal price differences might affect this, investigated in Section 6. The Auckland prices give some hint that larger PV system will still maximise returns, since the summer peak distribution price is zero in Auckland.

While the simple day/night price structure gives high returns overall, it is anticipated that more complex time-of-use price structures (such as that leading to the results in Figure 21) will become more common. This is due to retailers seeking to reflect the cost of energy during peak periods, electricity distributors implementing pricing consistent with the Electricity Authority's pricing principles, and retailers passing on that distribution unit price which is concentrated into peak periods.

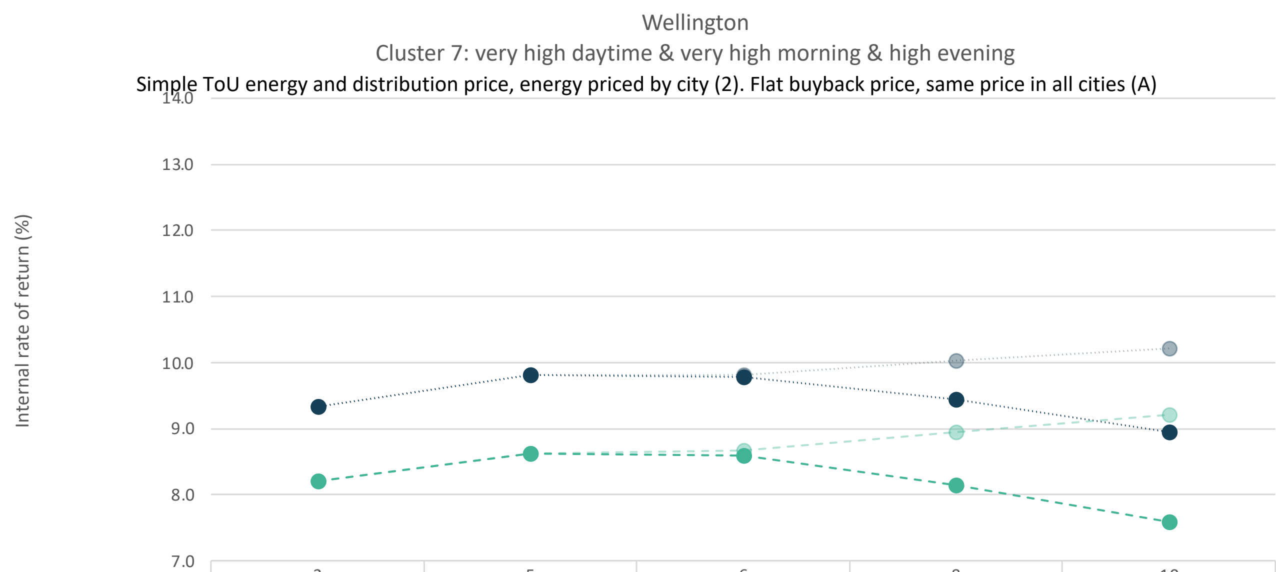
The higher returns available with the more complex time-of-use price structures that will result from lifting the export limit are directly relevant to MBIE's 2024 consultation on raising the upper voltage limit from +6% to +10% of 230 Volts. This shows an increase in solar PV hosting capacity by a factor of roughly 2-3 times (Miller, 2024), reducing the incidence of both LV network congestion and solar PV curtailment. The results in this section are showing that it is usually beneficial to install a larger system if exporting more is possible. Thus, those who can afford a larger system could do so with the prospect of incremental economic benefit, rather than be capacity constrained. This may lead to a behavioural shift in installing larger PV systems, which could result in greater solar export and renewable energy generation. However, a factor that may negate the benefit of a larger system is a seasonal shift in prices, such as a lower summer midday price because of excessive solar generation. This would act as a signal to increase self-consumption, and may negate benefits from larger systems. Section 6 investigates this further.

Figure 20 – Rates of return of the cluster that gives the highest rates of return versus PV capacity for both annual consumptions and with and without a 5 kW export limit, for a simple two-rate day/night price structure. From Table 10b this cluster is almost always 7, and 4 for Queenstown with a 5 kW export limit. The export limit is given in the table row headings beside the annual consumption.



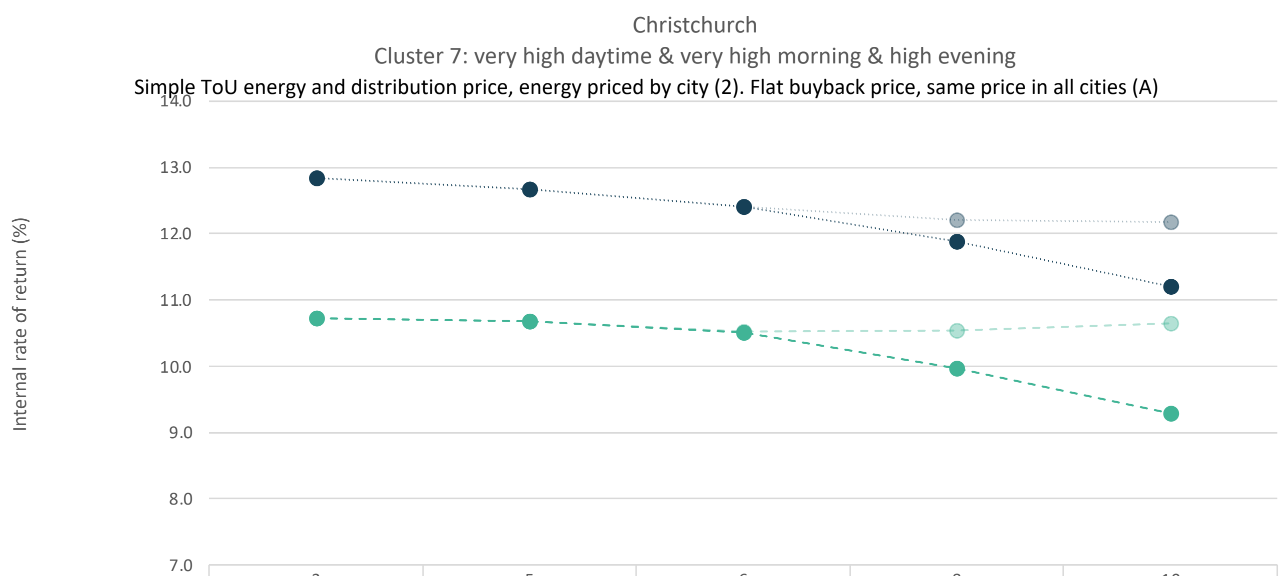
	3	5	6	8	10
12,000 kWh pa, 15 kW	12.5	12.3	12.1	12.0	12.0
12,000 kWh pa, 5 kW	12.5	12.3	12.1	11.8	11.3
8,000 kWh pa, 15 kW	10.4	10.5	10.4	10.5	10.6
8,000 kWh pa, 5 kW	10.4	10.5	10.4	10.0	9.5

PV Capacity (kW-ac), DC:AC ratio of 1.2



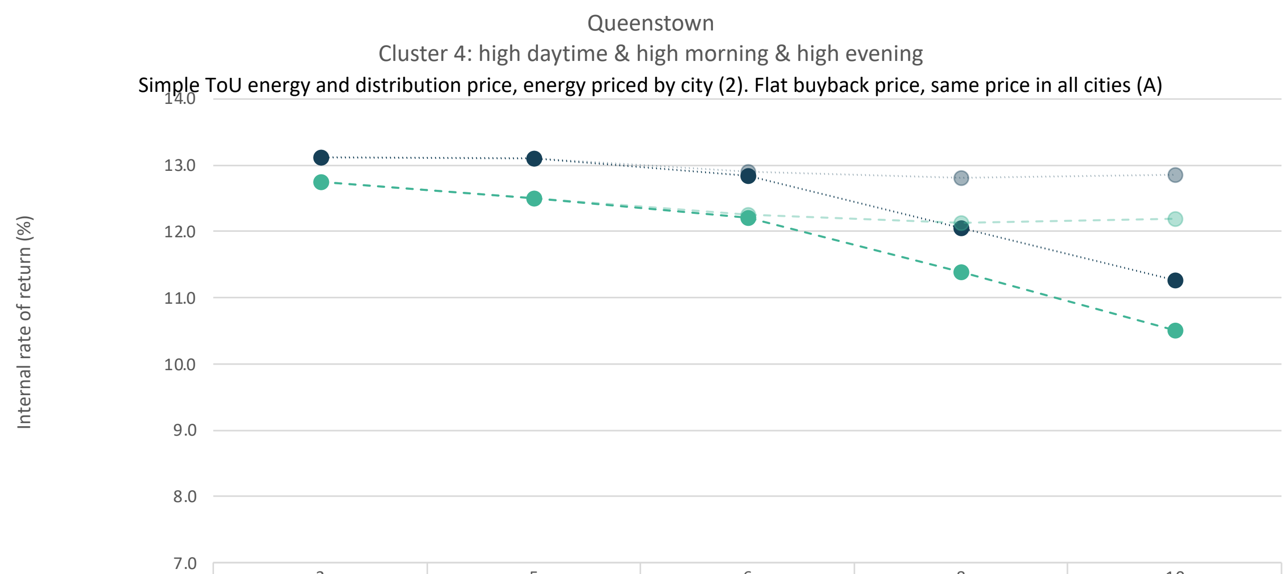
	3	5	6	8	10
12,000 kWh pa, 15 kW	9.3	9.8	9.8	10.0	10.2
12,000 kWh pa, 5 kW	9.3	9.8	9.8	9.4	8.9
8,000 kWh pa, 15 kW	8.2	8.6	8.7	8.9	9.2
8,000 kWh pa, 5 kW	8.2	8.6	8.6	8.1	7.6

PV Capacity (kW-ac), DC:AC ratio of 1.2



	3	5	6	8	10
12,000 kWh pa, 15 kW	12.8	12.7	12.4	12.2	12.2
12,000 kWh pa, 5 kW	12.8	12.7	12.4	11.9	11.2
8,000 kWh pa, 15 kW	10.7	10.7	10.5	10.5	10.6
8,000 kWh pa, 5 kW	10.7	10.7	10.5	10.0	9.3

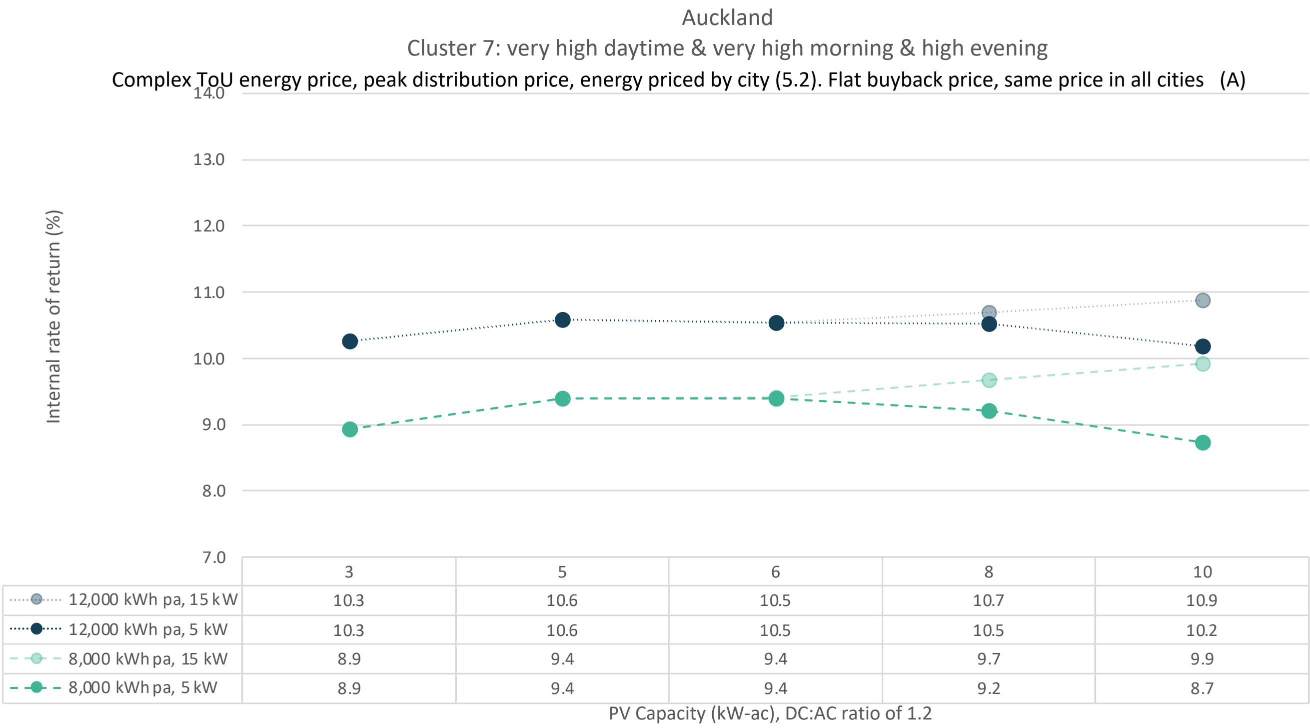
PV Capacity (kW-ac), DC:AC ratio of 1.2



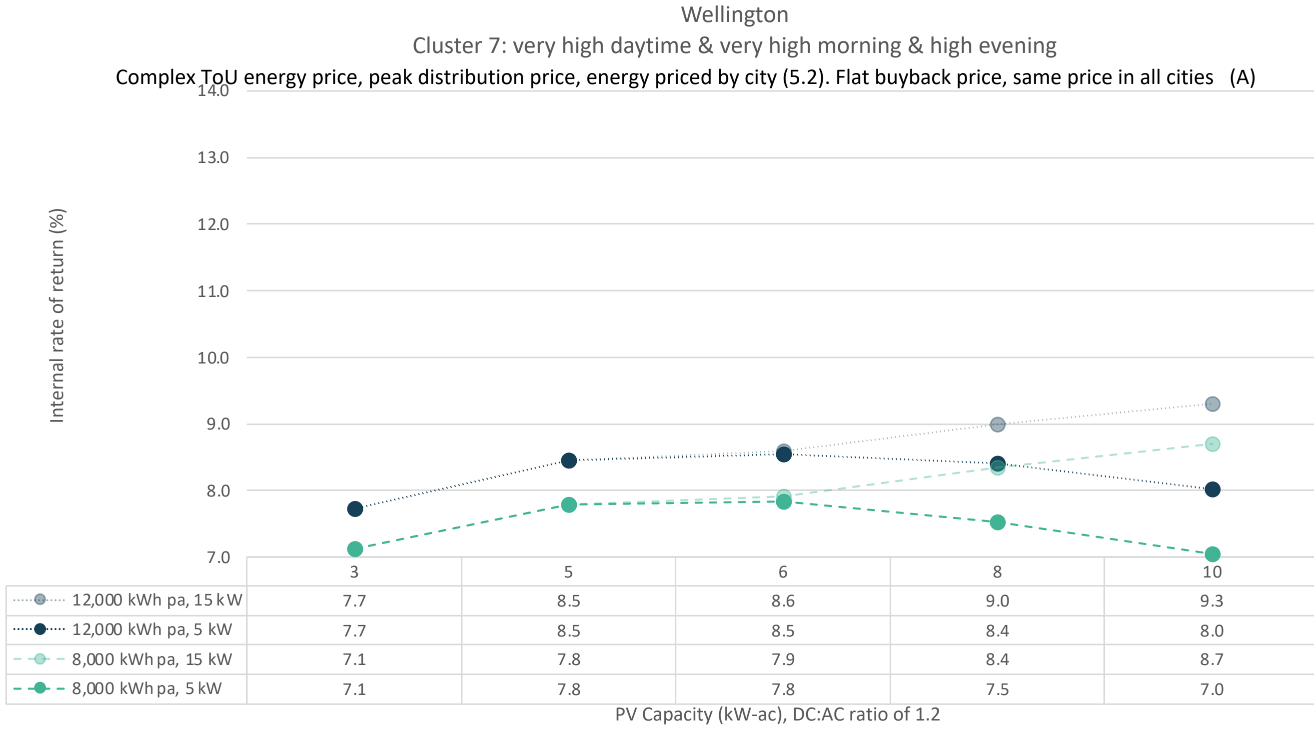
	3	5	6	8	10
12,000 kWh pa, 15 kW	13.1	13.1	12.9	12.8	12.9
12,000 kWh pa, 5 kW	13.1	13.1	12.8	12.1	11.3
8,000 kWh pa, 15 kW	12.8	12.5	12.3	12.1	12.2
8,000 kWh pa, 5 kW	12.8	12.5	12.2	11.4	10.5

PV Capacity (kW-ac), DC:AC ratio of 1.2

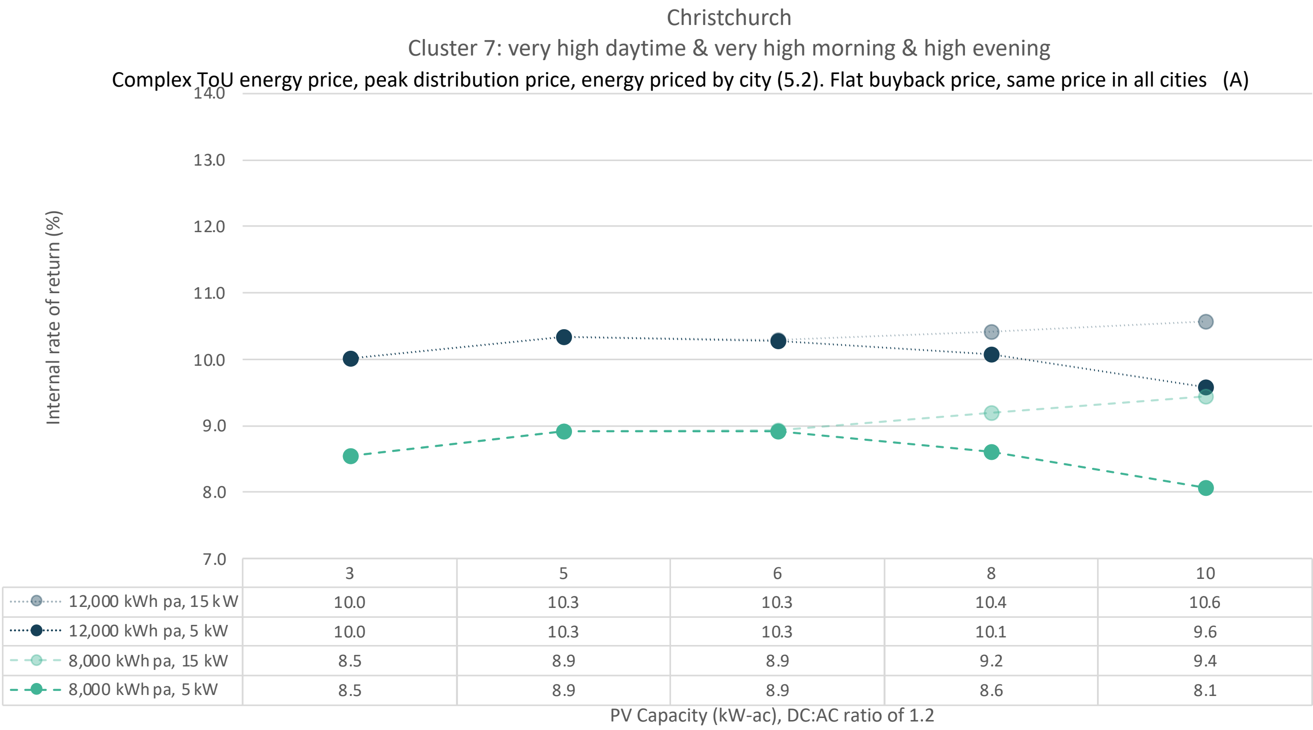
Figure 21: Rates of return of the cluster that gives the highest rates of return versus PV capacity for both annual consumptions and with and without a 5 kW export limit, for a complex time-of-use price structure. From Table 10b this cluster is almost always 7, and 4 for Queenstown with a 5 kW export limit. The export limit is given in the table row headings beside the annual consumption.



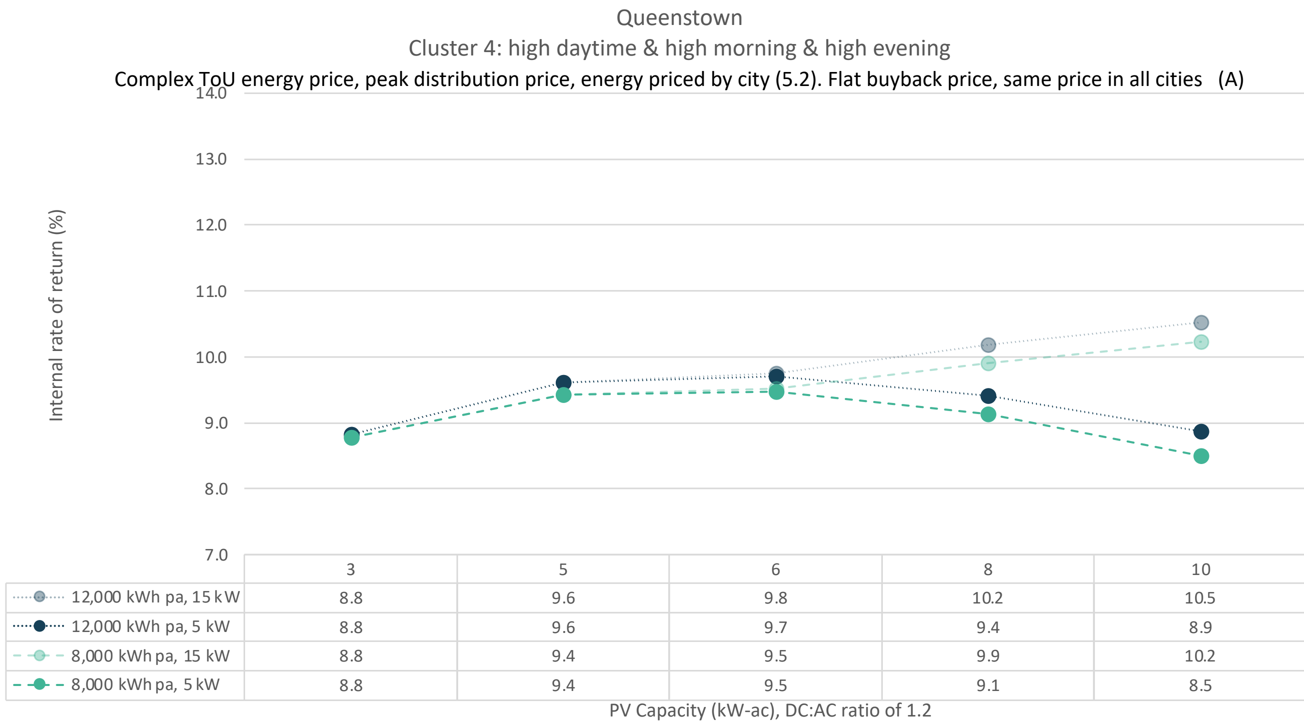
	3	5	6	8	10
12,000 kWh pa, 15 kW	10.3	10.6	10.5	10.7	10.9
12,000 kWh pa, 5 kW	10.3	10.6	10.5	10.5	10.2
8,000 kWh pa, 15 kW	8.9	9.4	9.4	9.7	9.9
8,000 kWh pa, 5 kW	8.9	9.4	9.4	9.2	8.7



	3	5	6	8	10
12,000 kWh pa, 15 kW	7.7	8.5	8.6	9.0	9.3
12,000 kWh pa, 5 kW	7.7	8.5	8.5	8.4	8.0
8,000 kWh pa, 15 kW	7.1	7.8	7.9	8.4	8.7
8,000 kWh pa, 5 kW	7.1	7.8	7.8	7.5	7.0



	3	5	6	8	10
12,000 kWh pa, 15 kW	10.0	10.3	10.3	10.4	10.6
12,000 kWh pa, 5 kW	10.0	10.3	10.3	10.1	9.6
8,000 kWh pa, 15 kW	8.5	8.9	8.9	9.2	9.4
8,000 kWh pa, 5 kW	8.5	8.9	8.9	8.6	8.1



	3	5	6	8	10
12,000 kWh pa, 15 kW	8.8	9.6	9.8	10.2	10.5
12,000 kWh pa, 5 kW	8.8	9.6	9.7	9.4	8.9
8,000 kWh pa, 15 kW	8.8	9.4	9.5	9.9	10.2
8,000 kWh pa, 5 kW	8.8	9.4	9.5	9.1	8.5

4.3 Sensitivity of returns to input parameters

Figure 22 shows the sensitivities to certain inputs for each city with a 5 kW PV system and an 8,000 kWh pa consumer of load type that gives maximum returns, as identified in Table 10b. In addition to Figure 22, an assessment of sensitivities to inputs for other consumption levels, price structure, and solar PV capacities shows the following.

1. All changes in return from sensitivities reduce slightly with 12,000 kWh per annum but are similar magnitudes. In other words, a 12,000 kWh pa consumer is slightly less sensitive to changes in sensitivity parameters than a, 8,000 kWh pa consumer, but the sensitivity is still high.
2. All changes in return from sensitivities increase with the complex time-of-use price structure at all annual consumptions. In other words, a more complex time-of-use price structure leads to slightly higher sensitivity to changes in sensitivity parameters.

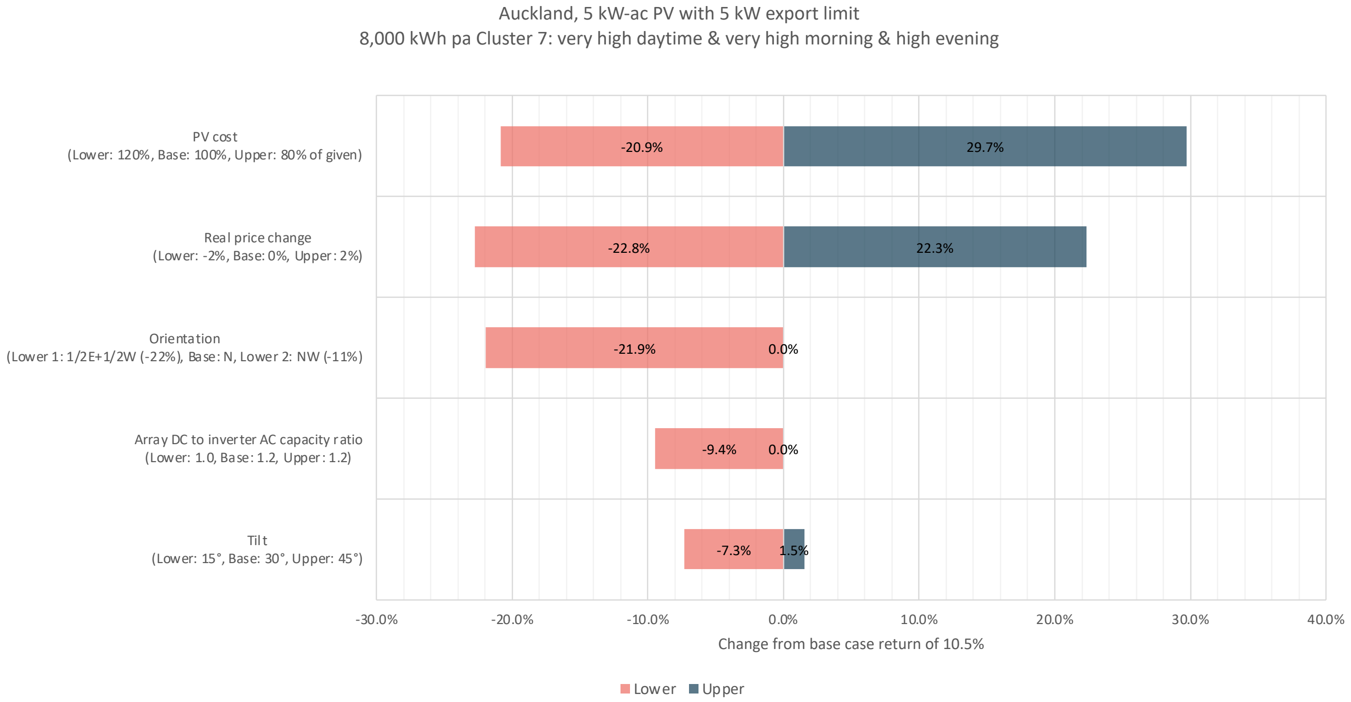
With an 8 kW-ac solar PV installation, 8,000 kWh pa consumer, complex time-of-use price structure, and a 5 kW export limit, there is:

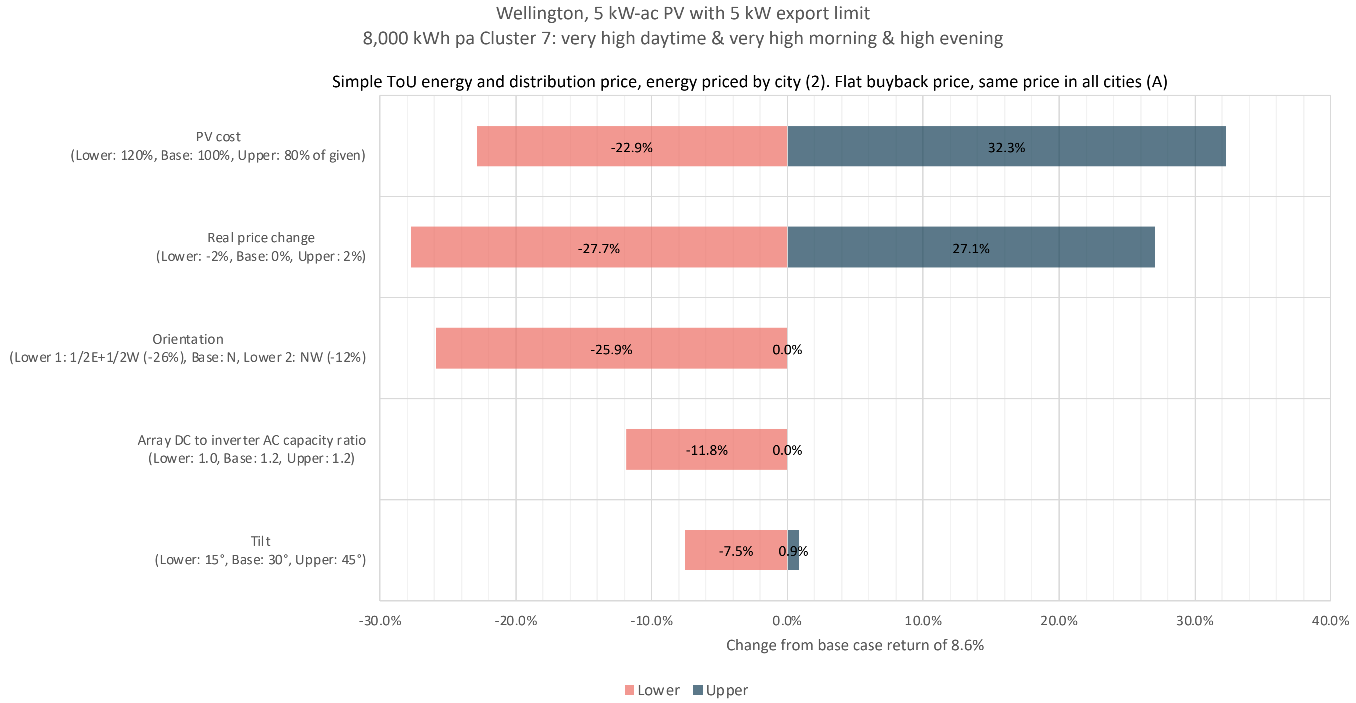
3. Little difference in return from changes to PV cost compared to Figure 20.
4. The difference in return due to real electricity price change widens because there are more exports, the income from which depends on price.
5. The difference in returns due to changes in orientation, tilt and DC:AC ratio is not as high as other sensitivity parameters. This is because the high capacity, with export limit, offsets the reduction in generation from the orientation change.

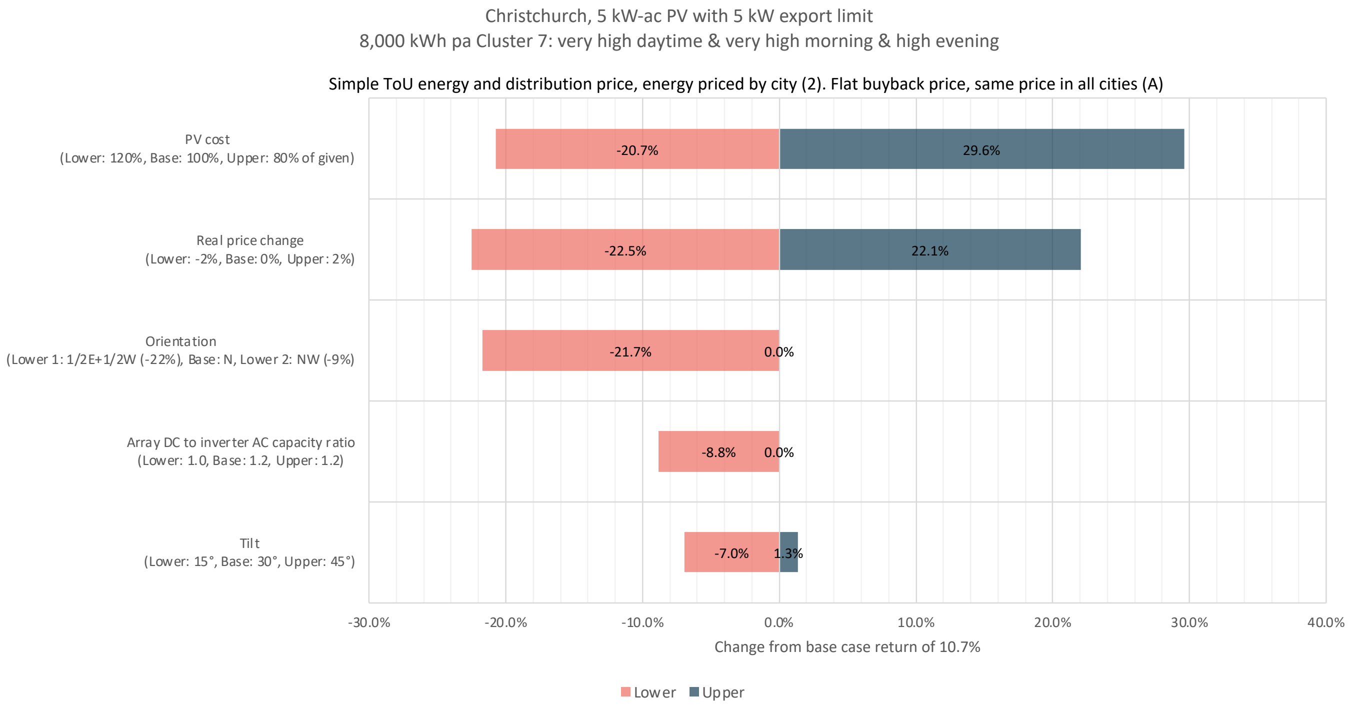
Increasing the export limit for the 8 kW-ac solar PV installation from 5 kW to 15 kW yields the results shown in Figure 23. Most notably, it shows:

6. Greater sensitivity to the PV array to inverter ratio (DC:AC ratio). This is because more energy can be exported, thus increasing the sensitivity compared to a system configuration that does not export as much energy (a DC:AC ratio of 1.0).

Figure 22 – Sensitivities to certain inputs for each city with a 5 kW PV system and an 8,000 kWh pa consumer of load type that gives maximum returns. Sensitivities are shown as the change in return from the Base Case.







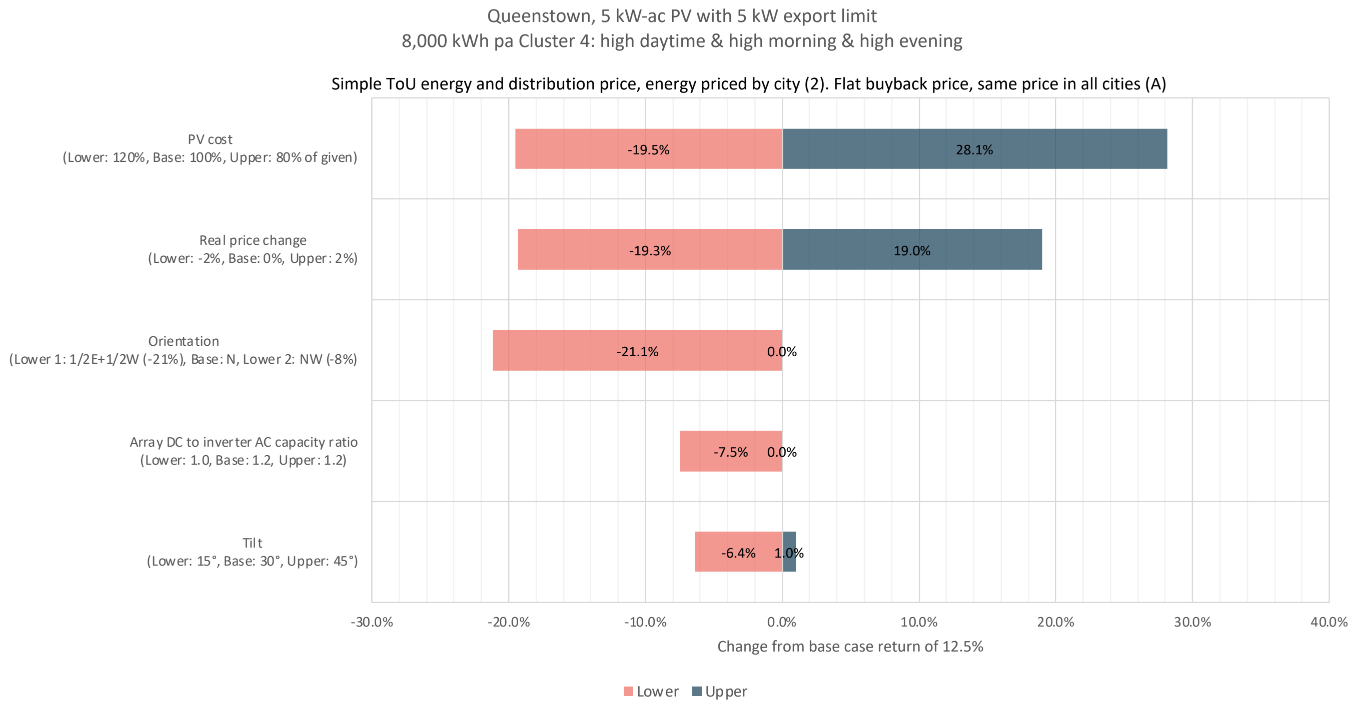
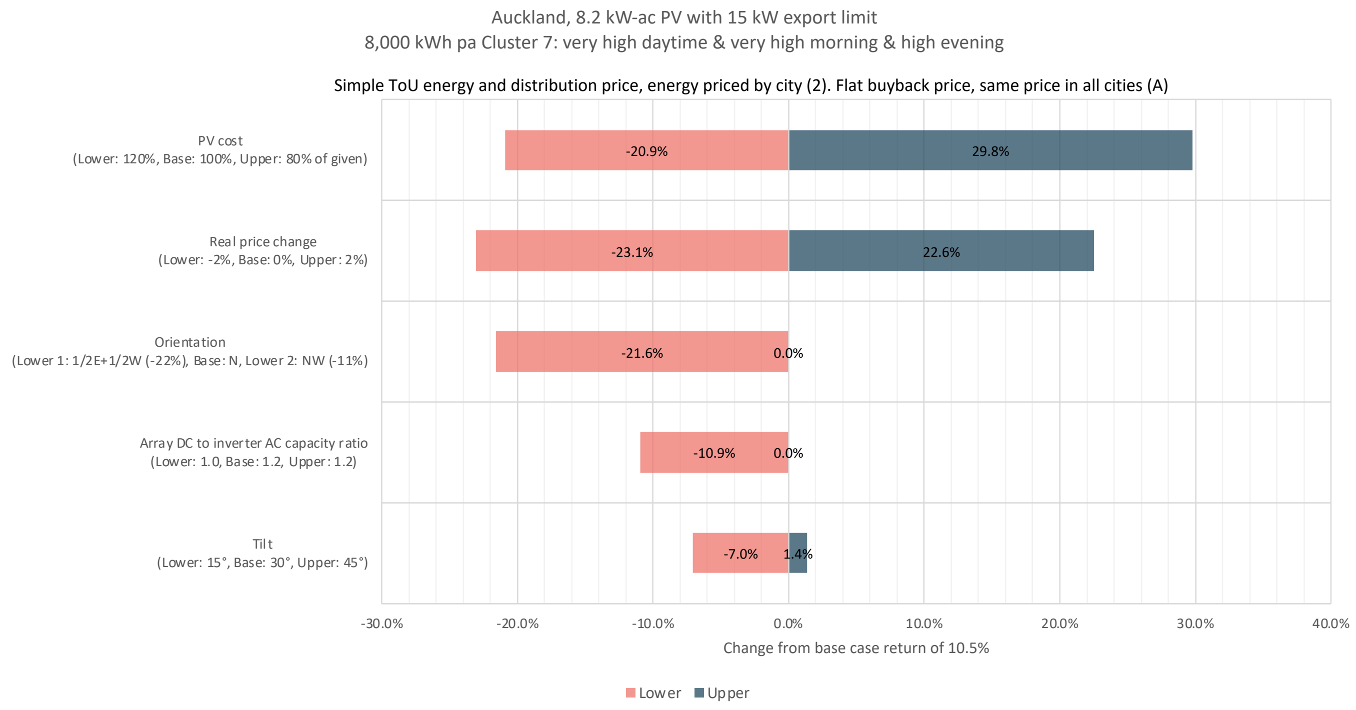
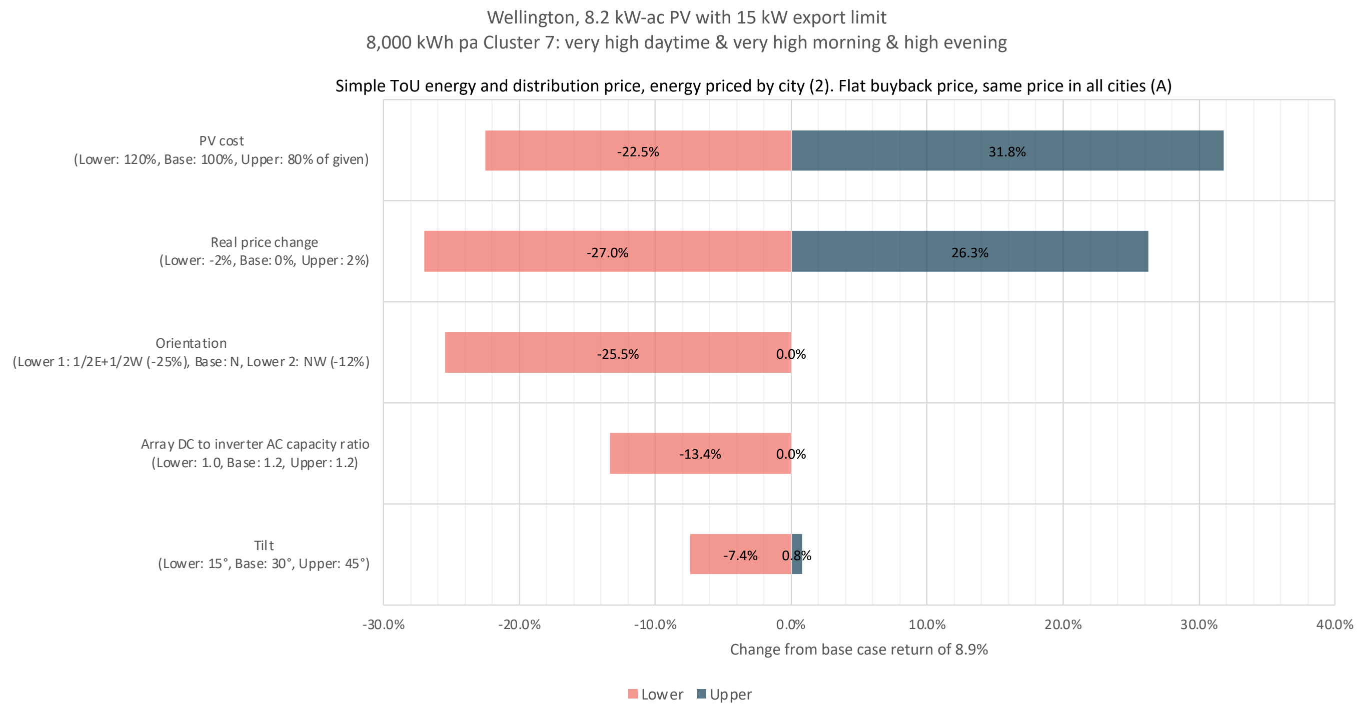
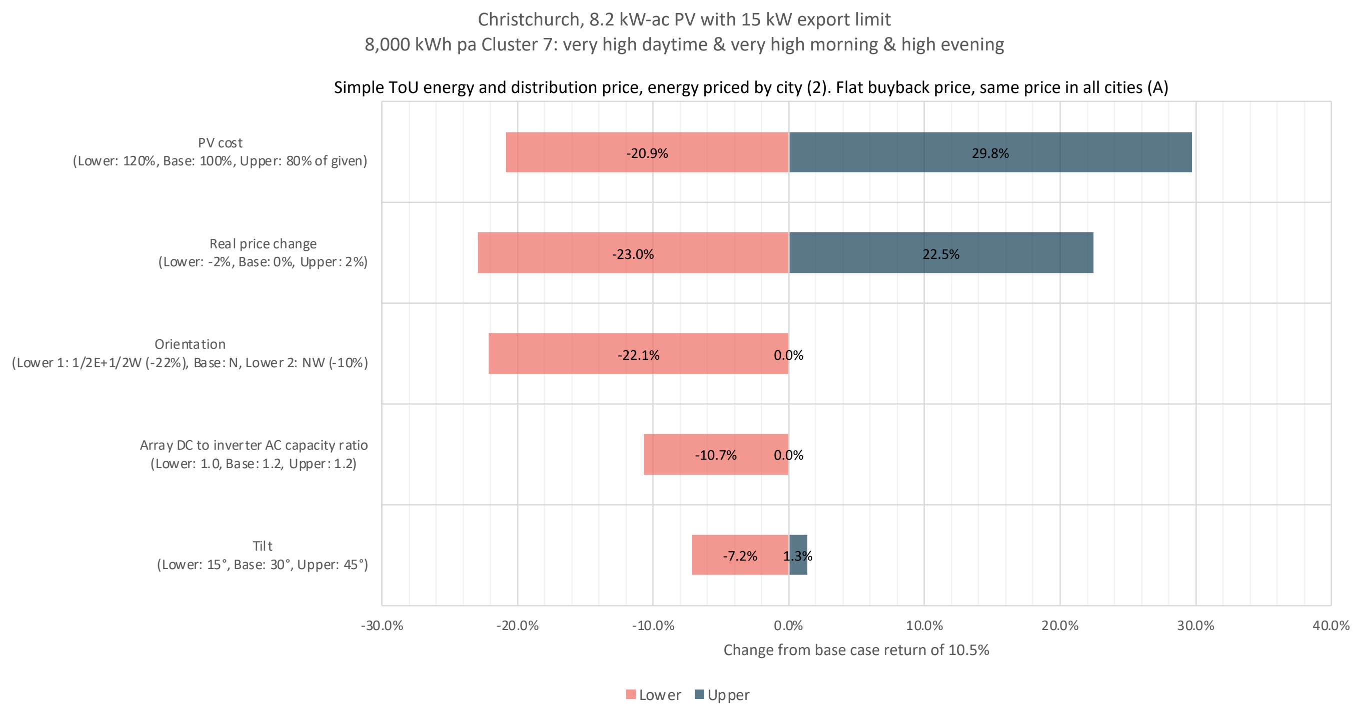
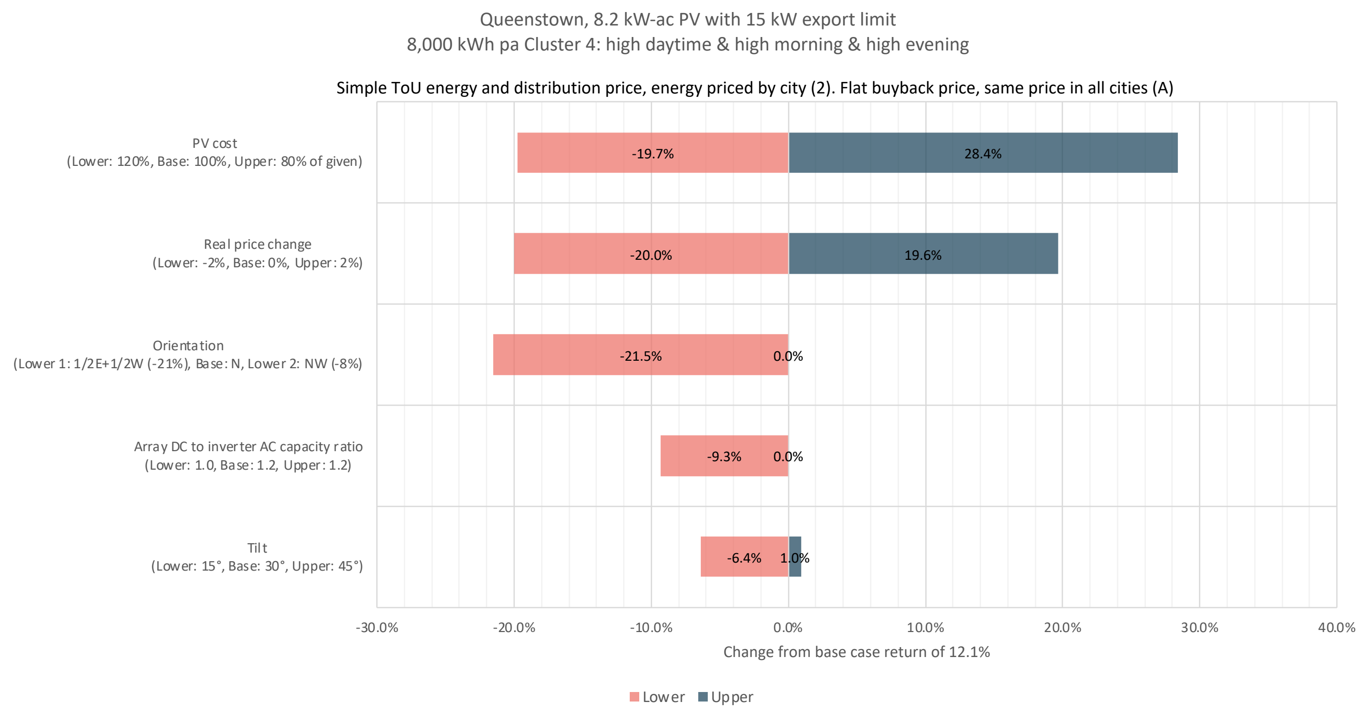


Figure 23 – Sensitivities to certain inputs for each city with an 8.2 kW PV system and an 8,000 kWh pa consumer of load type that gives maximum returns, with the export limit relaxed from 5 kW to 15 kW. Sensitivities are shown as the change in return from the Base Case.









In general, the following observations are made about sensitivities:

1. The cost of the PV system has a major impact on return, increasing the return by about 3 percentage points when the system cost is reduced by 20%, which equates to a reduction in simple payback from 9 years to 7 years. This highlights the importance of efficiencies in the PV installation industry to reduce costs of PV to the consumer, and in overheads associated with PV installations.
2. Real price changes also have a major impact on returns, with returns roughly 2 percentage points higher under a sustained real electricity price increase of 2%. However, historically real electricity prices have remained reasonably stable, so this scenario is possibly not likely.
3. Other factors such as orientation – the input that has the next highest influence on returns – and tilt are difficult to control since the orientation and roof slope of an existing home are set. However, the DC:AC ratio (array to inverter capacity ratio) is easily controlled by selecting a system design with a deliberately oversized array capacity, providing there is sufficient roof area. Doing so can increase the returns by about one percentage point.

In conclusion, when selecting a solar PV installation, consumers should focus on:

1. Price of the system. Multiple quotes from reputable suppliers are recommended.

   However, care should be taken to not compromise the quality of components. Consumers should seek PV module *manufacturing* warranties of over 20 years (note that this is not the *performance* warranty, which relates to annual degradation) and inverter warranties over 15 years. They should ensure that the inverter used in the system is from a reputable supplier and that it includes internet connectivity, has a good smart phone app, and supports relevant standards.
2. System design. If roof space permits, oversizing the PV array capacity by a ratio of at least 1.2, possibly even 1.3, and ensuring that the additional cost of PV modules, racking, and wiring is well below 1 $/Wp-dc.
3. Retailer and price structure and prices. Selecting a retailer with an appropriate price structure and buyback rate to maximise returns.
4. There may be other actions that a consumer can take, such as shifting load with storage, hot water and/or battery, which is investigated further in the next section.

And the industry should focus on:

1. Reducing installation costs and bringing more efficiency to solar PV installation by installers to reduce costs further.
2. Reducing overhead costs including cost reductions for export meters and distributor application fees through distributors automating the PV application process and reducing the inspection fee.
3. Removing export limits by relaxing the upper voltage limit in the regulations from +6% to +10%. As shown, this can significantly increase returns, and importantly will improve the performance of higher capacity PV systems leading to higher renewable energy generation in New Zealand.

Increasing export limits can also be achieved by electricity distributors understanding the capacity of their low voltage networks to host PV now and well into the future, which will enable higher export limits in some LV networks rather than applying a blanket 5 kW or lower export limit across all consumers.

4. There are other actions related to removing export limits that the industry may be able to take. These include some control of hot water storage of consumers without solar PV to maximise local use of exported energy, especially at high sunshine times such as the middle of the day in summer. This may also assist with the transition from gas hot water heating to electric storage hot water heating by limiting maximum demand increase due to hot water heating. This is especially the case in distribution networks where gas has been the norm, and that have a lower after diversity maximum demand (ADMD) design as a result.

   For example, in a low voltage network in Christchurch with 35 residential ICPs, all with storage hot water, if five ICPs each had 5 kW-ac solar PV (14% penetration) with an average of 45% self-consumption each, their excess solar could supply 20% of the annual hot water energy requirements (32% in January and 6% in July) if the hot water was controlled appropriately to coincide with solar PV exports. In turn this would reduce exports to the wider distribution network, help control constraints due to over-voltage and maximise exports of solar.

   If the penetration of solar doubled to 10 ICPs (28%) the excess solar energy could supply 40% of the annual hot water energy requirements (64% in January and 12% in July).

4.4 Variation of returns as only solar and only prices change between cities

This sub-section briefly examines the returns between cities when only one key input to solar returns is varied. It was shown in Sub-section 4.2 that the price structure and prices can change the return of solar PV substantially. Indeed, there are several factors that influence PV's performance, including:

1. Price structure and level
2. Solar generation
3. Load profile shape and total annual consumption

In Figure 24 the same solar generation and load profiles are used in each city, with only the price relating to the city used. This allows the difference due to price to be seen. Figure 25 is the same, but with the more complex time-of-use price structure. The following can be seen from these:

- Queenstown's return is highest in most clusters, followed by Christchurch, Auckland, and Wellington. This difference is most pronounced with the higher annual consumption 12,000 kWh pa load.
- When the more complex time-of-use price structure is adopted, the differences in returns due to price diminish, and Queenstown's returns drop in general to just above Wellington.

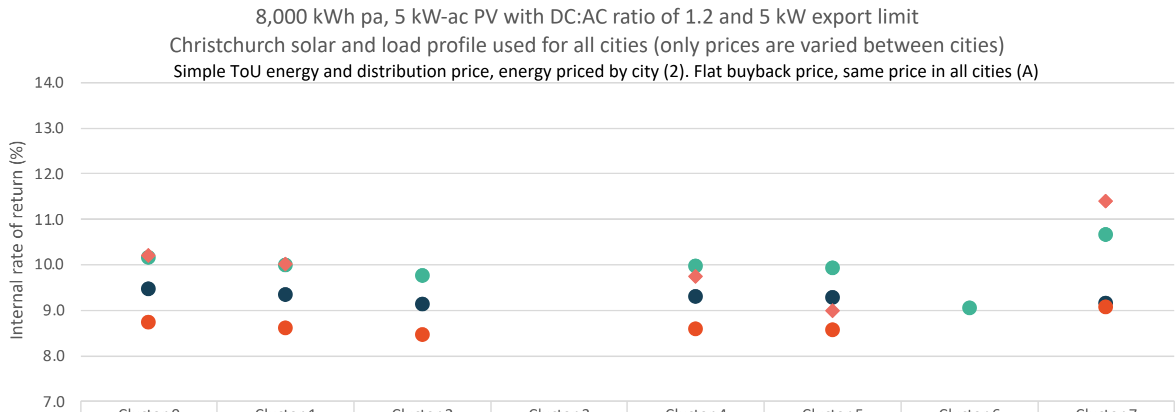
This illustrates that the consistently high performance of Queenstown in previous sections is not only due to it having the highest solar capacity factor, but also due to existing prices in Queenstown promoting solar more – those prices being a day/night structure with distribution prices not yet fully compliant with the Electricity Authority's distribution pricing principles (discussed in Appendix 8).

Despite identifying that Queenstown's higher returns are in part due to prices that are more advantageous for solar PV, it is still of interest to know how much the higher capacity factor for Queenstown contributes to its higher returns. In Figure 26 the same prices and load profile are used in each city, with only solar relating to the city used. This allows the differences due to solar to be seen. The following can be seen from Figure 26:

- The order of the returns generally follows the order of the capacity factors in each city, with the difference most pronounced with the higher annual consumption 12,000 kWh pa load. Queenstown is well ahead in most cases.

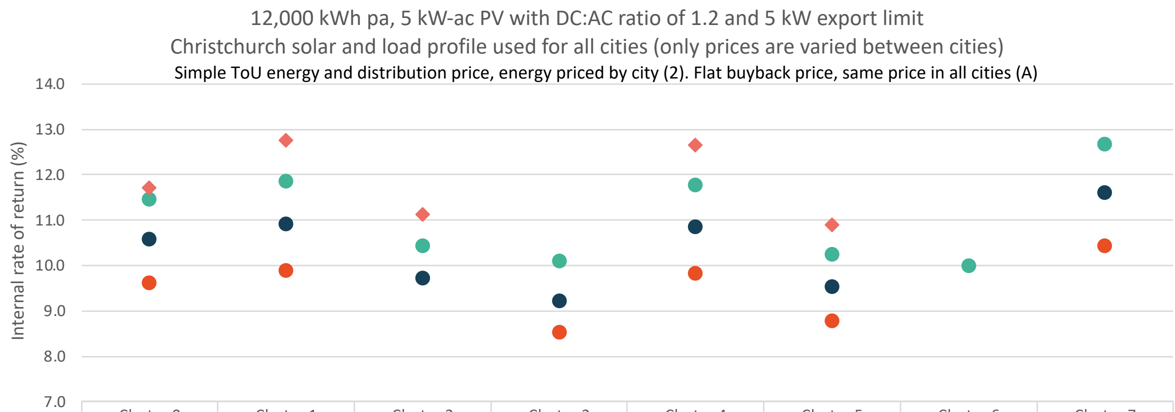
The overall conclusion from this is that price differences between cities can accentuate differences in returns between cities, that these differences are more pronounced with higher annual consumption loads, and that as prices trend towards more cost reflective prices, the differences reduce.

Figure 24: Returns for 5 kW-ac solar PV installations that show the returns in each city due to prices with a day/night retail price structure and flat buyback price. To achieve this the same solar generation and load profiles are used in all cities. In this case Christchurch's solar generation and load profiles are used.



	Cluster 0 Day: Medium AM: Medium PM: Medium	Cluster 1 Day: Very high AM: High PM: Very high	Cluster 2 Day: Very high AM: Low PM: Very high	Cluster 3 Day: Low AM: Low PM: Medium	Cluster 4 Day: High AM: High PM: High	Cluster 5 Day: High AM: Low PM: Very high	Cluster 6 Day: Very low AM: Very low PM: Low	Cluster 7 Day: Very high AM: Very high PM: High
Auckland	9.5	9.3	9.1	0.0	9.3	9.3	0.0	9.2
Wellington	8.7	8.6	8.5	0.0	8.6	8.6	0.0	9.1
Christchurch	10.2	10.0	9.8	0.0	10.0	9.9	9.1	10.7
Queenstown	10.2	10.0	0.0	0.0	9.8	9.0	0.0	11.4

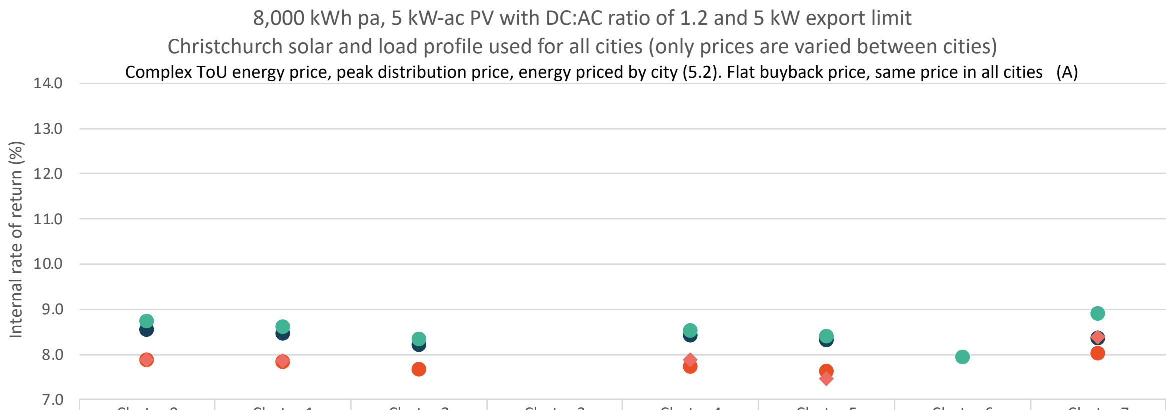
Cluster



	Cluster 0 Day: Medium AM: Medium PM: Medium	Cluster 1 Day: Very high AM: High PM: Very high	Cluster 2 Day: Very high AM: Low PM: Very high	Cluster 3 Day: Low AM: Low PM: Medium	Cluster 4 Day: High AM: High PM: High	Cluster 5 Day: High AM: Low PM: Very high	Cluster 6 Day: Very low AM: Very low PM: Low	Cluster 7 Day: Very high AM: Very high PM: High
Auckland	10.6	10.9	9.7	9.2	10.9	9.5	0.0	11.6
Wellington	9.6	9.9	0.0	8.5	9.8	8.8	0.0	10.4
Christchurch	11.5	11.9	10.4	10.1	11.8	10.2	10.0	12.7
Queenstown	11.7	12.8	11.1	0.0	12.7	10.9	0.0	0.0

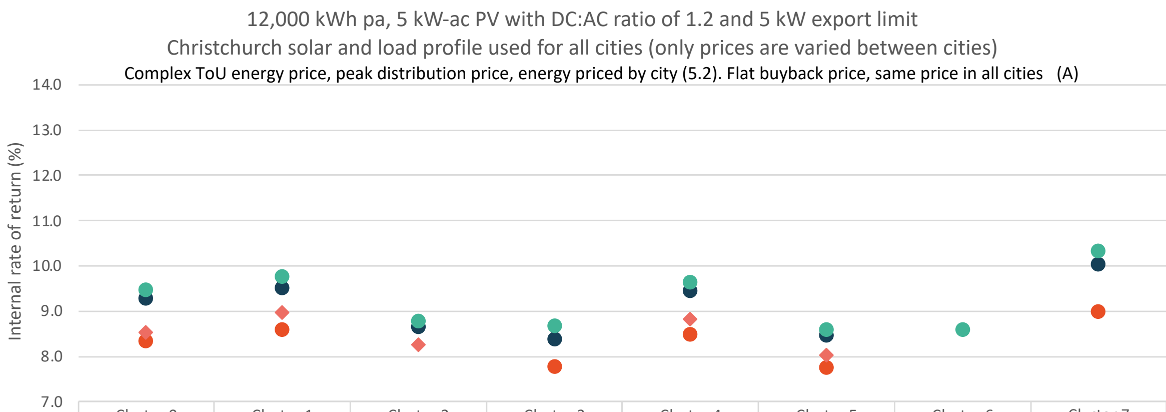
Cluster

Figure 25: Returns for 5 kW-ac solar PV installations that show the returns in each city due to prices with a complex time-of-use retail price structure and flat buyback price. To achieve this the same solar generation and load profiles are used in all cities. In this case Christchurch's solar generation and load profiles are used.



	Cluster 0 Day: Medium AM: Medium PM: Medium	Cluster 1 Day: Very high AM: High PM: Very high	Cluster 2 Day: Very high AM: Low PM: Very high	Cluster 3 Day: Low AM: Low PM: Medium	Cluster 4 Day: High AM: High PM: High	Cluster 5 Day: High AM: Low PM: Very high	Cluster 6 Day: Very low AM: Very low PM: Low	Cluster 7 Day: Very high AM: Very high PM: High
Auckland	8.5	8.5	8.2	0.0	8.4	8.3	0.0	8.4
Wellington	7.9	7.9	7.7	0.0	7.7	7.6	0.0	8.0
Christchurch	8.7	8.6	8.4	0.0	8.5	8.4	7.9	8.9
Queenstown	7.9	7.9	0.0	0.0	7.9	7.5	0.0	8.4

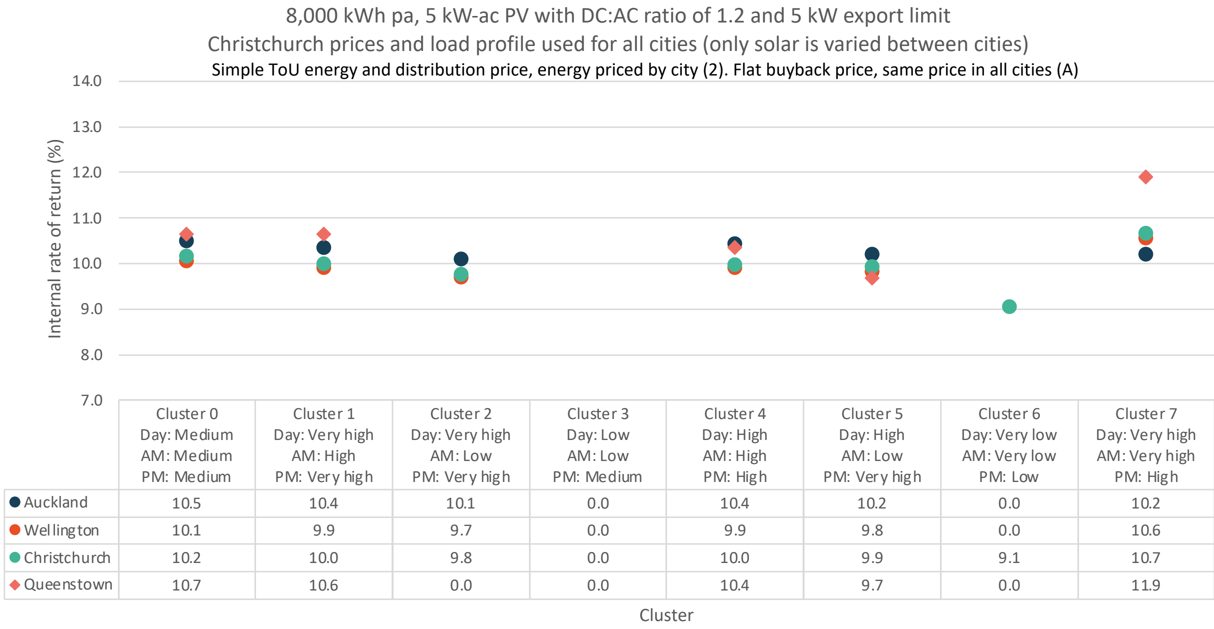
Cluster



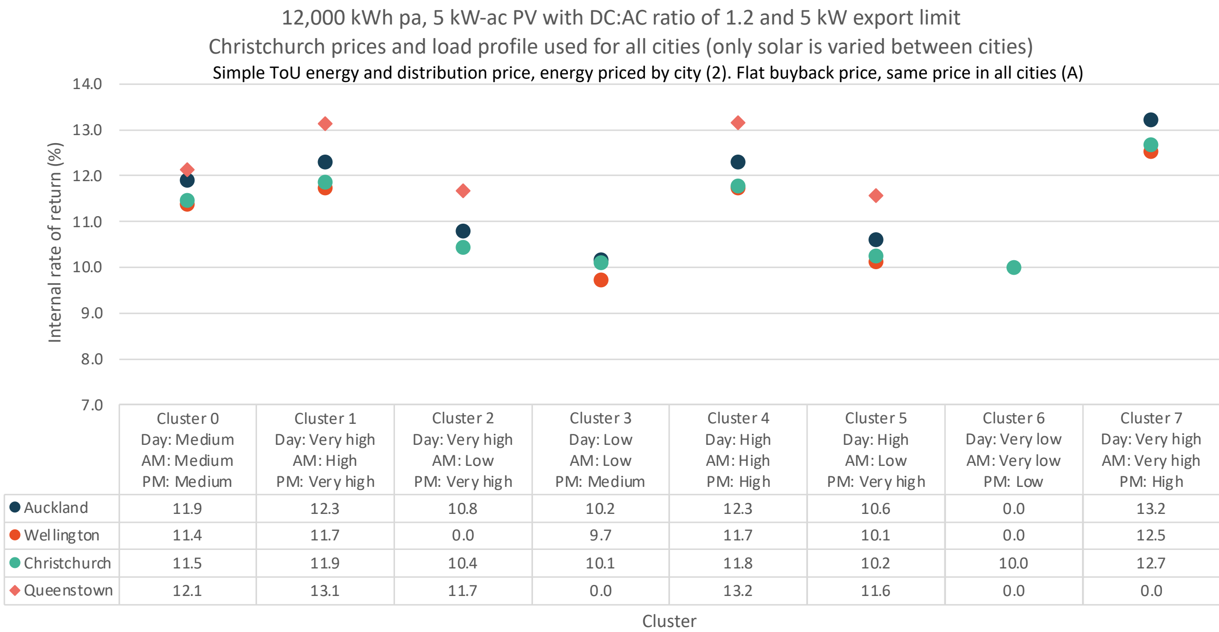
	Cluster 0 Day: Medium AM: Medium PM: Medium	Cluster 1 Day: Very high AM: High PM: Very high	Cluster 2 Day: Very high AM: Low PM: Very high	Cluster 3 Day: Low AM: Low PM: Medium	Cluster 4 Day: High AM: High PM: High	Cluster 5 Day: High AM: Low PM: Very high	Cluster 6 Day: Very low AM: Very low PM: Low	Cluster 7 Day: Very high AM: Very high PM: High
Auckland	9.3	9.5	8.7	8.4	9.5	8.5	0.0	10.0
Wellington	8.4	8.6	0.0	7.8	8.5	7.8	0.0	9.0
Christchurch	9.5	9.8	8.8	8.7	9.7	8.6	8.6	10.3
Queenstown	8.5	9.0	8.3	0.0	8.8	8.0	0.0	0.0

Cluster

Figure 26: Returns for 5 kW-ac solar PV installations that show the returns in each city due to solar with a day/night retail price structure and flat buyback price. To achieve this the same prices and load profiles are used in all cities. In this case Christchurch's prices and load profiles are used.



	Cluster 0 Day: Medium AM: Medium PM: Medium	Cluster 1 Day: Very high AM: High PM: Very high	Cluster 2 Day: Very high AM: Low PM: Very high	Cluster 3 Day: Low AM: Low PM: Medium	Cluster 4 Day: High AM: High PM: High	Cluster 5 Day: High AM: Low PM: Very high	Cluster 6 Day: Very low AM: Very low PM: Low	Cluster 7 Day: Very high AM: Very high PM: High
Auckland	10.5	10.4	10.1	0.0	10.4	10.2	0.0	10.2
Wellington	10.1	9.9	9.7	0.0	9.9	9.8	0.0	10.6
Christchurch	10.2	10.0	9.8	0.0	10.0	9.9	9.1	10.7
Queenstown	10.7	10.6	0.0	0.0	10.4	9.7	0.0	11.9



	Cluster 0 Day: Medium AM: Medium PM: Medium	Cluster 1 Day: Very high AM: High PM: Very high	Cluster 2 Day: Very high AM: Low PM: Very high	Cluster 3 Day: Low AM: Low PM: Medium	Cluster 4 Day: High AM: High PM: High	Cluster 5 Day: High AM: Low PM: Very high	Cluster 6 Day: Very low AM: Very low PM: Low	Cluster 7 Day: Very high AM: Very high PM: High
Auckland	11.9	12.3	10.8	10.2	12.3	10.6	0.0	13.2
Wellington	11.4	11.7	0.0	9.7	11.7	10.1	0.0	12.5
Christchurch	11.5	11.9	10.4	10.1	11.8	10.2	10.0	12.7
Queenstown	12.1	13.1	11.7	0.0	13.2	11.6	0.0	0.0

4.5 Comparison of returns with utility-scale solar

It is of interest to compare the rates of return of residential rooftop solar PV with rates of return of utility-scale solar. Apart from the obvious scale and layout differences, two key differences between residential and utility solar are the capital cost and the price received for the energy. These have been discussed at length for residential solar PV in Sub-section 3.2 and its associated appendixes. In the case of utility-scale solar there have been ongoing declines in capital cost to the point where these are now estimated to be in the range of 0.8 $/Wp-ac to 1.1 $/Wp-ac for a 200 MW tracking system with inverter loading ratio of 1.2.[5] These costs do not include transmission connection nor land acquisition/leasing.

A calculation of generation-weighted average prices for solar generation in the four centres gives an indication of historical prices and is summarised in Table 12. These are an indication only, as they use generation from residential solar PV, which will have a different generation profile to a utility-scale tracking system.

Table 12: Generation weighted average prices ($/MWh excluding GST) for the locations considered for the rooftop systems in the Base Case (north orientation, 30° tilt and DC:AC ratio of 1.2).

Year	Auckland	Wellington	Christchurch	Queenstown
2015	80	76	77	72
2016	66	58	57	53
2017	84	79	82	78
2018	134	120	118	112
2019	141	125	125	117
2020	121	108	99	95
2021	179	162	167	159
2022	132	120	121	115
2023	144	129	127	118
Average	120	108	108	102

[5] These are consistent with real price declines in the two scenarios given in the appendix of (Miller A., May 2020), adjusted by general CPI change between 3Q2020 and 4Q2024, from the Reserve Bank of New Zealand's inflation calculator.

Using the figures from Table 1 of (Miller A., May 2020), with inflation adjustment from 2020 to 2025, and increasing the capacity factor of a tracking system to 0.22, a full discounted cashflow model has been constructed to understand the rates of return possible from utility-scale solar.[6] This is similar to the model described in Sub-section 2.2.1 of (Miller A., May 2020) but uses real calculations (no inflation is included) to allow comparison with the residential rooftop results in this study. Results from this model for ranges of capital cost and price inputs are tabulated in Table 13.

Table 13: Estimated rates of return for a 200 MW and 1.2 inverter loading ratio utility-scale solar farm under different capital cost and energy price scenarios. Land and transmission costs are not included in the capital cost but are accounted for in the model used to calculate these returns.

Capital Cost	Price ($/MWh)	
($/W-ac)	100	120
0.8	11.7%	14.6%
1.1	8.8%	11.3%

As shown in Table 13 the utility-scale solar farm returns are similar to those of residential rooftop solar PV with the day/night time-of-use price structure. However, the utility-scale returns are generally higher compared to residential rooftop solar PV with the more complex time-of-use price structure that also passes through more cost reflective distribution prices. While the capital costs of residential rooftop solar PV are more than double the capital costs of utility-scale solar given in Table 13, residential roof-top solar effectively receives a higher price for its energy, in particular self-consumption, under the day/night price structure. However, this price reduces at off-peak times when solar energy generation is usually stronger, leading to lower returns under the complex time-of-use price structure. Further, the comparison has been made with the load type (cluster) that gives the highest returns. Hence it is concluded that utility-scale solar returns are similar to residential rooftop solar PV returns for some load types, and more so in certain locations; but utility-scale returns will be better in some instances and locations compared to residential rooftop solar PV for the same locations and load types.

The next section investigates how storage combined with residential rooftop solar PV could improve the returns.

[6] Inflation adjustment from 3Q2020 and 4Q2024 used the Reserve Bank of New Zealand's inflation calculator.

5. The benefits of solar PV with energy storage

5.1 Introduction, objectives, and methodology

This section examines the relationship between PV with and without storage technology and return, by city.

In the previous section it was shown that a more complex time-of-use retail price with constant buyback price lowered returns from solar PV, but that it also reduced the differences between cities and more accurately reflected the value of higher capacity installations. Such a price structure also values energy more accurately by time-of-use, thereby rewarding solar generation that has the greatest impact on demand reduction in peak periods. This happens in combination with load type – those loads with the greatest potential for peak reduction can have higher value, as shown in the last section. For these reasons, with generation capacity and network capacity scarcer at times of peak demand, complex time-of-use pricing structures are expected to become more common place.

Even on clear days, solar does not always generate during peak periods, such as early on winter mornings and on winter evenings, so on its own it may not be able to take full advantage of more complex time-of-use price structures. This section tests whether storage can improve the value of solar PV to consumers, and which storage technology gives the greatest value.

It is expected that the improvement in value will be through increasing self-consumption rather than exports. This could be through use of hot water storage with a diverter and/or time technology. Further improvement in value is expected from reduction of demand during peak periods, in line with the earlier discussion, as might be achieved by more battery technology that can automatically respond to time-of-use prices and solar generation.

The same model as described in Sub-section 3.1 and applied in the previous section is used. As per the earlier discussion, a complex time-of-use price structure (Row 5.2 from Table 7) is used with a flat export price (Row A from Table 8). The returns by storage type over all load types (clusters) for a 5 kW-ac PV system are examined first, then one load type of particular interest is investigated further. Following this, time-of-use buyback prices are introduced (Row E from Table 8), and combinations of annual consumption and export limits are investigated. The counterfactual throughout is no storage, so that all the various storage options are compared to this. The retail price structure used with the no storage counterfactual is the same time-of-use price structure used with the storage options, on the assumption that retail electricity pricing will move to more complex time-of-use to better reflect energy and distribution network costs.

The storage options evaluated in this section are:

- No storage – PV on its own, as explored in the previous section and the counterfactual to the storage cases.
- Diverter – a device designed to direct solar energy to heat hot water whenever there is excess solar generation.
- Timer – a time-based switch on the hot water cylinder to heat between the hours of 11am and 3pm.
- 5 kWh battery – the usable battery capacity based on 70% depth of discharge, with associated cost of 714 $/kWh (see Appendix 5 for details). Appendix 4 details the battery operating and maintenance cost model. The solar inverter is assumed to have battery capability and to implement an algorithm that maximises arbitrage opportunities from the battery, as described in Appendix 4, as well as offering instantaneous reserves from the battery.
- 10 kWh battery – the same model as the 5 kWh battery, but with 10 kWh capacity based on 70% depth of discharge.
- 30 kWh vehicle-to-grid (V2G) electric vehicle (EV) with a V2G inverter AC coupled into the AC system in addition to the PV inverter, with appropriate controls to detect solar generation and maximise arbitrage opportunities as well as offer instantaneous reserves. The V2G inverter is assumed to cost $6,000. The algorithm for V2G uses the same battery control algorithm described in Appendix 4, although the EV is assumed to only be plugged in and available as a battery for one weekend day and three weekdays per week, with only 30 kWh of usable battery capacity available. To preserve battery life, a battery of 60 kWh or greater is used, with a 50% or less depth of discharge. The cost of associated battery degradation, while minimal, is not included in the analysis.

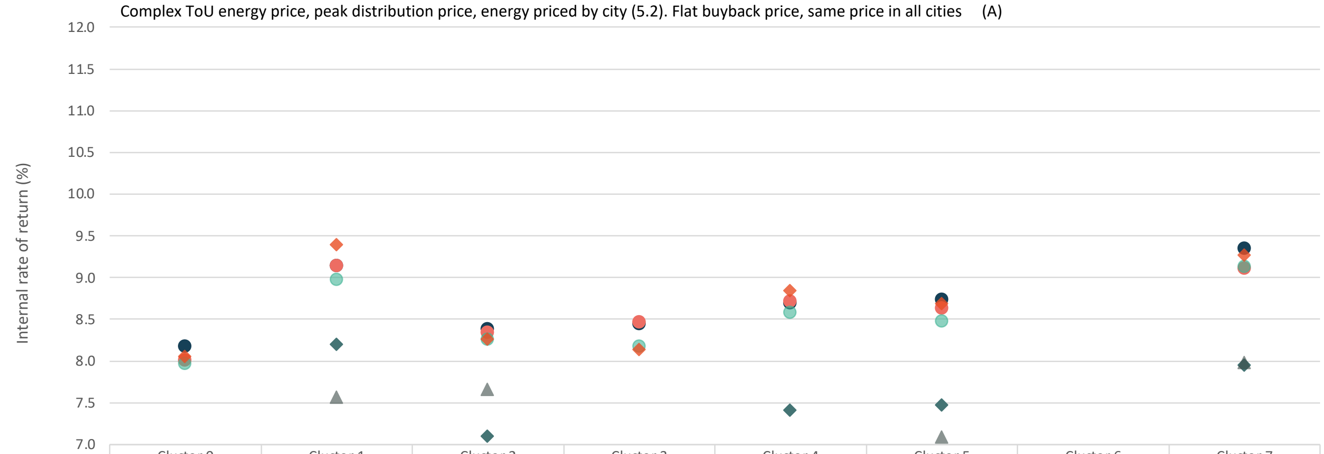
5.2 The benefits of energy storage

Figure 27 and Figure 28 show the rates of return of solar PV with various forms of energy storage, as well as the 'no storage' counterfactual, which corresponds to the analysis in the previous section. These give a visual indication of the relative performance of each storage type in each city for one solar PV capacity, with large differences indicated between annual consumptions.

Figure 27 – 5 kW-ac solar PV with storage performance by 8,000 kWh pa consumption load types with a 5 kW export limit.

Auckland 8,000 kWh pa consumers. 5 kW-ac PV with DC:AC ratio of 1.2 and 5 kW export limit

Complex ToU energy price, peak distribution price, energy priced by city (5.2). Flat buyback price, same price in all cities (A)



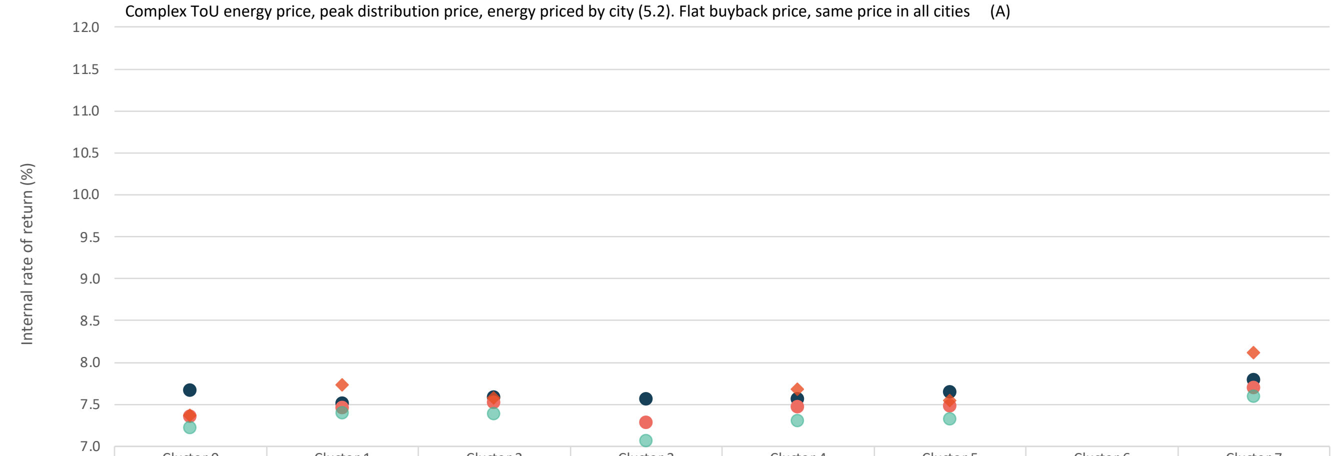
	Cluster 0 Day: Medium AM: Medium PM: Medium	Cluster 1 Day: Very high AM: High PM: Very high	Cluster 2 Day: Very high AM: Low PM: Very high	Cluster 3 Day: Low AM: Low PM: Medium	Cluster 4 Day: High AM: High PM: High	Cluster 5 Day: High AM: Low PM: Very high	Cluster 6 Day: Very low AM: Very low PM: Low	Cluster 7 Day: Very high AM: Very high PM: High
No storage	8.2	9.1	8.4	8.4	8.7	8.7	0.0	9.4
Diverter	8.0	9.1	8.4	8.5	8.7	8.6	0.0	9.1
Timer	8.0	9.0	8.3	8.2	8.6	8.5	0.0	9.1
5 kWh**	8.1	9.4	8.3	8.1	8.8	8.7	0.0	9.3
10 kWh**	6.4	8.2	7.1	6.5	7.4	7.5	0.0	8.0
30 kWh V2G**	6.3	7.6	7.7	6.2	7.0	7.1	0.0	8.0

Cluster

** 5 or 10 kWh stationary battery, 30 kWh usable vehicle battery

Wellington 8,000 kWh pa consumers. 5 kW-ac PV with DC:AC ratio of 1.2 and 5 kW export limit

Complex ToU energy price, peak distribution price, energy priced by city (5.2). Flat buyback price, same price in all cities (A)



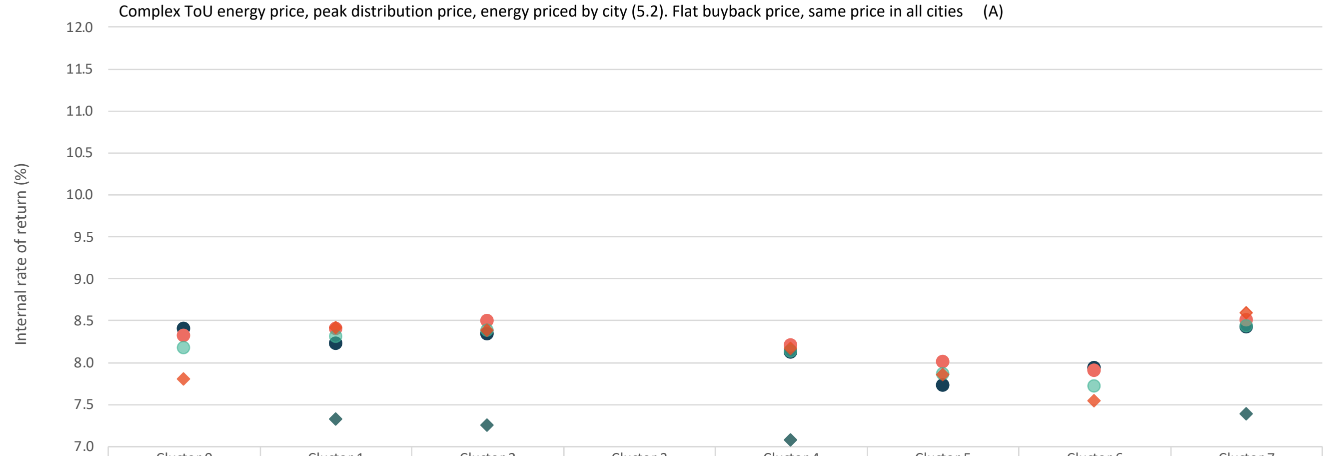
	Cluster 0 Day: Medium AM: Medium PM: Medium	Cluster 1 Day: Very high AM: High PM: Very high	Cluster 2 Day: Very high AM: Low PM: Very high	Cluster 3 Day: Low AM: Low PM: Medium	Cluster 4 Day: High AM: High PM: High	Cluster 5 Day: High AM: Low PM: Very high	Cluster 6 Day: Very low AM: Very low PM: Low	Cluster 7 Day: Very high AM: Very high PM: High
No storage	7.7	7.5	7.6	7.6	7.6	7.7	0.0	7.8
Diverter	7.4	7.5	7.5	7.3	7.5	7.5	0.0	7.7
Timer	7.2	7.4	7.4	7.1	7.3	7.3	0.0	7.6
5 kWh**	7.4	7.7	7.6	7.0	7.7	7.6	0.0	8.1
10 kWh**	6.0	6.8	6.8	5.4	6.6	6.5	0.0	6.9
30 kWh V2G**	5.7	6.5	6.5	5.2	6.2	6.0	0.0	6.4

Cluster

** 5 or 10 kWh stationary battery, 30 kWh usable vehicle battery

Christchurch 8,000 kWh pa consumers. 5 kW-ac PV with DC:AC ratio of 1.2 and 5 kW export limit

Complex ToU energy price, peak distribution price, energy priced by city (5.2). Flat buyback price, same price in all cities (A)



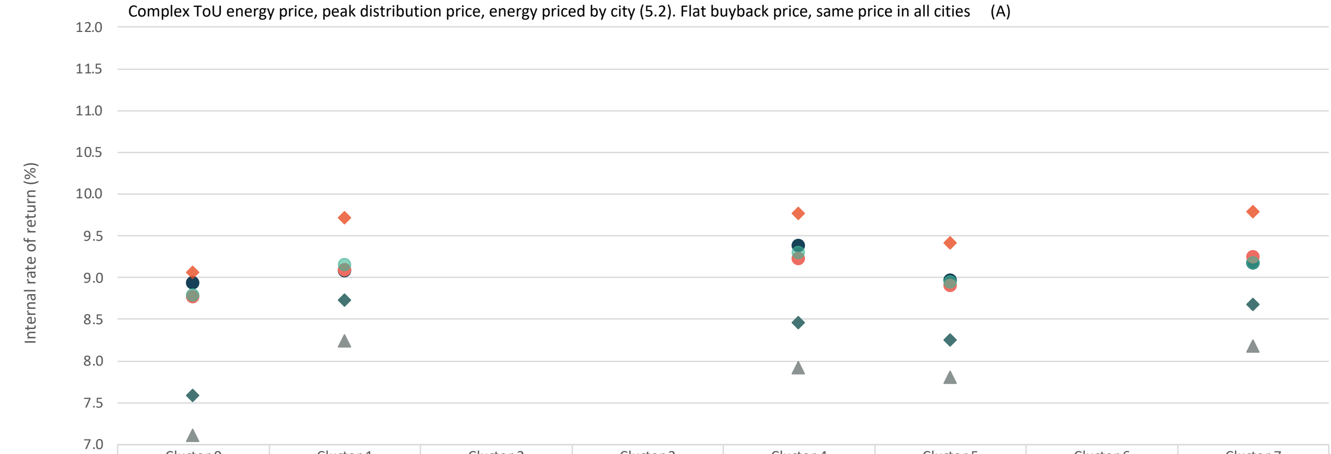
	Cluster 0 Day: Medium AM: Medium PM: Medium	Cluster 1 Day: Very high AM: High PM: Very high	Cluster 2 Day: Very high AM: Low PM: Very high	Cluster 3 Day: Low AM: Low PM: Medium	Cluster 4 Day: High AM: High PM: High	Cluster 5 Day: High AM: Low PM: Very high	Cluster 6 Day: Very low AM: Very low PM: Low	Cluster 7 Day: Very high AM: Very high PM: High
No storage	8.4	8.2	8.3	0.0	8.1	7.7	7.9	8.4
Diverter	8.3	8.4	8.5	0.0	8.2	8.0	7.9	8.5
Timer	8.2	8.3	8.4	0.0	8.1	7.9	7.7	8.4
5 kWh**	7.8	8.4	8.4	0.0	8.2	7.9	7.5	8.6
10 kWh**	6.3	7.3	7.3	0.0	7.1	6.9	5.8	7.4
30 kWh V2G**	6.3	6.9	6.8	0.0	6.7	6.3	5.5	6.8

Cluster

** 5 or 10 kWh stationary battery, 30 kWh usable vehicle battery

Queenstown 8,000 kWh pa consumers. 5 kW-ac PV with DC:AC ratio of 1.2 and 5 kW export limit

Complex ToU energy price, peak distribution price, energy priced by city (5.2). Flat buyback price, same price in all cities (A)



	Cluster 0 Day: Medium AM: Medium PM: Medium	Cluster 1 Day: Very high AM: High PM: Very high	Cluster 2 Day: Very high AM: Low PM: Very high	Cluster 3 Day: Low AM: Low PM: Medium	Cluster 4 Day: High AM: High PM: High	Cluster 5 Day: High AM: Low PM: Very high	Cluster 6 Day: Very low AM: Very low PM: Low	Cluster 7 Day: Very high AM: Very high PM: High
No storage	8.9	9.1	0.0	0.0	9.4	9.0	0.0	9.2
Diverter	8.8	9.1	0.0	0.0	9.2	8.9	0.0	9.3
Timer	8.8	9.2	0.0	0.0	9.3	9.0	0.0	9.2
5 kWh**	9.1	9.7	0.0	0.0	9.8	9.4	0.0	9.8
10 kWh**	7.6	8.7	0.0	0.0	8.5	8.3	0.0	8.7
30 kWh V2G**	7.1	8.2	0.0	0.0	7.9	7.8	0.0	8.2

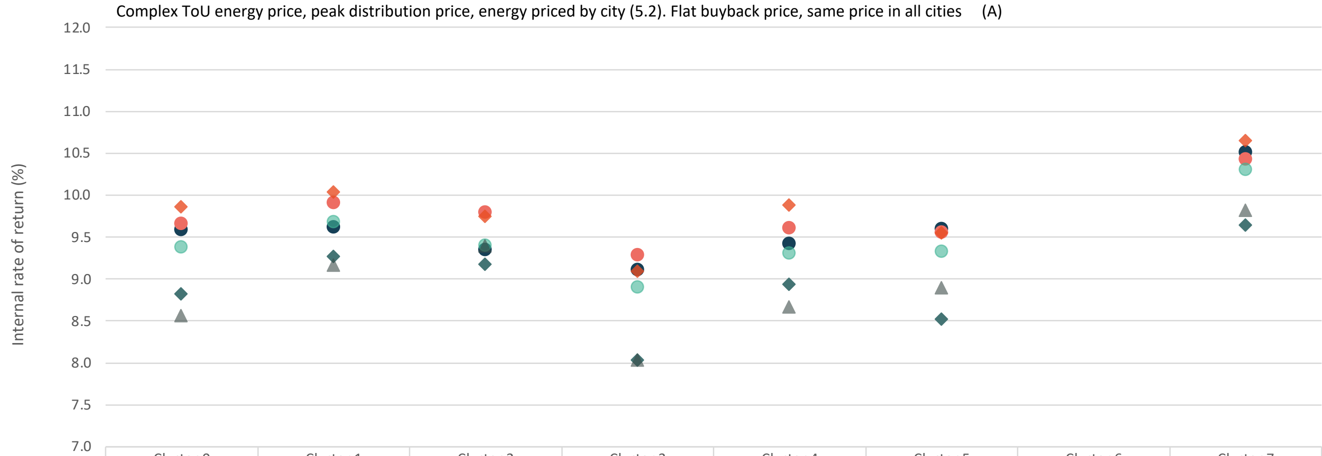
Cluster

** 5 or 10 kWh stationary battery, 30 kWh usable vehicle battery

Figure 28: 5 kW-ac solar PV with storage performance by 12,000 kWh pa consumption load types with a 5 kW export limit.

Auckland 12,000 kWh pa consumers. 5 kW-ac PV with DC:AC ratio of 1.2 and 5 kW export limit

Complex ToU energy price, peak distribution price, energy priced by city (5.2). Flat buyback price, same price in all cities (A)



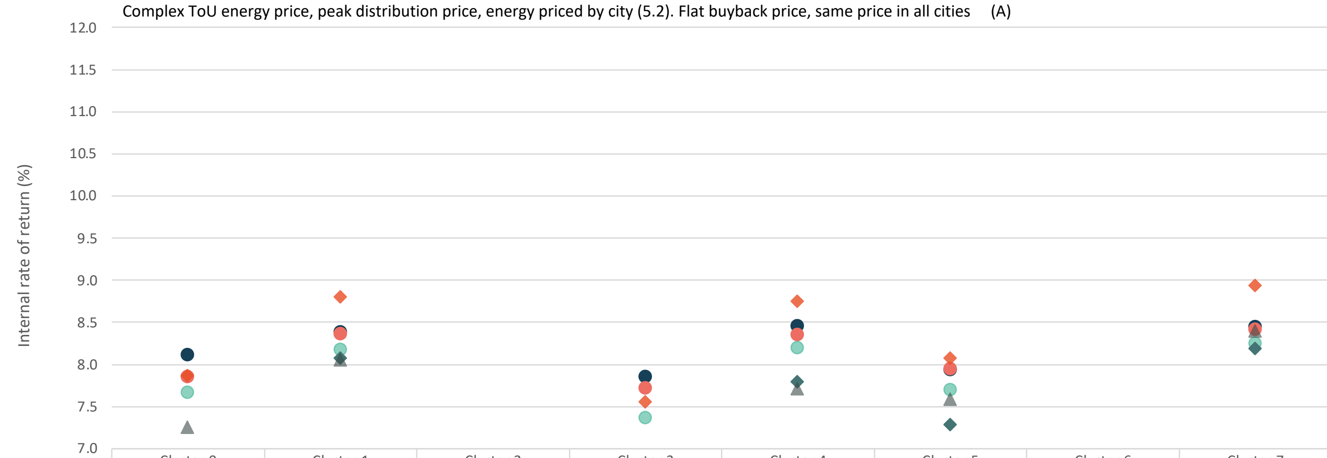
	Cluster 0 Day: Medium AM: Medium PM: Medium	Cluster 1 Day: Very high AM: High PM: Very high	Cluster 2 Day: Very high AM: Low PM: Very high	Cluster 3 Day: Low AM: Low PM: Medium	Cluster 4 Day: High AM: High PM: High	Cluster 5 Day: High AM: Low PM: Very high	Cluster 6 Day: Very low AM: Very low PM: Low	Cluster 7 Day: Very high AM: Very high PM: High
No storage	9.6	9.6	9.4	9.1	9.4	9.6	0.0	10.5
Diverter	9.7	9.9	9.8	9.3	9.6	9.6	0.0	10.4
Timer	9.4	9.7	9.4	8.9	9.3	9.3	0.0	10.3
5 kWh**	9.9	10.0	9.7	9.1	9.9	9.6	0.0	10.7
10 kWh**	8.8	9.3	9.2	8.0	8.9	8.5	0.0	9.6
30 kWh V2G**	8.6	9.2	9.4	8.0	8.7	8.9	0.0	9.8

Cluster

** 5 or 10 kWh stationary battery, 30 kWh usable vehicle battery

Wellington 12,000 kWh pa consumers. 5 kW-ac PV with DC:AC ratio of 1.2 and 5 kW export limit

Complex ToU energy price, peak distribution price, energy priced by city (5.2). Flat buyback price, same price in all cities (A)



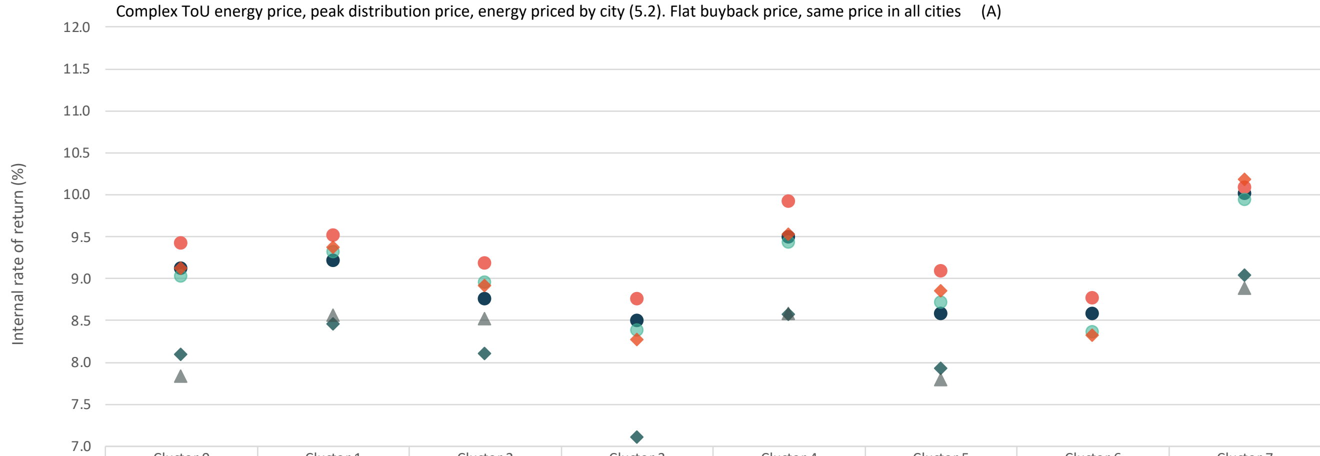
	Cluster 0 Day: Medium AM: Medium PM: Medium	Cluster 1 Day: Very high AM: High PM: Very high	Cluster 2 Day: Very high AM: Low PM: Very high	Cluster 3 Day: Low AM: Low PM: Medium	Cluster 4 Day: High AM: High PM: High	Cluster 5 Day: High AM: Low PM: Very high	Cluster 6 Day: Very low AM: Very low PM: Low	Cluster 7 Day: Very high AM: Very high PM: High
No storage	8.1	8.4	0.0	7.9	8.5	7.9	0.0	8.5
Diverter	7.9	8.4	0.0	7.7	8.4	8.0	0.0	8.4
Timer	7.7	8.2	0.0	7.4	8.2	7.7	0.0	8.3
5 kWh**	7.9	8.8	0.0	7.6	8.8	8.1	0.0	8.9
10 kWh**	6.9	8.1	0.0	6.6	7.8	7.3	0.0	8.2
30 kWh V2G**	7.3	8.1	0.0	6.7	7.7	7.6	0.0	8.4

Cluster

** 5 or 10 kWh stationary battery, 30 kWh usable vehicle battery

Christchurch 12,000 kWh pa consumers. 5 kW-ac PV with DC:AC ratio of 1.2 and 5 kW export limit

Complex ToU energy price, peak distribution price, energy priced by city (5.2). Flat buyback price, same price in all cities (A)



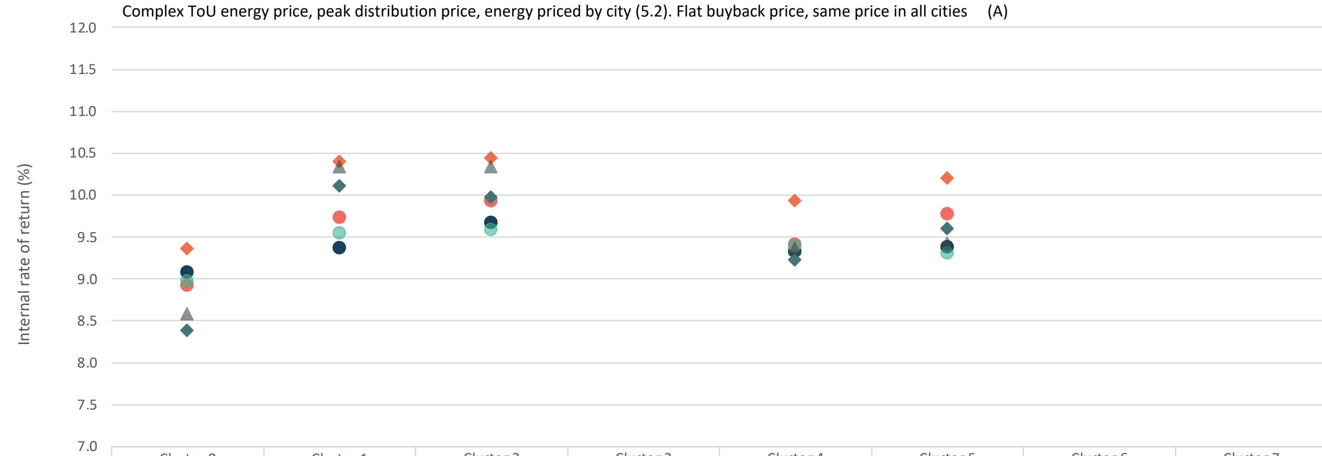
	Cluster 0 Day: Medium AM: Medium PM: Medium	Cluster 1 Day: Very high AM: High PM: Very high	Cluster 2 Day: Very high AM: Low PM: Very high	Cluster 3 Day: Low AM: Low PM: Medium	Cluster 4 Day: High AM: High PM: High	Cluster 5 Day: High AM: Low PM: Very high	Cluster 6 Day: Very low AM: Very low PM: Low	Cluster 7 Day: Very high AM: Very high PM: High
No storage	9.1	9.2	8.8	8.5	9.5	8.6	8.6	10.0
Diverter	9.4	9.5	9.2	8.8	9.9	9.1	8.8	10.1
Timer	9.0	9.3	9.0	8.4	9.4	8.7	8.4	9.9
5 kWh**	9.1	9.4	8.9	8.3	9.5	8.9	8.3	10.2
10 kWh**	8.1	8.5	8.1	7.1	8.6	7.9	7.0	9.0
30 kWh V2G**	7.8	8.6	8.5	6.9	8.6	7.8	6.5	8.9

Cluster

** 5 or 10 kWh stationary battery, 30 kWh usable vehicle battery

Queenstown 12,000 kWh pa consumers. 5 kW-ac PV with DC:AC ratio of 1.2 and 5 kW export limit

Complex ToU energy price, peak distribution price, energy priced by city (5.2). Flat buyback price, same price in all cities (A)



	Cluster 0 Day: Medium AM: Medium PM: Medium	Cluster 1 Day: Very high AM: High PM: Very high	Cluster 2 Day: Very high AM: Low PM: Very high	Cluster 3 Day: Low AM: Low PM: Medium	Cluster 4 Day: High AM: High PM: High	Cluster 5 Day: High AM: Low PM: Very high	Cluster 6 Day: Very low AM: Very low PM: Low	Cluster 7 Day: Very high AM: Very high PM: High
No storage	9.1	9.4	9.7	0.0	9.3	9.4	0.0	0.0
Diverter	8.9	9.7	9.9	0.0	9.4	9.8	0.0	0.0
Timer	9.0	9.5	9.6	0.0	9.4	9.3	0.0	0.0
5 kWh**	9.4	10.4	10.4	0.0	9.9	10.2	0.0	0.0
10 kWh**	8.4	10.1	10.0	0.0	9.2	9.6	0.0	0.0
30 kWh V2G**	8.6	10.3	10.3	0.0	9.4	9.4	0.0	0.0

Cluster

** 5 or 10 kWh stationary battery, 30 kWh usable vehicle battery

Notably, there is an improvement in rate of return from the 'no storage' counterfactual at the higher annual consumption of 12,000 kWh pa. An example is shown in Figure 29 for Cluster 1 in Auckland. Cluster 1 is now used to illustrate results instead of Cluster 7 as it shows a high return in Figure 27, and has a higher proportion of consumers overall and from each city.

Examining these alongside Figure 27 and Figure 28 enables the following observations:

1. Diverter performance

a. The diverter gives mixed results in Auckland, with small improvements in Clusters 1, 3 and 4 but reduced performance in Clusters 0, 5 and 7.

b. Wellington also shows mixed results.

c. Christchurch shows small but consistent improvements in performance from diverters over most clusters – up to about 0.7 percentage points with 12,000 kWh pa loads.

d. Generally, diverter performance improves as the solar PV capacity increases, although this relationship is not as strong when the export limit is removed, as the excess solar generation from higher capacity systems can be exported.

e. The reason for differences between cities is likely related to price differences. The diverter removes most hot water load from peak periods (7am-11am and 5pm-9pm). Therefore, any city with a higher peak price generally shows greater improvement.

   Christchurch, and to some extent Queenstown, are cases in point where most clusters show improvement, and where the peak price is slightly higher than other cities across the whole year.

2. Timer performance

a. The timer performance improvements follow a similar pattern to diverters but are strongly correlated with solar PV capacity – the improvement in return increases with solar PV capacity. This is because there is more chance of solar fully supplying hot water load when the timer turns on between 11am and 3pm when the solar PV capacity is higher.

Further, examination of the following figures that show the percentage point change from the 'no storage' case to each storage case enables the following observations:

3. Batteries and V2G

a. In Auckland, a 5 kWh battery almost always improves returns. The improvement is strongest with very high morning peak ratio and daytime load ratios. For example, in Figure 29 Auckland shows improvement of nearly a percentage point with 10 kW-ac solar PV in Cluster 1 (very high daytime ratio and high morning peak ratio), but this drops to a 0.5% point improvement with Cluster 3 (low daytime ratio and low morning peak ratio) as shown in Figure 30.

Wellington is the same, although slightly stronger improvements can be seen (Figure 31). This is due to the peak distribution price in Auckland only applying in the winter. Christchurch is similar (Figure 32).

Queenstown (Figure 33) has even better improvements, due to greater differences between peak and night, and off-peak and night prices. These differences are also present for more days due to distribution price peak periods extending to weekends.

b. The 10 kWh battery follows the same pattern, although it is almost always behind the 5 kWh battery in its improvement in returns. In fact, it often reduces returns. The primary reason for this is that the effectiveness of a battery declines as its capacity increases, depending on the pricing, due to solar generation eclipsing the opportunities for the battery to discharge later in the day, especially in summer. This is demonstrated in Appendix 4, battery model description.

c. Improvements in returns from batteries usually decline when the export limit is lifted with larger solar PV capacity systems. This is because lifting the export limit offers more opportunity to export solar energy without a battery, instead of ‘spilling’ it. The flat buyback rate used in the model is of a similar level to the difference between peak and off-peak or night prices which a battery would arbitrage. However, when the time-of-use buyback price is introduced, this decline is somewhat reversed, with the batteries almost always improving in performance. This is because the buyback rate is reduced when solar is predominantly exporting.

This is apparent in almost all cities and clusters. As an example, comparing Christchurch with a flat buyback price (Figure 32) with Christchurch with a time-of-use buyback price (Figure 34).

This improvement in performance when a time-of-use buyback price is introduced is because batteries can export at higher prices, such as during peaks, rather than solar PV without storage simply exporting at the flat buyback rate in the middle of the day. However, the improvement is still outweighed by the export limit lifting, because systems with batteries still have their higher capital cost to recover. Thus, the improvement in returns over no storage is still generally not positive. The peak period buyback prices in the model were in the order of 25 c/kWh (Sub-section 3.2.4.2). Even higher buyback prices in peak periods, such as introduced by one electricity retailer over Winter 2024, may be sufficient to push battery systems into positive returns. Section 6 discusses higher buyback rates in peak periods.

From this it is concluded that buyback prices that reflect the cost of energy, generation capacity scarcity, and capacity constraints in distribution networks are important.

There is an important conclusion from this section. If export limits are lifted by electricity distributors, and battery storage becomes more accessible (lower prices), energy and distribution pricing that more strongly reflects time-of-use becomes more important. This is to avoid issues such as large amounts of simultaneous export and indicates more need to differentiate distribution and retail prices by season.

4. Vehicle-to-grid

Vehicle-to-grid returns vary substantially between different cases. For example, Queenstown Figure 33 results suggest that V2G can be very beneficial, in some instances outperforming a 10 kWh battery. In the model the EV battery is only available from Sunday-Wednesday inclusive, to reflect EV availability when it is not in use for transport. If V2G can be enabled over all weekdays its performance would be substantially better. As expected, the effectiveness of V2G is highly dependent on the availability of the EV. Given the cost of the V2G charger in the model ($6,000) and the additional overheads to allow export, distributor approval, and inspection, there is a high cost penalty on V2G. If the cost of the V2G charger could be reduced, it would become more viable.

There is a further challenge with V2G, that being the vehicle manufacturer warranty. Most EV manufacturers will not warrant EVs for use with V2G. There may be some validity in this because the battery charge/discharge is out of the control of the EV's battery management system. This suggests further work is required to find suitable V2G chargers that satisfy EV manufacturers.

5. Annual consumption and general conclusions

In almost all cases the performance of storage improves with higher annual consumption. This supports the conclusions from the earlier section that as electrification continues, and more energy use transitions to electricity, not only do solar PV returns improve, but so do returns from storage. Moreover, as consumption increases from electrification, it is likely that peak demand will increase, increasing the cost of energy and/or electricity distribution. Pricing to encourage time-of-use away from peak periods, using diverter technology initially, and batteries as demonstrated here, becomes even more important.

Clearly, battery response to peak prices is only possible with battery control algorithms that can respond to prices. While availability of batteries at lower than current retail prices is very important, so too is the availability of battery control systems.

There is also concern that many batteries operating with the same method of response to the same prices will increase synchronous demand, leading to new peaks. Consideration of how to manage this is crucial. The next section investigates how solar PV and battery storage respond to a variety of pricing structures.

Figure 29 – Auckland Cluster 1 changes in rate of return by storage type. The change is an absolute percentage change.

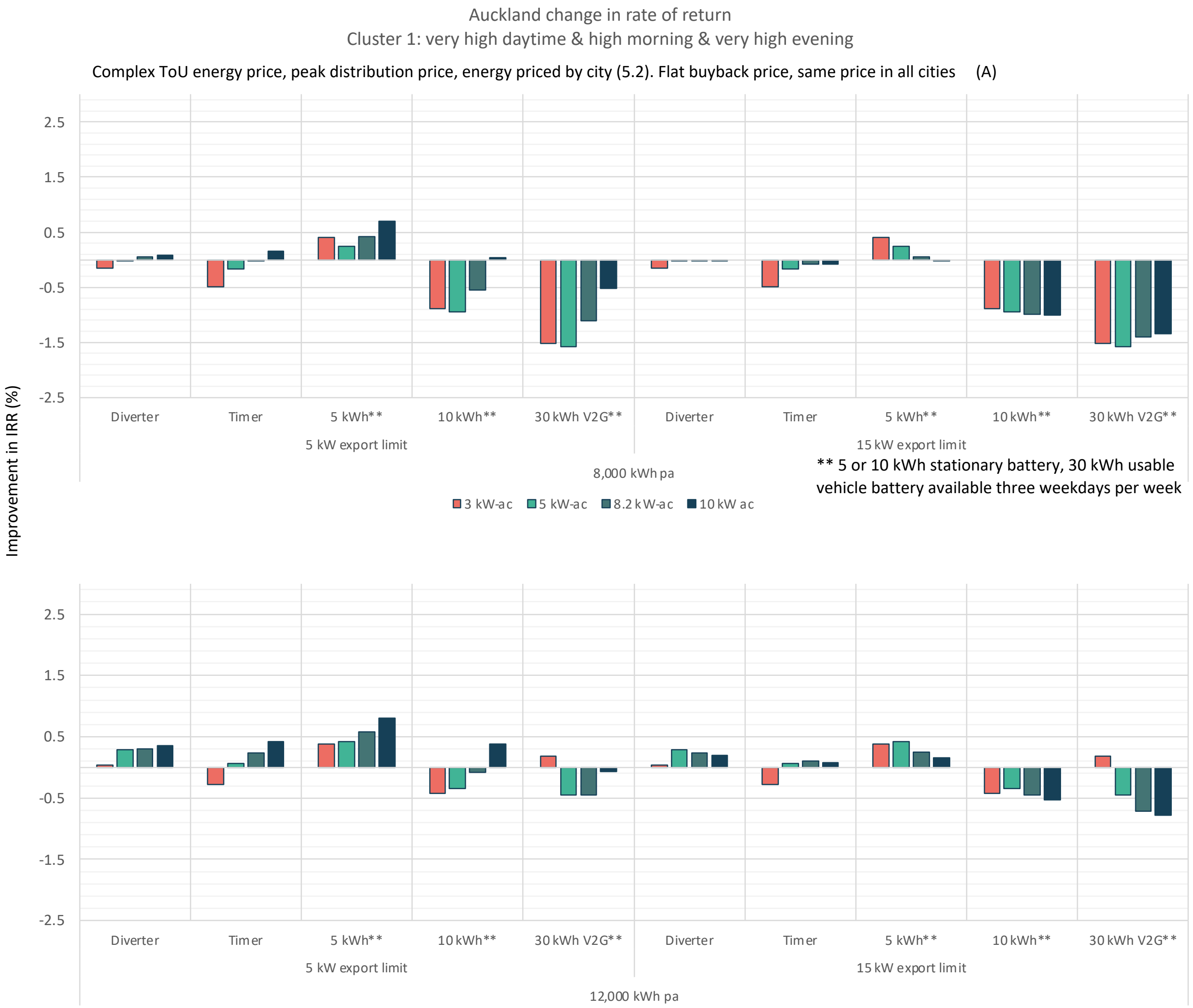


Figure 30 – Auckland Cluster 3 changes in rate of return by storage type.

Figure 31 – Wellington Cluster 1 changes in rate of return by storage type.

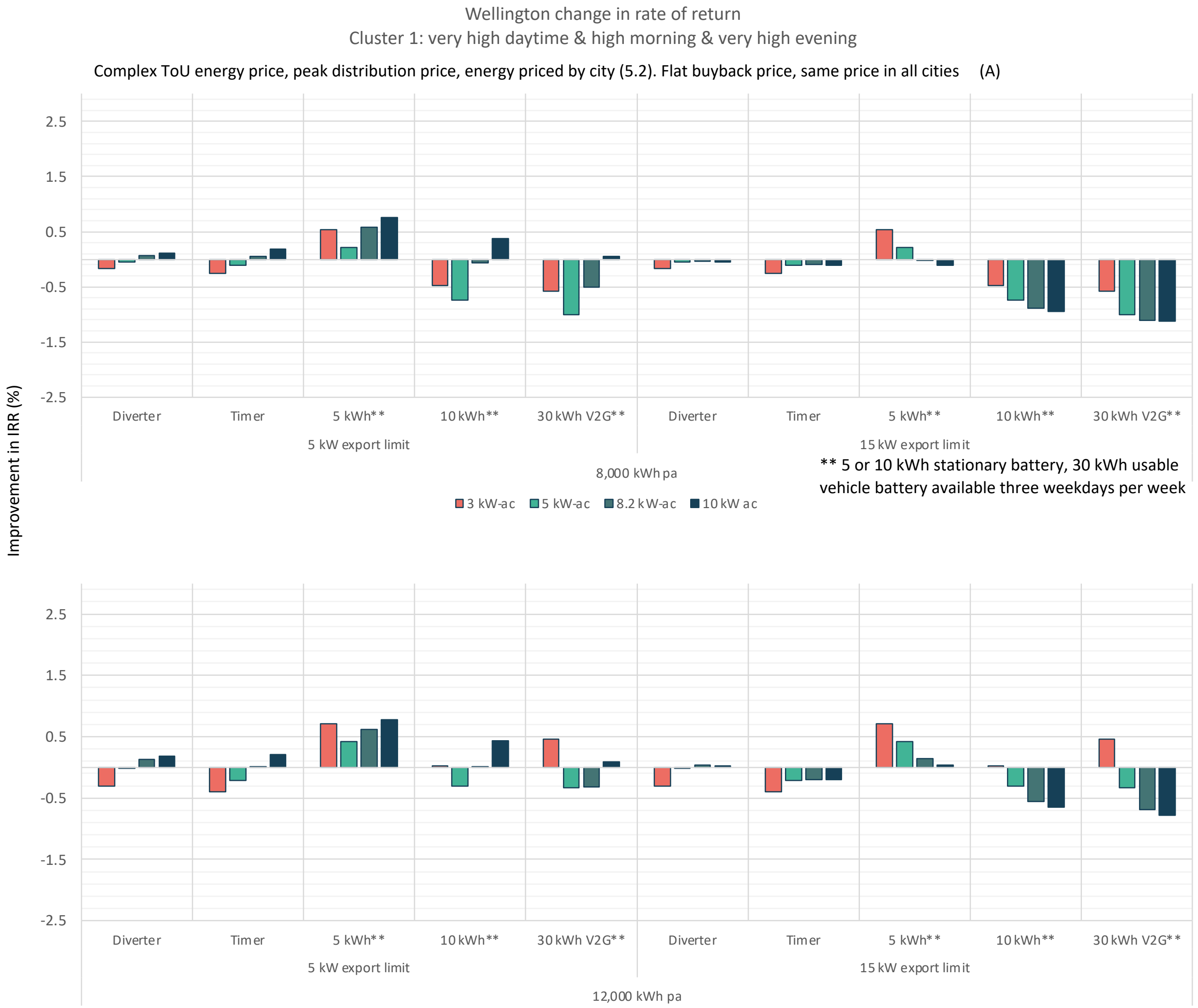


Figure 32 – Christchurch Cluster 1 changes in rate of return by storage type.

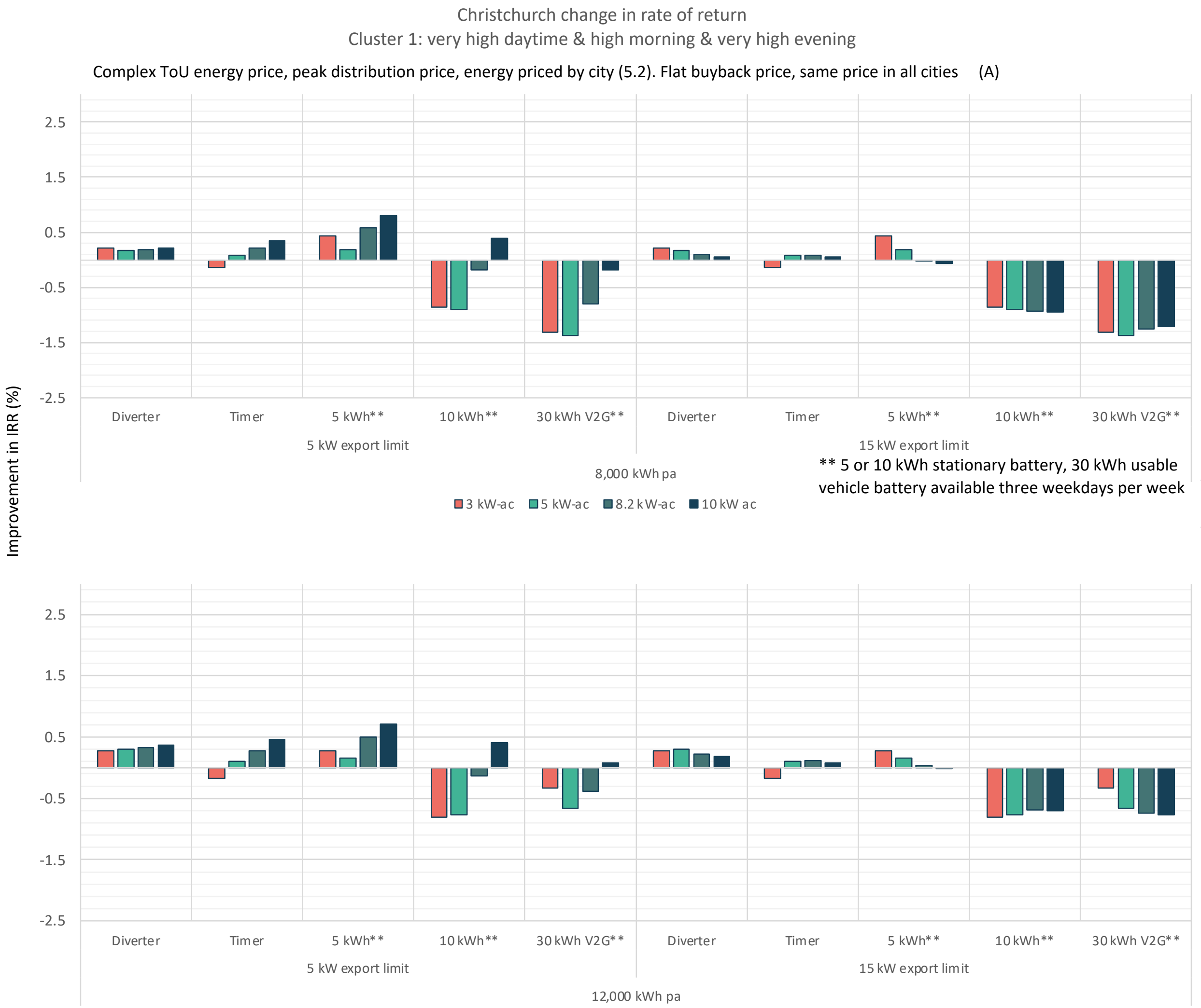


Figure 33 – Queenstown Cluster 1 changes in rate of return by storage type.

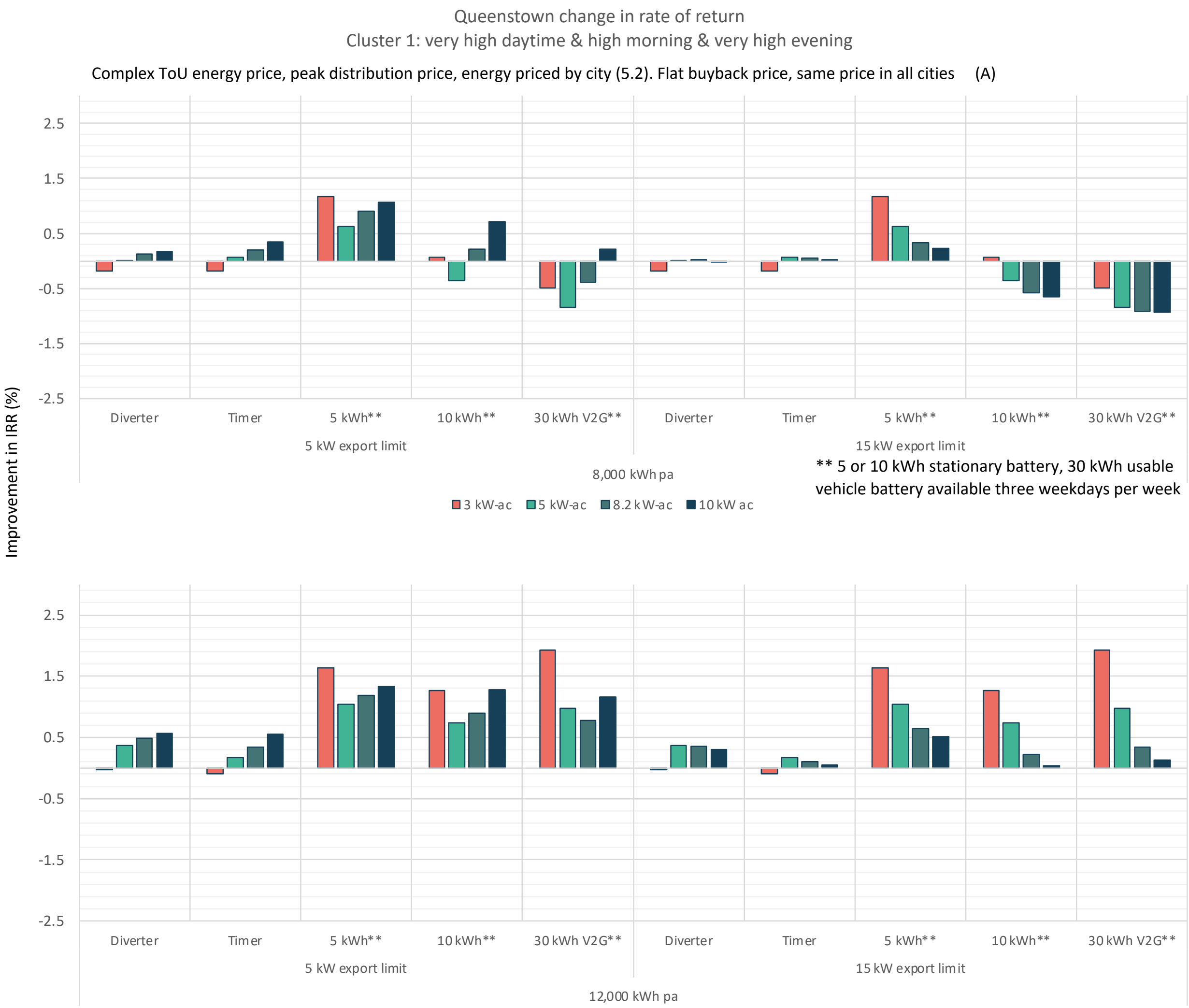
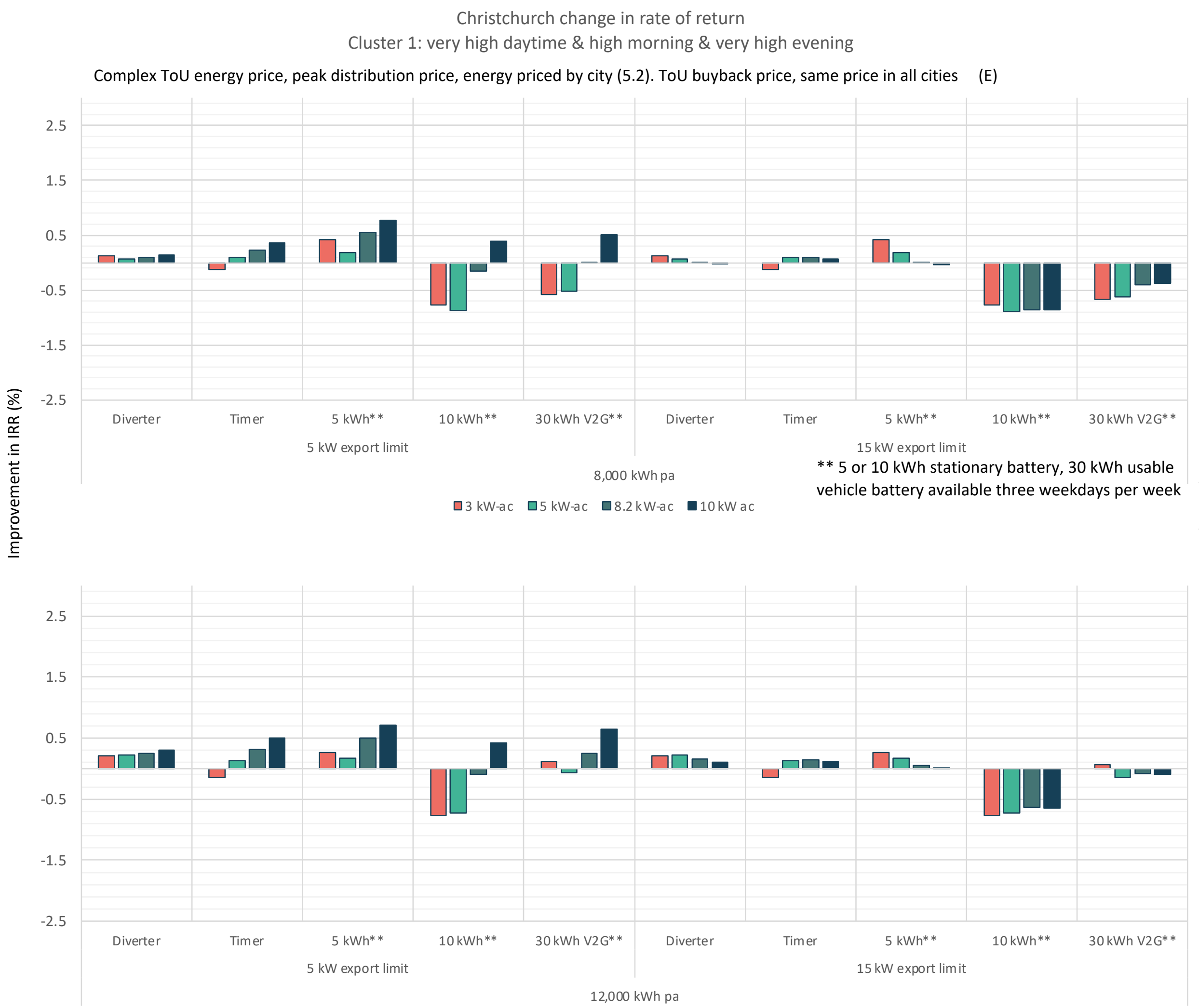


Figure 34 – Christchurch Cluster 1 with time-of-use buyback price, changes in rate of return by storage type.



6. The influence of price structures on rates of return and peak period exports of solar PV with battery energy storage

In the last section it was shown that time-of-use retail prices can, in some cases, improve the rate of return of solar PV with a battery compared to PV without a battery. However, the improvement is small and often occurs when there is a lower return for a system with a battery relative to one without. It is also observed that a greater improvement is gained by increasing the export limit to allow more energy to be exported at the buyback rate at any time of the day. The last section also showed that time-of-use buyback prices can improve the rate-of-return and may in some cases reverse the effect of increasing the export limit to some degree, especially with V2G. This is because time-of-use buyback prices reward exports more in peak periods. As a result, the battery control exports more in peak periods, which increases export income. Hence the conclusion "If export limits are lifted by electricity distributors, and battery storage becomes more accessible (lower prices), energy and distribution pricing that more strongly reflects time-of-use becomes more important."

This section investigates differences in rates of return from a variety of retail and buyback price structures. It attempts to understand what price structure for PV and battery energy storage gives the maximum rate of return. It also attempts to understand whether rates of return of PV and battery energy storage might be improved by reflecting a component of a distributor's peak price in the buyback price peak period. The cost of this is also investigated. This work was carried out for the Electricity Authority, to assist the Competition Taskforce Part 2A (2A Requiring distributors to pay a rebate when consumers supply electricity at peak times).[7] This section then goes further to understand changes in exports coincident with distributor defined peak periods.

The section is divided into three parts:

1. Sub-section 6.1 investigates the changes in returns from various retail, distribution, and buyback price structures. It also re-visits the analysis from Sub-section 4.2 to understand how time-of-use retail and buyback price structures in combination with battery energy storage change the relationship between rate of return and solar PV capacity. This seeks to understand whether the solar PV capacity that maximises rate of return while there is an export limit in place increases compared to solar PV with no storage.
2. Sub-section 6.1.2 investigates the changes in returns from the same price structures, but with additional buyback price in peak periods, reflecting the distributors peak price component in pricing that is fully compliant with the Electricity Authority's distribution pricing principles.
3. Sub-section 6.3 investigates the impact on demand reduction in peak periods from the above price structures.

[7] https://www.ea.govt.nz/projects/all/energy-competition-task-force/

6.1 Rates of return with different distribution pricing

The questions addressed in this sub-section are:

1. What price structure maximises the rate of return of a solar PV and battery system?
2. Does the presence of a battery lift the performance of higher capacity solar PV, given that Sub-section 4.2 showed that performance declined as solar PV capacity increased under the constraint of an export limit.

6.1.1 Price structure and return

To answer the first question, rates of return for various price structures are considered. Continuing from the previous section, Cluster 1 is used, although the difference between clusters is also investigated.

Table 14, shows the rate of return with a battery and the difference between the return with a battery and with only solar. In most cases, a 10 kWh battery lowers the returns, except for the 9pm-midnight free price structure. However, the buyback rate used with this is that given in Sub-section 3.2.4, which is likely higher than available with this price structure. Such high returns are therefore unlikely. Appendix 9 gives more detailed results from this section.

Consistent with earlier conclusions, lowering the battery to 5 kW increases the returns when a battery is included. Moving to higher resolution shows an increase with more time-of-use price structures with a 5 kW solar PV and 5 kWh battery. Improvement with time-of-use price structures is evident with larger batteries, such as 10 kWh, despite it decreasing returns over just solar PV. V2G gives higher returns with the complex time-of-use retail and buyback price structures – as shown in Appendix 9. With other clusters (4 and 7 for example) a small increase in return is observable as more time-of-use price structures are introduced. This is expected, as they have high daytime and morning peak ratios. Overall, however, any improvement from the introduction of time-of-use price structures small, suggesting a need for stronger time-of-use price differentials. The conclusion from the previous section therefore remains, with emphasis on reflecting time-of-use in retail and distribution prices.

- If export limits are lifted by electricity distributors, and battery storage becomes more accessible (lower prices), energy and distribution pricing that very strongly reflects time-of-use becomes more important.

Even with stronger time-of-use prices, their ability to effect energy and network use at more appropriate times is entirely dependent on battery control algorithms than can respond to these prices. This strengthens the conclusion from the previous section.

- Battery response to peak prices is only possible with battery control algorithms that can respond to prices. While availability of batteries at lower than current retail prices is very important, so too is the availability of battery control systems.

As shown in Appendix 9, V2G offers the highest improvement in returns, although it is very dependent on the availability of the EV to be plugged in to the V2G charger. From this, and the observations from the previous section about V2G, the following conclusion is made:

- The ability for consumers to add storage to their existing or new solar PV installations through V2G offers significant benefits, potentially more compared to stationary batteries depending on the availability of the EV. However, there are significant barriers to this such as the availability of cost effective and reliable V2G chargers and the ability to use most EVs with V2G. The industry should source more cost effective V2G charger solutions that are compliant with EV manufacturers so that consumers do no void EV warranties by using them, and to ensure that V2G is a financially viable investment.

Notwithstanding the improvements possible from V2G, given that the improvement in returns with a battery demonstrated in this section is so small, the next sub-section explores additional incentives to improve the relative economics of solar PV and batteries.

Table 14 – Changes in rates of return with battery storage and various retail and buyback price structures. (a) With a 10 kWh battery and (b) a 5 kWh battery.

Rates of return when battery storage is added. 5 kW export limit. Solar capacity used is 5 kW-ac, battery capacity used is 10 kWh
Cluster 1: very high daytime & high morning & very high evening

Retail and buyback price structure	Auckland			Wellington			Christchurch			Queenstown		
	Solar only (counter-factual)	Solar and battery	Increase with battery	Solar only (counter-factual)	Solar and battery	Increase with battery	Solar only (counter-factual)	Solar and battery	Increase with battery	Solar only (counter-factual)	Solar and battery	Increase with battery
9pm-midnight free retail price (3) with flat buyback price (A)	9.9	10.5	0.6	8.0	8.8	0.8	8.9	9.9	1.0	11.8	13.0	1.2
Complex ToU retail price (5.2) with flat buyback price (A)	9.1	8.2	-0.9	7.5	6.8	-0.7	8.2	7.3	-0.9	9.1	8.7	-0.4
Complex ToU retail price (5.2) with complex ToU buyback price (E)	9.3	8.4	-0.9	7.7	7.1	-0.6	8.4	7.5	-0.9	9.3	9.2	-0.1
Complex ToU retail price (7.2) with complex ToU buyback price (I), both with seasonal variation	9.2	8.2	-0.9	7.5	6.9	-0.6	8.2	7.5	-0.7	9.0	9.3	0.3

Rates of return when battery storage is added. 5 kW export limit. Solar capacity used is 5 kW-ac, battery capacity used is 5 kWh
Cluster 1: very high daytime & high morning & very high evening

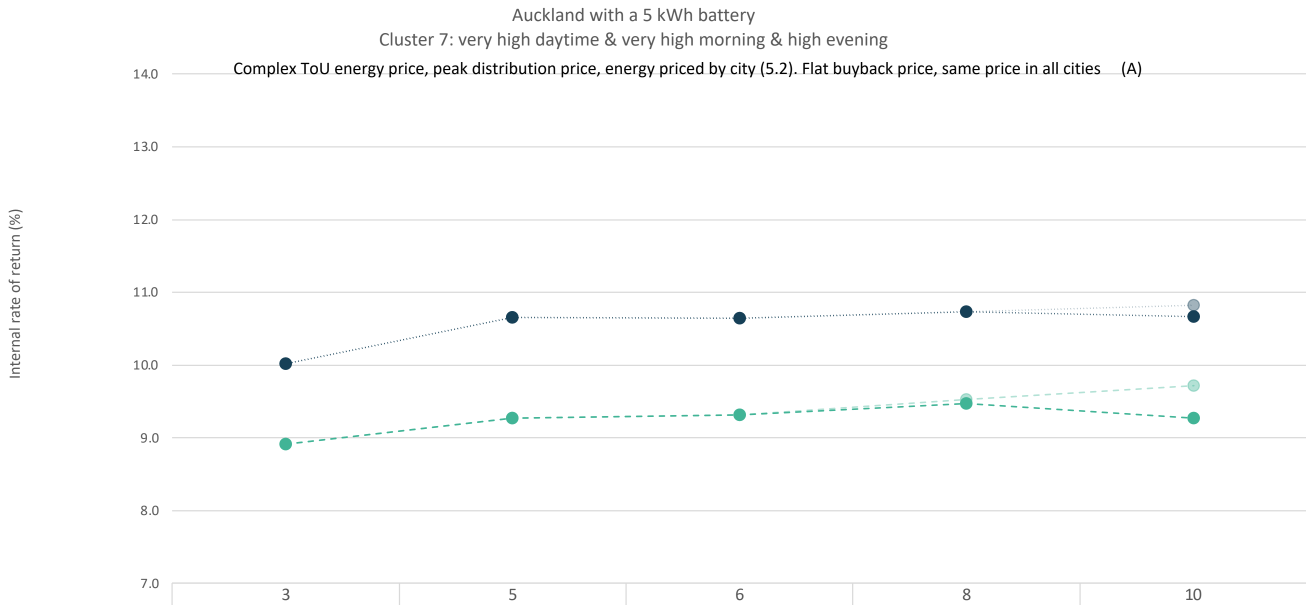
Retail and buyback price structure	Auckland			Wellington			Christchurch			Queenstown		
	Solar only (counter-factual)	Solar and battery	Increase with battery	Solar only (counter-factual)	Solar and battery	Increase with battery	Solar only (counter-factual)	Solar and battery	Increase with battery	Solar only (counter-factual)	Solar and battery	Increase with battery
9pm-midnight free retail price (3) with flat buyback price (A)	9.9	10.8	0.8	8.0	8.8	0.8	8.9	10.1	1.2	11.8	13.3	1.5
Complex ToU retail price (5.2) with flat buyback price (A)	9.1	9.4	0.2	7.5	7.7	0.2	8.2	8.4	0.2	9.1	9.7	0.6
Complex ToU retail price (5.2) with complex ToU buyback price (E)	9.3	9.5	0.3	7.7	8.0	0.2	8.4	8.6	0.2	9.3	9.9	0.7
Complex ToU retail price (7.2) with complex ToU buyback price (I), both with seasonal variation	9.2	9.3	0.2	7.5	7.7	0.2	8.2	8.4	0.3	9.0	9.9	0.9

6.1.2 Return versus solar PV capacity with a battery

To answer the second question, the analysis from Sub-section 4.2 is repeated, but with a 5 kWh battery and complex time-of-use retail price, for both a flat export price and time-of-use export price. The results are given in Figure 35 and Figure 36. These shows that the rate of return does increase at higher solar PV capacities, with less separation between the rates of return with a 5 kW export limit and 15 kW export limit. It is interesting that the performance of solar PV with a battery is maintained or improved despite there being a 10% energy loss associated with the battery.

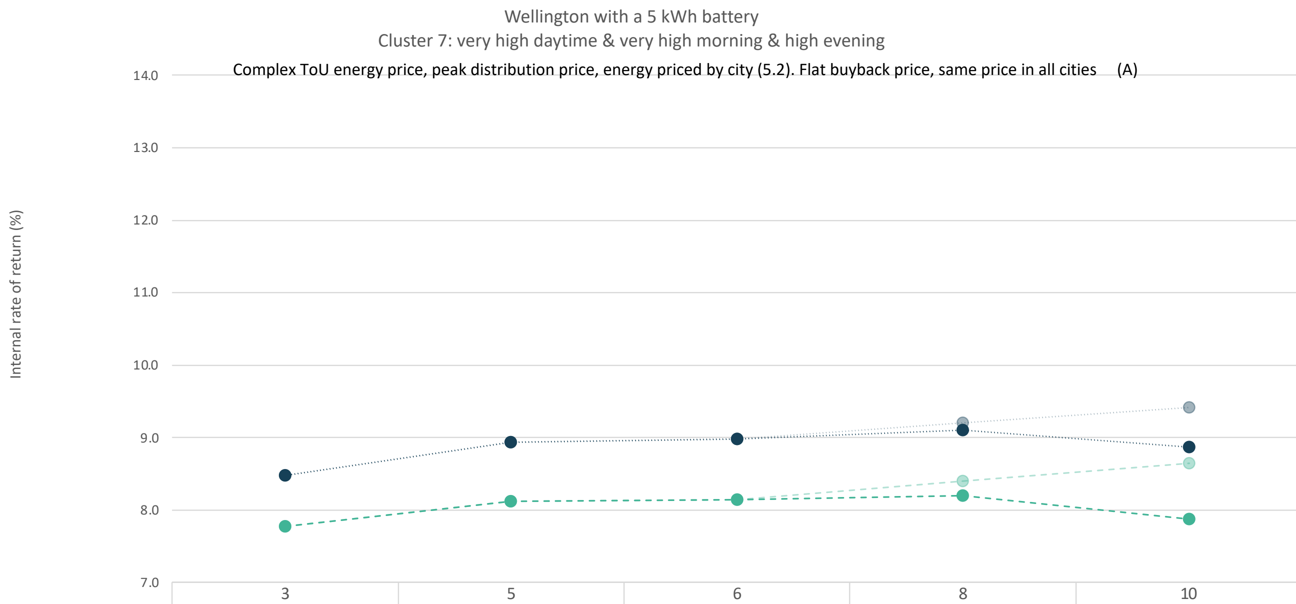
Figure 36 also shows slightly higher performance with a complex time-of-use buyback price structure. From this it is concluded that the presence of a battery with a time-of-use retail price can negate the performance limiting effects of export limits by making better use of excess solar energy within the ICP. Furthermore, time-of-use buyback prices strengthen the performance even further.

Figure 35 – Rates of return of the same cluster as used in Sub-section 4.2 for a complex time-of-use retail price structure. From Table 10b this cluster is almost always 7, and 4 for Queenstown with a 5 kW export limit. The export limit is given in the table row headings beside the annual consumption.



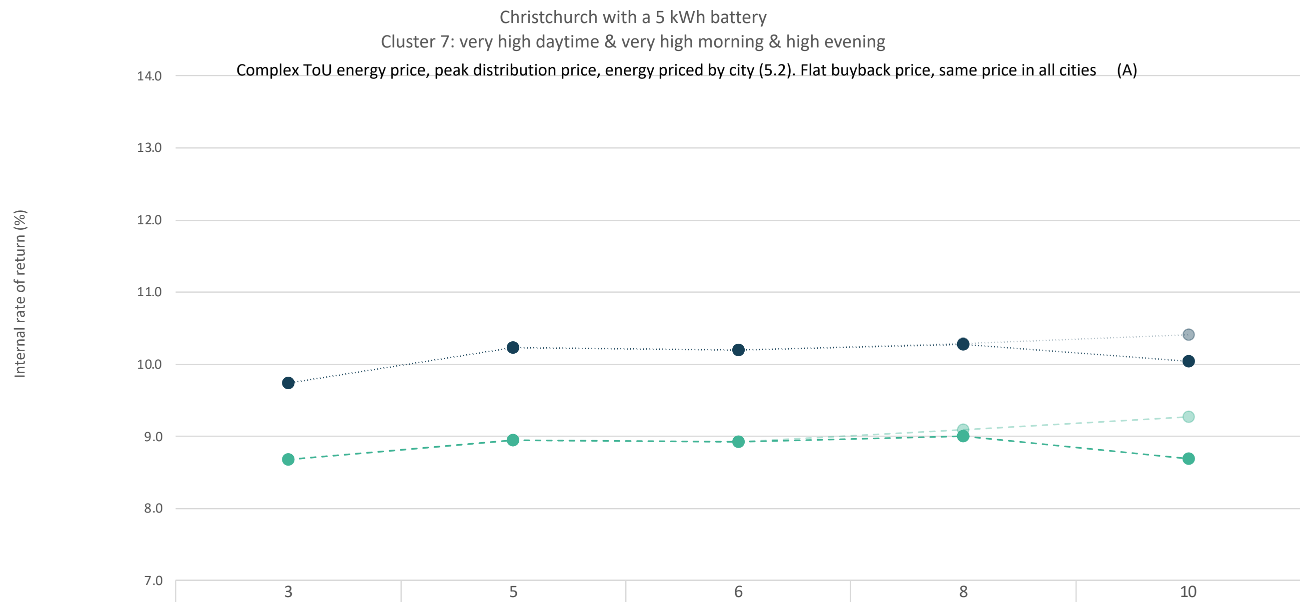
	3	5	6	8	10
12,000 kWh pa, 15 kW	10.0	10.7	10.6	10.7	10.8
12,000 kWh pa, 5 kW	10.0	10.7	10.6	10.7	10.7
8,000 kWh pa, 15 kW	8.9	9.3	9.3	9.5	9.7
8,000 kWh pa, 5 kW	8.9	9.3	9.3	9.5	9.3

PV Capacity (kW-ac), DC:AC ratio of 1.2



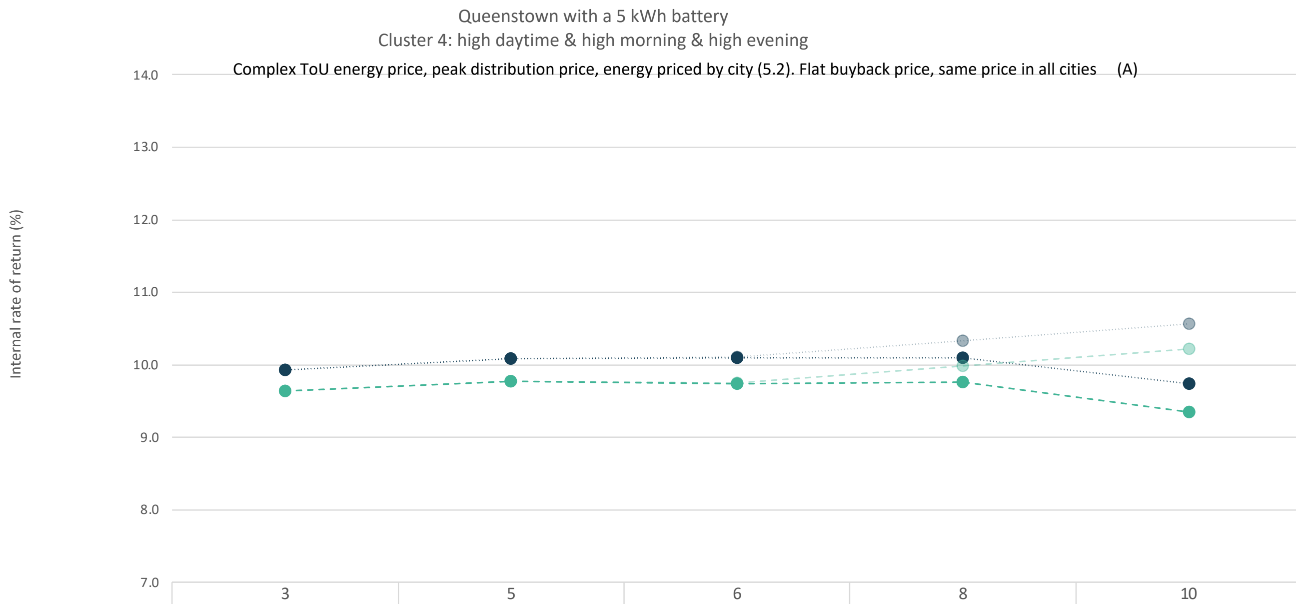
	3	5	6	8	10
12,000 kWh pa, 15 kW	8.5	8.9	9.0	9.2	9.4
12,000 kWh pa, 5 kW	8.5	8.9	9.0	9.1	8.9
8,000 kWh pa, 15 kW	7.8	8.1	8.1	8.4	8.6
8,000 kWh pa, 5 kW	7.8	8.1	8.1	8.2	7.9

PV Capacity (kW-ac), DC:AC ratio of 1.2



	3	5	6	8	10
12,000 kWh pa, 15 kW	9.7	10.2	10.2	10.3	10.4
12,000 kWh pa, 5 kW	9.7	10.2	10.2	10.3	10.0
8,000 kWh pa, 15 kW	8.7	8.9	8.9	9.1	9.3
8,000 kWh pa, 5 kW	8.7	8.9	8.9	9.0	8.7

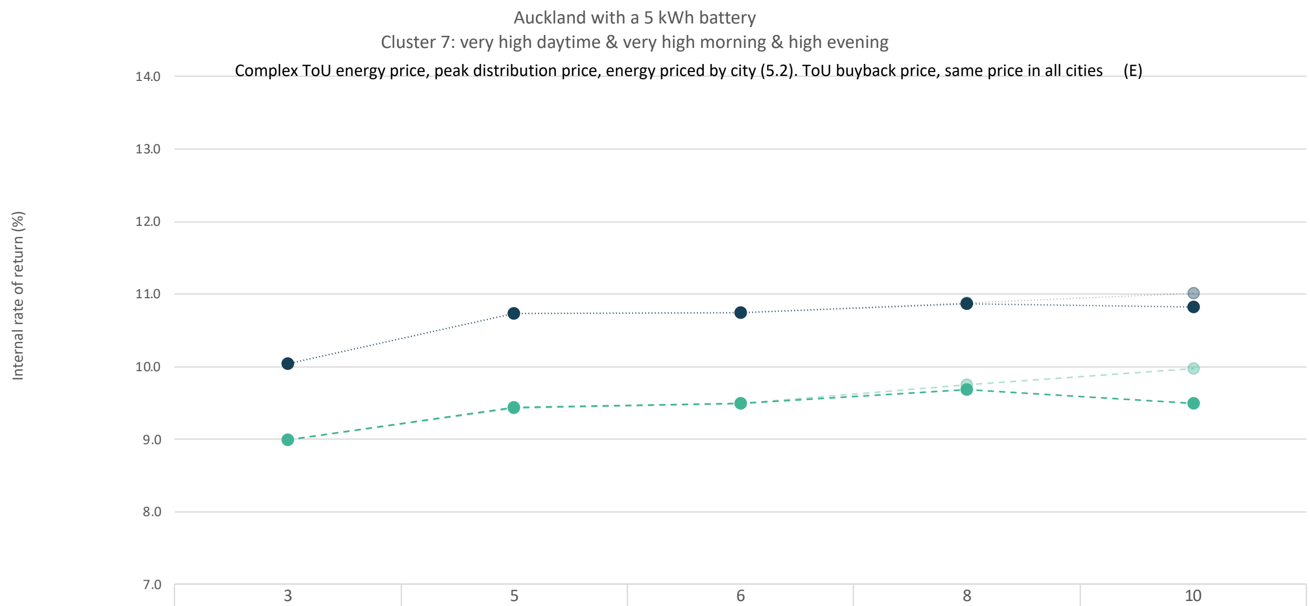
PV Capacity (kW-ac), DC:AC ratio of 1.2



	3	5	6	8	10
12,000 kWh pa, 15 kW	9.9	10.1	10.1	10.3	10.6
12,000 kWh pa, 5 kW	9.9	10.1	10.1	10.1	9.7
8,000 kWh pa, 15 kW	9.6	9.8	9.8	10.0	10.2
8,000 kWh pa, 5 kW	9.6	9.8	9.7	9.8	9.3

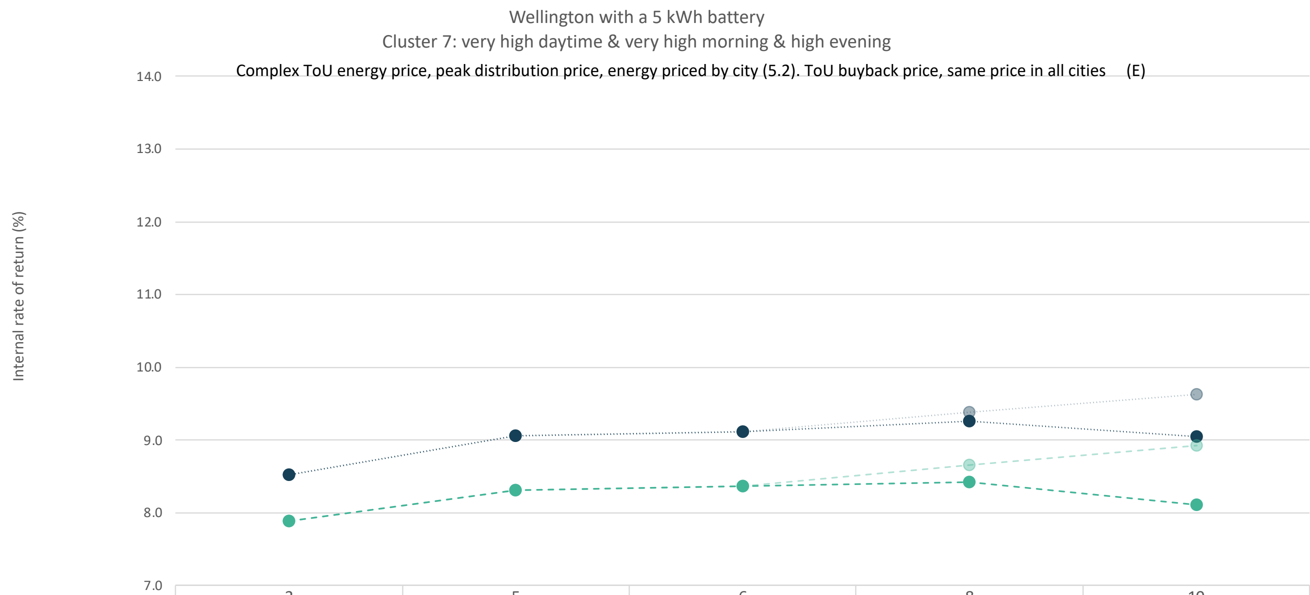
PV Capacity (kW-ac), DC:AC ratio of 1.2

Figure 36 – Rates of return of the same cluster as used in Sub-section 4.2 for a complex time-of-use retail price structure and a complex buyback price structure. From Table 10b this cluster is almost always 7, and 4 for Queenstown with a 5 kW export limit. The export limit is given in the table row headings beside the annual consumption.



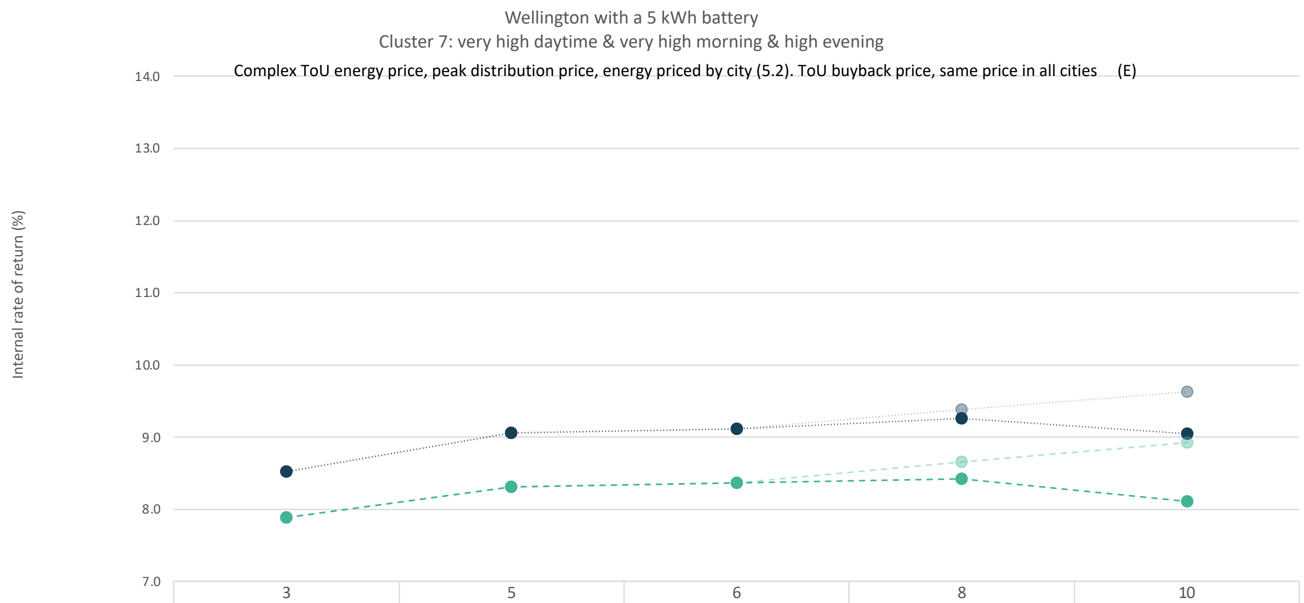
	3	5	6	8	10
12,000 kWh pa, 15 kW	10.0	10.7	10.7	10.9	11.0
12,000 kWh pa, 5 kW	10.0	10.7	10.7	10.9	10.8
8,000 kWh pa, 15 kW	9.0	9.4	9.5	9.8	10.0
8,000 kWh pa, 5 kW	9.0	9.4	9.5	9.7	9.5

PV Capacity (kW-ac), DC:AC ratio of 1.2



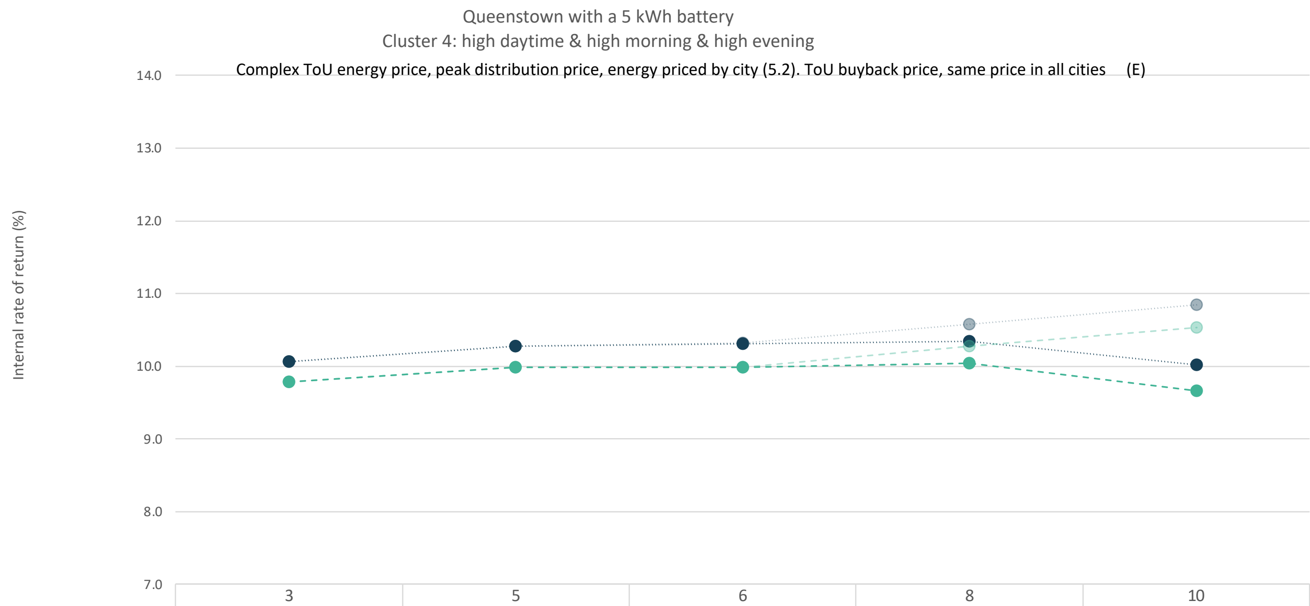
	3	5	6	8	10
12,000 kWh pa, 15 kW	8.5	9.1	9.1	9.4	9.6
12,000 kWh pa, 5 kW	8.5	9.1	9.1	9.3	9.0
8,000 kWh pa, 15 kW	7.9	8.3	8.4	8.7	8.9
8,000 kWh pa, 5 kW	7.9	8.3	8.4	8.4	8.1

PV Capacity (kW-ac), DC:AC ratio of 1.2



	3	5	6	8	10
12,000 kWh pa, 15 kW	8.5	9.1	9.1	9.4	9.6
12,000 kWh pa, 5 kW	8.5	9.1	9.1	9.3	9.0
8,000 kWh pa, 15 kW	7.9	8.3	8.4	8.7	8.9
8,000 kWh pa, 5 kW	7.9	8.3	8.4	8.4	8.1

PV Capacity (kW-ac), DC:AC ratio of 1.2



	3	5	6	8	10
12,000 kWh pa, 15 kW	10.1	10.3	10.3	10.6	10.8
12,000 kWh pa, 5 kW	10.1	10.3	10.3	10.3	10.0
8,000 kWh pa, 15 kW	9.8	10.0	10.0	10.3	10.5
8,000 kWh pa, 5 kW	9.8	10.0	10.0	10.0	9.7

PV Capacity (kW-ac), DC:AC ratio of 1.2

6.2 Changes in returns from an additional buyback price in distributor peaks

This sub-section investigates the changes in returns from the same price structures used in the previous sub-section, but with additional buyback price in peak periods. The additional price is a multiplier of the distributor's peak price component in pricing that is fully compliant with the Electricity Authority's distribution pricing principles – in effect a multiplier of the long-run marginal cost (LRMC) of the distribution network. Two multipliers are used: 50% and 100%.

The questions asked in this section are:

1. Does the additional buyback make a PV and battery system more economic, or can this be achieved with appropriate time-of-use retail and buyback price structures?
2. What would the cost of such a payment be?

The counterfactual in this case is the status quo, where there is no additional price in buyback prices during peak periods – the results used in the previous sub-section. In line with the previous section, Cluster 1 is used for the main results.

6.2.1 Changes in rates of return

Results giving the rates of return with and without the peak price adjustment, as well as the difference are given in Table 15 for various solar and battery options and retail and buyback price structures. Results are also given for another load type in Table 16 as an indication of difference between clusters. Appendix 9 gives detailed results that include more price structures and more battery and solar capacities.

These show an improvement in the rate of return of the proposed peak adjustment, generally assisted by an increasing time-of-use component in retail and buyback prices. However, the improvement is rarely enough to beat the 9pm-midnight rate of return, similar to the results presented in the previous sub-section. However, it is questionable whether the 9pm-midnight would give such high results, since it is likely to have a lower buyback price, whereas the same buyback price was used in all price structures.

From this it is concluded that the additional buyback price does make PV and battery systems more economic. It most likely improves the economics of PV and battery systems beyond what other price structures can offer. It is also concluded that time-of-use buyback prices are equally important in improving the performance of PV and battery systems. However, the conclusions from the previous sub-section still hold: the success of such changes to pricing are dependent on battery control algorithms than can respond to these prices. Further they are dependent on the availability of batteries at a suitably low installed cost.

6.2.2 Payments required in peak periods

Examples of the payments required to fund the peak period payments are given in Table 17. In line with rates of return changes varying between cities, these also show payments varying between cities. This is related to the peak period definition by the electricity distributor. For example, from Table 17, payments in Auckland are significantly lower than in Queenstown. In Auckland the peak period covers winter weekdays only (roughly 1,040 hours), whereas in Queenstown the peak period applies to the entire year, weekends as well as weekdays, and extends for a longer period in each day (roughly 3,640 hours). More detail is given in Appendix 9.

From this it is concluded that, with such payments required in peak periods, electricity distributors will need to pay close attention to the definition of peak periods to avoid overpayments.

Table 15: Rates of return of solar and battery options for Cluster 1 8,000 kWh pa load and 5 kW export limit with: (a) a 50% peak price adjustment

Peak period payments with proposed 50% additional export price in peak period compared to status quo of no additional export price. 5 kW export limit
Solar capacity used is 5 kW-ac, battery capacity used is 10 kWh. Cluster 1: very high daytime & high morning & very high evening

Retail and buyback price structure	Technology	Auckland			Wellington			Christchurch			Queenstown		
		Status quo (%)	Proposal (%)	Proposal increase (%)	Status quo (%)	Proposal (%)	Proposal increase (%)	Status quo (%)	Proposal (%)	Proposal increase (%)	Status quo (%)	Proposal (%)	Proposal increase (%)
9pm-midnight free retail price (3) with flat buyback price (A)	Investment in solar, no battery	9.9	10.0	0.1	8.0	8.4	0.3	8.9	9.3	0.4	11.8	12.9	1.1
	Investment in battery, no solar	7.3	7.3	0.0	5.8	5.9	0.1	7.3	7.3	0.1	10.9	11.1	0.2
	Investment in combined solar and battery	10.5	10.7	0.2	8.8	9.5	0.7	9.9	10.7	0.8	13.0	14.6	1.6
Complex ToU retail price (5.2) with flat buyback price (A)	Investment in solar, no battery	9.1	9.2	0.1	7.5	7.9	0.4	8.2	8.6	0.4	9.1	10.2	1.1
	Investment in battery, no solar	3.9	3.9	0.0	2.9	2.9	0.0	2.8	2.8	0.0	6.3	7.4	1.1
	Investment in combined solar and battery	8.2	8.4	0.2	6.8	7.4	0.7	7.3	8.1	0.7	8.7	10.5	1.8
Complex ToU retail price (5.2) with complex ToU buyback price (E)	Investment in solar, no battery	9.3	9.4	0.1	7.7	8.1	0.4	8.4	8.8	0.4	9.3	10.4	1.1
	Investment in battery, no solar	3.9	3.9	0.0	2.9	3.1	0.2	2.7	2.9	0.3	6.2	7.6	1.4
	Investment in combined solar and battery	8.4	8.7	0.3	7.1	8.0	0.9	7.5	8.6	1.0	9.2	10.8	1.7
Complex ToU retail price (7.2) with complex ToU buyback price (I), both with seasonal variation	Investment in solar, no battery	9.2	9.2	0.1	7.5	7.9	0.4	8.2	8.5	0.4	9.0	10.1	1.1
	Investment in battery, no solar	3.7	3.6	0.0	2.8	2.9	0.1	3.2	3.4	0.1	5.9	6.3	0.4
	Investment in combined solar and battery	8.2	8.6	0.3	6.9	7.7	0.9	7.5	8.4	1.0	9.3	10.9	1.6

Table 15: Rates of return of solar and battery options for Cluster 1 8,000 kWh pa load and 5 kW export limit with: (b) a 100% peak price adjustment.

Peak period payments with proposed 100% additional export price in peak period compared to status quo of no additional export price. 5 kW export limit
Solar capacity used is 5 kW-ac, battery capacity used is 10 kWh. Cluster 1: very high daytime & high morning & very high evening

Retail and buyback price structure	Technology	Auckland			Wellington			Christchurch			Queenstown		
		Status quo (%)	Proposal (%)	Proposal increase (%)	Status quo (%)	Proposal (%)	Proposal increase (%)	Status quo (%)	Proposal (%)	Proposal increase (%)	Status quo (%)	Proposal (%)	Proposal increase (%)
9pm-midnight free retail price (3) with flat buyback price (A)	Investment in solar, no battery	9.9	10.1	0.2	8.0	8.7	0.7	8.9	9.6	0.7	11.8	14.0	2.1
	Investment in battery, no solar	7.3	7.3	0.0	5.8	5.9	0.2	7.3	7.4	0.1	10.9	11.2	0.3
	Investment in combined solar and battery	10.5	10.9	0.3	8.8	10.1	1.2	9.9	11.4	1.5	13.0	16.0	2.9
Complex ToU retail price (5.2) with flat buyback price (A)	Investment in solar, no battery	9.1	9.3	0.2	7.5	8.2	0.7	8.2	9.0	0.7	9.1	11.3	2.2
	Investment in battery, no solar	3.9	3.9	0.0	2.9	3.2	0.3	2.8	3.1	0.3	6.3	8.7	2.4
	Investment in combined solar and battery	8.2	8.7	0.5	6.8	8.4	1.6	7.3	9.1	1.7	8.7	12.0	3.2
Complex ToU retail price (5.2) with complex ToU buyback price (E)	Investment in solar, no battery	9.3	9.5	0.2	7.7	8.4	0.7	8.4	9.1	0.7	9.3	11.5	2.2
	Investment in battery, no solar	3.9	3.9	0.0	2.9	3.4	0.5	2.7	3.2	0.5	6.2	9.2	3.0
	Investment in combined solar and battery	8.4	9.1	0.6	7.1	8.9	1.8	7.5	9.6	2.0	9.2	12.5	3.3
Complex ToU retail price (7.2) with complex ToU buyback price (I), both with seasonal variation	Investment in solar, no battery	9.2	9.3	0.2	7.5	8.2	0.7	8.2	8.9	0.7	9.0	11.2	2.2
	Investment in battery, no solar	3.7	3.7	0.0	2.8	3.2	0.5	3.2	3.5	0.3	5.9	6.7	0.8
	Investment in combined solar and battery	8.2	8.9	0.7	6.9	8.7	1.8	7.5	9.4	2.0	9.3	12.5	3.2

Table 16: Rates of return of solar and battery options for Cluster 2 8,000 kWh pa load and 5 kW export limit with: (a) a 50% peak price adjustment

Rates of return with proposed 50% additional export price in peak period compared to status quo of no additional export price. 5 kW export limit. Solar capacity used is 5 kW-ac, battery capacity used is 10 kWh. Cluster 0: medium daytime & medium morning & medium evening.

Retail and buyback price structure	Technology	Auckland			Wellington			Christchurch			Queenstown		
		Status quo (%)	Proposal (%)	Proposal increase (%)	Status quo (%)	Proposal (%)	Proposal increase (%)	Status quo (%)	Proposal (%)	Proposal increase (%)	Status quo (%)	Proposal (%)	Proposal increase (%)
9pm-midnight free retail price (3) with flat buyback price (A)	Investment in solar, no battery	8.6	8.8	0.1	8.1	8.4	0.3	9.0	9.4	0.3	11.6	12.8	1.1
	Investment in battery, no solar	6.5	6.5	0.0	5.7	5.7	0.0	6.8	6.8	0.1	10.6	10.8	0.1
	Investment in combined solar and battery	9.0	9.4	0.4	8.5	9.2	0.8	9.5	10.4	0.8	12.4	14.2	1.8
Complex ToU retail price (5.2) with flat buyback price (A)	Investment in solar, no battery	8.2	8.3	0.1	7.7	8.0	0.3	8.4	8.8	0.4	8.9	10.1	1.2
	Investment in battery, no solar	2.8	2.8	0.0	2.6	2.4	-0.2	0.9	1.4	0.5	4.4	6.1	1.7
	Investment in combined solar and battery	6.4	7.0	0.5	6.0	6.9	0.9	6.3	7.4	1.1	7.6	10.0	2.4
Complex ToU retail price (5.2) with complex ToU buyback price (E)	Investment in solar, no battery	8.4	8.5	0.1	7.8	8.1	0.3	8.6	8.9	0.3	9.1	10.3	1.2
	Investment in battery, no solar	2.8	2.6	-0.1	2.6	2.7	0.1	1.0	1.7	0.7	4.0	6.5	2.6
	Investment in combined solar and battery	6.9	7.4	0.4	6.5	7.6	1.0	6.8	8.0	1.2	8.3	10.5	2.2
Complex ToU retail price (7.2) with complex ToU buyback price (I), both with seasonal variation	Investment in solar, no battery	8.2	8.4	0.1	7.6	7.9	0.3	8.3	8.7	0.4	8.9	10.1	1.2
	Investment in battery, no solar	2.8	2.6	-0.1	2.5	2.5	0.0	1.9	2.2	0.2	5.1	5.8	0.7
	Investment in combined solar and battery	6.8	7.3	0.5	6.3	7.3	1.0	6.7	7.9	1.2	8.5	10.6	2.1

Table 16: Rates of return of solar and battery options for Cluster 2 8,000 kWh pa load and 5 kW export limit with: (b) a 100% peak price adjustment.

Rates of return with proposed 100% additional export price in peak period compared to status quo of no additional export price. 5 kW export limit. Solar capacity used is 5 kW-ac, battery capacity used is 10 kWh. Cluster 0: medium daytime & medium morning & medium evening.

Retail and buyback price structure	Technology	Auckland			Wellington			Christchurch			Queenstown		
		Status quo (%)	Proposal (%)	Proposal increase (%)	Status quo (%)	Proposal (%)	Proposal increase (%)	Status quo (%)	Proposal (%)	Proposal increase (%)	Status quo (%)	Proposal (%)	Proposal increase (%)
9pm-midnight free retail price (3) with flat buyback price (A)	Investment in solar, no battery	8.6	8.9	0.2	8.1	8.7	0.6	9.0	9.7	0.7	11.6	13.9	2.2
	Investment in battery, no solar	6.5	6.5	0.0	5.7	5.7	0.1	6.8	6.8	0.1	10.6	10.9	0.2
	Investment in combined solar and battery	9.0	9.7	0.7	8.5	9.9	1.4	9.5	11.1	1.6	12.4	15.8	3.5
Complex ToU retail price (5.2) with flat buyback price (A)	Investment in solar, no battery	8.2	8.4	0.3	7.7	8.3	0.6	8.4	9.1	0.7	8.9	11.3	2.4
	Investment in battery, no solar	2.8	2.8	0.0	2.6	2.9	0.3	0.9	2.1	1.2	4.4	8.5	4.1
	Investment in combined solar and battery	6.4	7.5	1.0	6.0	8.1	2.0	6.3	8.6	2.3	7.6	11.8	4.2
Complex ToU retail price (5.2) with complex ToU buyback price (E)	Investment in solar, no battery	8.4	8.6	0.3	7.8	8.5	0.6	8.6	9.3	0.7	9.1	11.5	2.3
	Investment in battery, no solar	2.8	2.9	0.2	2.6	3.2	0.6	1.0	2.4	1.4	4.0	9.3	5.3
	Investment in combined solar and battery	6.9	8.0	1.0	6.5	8.7	2.1	6.8	9.2	2.4	8.3	12.6	4.3
Complex ToU retail price (7.2) with complex ToU buyback price (I), both with seasonal variation	Investment in solar, no battery	8.2	8.5	0.3	7.6	8.2	0.6	8.3	9.0	0.7	8.9	11.2	2.4
	Investment in battery, no solar	2.8	2.9	0.2	2.5	3.1	0.5	1.9	2.7	0.8	5.1	6.5	1.4
	Investment in combined solar and battery	6.8	7.9	1.1	6.3	8.5	2.1	6.7	9.1	2.4	8.5	12.7	4.2

Table 17 – Annual payments required for the additional buyback rate for: (a) a 50% peak price adjustment Cluster 1 and 5 kW export limit.

Peak period payments with proposed 50% additional export price in peak period compared to status quo of no additional export price. 5 kW export limit
Solar capacity used is 5 kW-ac, battery capacity used is 10 kWh
Cluster 1: very high daytime & high morning & very high evening

Retail and buyback price structure	Technology	Auckland	Wellington	Christchurch	Queenstown
9pm-midnight free retail price with flat buyback price	Investment in solar, no battery	$11	$39	$41	$132
	Investment in battery, no solar	$0	$5	$4	$9
	Investment in combined solar and battery	$29	$104	$123	$263
Complex ToU retail price with flat buyback price	Investment in solar, no battery	$11	$39	$41	$132
	Investment in battery, no solar	$0	$20	$14	$89
	Investment in combined solar and battery	$50	$154	$165	$262
Complex ToU retail price with complex ToU buyback price	Investment in solar, no battery	$11	$39	$41	$132
	Investment in battery, no solar	$3	$20	$14	$99
	Investment in combined solar and battery	$61	$154	$165	$288
Complex ToU retail price with complex ToU buyback price, both with seasonal variation	Investment in solar, no battery	$11	$39	$41	$132
	Investment in battery, no solar	$3	$20	$6	$27
	Investment in combined solar and battery	$61	$154	$154	$283

Table 17 – Annual payments required for the additional buyback rate for: (b) a 100% peak price adjustment. Cluster 1 and 5 kW export limit.

Peak period payments with proposed 100% additional export price in peak period compared to status quo of no additional export price. 5 kW export limit
Solar capacity used is 5 kW-ac, battery capacity used is 10 kWh
Cluster 1: very high daytime & high morning & very high evening

Retail and buyback price structure	Technology	Auckland	Wellington	Christchurch	Queenstown
9pm-midnight free retail price with flat buyback price	Investment in solar, no battery	$22	$78	$83	$264
	Investment in battery, no solar	$0	$11	$8	$18
	Investment in combined solar and battery	$57	$210	$245	$526
Complex ToU retail price with flat buyback price	Investment in solar, no battery	$22	$78	$83	$264
	Investment in battery, no solar	$6	$40	$28	$179
	Investment in combined solar and battery	$122	$307	$330	$525
Complex ToU retail price with complex ToU buyback price	Investment in solar, no battery	$22	$78	$83	$264
	Investment in battery, no solar	$6	$40	$28	$198
	Investment in combined solar and battery	$122	$307	$330	$576
Complex ToU retail price with complex ToU buyback price, both with seasonal variation	Investment in solar, no battery	$22	$78	$83	$264
	Investment in battery, no solar	$6	$40	$28	$55
	Investment in combined solar and battery	$122	$307	$330	$620

6.3 Demand reduction during peak periods resulting from selected price structures

Sub-section 6.4 focused on improvements to rate of return available from increased peak buyback rates. This is important to the economics of distributed generation and storage, as modelled battery capacity charge and discharge patterns respond to price signals. Since New Zealand's electricity system in general experiences peak demand in a winter morning and evening, the effect of time-of-use prices, including the additional buyback peak period prices, on peak period demand reduction is of interest. This sub-section investigates the impact on exports in peak periods from the time-of-use prices and the buyback prices investigated in Sub-section 6.4. The questions asked are:

1. Does the additional buyback result in more export (effectively leading to demand reduction) during peak periods (morning and evening) or can this be achieved with appropriate time-of-use retail and buyback price structures.
2. Does a 9pm-midnight price structure give suitable demand reduction (or export) in peak periods, or does it tend to favour just one peak period?

Results for Christchurch are shown in Figure 37, with results for all cities shown in Appendix 9. Evident from this is a trend towards more export of energy in peak periods as pricing becomes more time-of-use based. For example, in the left section (no additional buyback price) the time-of-use retail and buyback price combination achieves the most energy exports, more than double that of solar PV without a battery (where solar generation happens to exceed demand). For the 10 kWh battery this equates to an average export from stored battery energy during the morning peak of 1.7 kW for example. A similar effect is seen in the evening peak, although not as high due to higher demand.

If numerous solar PV and battery systems were to export in this way, by responding to time-of-use prices, peak demand and therefore energy cost, and possibly even the cost of the network, could be reduced across all consumers. Figure 37 also shows in the middle and right sections a lift in exports with the increased buyback price. This demonstrates higher exports during peak periods, which adds a further dimension to the conclusions from the previous sections. That is that not only does time-of-use pricing for retail electricity and solar buyback improve the economics of solar PV and storage, but it also strengthens behaviour of solar PV and battery systems that will reduce peak demand. In so doing it will potentially reduce the overall cost of electricity by reducing peak capacity requirements, and potentially by reducing the need for network investment. This is especially the case if buyback rates include a peak price component.

It does bring into focus the importance of other conclusions: the peak periods need to be defined carefully, battery control systems that respond to peak prices are required, and ongoing installed cost reductions of batteries are required.

6.3.1 Seasonal peak demand reduction

It has been shown above that there is more energy from solar PV concentrated into peak periods with strong time-of-use pricing, including additional buyback prices in peak periods. As noted earlier, New Zealand's electricity system in general experiences peak demand in a winter morning and evening. It is therefore of interest to understand peak demand reduction by time of year, and how the various price structures influence this with battery energy storage, compared to no battery energy storage.

Figure 38 shows the average peak demand reduction by month of year for Christchurch. Results for all cities are shown in Appendix 9, and follow a similar pattern. The following are evident from this:

- The average morning and evening peak demand reduction from solar PV alone is about 0.25 to 0.5 kW in the winter with 5 kW-ac solar and 10 kW-ac solar respectively. This is about 1-2 kW lower than the peak reduction in summer.
- Adding a 10 kWh battery and introducing a time-of-use retail price, but maintaining a flat buyback price, lifts the peak demand reduction to about 1.5 kW in the winter.
- With 5 kW-ac solar PV this remains fairly constant throughout the year but lifts in summer months with 10 kW-ac solar. The peak demand reduction is higher in summer months with a 5 kW export limit, because the battery is forced to store any net solar generation in excess of the export limit, and releases that energy at the following highest price period, that being the evening peak.
- When a time-of-use retail and buyback prices are introduced (the two top lines in Figure 38), the peak demand reduction grows further to about 2 kW compared to no battery in winter with 5 kW-ac solar PV, and to just over 2 kW compared to no battery in winter with 10 kW-ac solar PV. Peak period exports in summer months are very strong.
- At this point, there is little difference between 5 kW and 15 kW export limits. This is due to the battery preferring to store and release energy at the higher peak buyback price in the peak period, rather than simply exporting it at the lower off-peak price in the middle of the day.
- The addition of seasonal price variation shows a reduction in summer months (October to March inclusive). This is due to a lower peak retail price and peak buyback price in summer, resulting in a levelling out of exports across the day.

Other cities and annual consumption levels show the same pattern, with a consistent 2 kW or more difference in demand reduction between solar PV with a battery and strong time-of-use pricing and solar PV with no battery. From this it is tentatively concluded that solar PV between 5 kW-ac and 10 kW-ac with a battery, and with strong time-of-use prices and suitable battery control algorithms, can result in peak demand reduction of 2 kW or more. Over many consumers, this could lead to a substantial demand reduction across New Zealand, avoiding the need for peak generation capacity, and possibly avoiding distribution network and transmission network expenditure. For example, if 100,000 ICPs have solar PV installed with a 10kW battery, a combined 200 MW peak demand reduction could be achieved.

The conclusion is tentative, as further analysis by days in winter months is required to understand whether the demand reduction is consistent, and how it applies across New Zealand after geographical diversity of solar generation is considered. However, with appropriate battery control algorithms and time-of-use pricing, it is theoretically still possible to achieve such demand reduction even if solar generation is low for an extended period of several days. This is because a battery should be able to shift energy from night-time to the peak periods. As already concluded, such operation requires appropriate battery control algorithms.

The above analysis has shown the potential of residential solar PV and batteries to avoid the need for peak generation capacity, and possibly network capacity, if they are deployed on a large enough scale. However, they are simply not suitable for energy storage between seasons. The economics of battery energy storage has already been shown to be marginal at prices reduced from current installed battery prices, except for specific load profile types and locations. To use batteries to store energy between seasons reduces their cycles from roughly once per day to about once per year, massively increasing the levelised cost of storage. Batteries alone do not solve the challenge New Zealand has of higher energy demand but lower renewable energy availability in winter. The combination of solar PV and batteries might help with this, especially if PV and batteries are deployed in locations with relatively higher winter solar generation.

It is recommended that further work be undertaken to confirm reliable winter peak demand reduction by solar PV and batteries. It is also recommended that further work be undertaken to understand how solar generation locations might be optimised to contribute relatively more energy in winter, and in particular any inverse correlation between hydro inflows and solar generation by location.

Figure 37 – Energy exports during peak periods for Christchurch.

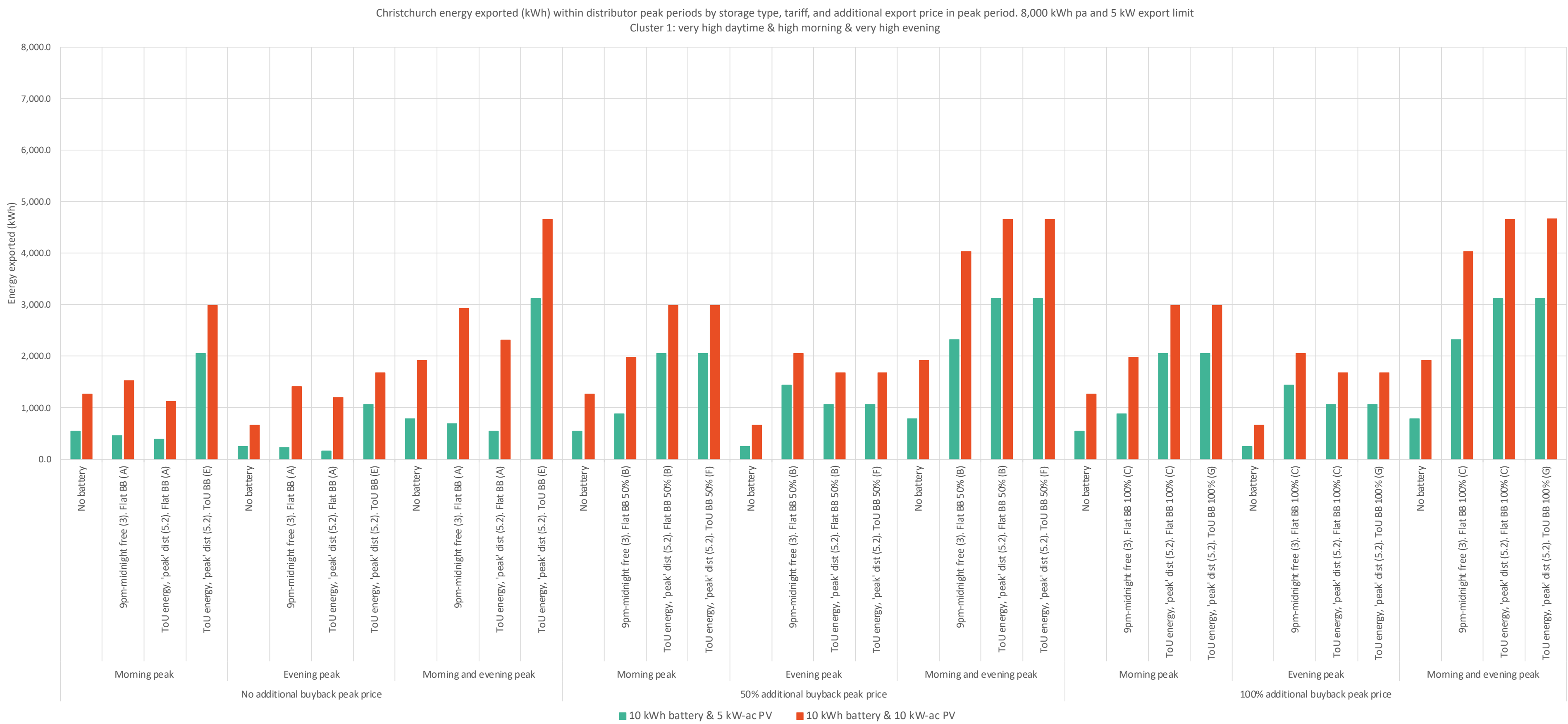
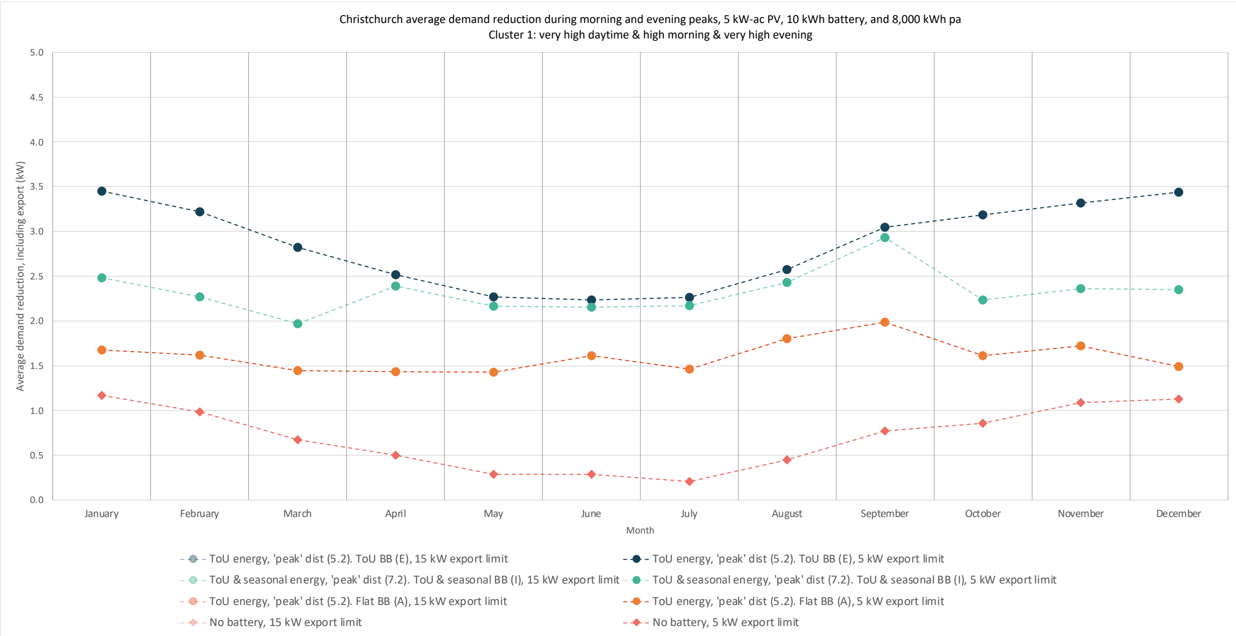
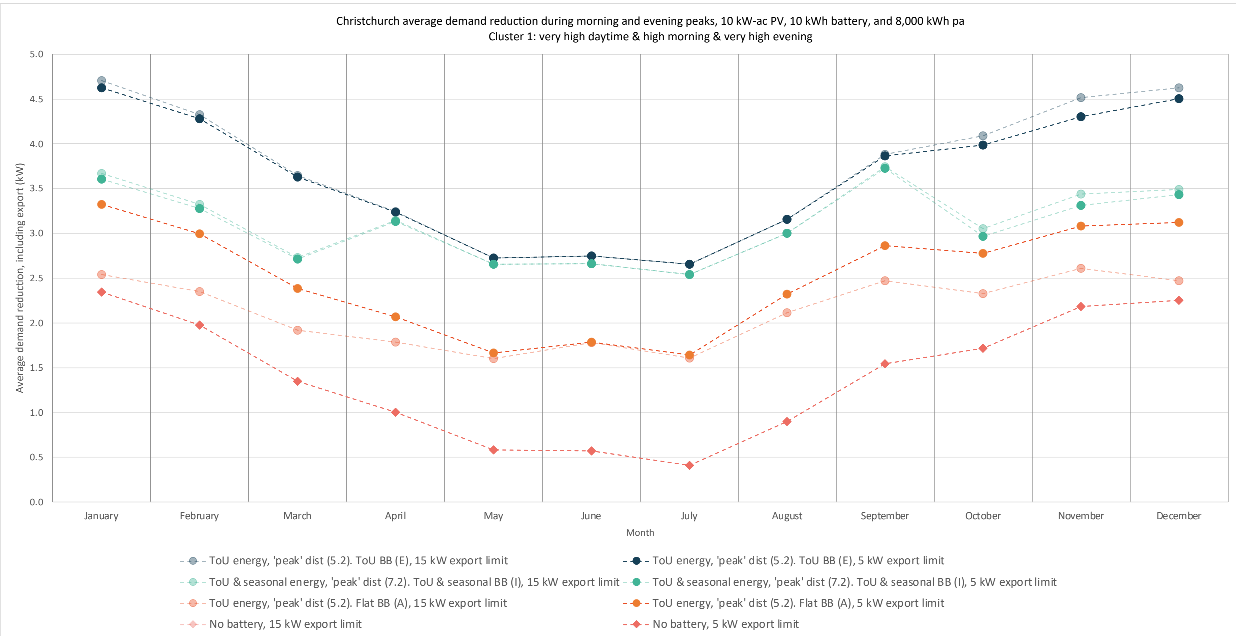


Figure 38 – Christchurch peak demand reduction with (a) 5 kW solar PV, where the 15 kW export limit points are directly below the 5 kW export limit points (lifting the export limit makes no difference because the inverter only produces a maximum of 5 kW, equal to the export limit), and (b) 10 kW solar PV.





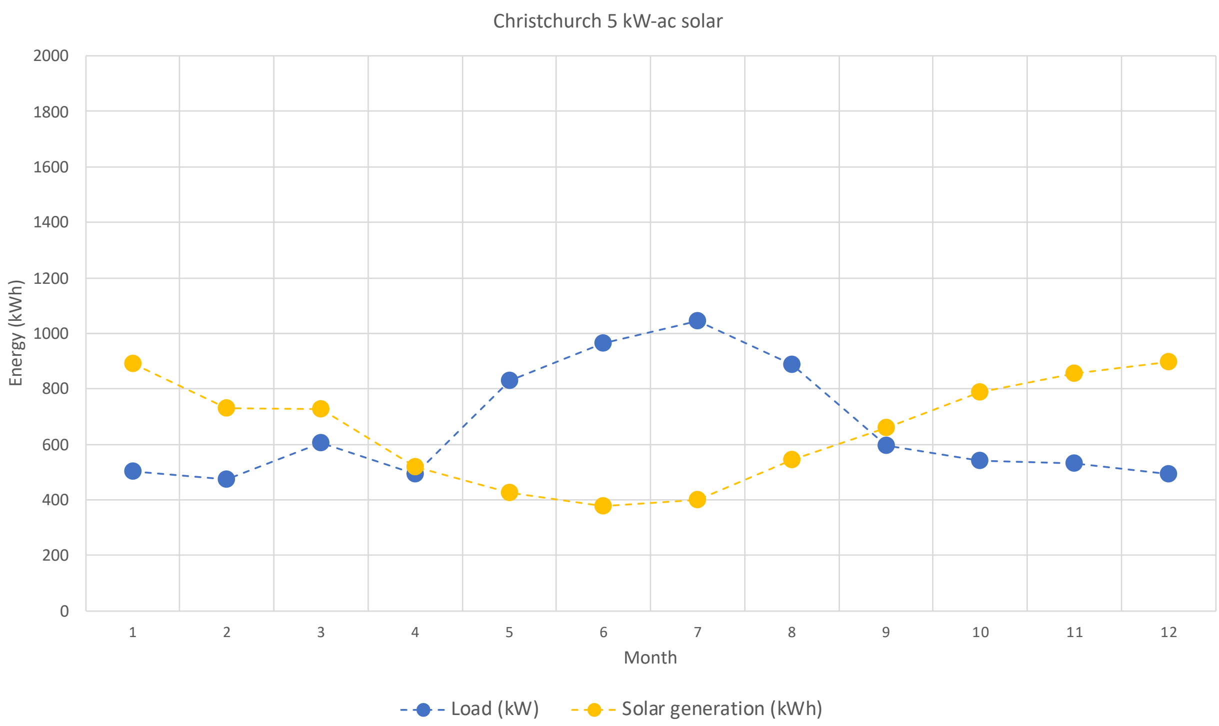
7. Resilience and backup power using solar PV and battery energy storage

The previous section demonstrated how solar PV with energy storage can reduce peak demand during peak periods, provided there are suitable time-of-use retail prices and buyback prices. This can apply within a day, as a realistic time over which a battery can store energy and provide an economic proposition by being cycled daily. It highlights one of the key economic benefits of solar PV with energy storage to New Zealand – as a replacement for peaking generation, and limiting the size of the transmission and distribution networks. This will only work if retail and buyback prices are time-of-use and reflect peaks effectively, and provided solar PV and battery system remain connected to networks.

7.1 Solar PV and self-sufficiency

The concept of 'leaving the grid' and becoming self-sufficient with solar and batteries is sometimes raised. Figure 39 gives an example of how solar generation and residential demand typically vary by month over a year. As shown, they are typically inversely correlated; household energy demand is usually lowest in the summer when solar generation is highest, and household energy demand is usually highest in the winter when solar generation is lowest.

Figure 39 – Energy demand and solar generation by month in Christchurch (Cluster 0 8,000 kWh pa ICP).



As a thought experiment, the capacity of solar required to cover the highest demand and lowest solar generation month, week, and day are considered, assuming that the solar energy can be stored over these time periods, and without considering energy losses by cycling energy through the inverter and battery. The results for each city, using a sample load profile, are shown in Table 18. This illustrates how a 5 kW-ac solar PV installation with a sufficiently large battery that can store energy between seasons can supply the annual energy needs of the example ICP in Auckland, Wellington, and Christchurch, and only 4 kW-ac is required in Queenstown. This would require a very large battery capable of storing hundreds of kWh over a long period to store solar generation from the summer to supply the ICP in the winter. Reducing the period to just a month, and therefore reducing the battery capacity required, increases the solar PV capacity required to 24 kW-ac in Auckland, and 14, 13, and 12 kW-ac in Wellington, Christchurch and Queenstown respectively for the example ICP considered. Reducing the timescale, and therefore battery capacity required, even further to a week roughly doubles the solar PV capacity required, but would still require a large battery. Reducing it to the highest demand day and lowest solar generation day in the year requires a very large solar PV capacity, and still requires a battery of many tens of kWh. This is why off-grid power systems almost always require a backup fossil fuel powered generation and some other form of heating, as it is very expensive to be self-sufficient with solar PV and battery alone, and/or requires substantial changes to energy use. Moreover, it illustrates why the connection to the electricity network is so important.

Table 18 – The capacity of solar PV required to meet the average energy needs of a sample ICP over different time periods, assuming the solar energy can be stored over this period (no losses are considered). Cluster 0 8,000 kWh pa ICPs.

Time period	Auckland	Wellington	Christchurch	Queenstown
Year	5	5	5	4
Month	24	14	13	12
Week	45	31	25	19
Day	178	123	167	177

7.2 The importance of a connection to the electricity network and the associated economic benefit

PV solar and network losses presents both a risk and opportunity to distribution network companies. With solar PV alone there is the risk of continuing growth in peak demand, since there is insufficient solar generation coincident with peak demand periods – illustrated in Figure 40. Therefore, solar PV alone does not offer a means of limiting peak demand. Figure 40 illustrates why the rate of return for solar decreases with more complex time-of-use price structures – that solar PV does not match most electricity consumption in New Zealand, which follows a pattern of higher consumption in winter particularly during peak periods.

However, as shown in the previous section, solar PV with sufficient battery storage, and suitable time-of-use retail and buyback prices, can meet peak demand, which is an opportunity to distribution network companies to limit the need for investment in their networks (as discussed earlier it is also an opportunity to limit the size of the transmission network and the need for peaking generation). Herein lies the key economic benefit to New Zealand. While it has been shown that residential rooftop solar PV alone has similar returns to utility-scale solar, residential rooftop solar PV at a sufficient scale can access more benefits because it is distributed in distribution networks. To fully utilise such benefits, static time-of-use pricing may be sufficient initially.

Figure 41 shows how the battery responds to static time-of-use prices for an example ICP. Christchurch is used in this example, to demonstrate the battery responding to the Orion 'Super off-peak' price between 3am and 5am. This also shows how the peak load reduction demonstrated in the previous section occurs in both the morning and evening peaks. However, with a large number of battery system responding in the same way as shown in Figure 41, it is possible that new demand peaks from synchronous response will occur. Therefore, over time as the time of peak demand changes, more dynamic pricing, or some other signal, is likely to be required. An example is the Aurora Energy Upper Clutha non-network support arrangement, where battery capacity is reserved a day ahead if demand is expected to exceed the sub-transmission line capacity. If capacity does near the limit of the sub-transmission line, the solar PV and battery systems are requested to discharge in tranches to limit the maximum demand on the sub-transmission line. This benefits all consumers by avoiding the need to upgrade the sub-transmission line.

7.3 Peak demand growth and battery response

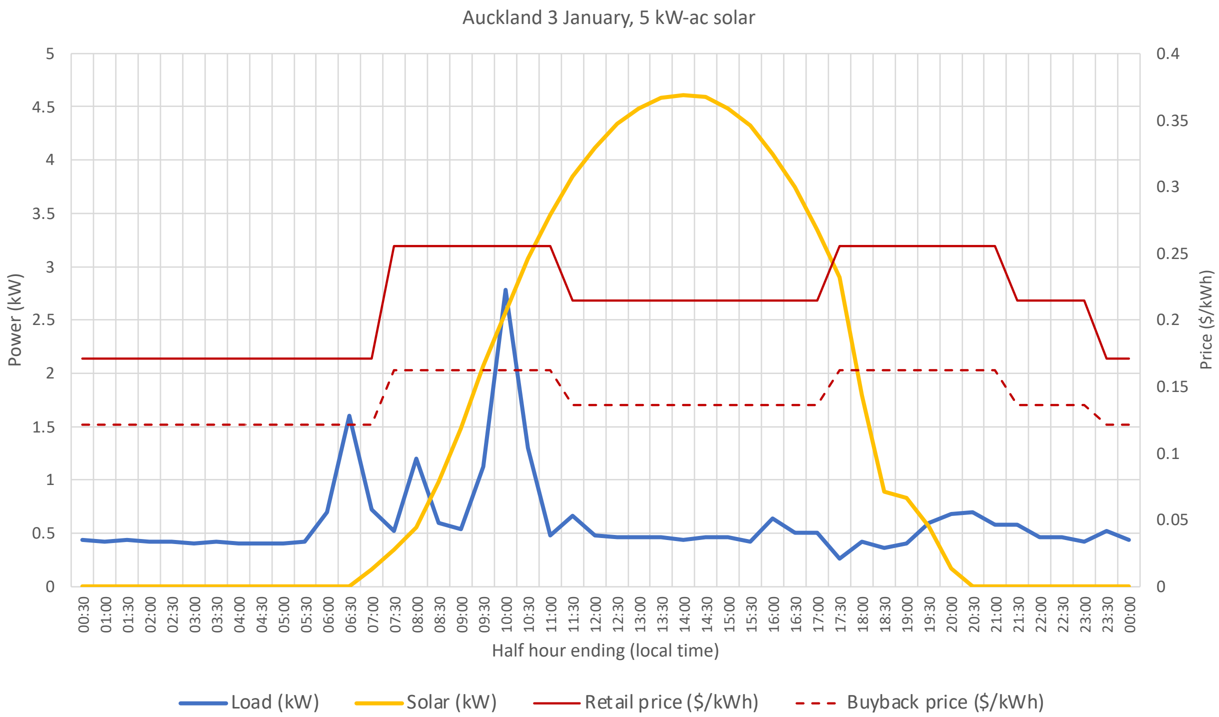
A further consideration is peak demand growth from solar PV and battery system response to prices. Simple price structures, such as the example in Figure 42, have the potential to cause significant synchronous demand when their low-price periods begin, and significant synchronous export when their low-price periods end. The example in Figure 42 deliberately shows a 10 kW-ac PV system, which has an inverter capable of charging the battery at 10 kW. Figure 43 shows the same day but with a capacity limit on both demand and export in place, as a possible means of limiting peak demand. However, the demand and export are still synchronous and with large-scale adoption have the potential to cause new demand peaks. This would be counter to the benefits of solar PV and batteries discussed earlier and potentially lead to distribution network constraints. It is therefore of the utmost concern.

As a result of this analysis, it is recommended that further investigation be undertaken into synchronous demand, and export, resulting from time-of-use price structures, with the goal of limiting new network peaks resulting from such behaviour.

7.4 Losses

A further consideration of solar PV is losses in distribution networks. Since each LV network is unique in structure and extent, as discussed in Miller (2024), losses from solar PV will vary by network and location of the ICP in the network. However, in general they are expected to follow a ‘U’ shaped curve where solar PV generation initially decreases losses, by offsetting ICP consumption, but eventually increase losses as excess energy is exported. As in the case of network peaks, if controlled appropriately, battery energy storage combined with solar PV is expected to reduce losses by reducing consumption at network peaks. Furthermore, as introduced earlier, the concept of turning storage hot water heating on midday when there is excess solar generation could also reduce losses by using energy within an LV network. Losses and loss reduction using solar PV, batteries, and hot water energy storage is something that requires further investigation.

Figure 40 – solar PV generation on a summer and winter day in Auckland. The retail price is a complex time-of-use structure (5.2) and the buyback price is also a complex time-of-use structure (E).



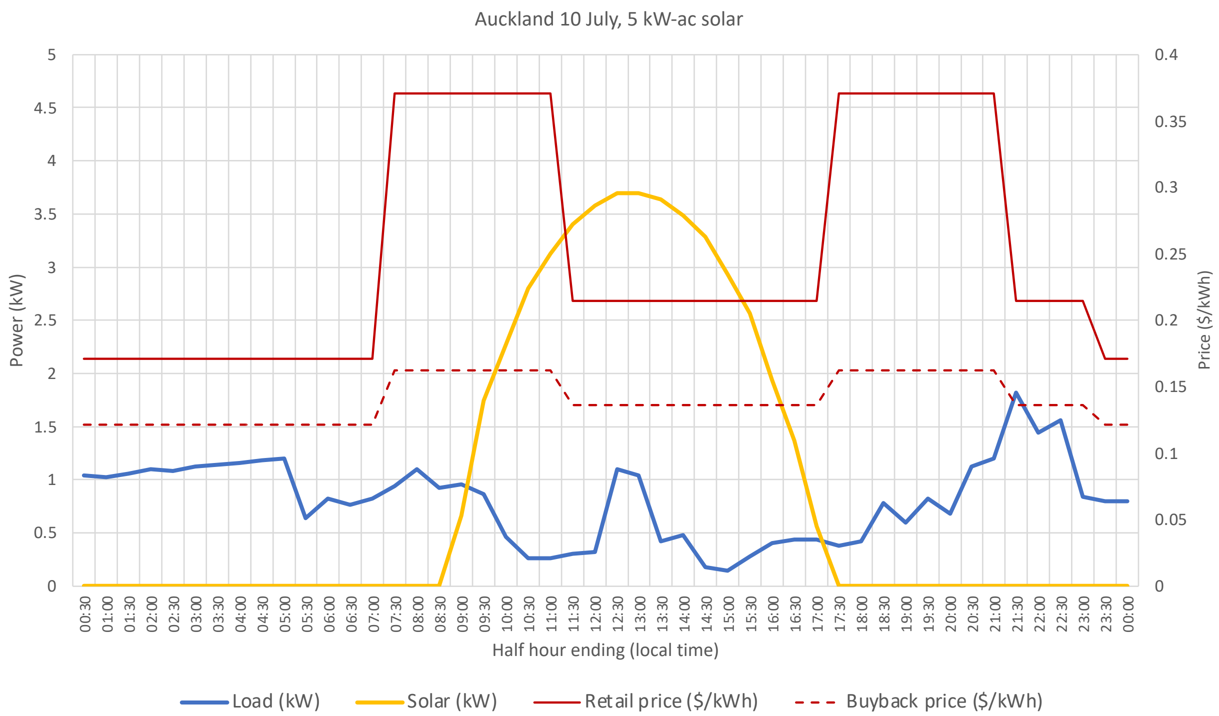


Figure 41 – Battery operation in Christchurch. The retail price is a complex time-of-use price which assumed the distribution price is passed through (5.2) and the buyback price is a complex time-of-use buyback (E).

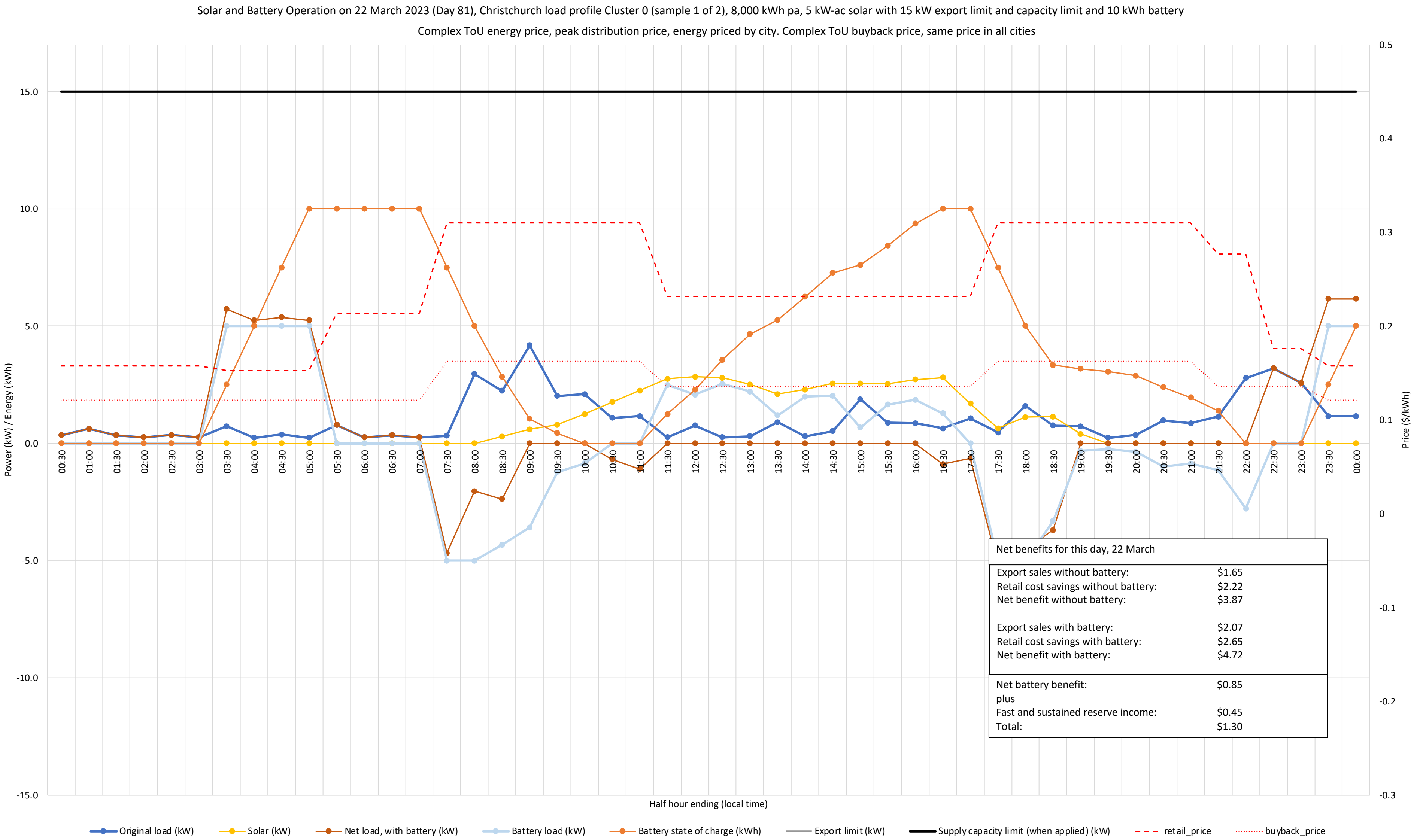


Figure 42 – 9pm-midnight free price structure with flat buyback price, showing the demand spike of 10 kW with a 10 kW inverter at 9pm-10pm.

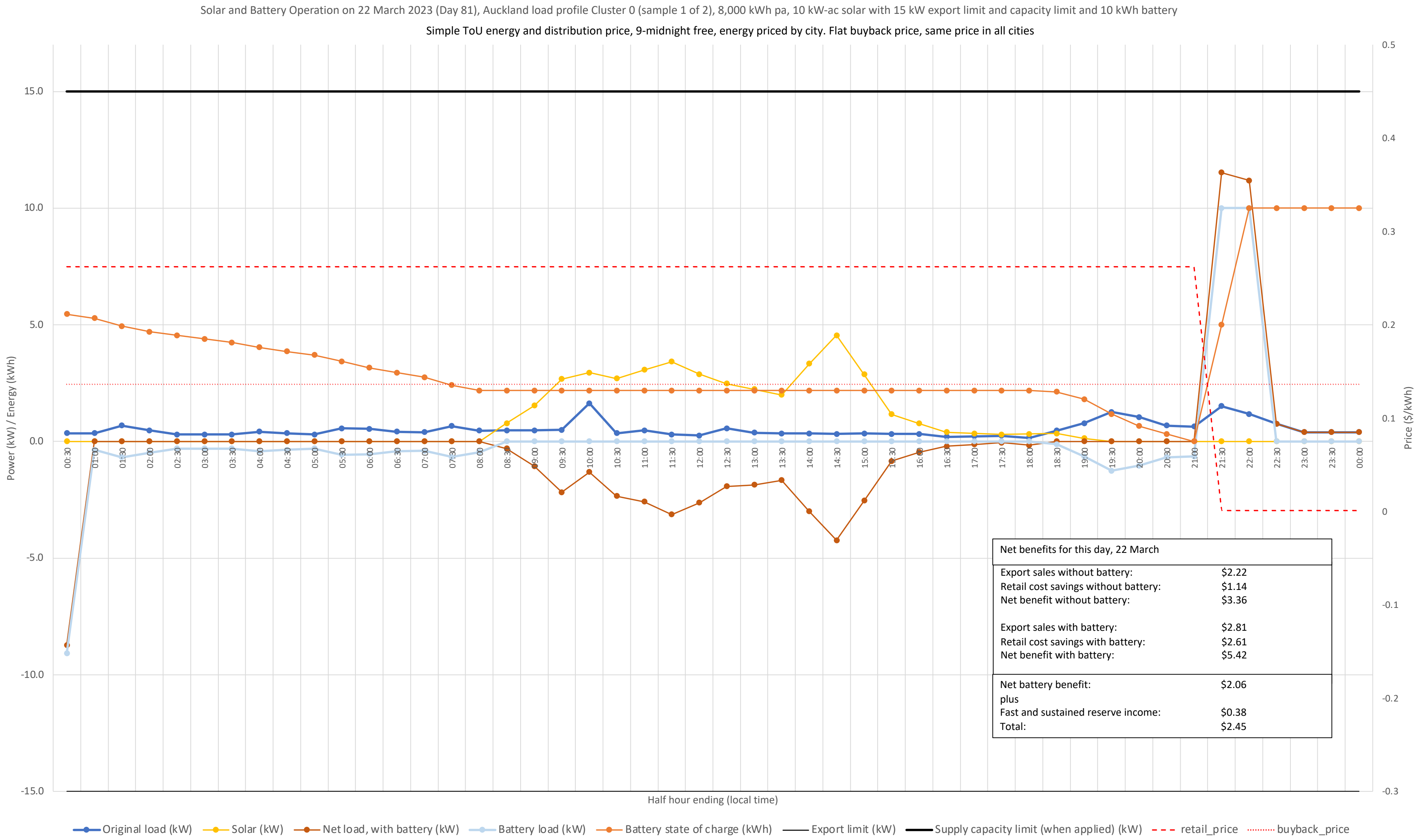
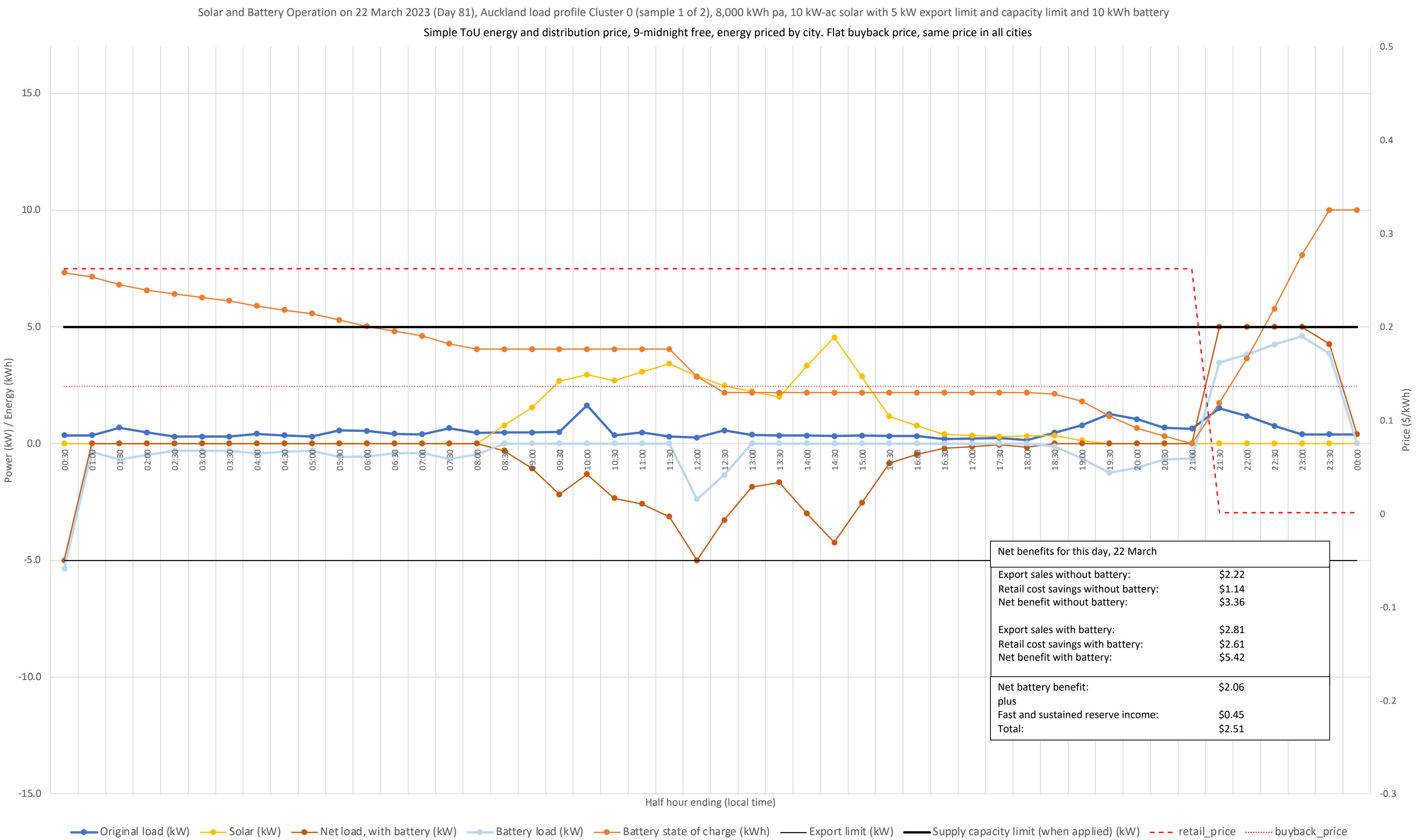


Figure 43 – 9pm-midnight free price structure with flat buyback price, with a capacity limiting tariff, which limits the demand spike to 5 kW at 9pm-10pm, but is still synchronous.



8. Conclusions and Recommendations

8.1 PV solar without storage

The following observations and conclusions are made:

1. There is a clear increase in rate of return from PV as annual electricity consumption of a household increases. This is due to higher self-consumption of solar energy, offsetting a retail price that is higher than the buyback price.

   This is directly relevant to electrification: as consumers use more electricity for transport and storage hot water heating, the returns available from solar PV, whether installed before the increases in electricity use or after, will improve.
2. Consumers with high daytime demand compared to average demand, especially high morning peak demand compared to average demand, tend to have higher returns. The reason is that they have higher self-consumption during morning peak periods, especially in winter. This applies under a simple day/night retail price structure and flat buyback price, as well as a more complex time-of-use retail price structure and flat buyback price.
3. Despite consumers with high morning peak ratio load profile having higher returns, it is shown that:

   a. It is not possible to rely on solar generation alone to reduce network consumption during the whole of a peak period, unless it is combined with a battery. The battery would store energy at off-peak times, and/or when there is excess solar generation, and release it during peaks.

   b. It is also still preferable to have north oriented solar PV. A half-east and half-west oriented system will not materially lift performance compared to a north facing array, or even a northwest facing array. In fact, the performance of a half-east and half-west oriented system will almost always be worse that a north oriented system.
4. Returns vary by city, with the median return for Wellington just above 7%, Christchurch and Auckland around 7.8%, and Queenstown around 9.5%. These differences are due to solar resource and price differences between the cities. However, as retailers trend towards more time-of-use pricing structures (peak/off-peak/night), price related differences between cities narrow.
5. Overall, returns from solar PV diminish as the market trends toward more complex time-of-use price structures (peak/off-peak/night).
6. The solar PV capacity that gives maximum returns is:

   a. 3 kW-ac when a 5 kW export limit is in place and with a simple day/night price structure, and 5 kW-ac when a 5 kW export limit is in place and with complex time-of-use prices.

   b. This shifts to the 10 kW-ac solar PV capacity when the export limit is lifted, with both a simple day/night price structure and a more complex peak/off-peak/night price structure and flat buyback prices.

Key conclusions and recommendations from the above:

7. **It is usually beneficial to install a larger system if exporting more is possible, such as might be achieved by raising the upper voltage limit to 230 Volts + 10% in line with MBIE's consultation in late 2024.**
8. **This may lead to a consumer behavioural shift toward installing larger PV systems, which would result in greater solar export and overall renewable energy generation. Alternatively, it would allow more consumers within a given low voltage network to adopt solar before the network becomes constrained.**

Conclusions regarding the sensitivity of solar PV to configuration and other inputs are:

9. The cost of a PV system has a major impact on return.
10. Real electricity price changes also have a major impact on returns.
11. Other factors such as orientation and tilt angle are difficult to control in existing homes but the DC:AC ratio (array to inverter capacity ratio) is easily controlled by selecting a system design that deliberately oversizes the array capacity, providing there is sufficient roof space.

Key conclusions and recommendations for consumers:

12. **Seeking multiple quotes for a system to ensure that the price is appropriately low but that the components are high quality is crucial to maximising returns.**
13. **Consumers should seek manufacturing warranties of over 20 years on the PV modules, and inverter warranties of over 15 years. Consumers should also ensure that the inverter used in the system is from a reputable supplier and that it includes internet connectivity, and an app that allows the consumer to view real-time and historical energy use and generation.**
14. **If roof space permits, install a PV array that has capacity (kWp-dc) in the range of 1.2 to 1.3 times that of the inverter's capacity (kW-ac). Ensure from the quoted system cost that the cost of the additional racking, wiring, and PV models is well below 1 $/Wp-dc.**
15. **Select an electricity retailer with an appropriate price structure and buyback rates to maximise returns. Understand what price structures are available before opting to install solar PV, as they are likely to change with solar.**
16. **Shifting load with a hot water diverter generally increases the returns from solar, especially for annual consumption of 12,000 kWh pa and above.**

Key conclusions and recommendations for the industry:

17. **Reducing the cost of solar PV to consumers is critical to making it a viable purchase for them, while also ensuring high quality equipment. The industry should focus on bringing more efficiency to solar PV installation to reduce costs further.**
18. **Reductions in overhead costs should also be sought from metering equipment providers, distributors, and inspections.**

19. **Removing default 5 kW export limits where possible by relaxing the upper voltage limit in the Electricity (Safety) Regulations 2010 will increase returns and lead to more renewable energy generation in New Zealand.**
20. **However, simply increasing export limits is not the only way to maximise returns. In fact, it may delay the uptake of battery storage, which may in turn delay the *potential* benefits brought about by battery systems relating to peak load reduction.**
21. **The industry should consider control of electric storage hot water to maximise local network use of excess solar.**

Conclusions regarding the comparison of residential rooftop solar returns in relation to utility-scale solar returns:

22. Utility-scale solar returns are similar to residential rooftop solar PV returns for certain load types, and more so in certain locations. Some load types and locations will have poorer performance than utility-scale solar.
23. There are intangible benefits to consumers having their own solar generation, such as energy education, and directly taking part in contributing to New Zealand's renewable future, electrification, and greenhouse gas emission reduction.

8.2 PV solar with storage

Conclusions regarding solar PV with batteries:

24. At the battery prices used in the model, a 5 kWh battery almost always increases the returns from solar PV versus having no battery at all. However, this assumes a battery price of 500 $/kWh – roughly half the current retail price of batteries, representing expected near-term trends. With a 10 kWh battery the increase in returns disappears in many cases.
25. Careful choice of battery capacity is important. A larger capacity battery is not always the best choice, especially with larger solar installations and low household consumption, as the solar generation and export may negate opportunities for a battery to supply household load, leading to under-utilisation of the battery. There is a complex interaction between solar PV capacity, battery capacity, household demand and time-of-use prices. Consumers may be aided in making optimal choices by an independent tool, similar to EECA's Gen Less solar tool but expanded and with battery storage, aiding them in designing an optimal system.
26. The benefits provided by battery storage are based on the assumption that battery control works to arbitrage energy from the minimum charge price to maximum discharge price, with a very good forecast of day-ahead solar generation.
27. In almost all cases the performance of storage improves with higher annual consumption. This adds to the conclusions from the earlier section that as electrification continues, and more energy use transitions to renewable electricity, not only do solar PV returns improve, but so do returns from storage.
28. Solar PV financial returns with more complex time-of-use price structures can usually be improved with a battery. This further emphasises that cost reflective pricing reflecting generation and network scarcity during peak periods is crucial.

29. However, this pricing needs to reflect actual peak periods, rather than a blanket peak period over the entire year, as is currently typical. Otherwise, battery storage may be rewarded for responding when it doesn't provide material benefit.
30. Moreover, building on Conclusion 20, if export limits are lifted by electricity distributors and battery storage is more accessible (lower prices), energy and distribution pricing that is more strongly reflective of time-of-use becomes more important to avoid excessive simultaneous export, and other issues. This indicates more need to differentiate distribution and retail prices by season.

Conclusions 26 and 30 above are further supported by analysis presented in Section 6 concerning retail price structures and battery energy storage.

Key conclusions and recommendations for the electricity and solar industries:

31. **The PV installation industry needs to deliver lower battery prices to consumers. Currently, batteries are simply not an economic proposition for many, and many of the benefits they can bring, such as improving solar PV's economic returns, reducing distribution peak demand and demand during generation capacity shortages will not be realised. It is recommended that the PV installation industry, through industry bodies, collaborate on procurement to seek more bargaining power to acquiring batteries at lower prices, while maintaining quality, and that the lower prices are passed on to consumers.**
32. **Battery control systems capable of taking advantage of increasingly complex time-of-use pricing need to be introduced instead of relying on programming simple on/off behaviour coinciding with low cost periods within price structures which may not be viable long term.**
33. **Available solar calculators, such as EECA's Gen Less solar tool, should be extended to include a battery model to inform consumers on how a battery might benefit them, and ideally assist them in making informed choices on solar PV capacity, battery capacity, and retail price plans. Ideally, such a calculator would use a consumer's historical load profile, and be combined with electrification models that model changes to the load profile and annual consumption. This will require that systems to control and maximise battery returns are available and understood.**
34. **Electricity distributers and retailers need to consider more differentiation of peak pricing by time-of-year as well as time-of-day.**
35. **The ability for consumers to add storage to their existing or new solar PV installations through V2G offers significant benefits, potentially more compared to stationary batteries depending on the availability of the EV. The industry should source more cost effective reliable V2G charger solutions that are compliant with EV manufacturers so that consumers do no void EV warranties by using them, and to ensure that V2G is a financially viable investment.**

8.3 PV solar with storage and peak pricing

Key conclusions from the analysis of solar PV with battery storage under different pricing structures, and with additional buyback prices during peak times, are:

36. The additional buyback price during peak times makes PV and battery systems more economic. It most likely improves the economics of PV and battery systems beyond what other time-of-use price structures can offer.
37. However, time-of-use buyback prices are equally important in improving the performance of PV and battery systems.
38. Further, if additional payments are to be made to support buyback prices, electricity distributors will need to pay close attention to the definition of peak periods to avoid overpayments.

Overarching key conclusions relating to solar PV, battery storage, and time-of-use pricing are:

39. **Not only does time-of-use pricing for retail electricity and buyback improve the economics of solar PV and storage, but it also strengthens behaviour of solar PV and battery systems such that they will reduce peak demand. This includes effective peak demand reduction over winter months.**
40. **Through reducing peak demand, it will potentially reduce the overall cost of electricity by reducing peak capacity requirements, and potentially by reducing the need for network investment. This is especially the case if buyback rates include a peak price component.**

This brings into focus additional conclusions:

41. **The peak periods need to be defined carefully.**
42. **Battery control systems that respond to peak prices are required.**
43. **Ongoing installed cost reductions of batteries in particular, but also solar PV are required.**

9. References

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